BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-01:
Expert Report of Current Energy Group



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Resource Adequacy in the Pacific Northwest

An Assessment of Resource Adequacy Studies Following the Planned Retirement of Centralia

Prepared for Earthjustice, Sierra Club, and Environmental Defense Fund

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Executive Summary

On December 16, 2025, the U.S. Department of Energy (DOE) issued Order 202-25-11 under its authority under section 202(c) of the Federal Power Act to prevent the planned retirement of Unit 2 of the Centralia Power Plant on grounds of "a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes" in the Western Electricity Coordinating Council (WECC) Northwest region.[1] In support of this determination, DOE relied heavily on findings from the North American Electric Reliability Corporation (NERC) and Energy + Environmental Economics (E3).

As of 2025, WECC-Northwest includes Washington, Oregon, Montana, and parts of northern California and northern Idaho. The following map shows the WECC subregions.[2]

Figure 1: Map of the WECC subregions



[1] U.S. Department of Energy (DOE). "Order No. 202-25-11," December 16, 2025. https://www.energy.gov/documents/order-number-202-25-11.

[2] "2025–2026 Winter Reliability Assessment Western Overview," WECC, Subregion Reliability Highlights, November 2025, https://feature.wecc.org/seasonal-assessment-western-overview/index.html.

In this report, Current Energy Group (CEG), evaluates the resource adequacy and reliability findings contained in the studies relied upon by DOE, as well as several other prominent regional resource adequacy studies, and places them in broader regional planning context. CEG did not conduct a new or independent resource adequacy model. Rather, this assessment reviews, synthesizes, and interprets the results of existing national, regional, and utility-level studies to examine:

- The extent to which RA best practices have been followed,
- The geographic scope covered by the analyses,
- How load growth has been incorporated into RA analyses,
- If/how analyses planned for Centralia's retirement (and repowering)

Based on this review, CEG assesses whether the findings support the conclusion that WECC-Northwest faces an imminent or emergency-level resource adequacy crisis. As discussed below, no study supports the conclusion that WECC-Northwest faces a resource adequacy crisis, including the studies on which DOE relied. Any risk identified in the studies is more appropriately characterized as a medium-term planning challenge of the type regularly addressed by state, regional, and utility planning processes.

Near-Term Findings (2026)

All of the planning studies—those upon which DOE relied and the ones DOE does not discuss—assume Centralia Unit 2's retirement on December 31, 2025. Across the studies most directly relied upon by DOE, particularly NERC's 2025/2026 Winter Reliability Assessment and E3's Phase 1 results, the record does not support a finding of a resource adequacy crisis in 2026 or early 2027. The same goes for the other prominent planning studies.

NERC concludes that the region has sufficient capacity to meet expected peak demand this winter. NERC also does not identify violations of key probabilistic reliability metrics under normal assumptions. NERC identifies only one type of extreme scenario presenting risk, which is characterized as "[a]bove-normal peak demand combined with high generator outages in extreme conditions."[3] But the risk presented is only whether the region will maintain its reserve margin (*i.e.*, its buffer of additional resources above that necessary to meet demand), and NERC expressly concludes that the risk is addressed through imports.[4] In fact, NERC emphasizes that "[o]perating reserve margins are expected to be met after imports in all winter scenarios."[5] NERC's classification falls short of the "high risk" designation reserved for conditions in which operating reserve requirements cannot be met under expected conditions.

E3 also recently examined resource adequacy in Washington, Oregon, Montana, Idaho, Utah, and Wyoming, a somewhat different region than WECC-Northwest. In the area it examined, E3

[3] "2025–2026 Winter Reliability Assessment," page 37, NERC, November 2025, https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.
[4] "2025–2026 Winter Reliability Assessment," page 37, NERC.
[5] "2025–2026 Winter Reliability Assessment," page 37, NERC.

estimates that in 2026 resources will be slightly (approximately 380 MW) below 50,737 MW, the amount E3 estimates is needed to secure a full margin above peak demand and meet obligations under an international treaty. E3 does not identify this shortfall as an emergency, nor do we consider it an emergency. E3's modeled loss-of-load expectation is approximately 0.15, which represents a small deviation from commonly used planning thresholds (0.1 loss-of-load expectation) and does not indicate a material increase in the risk of load loss in 2026. E3's analysis, moreover, relies on conservative estimates of the region's import capabilities that are lower than levels observed during recent extreme events and assumptions for hydropower that do not reflect current hydrological conditions. When accounting for in-development resources, observed regional import performance during recent extreme events, and current hydrological conditions, the identified shortfall—which is less than 1 percent—would likely evaporate.

Other regional and utility-level planning studies, including those from the Western Electricity Coordinating Council, Bonneville Power Administration (BPA), and Puget Sound Energy (PSE), do not identify a shortfall. These entities thus further reinforce the conclusion that WECC-Northwest does not face a near-term reliability crisis.

Table 1: Summary of Short-Term Resource Adequacy Findings

Organization	Study	Sufficient Resources to Meet Peak Demand with Full Reserve Margin in 2026?	Assumed Centralia Coal Retirement?	Considered Multiple Reliability Metrics?
NERC	2025/2026 Winter Reliability Assessment	Yes	Yes	Yes
Western Electricity Coordinating Council	2024 Western Assessment of Resource Adequacy	Yes	Yes	Yes
Puget Sound Energy	2023 Update to Puget IRP	Yes	Yes	Yes
Bonneville Power Administration	BPA Resource Program (2024) and White Book (2025)	Yes	Yes	Yes
E3	Phase 1 Results	No*	Yes	Yes

*As discussed below, E3's study relied on several conservative assumptions that understate the contributions of existing and expected resources, including assumptions related to import capacity, planned resource additions, and Canadian hydropower entitlements.

Medium-Term Findings (2027–2031)

The studies reviewed by CEG consistently identify growing resource adequacy gaps in the latter part of the decade, driven primarily by potential rapid load growth, particularly from potential data center development, rather than by coal or other resource retirements. E3 projects a substantial resource gap by 2030 under its modeled assumptions, and this finding should be taken seriously as an indication that additional resources, transmission, and demand-side measures will be required. Notably, E3 explains that the entire resource gap is addressed by completion of projects that utilities have identified in their Integrated Resource Plans.

The reviewed studies—including from E3, NERC, Western Electricity Coordinating Council, the Northwest Power and Conservation Council, BPA, and Puget Sound Energy—do *not* characterize these medium-term challenges as an immediate reliability crisis. Instead, they present the emerging gap as a planning signal intended to inform timely action through established state and regional resource planning, procurement, and coordination processes. The studies emphasize the importance of accelerating resource development, refining load forecasts and reliability assumptions, expanding transmission capability, and strengthening regional coordination. The studies do not support a proposition that extraordinary federal interventions into established processes are necessary to address the challenges in the latter part of the decade. Rather, federal intervention sends mixed and counterproductive signals to the market that undermine existing planning and procurement practices.

Overall Conclusions

Taken together, the body of regional and national planning evidence does not support the conclusion that the Pacific Northwest faces an imminent or emergency-level resource adequacy crisis. The retirement of Centralia Unit 2 is a long-planned transition that is fully reflected in regional planning analyses and is not identified as a driver of either near-term or medium-term reliability risk.

The emergence of larger modeled shortfalls toward 2030 is an important finding, but one that reflects the normal function of resource adequacy planning: to identify risks early enough for state, regional, and utility processes to respond through deliberate, coordinated action, as they have done for decades.

What is Resource Adequacy?

Introduction

Electric resource adequacy and energy system reliability are among the most important, discussed, and analyzed energy challenges among utility practitioners, regulators, and policymakers. Both resource adequacy and reliability practices and requirements have evolved over time with the growth of the electricity system, advancements in economic and regulatory theory, and in response

to prominent grid failures like the Northeast blackouts of 1965 and 2003.[6] This has led to a layered planning and regulatory framework for the bulk power system involving national entities (the North American Electric Reliability Corporation and the Federal Energy Regulatory Commission), regional reliability organizations, and state regulators, each of which conducts ongoing assessments and planning studies. These layers intentionally overlap, with assessments from different organizations analyzing different geographies or using different methodologies and time horizons. Collectively, these resource adequacy and reliability planning efforts create a robust record with which to evaluate DOE's claims of a reliability and resource adequacy crisis.

Resource Adequacy describes the situation where an electric system has enough capacity available to meet customer demand, plus a reserve margin on top, in most hours under most conditions based on a chosen standard.[7,8] The National Laboratory of the Rockies (formerly National Renewable Energy Laboratory) defines a power system as being resource adequate "if it has procured sufficient resources (including supply, transmission, and responsive demand) such that it runs a sufficiently low risk of invoking emergency measures (such as involuntary load shedding) due to resource unavailability or deliverability constraint."[9] The level of risk deemed sufficient is typically defined by a resource adequacy standard (*e.g.*, the "1-in-10" standard discussed below) set by planners based on engineering judgement and acceptable cost. Because no system can ever be perfectly reliable, planners must determine how to appropriately balance incremental cost and risk reduction. Put simply, resource adequacy measures how much generation and other resources are available to meet load.

Resource adequacy and power system reliability are closely related but distinct concepts. Reliability refers to the ability of the electric system to deliver electricity to customers in real time, encompassing generation, transmission, and distribution. Even where the bulk power system is resource adequate and reliable, customers may still experience outages, primarily due to distribution-level issues, such as a downed residential line caused by a fallen tree.

How Resource Adequacy is Assessed

Resource adequacy planning is a well-established practice across the country where multiple entities independently produce resource adequacy assessments for each region, generally according to a centralized standard. These assessments often will complement or overlap but may use different methodological approaches or metrics. As there is no "national standard" for resource

[6] "Reliability Explainer," Federal Energy Regulatory Commission, accessed December 21, 2025, https://www.ferc.gov/reliability-explainer; "Resource Adequacy: History and Catalog of Metrics," Electric Power Research Institute, December 31, 2018, https://www.epri.com/research/products/000000003002013734.
[7] "Reliability Explainer," Federal Energy Regulatory Commission, accessed December 16, 2025, https://www.ferc.gov/reliability-explainer.
[8] "Resource Adequacy Basics," National Renewable Energy Laboratory, archived October 20, 2025, accessed December 16, 2025. https://web.archive.org/web/20251020042833/https://www.nrel.gov/research/resource-adequacy.
[9] "Probabilistic Resource Adequacy Suite (PRAS) v0.6 Model Documentation," National Renewable Energy Laboratory (now National Laboratory of the Rockies), May 2021, https://docs.nrel.gov/docs/fy21osti/79698.pdf.

adequacy, each state and grid operator (often the local utility) establishes its own approach. The collection of multiple, overlapping but independently produced studies help operators, policymakers, and the many vested stakeholders make decisions to ensure the adequacy of the bulk electric system.

The context of each study is important. Because each study is a product of its underlying methodology, assumptions, and goals, any reliance on a given study must be based on consideration of the study's particular context. A study's findings cannot be relied upon without due consideration of the context, including the underlying methodology, assumptions, and goals.

An essential component of each study is the metric or metrics used to measure resource adequacy. There are several metrics used across North America to capture different dimensions of resource adequacy. These metrics can be broadly categorized as deterministic or probabilistic.[10] Deterministic metrics were historically more common because they are relatively simple to calculate and rely on fixed assumptions about load, resource availability, and reserve margins. In recent years, however, many planning entities have increasingly relied on probabilistic metrics, which evaluate the distribution of possible outcomes across a wide range of system conditions. Probabilistic metrics are better suited to capturing uncertainty and risk and are generally viewed as more informative than deterministic metrics for assessing resource adequacy.

- **Loss of Load Expectation (LOLE).** This metric measures the expected number of loss-of-load event-days over the study's planning period. An event-day is usually defined as any single day in which electricity demand is not met at least once because system resources were not sufficient to meet demand, whether the event lasts 5 minutes or 5 hours. A single event that spans two days is counted as two event-days. In general, $LOLE = \frac{Number\ of\ Event-Days}{Total\ Time\ Period}$. The most common LOLE standard is "1-in-10," which refers to an expectation that there is no more than 1 event-day (resulting from insufficient resources) in a 10-year period. The 1-in-10 standard equates to a LOLE of 0.1, calculated as $0.1 = \frac{1\ event-day}{10\ years}$. LOLE is usually evaluated on a yearly timescale, but it can also be expressed at an hourly or daily timescale.
- **Loss of Load Hours (LOLH).** This metric is an expression of LOLE where an "event" is specified to be at the hourly level (*e.g.*, 15 hours in 10 years), allowing for higher resolution of the duration of potential shortfalls.
- **Loss of Load Probability (LOLP).** This metric is like LOLE, except that it measures the expected percentage of events over the planning period in which there was a loss of load. LOLP is equivalent to LOLE divided by the period chosen. For example, a 1-in-10 LOLE standard would lead to a LOLP of 0.0274% per day, calculated as:

$$LOLP = \left(\frac{1\ event-day}{10\ years}\right) * \left(\frac{1\ year}{365\ days}\right) * 100 = 0.0274\%$$

[10] "Metrics Explainers," Electric Power Research Institute, accessed 12/16/2025, https://msites.epri.com/resource-adequacy/metrics/metrics-explainers.

- **Expected Unserved Energy (EUE).** This metric measures the total expected amount of unserved energy, in MWh, over the planning period. Unlike LOLE and LOLP, which measure the frequency or likelihood of a loss-of-load event, EUE measures the magnitude of energy demand not served. While modeling tools would quantify actual EUE in given scenarios, a simple conceptual relationship is as follows: EUE is equal to the LOLE multiplied by the average magnitude of the shortfall. For example, if a model found that the average shortfall during an event was 200MW across a 1-in-10 LOLE standard, and further assuming that the event lasts a full 24 hours, the EUE per year would be 480MWh.
- **Planning Reserve Margin (PRM).** This metric measures the difference between the total resources and the expected peak load, divided by the peak load. It is expressed as a percentage.[11] For example, if a system has 107,000 MW of resources and an expected peak load of 100,000 MW, the system has a 7% reserve margin, calculated as:

$$PRM = \left(\frac{107{,}000 - 100{,}000}{100{,}000}\right) = 7\%$$

  The PRM assessment may, and typically does, "de-rate" resources based on the likelihood that a generator will be unavailable or produce less than its maximum potential output (i.e., less than its "nameplate capacity") during a peak demand period. The resulting figure is known as a generator's "accredited" capacity. For example, although the system's total nameplate capacity could be 225,000 MW, resource accreditation may result in only 107,000 MW being counted for PRM purposes. Accreditation is further discussed below.

Each metric measures a different aspect of system risk, and most regions rely on multiple metrics. PRM provides a high-level indicator of resource capacity relative to expected peak load, but it does not capture hourly or seasonal variability in resource availability. LOLE and LOLP quantify the probability and frequency of shortfall events, but do not identify the magnitude of a loss of load event. EUE is used to measure the total quantity of energy that cannot be served in a loss-of-load event. By using multiple metrics, planners can capture both the likelihood and the magnitude of potential shortages, which a single metric cannot do on its own.

The Northwest Power and Conservation Council, an interstate compact agency created by Congress to conduct long-term regional planning for the region, uses several metrics that measure both the likelihood and the magnitude of events. The Western Resource Adequacy Program, a voluntary regional reliability and capacity-sharing program composed of electric utilities across the Pacific Northwest and the broader Western Interconnection, uses LOLE as its primary metric in its probabilistic analysis.[12]

[11] "Metrics Explainers," Electric Power Research Institute, accessed 12/16/2025, https://msites.epri.com/resource-adequacy/metrics/metrics-explainers.

[12] "Western Resource Adequacy Program Tariff of Northwest Power Pool D/B/A Western Power Pool," Western Power Pool, March 16, 2025, https://www.westernpowerpool.org/private-media/documents/WRAP_Tariff_Effective_3.16.25.pdf.

Because these metrics evaluate system risk, the studies need a method for representing how much each resource will likely contribute to meeting demand during period of system stress. In LOLE-, LOLH-, or EUE-based analyses, this is typically done through probabilistic assumptions about unit availability, forced outages, and load shapes rather than relying on nameplate capacity alone to reflect each resource's expected availability during peak or net-peak hours. In most of the country, these performance assumptions guide grid operators when they assign resources an accredited capacity value. The most commonly used probabilistic accreditation method is Effective Load Carrying Capability (ELCC), which measures the contribution a resource makes to reducing loss-of-load risk, typically by comparing system reliability outcomes with and without the resource relative to a benchmark "perfect capacity" resource. The purpose of applying an accredited value (via ELCC or another method) to each resource is to ensure that resources are counted based on their contribution to reducing loss-of-load risk, rather than their installed capacity.

Who Conducts Resource Adequacy Planning

Resource adequacy planning occurs at multiple institutional layers, each producing a unique assessment based on its purview, methodology, and assumptions. States in the Western Interconnection do not have a single coordinating entity that sets resource adequacy requirements. As a result, there are several independent organizations, many with overlapping jurisdictions, that conduct and publish resource adequacy analyses for the Pacific Northwest. Each of these assessments provides complementary but sometimes divergent perspectives on system conditions.

At the national level, the North American Reliability Corporation, or NERC, is the entity responsible for ensuring the reliability and security of the North American bulk power system, under delegated authority from the Federal Energy Regulatory Commission (FERC).[13] NERC performs a variety of functions. It develops and enforces mandatory reliability standards. It also monitors the bulk power system. And NERC assesses system reliability through a variety of forecasts: (1) an annual 10-year forecast, (2) an annual forecast of the upcoming summer, usually issued about a month or two before summer begins, and (3) an annual forecast of the upcoming winter, also typically issued about a month or two before winter begins. Other NERC functions include "audit[ing] owners, operators, and users [of the bulk power system] for preparedness, as well as educat[ing] and train[ing] industry personnel."[14]

State regulators play an essential role in resource adequacy and reliability planning. Public Utility Commissions, such as the Washington Utilities and Transportation Commission in Washington state, typically approve utility resource adequacy assessments, specific power plants, and capital expenditures through their review of requested Certificates of Public Convenience and Necessity (CPCNs), rate cases, and integrated resource plans. Electric utilities, both investor-owned and consumer-owned, develop integrated resource plans that identify how the utility will meet

[13] "Reliability Explainer," Federal Energy Regulatory Commission, accessed December 16, 2025, https://www.ferc.gov/reliability-explainerhttps://www.ferc.gov/reliability-explainer.
[14] "Who We Are," North American Electric Reliability Corporation, accessed December 23, 2025, https://www.nerc.com/who-we-are.

customer demand over the planning horizon, usually 20 years. Electric utilities typically develop integrated resource plans every 2 to 3 years and rely on a variety of methods for evaluating resource adequacy and accrediting resources. The utility-specific resource adequacy assessment and the resource accreditation values are important components for identifying the utility's future resource needs.

In addition to state and national entities, there are several entities in the Pacific Northwest region that provide regional resource adequacy assessments.

1. **Western Electricity Coordinating Council (WECC)** is one of the six regional entities with delegated authority from NERC to ensure reliability and resource adequacy. As the FERC-approved regional manager for reliability for the Western Interconnection, its geographic focus spans 14 Western states, 2 Canadian provinces, and Northern Baja Mexico. [15] Its functions include setting standards, identifying threats and shortfalls, and monitoring compliance. As part of this role, WECC conducts interconnection-wide resource adequacy assessments. WECC's assessments are advisory rather than binding, but they provide one of the most comprehensive views of adequacy risks across the Western grid and can be (and are) used as inputs to utility, state, and regional resource adequacy planning processes. WECC is divided into eight sub-regions as shown in Figure 1.[16]
2. **Northwest Power and Conservation Council (NWPCC)** is a regional planning body created by Congress in 1980 to ensure reliable, affordable, and environmentally responsible energy for Washington, Oregon, Idaho, and Montana (Northwest). The council develops a regional power plan that guides Bonneville Power Administration, regional utilities, and federal hydropower operations in the region. The council conducts an annual resource adequacy assessment through a collaborative approach with its Resource Adequacy Committee[17] made up of regional utilities and stakeholders.[18]
3. **The Western Power Pool's Western Resource Adequacy Program (WRAP)** is the first coordinated regional resource adequacy planning and compliance program in the Northwest. Although participation is voluntary, member utilities enter into a binding agreement to meet common resource adequacy standards and comply with the program's planning and operational requirements. The program received FERC approval of its tariff in February 2023, establishing enforceable capacity sufficiency demonstrations, resource accreditation methods, and operational sharing provisions.[19] The Western Resource Adequacy Program will start binding operations in Winter 2027/2028 for the 16

[15] "About WECC," Western Electricity Coordinating Council (WECC), accessed December 23, 2025. https://www.wecc.org/about/about-wecc.
[16] "2025–2026 Winter Reliability Assessment Western Overview," WECC, Subregion Reliability Highlights, November 2025, https://feature.wecc.org/seasonal-assessment-western-overview/index.html.
[17] "Resource Adequacy Advisory Committee," Northwest Power and Conservation Council, accessed December 16, 2025, https://www.nwcouncil.org/energy/energy-advisory-committees/resource-adequacy-advisory-committee/.
[18] "Resource Adequacy Advisory Committee – Steering Committee Members," Northwest Power and Conservation Council, June 2024, https://nwcouncil.app.box.com/s/m922hdzzk0mxsoke01l9xgcvpqj0412o.
[19] "History," Western Power Pool, accessed December 16, 2025, https://www.westernpowerpool.org/about/history/.

participants who agreed to participate by October 31, 2025.[20] These participants include a number of utilities and entities in the WECC-Northwest region: BPA, Puget Sound Energy, PUD No. 1 of Chelan County, Avista Corp., Clatskanie People's Utility District, Constellation, PUD #2 of Grant County, NorthWestern Energy, Seattle City Light, Tacoma Power, and The Energy Authority, Inc. Before binding operations begin, the Western Resource Adequacy Program will release informational assessments on regional resource development, ELCCs, and calculated PRMs.[21] The Western Resource Adequacy Program will provide a consistent, region-wide framework for assessing and addressing resource adequacy needs and represents a significant step forward in strengthening reliability across the West.[22]

4. **Bonneville Power Administration (BPA)** is a federally managed, semi-independent power marketing agency and one of the largest regional electric planning entities in the Pacific Northwest. BPA markets power from 31 federal hydroelectric dams and one nuclear plant, owns and operates roughly 75 percent of the region's high-voltage transmission system, and provides power and transmission services to approximately 148 customers, including public utility districts, cooperatives, and investor-owned utilities.[23] BPA's hydrological data, operational planning studies, and transmission reliability evaluations are foundational inputs to regional RA modeling conducted by other organizations. BPA also produces its own long-term planning documents which assess resource adequacy needs.

In addition to the regional resource adequacy organizations, there are at least two other entities that provide input and operational data that are frequently used for developing resource adequacy assessments. While we do not discuss these organizations in detail, they are important for understanding the depth and breadth of planning in the region.

1. **Pacific Northwest Utilities Conference Committee (PNUCC)** is a member organization of utilities in the West, primarily the Northwest, with the purpose of sharing information and jointly addressing issues to the membership (including resource adequacy). PNUCC annually publishes its members' energy and peak demand forecasts, which serve as inputs in resource adequacy and other analytical assessments.

2. **NorthernGrid** is the FERC-jurisdictional regional transmission planning organization for much of the Northwest, as well as the Intermountain West, responsible for developing long-term transmission plans under FERC Order 1000. Its studies evaluate future load, resource additions, and system contingencies to identify needed transmission upgrades, all of which influence regional transfer capability.

[20] "WPP Notice to WRAP Resource Adequacy Participants Committee," Western Power Pool, October 31, 2025, https://www.westernpowerpool.org/news/wpp-notice-to-wrap-resource-adequacy-participants.
[21] "Metrics," Western Power Pool, accessed December 16, 2025, https://www.westernpowerpool.org/resources/wrap_metrics/.
[22] "Tariff & Business Practice Manuals," Western Power Pool, accessed 12/16/2025, https://www.westernpowerpool.org/resources/wrap_bpms/.
[23] Corrina Ikakoula, *Bonneville Power Administration Overview*, U.S. Department of Energy, January 2016, accessed December 16, 2025, https://www.energy.gov/sites/prod/files/2016/01/f28/0911review_ikakoula.pdf.

Summary and Interpretation

Resource adequacy planning is conducted widely across the country, and the variety of methods, geographic scopes, and modeling approaches provides a robust set of perspectives on system conditions. Resource adequacy is inherently probabilistic. It is not an end state but an ongoing evaluation of risk, and all findings include uncertainty. A projected shortfall in a given modeling approach does not ensure an outage, or even necessarily predict one, particularly where the projection is a small shortfall below a target reserve margin. Although individual studies may differ in their specific findings or the magnitude of particular metrics, consistent patterns across assessments offer meaningful signals about regional adequacy. For example, if multiple studies indicate medium-term capacity shortfalls, that alignment points to elevated medium-term risk; similarly, broad agreement on sufficient near-term resources suggests low near-term risk.

Analysis of PNW Resource Adequacy Reports and Findings

Introduction to Analysis Section

In this report, we identify the key Northwest resource adequacy studies, analyze their findings, and compare their conclusions against DOE's stated rationale in the 202(c) order. We analyze studies conducted by the North American Electric Reliability Corporation, the Western Electricity Coordinating Council, the Northwest Power and Conservation Council, E3 (a consulting firm), Bonneville Power Administration, and Puget Sound Energy. These assessments use a range of deterministic and probabilistic methods that evaluate system conditions across a variety of scenarios, including extreme weather, low hydro conditions, and delayed resource development.

As noted above, we assess each study across two planning horizons: the near-term (less than 1 year) and the medium-term (1 year to 5 years) focusing on modeling outcomes, underlying assumptions, and treatment of major system changes including resource retirements. The near-term analysis evaluates resource adequacy and reliability conditions under operating conditions in which system operators generally rely on the existing resource portfolio and established emergency and operational tools, rather than new resource procurement or infrastructure development. By contrast, the medium-term analysis evaluates planning organizations' findings and identifies potential deficiencies in underlying assumptions, models, or processes.

While these analyses identify elevated risks in certain circumstances, none conclude, and none supports a conclusion, that the studied regions are at imminent risk of failing to meet demand in 2026 or in the years immediately following. Importantly, all studies incorporate planned coal retirements, including Centralia, into their modeling frameworks. The retirement of Centralia is therefore not an unaccounted-for development, but rather a long-planned transition that is fully embedded in the region's resource outlook.

Analysis of Short-Term (2026) Findings

Summary of near-term (2026) findings: Near-term resource adequacy conditions for 2026 do not indicate that the region is likely to experience a resource adequacy shortfall. NERC's Winter

Reliability Assessment and Western Electricity Coordinating Council's Western Assessment of Resource Adequacy provide high resolution short-term findings, and analyses from BPA and Puget Sound Energy provide complementary short-term insights. All studies note that extreme winter conditions or significant delays in new generation could create challenges, but none identify an imminent crisis, recommend extraordinary measures, or predict that resources will be insufficient to meet demand. While E3's assessment identifies a modeled resource adequacy shortfall in 2026, that finding is driven by a set of conservative assumptions related to the region's imports capabilities and treaty obligations. E3's assessment also does not reflect the region's current weather conditions, which points towards support to resource adequacy. Table 1 summarizes our findings.

2025/2026 NERC Winter Reliability Assessment Short-Term Findings

NERC's annual Winter Reliability Assessment is an analysis of immediate reliability and resource adequacy in the United States and Canada for the upcoming winter season. NERC's 2025/2026 assessment, released in November 2025, found all regions to be resource adequate under normal peak-load conditions.[24]

NERC concludes that, in WECC-Northwest, "there is sufficient capacity in the area for expected peak conditions,"[25] and its probabilistic analysis finds no Expected Unserved Energy or Loss of Load Hours for Winter 2025–26 when planned additions are included. NERC also finds that, based on planned resource additions, imports, and expected demand growth, that no resource adequacy metrics are violated for the region, stating, "The results of the probabilistic assessment reveal no [expected unserved energy] or [loss of load hours] for Winter 2025–2026." [26] NERC further explains that the results for a case where new resource additions are not completed for Winter 2025-26 found "some" expected unserved energy and loss of load hours, without specifying the magnitude.[27] The region's reserve margin is projected at 30.9%, nearly double typical requirements.[28] Only in the most extreme conditions (*i.e.*, higher than expected demand paired with higher than expected generation outages) does NERC assess that the region risks pre-import shortfalls—and even then, the shortfalls are only below reserve margins (not expected peak load), and the region can rely on imports to restore reserve margins "in all winter scenarios."[29]

NERC also finds that planned Tier 1 resources ("soar[ing]" from 463 MW to more than 3 GW) and increased firm imports (6.1 GW) more than offset the reduction from retiring units.[30] The region's imports are particularly valuable for maintaining resource adequacy in extreme conditions. For

[24] "2025–2026 Winter Reliability Assessment," page 5, NERC, November 2025, https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.
[25] "2025–2026 Winter Reliability Assessment," NERC, page 6.
[26] "2025–2026 Winter Reliability Assessment," NERC, page 15.
[27] "2025–2026 Winter Reliability Assessment," NERC, page 15.
[28] "2025–2026 Winter Reliability Assessment," NERC, page 11.
[29] "2025–2026 Winter Reliability Assessment," NERC, page 37.
[30] "2025–2026 Winter Reliability Assessment," NERC, page 37.

example, in the January 2024 Arctic storm in the region, FERC found that, in addition to better coordination and forecasting, effective use of regional import capacity helped prevent any load shedding event despite extreme winter conditions.[31] NERC explains that, during the January 2024 event, "[t]he U.S. Northwest relied heavily on imports—averaging 4,745 MW during peaks and 5,241 MW across all hours, mostly from the Southwest and Rockies."[32] The region's import capacity are also a cost effective means to better utilize excess generation in other regions during normal conditions, meaning they support normal grid operations in addition to avoiding load shedding in extreme conditions. Together, increased in-region generation and more imports explain why NERC does not issue an emergency recommendation to WECC-Northwest, instead emphasizing preparedness, monitoring, and winterization of thermal units, all of which are steps that helped avoid emergencies in extraordinary winter conditions.

NERC identifies WECC-Northwest as one of these regions facing "elevated" risk, the middle of three risk categorizations ("normal," "elevated," and "high"). NERC's elevated risk categorization provides an indicator against a crisis being present. NERC reserves its "high risk" category for situations in which the region is unable to meet operating reserve requirements in normal peak conditions. If NERC had concluded there was an imminent resource adequacy crisis, it would have assigned the highest classification. Instead, NERC selected the lower risk category. And in context with the discussion and analysis in the 2025-26 winter assessment, it is clear that NERC does not identify anything near crisis conditions in WECC-Northwest.

In summary, our analysis finds that NERC's elevated risk ranking is a finding warranting attention by state and regional authorities but falls well short of demonstrating an imminent crisis.

2024 Western Electricity Coordinating Council's Western Assessment of Resource Adequacy Short-Term Findings

The Western Electricity Coordinating Council annually produces a Western Assessment of Resource Adequacy report, which provides an hourly, 10-year, and forward looking analysis of the WECC sub-regions, one of which is WECC-Northwest.[33] The Western Assessment of Resource Adequacy uses an energy-based probabilistic approach that incorporates planned new resources, demand growth (and its drivers), retirements, imports and other factors across several scenarios to estimate peak demand and potential hourly shortfalls. Moreover, to further analyze the approach's sensitivities, the Western Assessment of Resource Adequacy also relies on aggregated data from the regional balancing authorities in which the completion of planned resources are delayed or not completed.[34] While largely overlapping with the WECC-Northwest region used by NERC in the

[31] "System Performance Review of the January 2024 Arctic Storms," page 18, 20, and 21, FERC, April 25, 2024, https://www.ferc.gov/sites/default/files/2024-04/24_System%20Performance%20Review%20of%20the%20January%202024%20Arctic%20Storms_0425.pdf.
[32] "2025–2026 Winter Reliability Assessment," NERC, page 52.
[33] "Western Assessment of Resource Adequacy 2024: Scenario Analysis," Western Electricity Coordinating Council (WECC), December 3, 2024, https://feature.wecc.org/wara/.
[34] "Western Assessment of Resource Adequacy 2024: Scenario Analysis," WECC.

Winter Reliability Assessment, the Western Assessment of Resource Adequacy divides the Western Interconnection into five sub-regions (shown in Figure 2 below) for its 2024 Assessment (which is the most recent assessment).[35]

Figure 2: WECC subregions used for 2024 Western Assessment of Resource Adequacy



The 2024 Western Assessment of Resource Adequacy did not indicate any near-term resource adequacy shortfall for the Western Interconnection or the "NW Northwest" subregion, specifically. In all but the most extreme scenario (in which only 55% of planned resources are deployed), the study finds no demand at risk hours in 2026 and a minor number (~7) in 2027 for the NW Northwest subregion. In the moderate scenario (in which 85% of planned resources come online), the Western Electricity Coordinating Council concludes that there is "minimal impact [to NW Northwest] in the short-term."[36] Importantly, the extreme 55% build scenario is less likely to materialize in the near-term than over longer forecast horizons, as project development assumptions are generally more certain and less speculative closer to the present. Recent EIA data

[35] WECC updated its planning regions in 2025. See https://feature.wecc.org/seasonal-assessment-western-overview/index.html.
[36] "Western Assessment of Resource Adequacy 2024: Scenario Analysis," WECC.

for 2025 supports this conclusion. Based on Energy Information Administration 860M reports, Washington, Oregon, Idaho, and Montana added more than 1.6GW in 2025, slightly beating the 1.53GW of additions planned for 2025 and the ~1GW of additions in 2024.[37,38] 1.68GW is planned to be added in 2026 as of the October 2025 report. [39]

Figure 3: WARA Comparison of Resource Build Out Scenarios and Demand at-Risk Hours

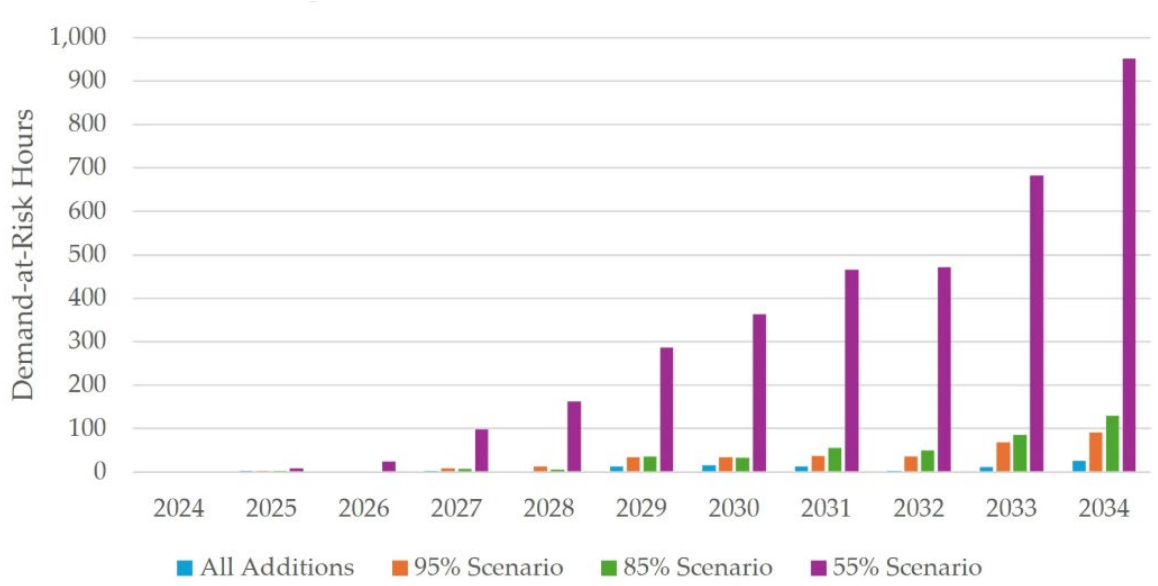


Figure 3 illustrates that the 2024 Western Assessment of Resource Adequacy results show modest delays in planned resource additions have limited impact on near-term reliability, while the extreme delays, such as the 55% build scenario, result in rapidly escalating demand-at-risk hours beginning in the late 2020s.[40] As previously discussed, a finding of demand at risk hours is not necessarily unusual nor a finding of an emergency. Planners take into account both the magnitude of the finding and the trend when making planning decisions, using both to identify the amount and type of measures needed. While any potential shortfall warrants attention, both the magnitude of any identified shortfalls and the rate of increase in 2026 and 2027 do not indicate a resource adequacy shortfall. For example, as shown in Figure 3 above, the 2024 Western Assessment of Resource Adequacy identifies demand-at-risk hours in 2025 under certain scenarios. However, actual system operations during 2025 did not result in supply shortfalls. Modest quantities of modeled demand-

[37] "Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)," December 2024 and October 2025 data, U.S. EIA, accessed December 16, 2025, https://www.eia.gov/electricity/data/eia860m/.
[38] "Electric Power Annual: Table 4.7.A," U.S. EIA, accessed December 16, 2025, https://www.eia.gov/electricity/annual/table.php?t=epa_04_07_a.html.
[39] "Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)," October 2025 data, U.S. EIA, accessed December 16, 2025, https://www.eia.gov/electricity/data/eia860m/.
[40] "Western Assessment of Resource Adequacy 2024: Scenario Analysis," WECC.

at-risk hours are not unusual and should be interpreted as early planning signals rather than evidence of an imminent resource adequacy shortfall.

E3 Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results, Short-Term Findings

E3 Study Overview

In September 2025, Energy + Environmental Economics (E3) presented the Phase 1 results of its "Resource Adequacy and the Energy Transition in the Pacific Northwest" analysis to the Washington Utilities and Transportation Commission and Washington State Department of Commerce Energy Division.[41] The E3 presentation is a high-level briefing of a resource adequacy assessment that E3 conducted on behalf of more than a dozen investor- and consumer-owned utilities. The E3 analysis is an examination of the "Greater Northwest" region, which appears to include most of the NERC Northwest subregion as well as parts of the WECC-Basin subregion.[42] The presentation was not accompanied by a report or other documentation of the study's inputs, assumptions, and methodologies.

In the presentation, E3 states that it found a resource gap (characterized as a "reliability position") across the Greater Northwest beginning in 2026 and growing each year through 2030. [43] Specifically, E3 states that it forecasts a resource gap of 1,321 MW in 2026. To reach this conclusion, E3 compares available resources against expected peak demand, inclusive of a planning reserve margin and estimated export obligations to Canada. However, the resulting finding of a resource gap is driven, in part, by a set of conservative underlying assumptions. First, E3 explains that its analysis does not include the contributions of 296 MW of "in-development" firm resources, nor the 645 MW of firm capacity equivalent "in-development" wind, solar, and battery projects.[44] When the projects currently being built are finalized, as is expected, the resource shortfall for 2026 declines to 380 MW (approximately 0.75% of total expected need for 2026). Second, E3 assumes that the Greater Northwest region is exporting power to Canada in all hours, even during peak conditions, to meet treaty obligations that are not mandatory. Third, E3 assumes an import level

[41] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," page 2, E3, Sept. 22, 2025, https://www.utc.wa.gov/sites/default/files/2025-10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20WA%20RA%20Meeting.pdf. The two state agencies held the resource adequacy meeting as required by state legislation. Revised Code of Washington 19.280.065, https://app.leg.wa.gov/rcw/default.aspx?cite=19.280.065.

[42] According to NERC's 2025-2026 Winter Reliability Assessment, the 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.

[43] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," E3, pages 7, 8, and 10.

[44] While wind and solar are not "dispatchable" resources in the traditional sense, they do provide a reliability contribution to grid that is well understood by utility system planners. This understanding has evolved over decades of improvements in statistical weather modeling, forecasting, and actual performance observations. All generators (including wind, solar, gas, coal, etc.) have a statistical probability of being available to assist the grid during periods that are typically high-stress conditions (e.g., late afternoon in August). The contribution of each resource, after accounting for this statistical probability is often referred to as the Effective Load Carrying Capability or ELCC. This represents the "firm capacity" equivalent of the resource being considered.

that is significantly less than the level of imports experienced during the region's cold weather event in January 2024. As explained in more detail below, these three conservative assumptions contribute directly to E3's conclusion that the region has a modest "resource gap,"

Figure 4: E3 Total Resource Need Results for the Greater Northwest

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*

E3 Study Put into Context

E3's presentation of its Phase 1 results included a 25-page slide deck but did not provide any other documentation or explanations of the assumptions and inputs used in the model. The data underlying E3's analysis does not accompany the presentation. The lack of documentation for the E3 Study is not necessarily surprising as the work product is only Phase 1 of a consultant study meant to inform Washington state policymakers on general, high-level themes of "long-term" resource adequacy projections in the Greater Northwest. Nevertheless, the absence of summary-level information regarding key parameters, as well as the unavailability of underlying data and calculation methods, limits the ability of third parties to independently verify the study's findings. With that caveat, CEG contacted E3 to better understand how their model was designed. Where appropriate, CEG contextualized our analysis of the E3 study with supplemental information provided by E3 but not contained in the slide deck.

Total Resource Need

As an initial matter, E3's finding of a "resource gap" does not necessarily indicate an immediate or persistent shortage of electricity on the grid. Rather, it reflects that, under the study's modeling assumptions, the system's set of available resources ("Existing Portfolio w/ Retirements") is lower

than E3's estimate of Total Resource Need, resulting in modeled risk metrics that exceed the study's defined tolerance level. The identified resource gap represents the additional accredited capacity required to bring modeled system risk back into compliance with the chosen reliability standard and is contingent on the assumptions embedded in the analysis.

The presentation, as shown in the excerpt in the figure above, identifies the Total Resource Need as "peak demand + planning reserve margin as well as obligation to serve the Columbia River Treaty regime."[45] The presentation does not identify the numerical values that sum to the total need and does not provide sufficient detail to clearly understand how each of these elements contributes to the total resource need or how the resulting Total Resource Need is calibrated to a specific probabilistic reliability standard.

In probabilistic resource adequacy frameworks, the Total Resource Need is typically defined by the level of accredited capacity required to satisfy a chosen reliability metric, most commonly a loss-of-load expectation (LOLE) of 0.1 events per year (i.e., a one-in-ten-year standard). Under such frameworks, a small, modeled resource shortfall does not necessarily indicate a qualitatively different reliability outcome, but rather that the modeled system slightly exceeds the selected risk threshold. For this study, E3 did in fact use a 0.1 LOLE. And although this information is not in the slide deck, E3 also found that the LOLE with its projected 2026 shortfall is 0,15. While 0.15 exceeds the 0.1 planning target, the incremental increase is relatively small in absolute terms and should be interpreted in the context of near-term uncertainty and conservative modeling assumptions.

Consistent with other resource adequacy studies, E3 finds that reliability risk in the Greater Northwest is most pronounced during winter periods. The most immediate modeled risk arises under a combination of extreme cold temperatures and reduced hydropower availability, such as during drought conditions.[46] As detailed below, the evidence available by December 16, 2025, the day of the DOE order, suggests that the extreme scenario will not occur during Winter 2025-26.

Imports Assumption

The E3 Study assumes a firm import limit of 3,750 MW to the Greater Northwest region. [47] Recent historical evidence, however, indicates that the Northwest has been able to achieve materially higher levels of imports under stressed system conditions. During the January 2024 Cold Weather Winter event, imports reached approximately 6,000 MW,[48] averaged 4,745 MW during peak hours, and averaged 5,241 MW across all hours.[49] These import levels were achieved even while California was a net importer during the same period.[50] Had E3 modeled import capability at levels

[45] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," E3, page 10.
[46] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," E3, pages 11-12.
[47] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," E3, page 10.
[48] "Memorandum: January 2024 Cold Weather Event," page 8, Northwest Power and Conservation Council, March 5, 2024, https://www.nwcouncil.org/fs/18649/2024_03_5.pdf.
[49] "2025–2026 Winter Reliability Assessment," NERC, page 52.
[50] "2025–2026 Winter Reliability Assessment," NERC, page 52.

consistent with the observed performance in January 2024, it would materially affect the projected reliability outcomes and would eliminate the modeled shortages through at least 2026. In its independent evaluation of E3's Phase 1 results, Sylvan Energy Analytics assumed winter import capability of up to 5,000MW, including 3,000 MW into the Pacific Northwest from non-Canadian sources, 1,000 MW from Canada, and 1,000 MW into the PacifiCorp East balancing area, based on the observed regional import levels during 2024 winter event.[51]

Canadian Hydropower Entitlements under the Columbia River Treaty

The Canadian Entitlement for the 2026 to 2029 operating years is 660 MW in hydropower generation capacity and 305 average MW (aMW) of energy.[52] E3 modeled that the region would export power 660 MW of power into Canada in all hours, even during peak periods. E3's analysis did not allow for the Greater Northwest region to rely on Canadian imports and storage during peak hours. The Columbia River Treaty does not mandate that the US export power to Canada at all hours, even during peak periods. Rather, the Treaty establishes an obligation for the US to provide Canada with an agreed share of power benefits on an annual basis but allows operational flexibility in the timing and coordination of deliveries, particularly under conditions of system stress. Sylvan Energy Analytics modeled the region exporting 660 average MW into Canada across a month but allowed Canadian imports in any given hour.[53]

Reserve Margin

As described earlier, Total Resource Need reflects a reserve margin that is intended to satisfy a probabilistic reliability criterion. In practice, small differences in the implied reserve margin associated with that criterion can determine whether a system appears to be in surplus or deficit, particularly where the modeled shortfall is relatively small, as is the case here. The E3 presentation does not disclose the reliability standard applied, such as a target loss of load expectation, nor does it provide sufficient information to infer the implied planning reserve margin embedded in the Total Resource Need or to understand how obligations associated with the Columbia River Treaty are incorporated into that calculation. As a result, it is not possible to use the slide deck to evaluate the sensitivity of the results to reasonable alternative reliability assumptions.

By way of illustration, regional resource adequacy practices commonly rely on reliability standards that result in implied planning reserve margins within a relatively narrow range. The Pacific

[51] Hart, Elaine. "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, January 2026. https://gridlab.org/portfolio-item/pnw_nearterm_winterra/.
[52] "Details About the Key Elements Agreed Between the United States and Canada Regarding Modernization of the Columbia River Treaty Regime" U.S. Department of State, July 26, 2024. https://www.state.gov/bureau-of-western-hemisphere-affairs/details-about-the-key-elements-agreed-between-the-united-states-and-canada-regarding-modernization-of-the-columbia-river-treaty-regime.
[53] Hart, Elaine. "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, January 2026. https://gridlab.org/portfolio-item/pnw_nearterm_winterra/.

Northwest Utilities Conference Committee, for example, has historically relied on a planning reserve margin of approximately 16%.[54] If the implied reserve margin resulting from E3's reliability criterion was modestly lower, such as 15%, the resulting capacity balance could differ materially. Using E3's own figures, the 2026 system shows approximately 50,357 MW of accredited capacity against a stated Total Resource Need of 50,737 MW, implying a shortfall of roughly 380 MW, a magnitude that could be affected by relatively small differences in implied reserve margin.[55]

As demonstrated earlier, regional resource adequacy frameworks differ meaningfully in their reliability standards, planning reserve margin targets, and resource accreditation methodologies. Consequently, a system configuration that satisfies adequacy criteria in one region may not be evaluated the same way in another, even under similar system conditions. For example, ERCOT applies a minimum planning reserve margin target of 13.75 percent of peak demand,[56] while the Southwest Power Pool set a planning reserve margin of 15%[57] but allows for a lower PRM (9.89%) if the system is at least 75% hydro-based generation.[58] This reflects the view that hydro-dominated systems possess distinct operational attributes that influence reliability outcomes and resource adequacy assessments.

Winter 2025-2026 Conditions

The E3 presentation is an illustrative resource adequacy analysis intended to identify potential resource adequacy risks through 2030. It is designed to be informative and to support preliminary policy consideration, rather than to serve as a near-term operational assessment of the current 2025-2026 Winter. The study establishes planning thresholds, not real-time reliability metrics, and relies on annual average assumptions. For example, the presentation's hydropower generation is modeled using historical average hydrologic conditions from 1989 through 2018.

There is good reason to believe that the actual circumstances this winter pose less risk than the assumptions used in the E3 presentation. While system planners reasonably strive to meet a 1-in-10 loss-of-load expectation (LOLE) standard over the planning horizon, short-term deviations from that benchmark do not, by themselves, indicate the likelihood of load loss in any specific operating year. Assessing near-term reliability risk requires greater reliance on contemporaneous weather, hydrological, and resource availability projections. This is particularly true in the Pacific Northwest, where hydrological conditions are a dominant driver of winter reliability outcomes. E3's Report appropriately emphasizes water-year analysis for this reason. By the date of the Department of Energy order on December 16, 2025, hydrology and temperature forecasts indicated that many of

[54] "Northwest Regional Forecast of Power Loads and Resources: August 2025 through July 2035," page 11, Pacific Northwest Utilities Conference Committee, April 2025, https://www.pnucc.org/wp-content/uploads/2025-PNUCC-Northwest-Regional-Forecast-final.pdf.
[55] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," E3, pages 7, 8, 10.
[56] "Resource Adequacy," Electric Reliability Council of Texas, accessed December 16, 2025, https://www.ercot.com/gridinfo/resource.
[57] Southwest Power Pool (SPP) et al., "SPP Planning Criteria Revision 4.1A," May 12, 2023, https://www.spp.org/documents/69547/spp%20planning%20criteria%20v4.1a.pdf.
[58] Southwest Power Pool (SPP) et al., "SPP Planning Criteria Revision 4.1A."

the worst-case low-hydropower conditions reflected in the study had already been reduced to low-probability scenarios. As of December 15, 2025, Pacific Northwest snowpack and hydro reservoir forecasts indicate that regional hydrologic conditions are relatively strong.[59] NOAA's 120-day hydrologic outlook for the Columbia River Basin shows most rivers expected to experience near- or above-average conditions.[60] The figure below shows the hydrological forecast from the NOAA Northwest River Forecast Center at BPA's largest hydropower project, Grand Coulee dam (current forecast as of December 22,2025 and previous forecast in dark red as of December 15, 2025). The 120-day forecast indicates that as of December 15, 2025, hydrological conditions were expected to be at or above average through April 2026.

[59] Northwest River Forecast Center, "Northwest River Forecast Center," National Oceanic and Atmospheric Administration, accessed December 22, 2025, https://www.nwrfc.noaa.gov/rfc/
[60] Northwest River Forecast Center, "Northwest River Forecast Center," National Oceanic and Atmospheric Administration, accessed December 22, 2025, https://www.nwrfc.noaa.gov/rfc/

Figure 5: Hydrology Forecast for Grand Coulee Dam (December 22, 2025 to April 21, 2026)[61]

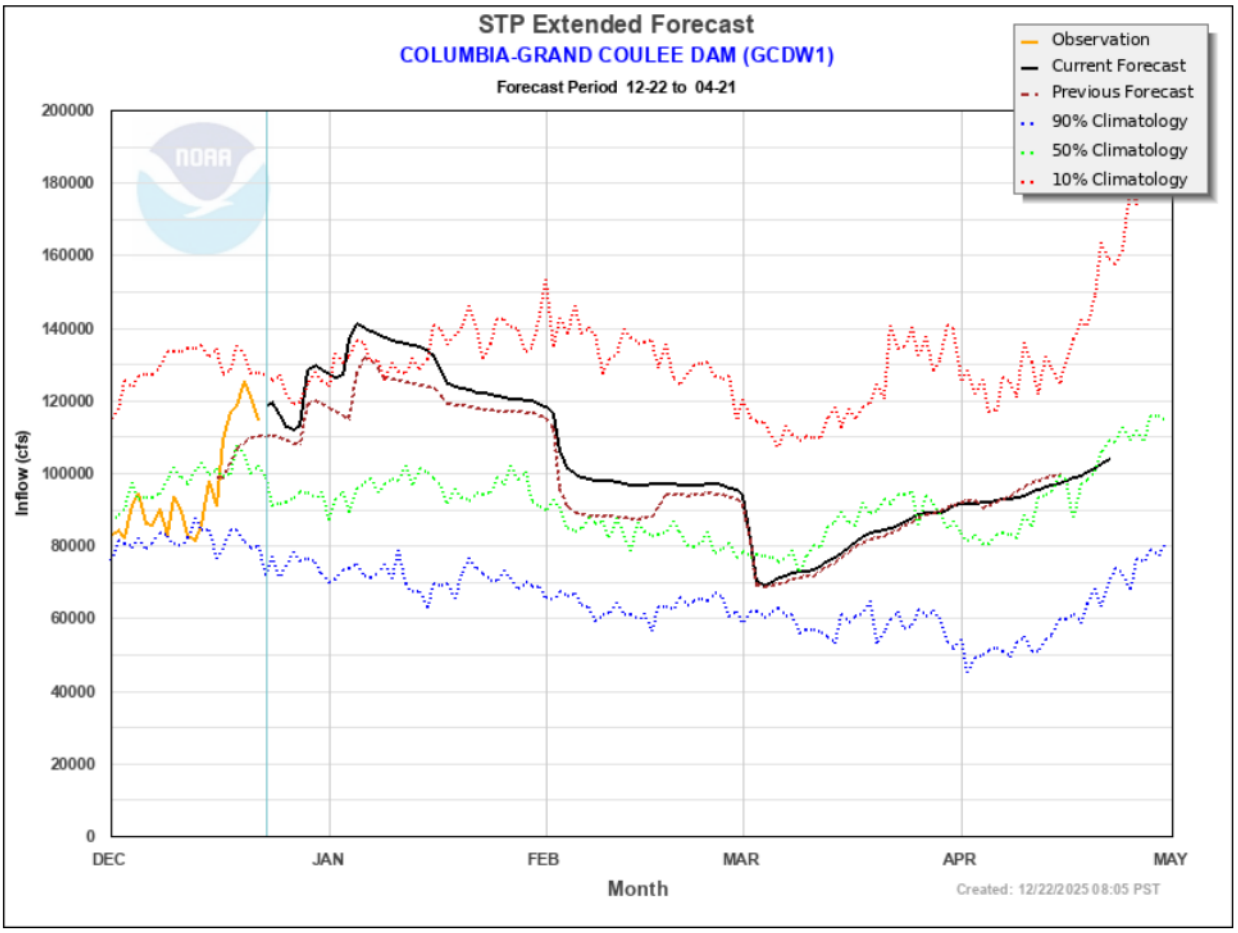


Figure 5 shows the forecasted inflows to the Columbia River at Grand Coulee Dam as compared with historical flow conditions for the same time of year. Measuring the hydropower output at Grand Coulee Dam is appropriate because it is the largest and most operationally influential facility in the Columbia River system, making its flows a reliable proxy for basin-wide hydrological conditions that drive regional winter energy availability. The black solid line represents the current forecast issued on December 22, 2025, and the red dashed line, titled "previous forecast," represents the December 15, 2025, forecast, the day before DOE issued its Order for Centralia. CEG was unable to locate an equivalent figure released on December 15, 2025. The green dotted line represents the 50 percent climatology, or median historical inflow for each day of the year. The blue and upper red dotted lines show low and high historical flow levels for the season. Together, the climatology lines provide a reference for whether forecasted inflows are below, near, or above typical historical conditions.

[61] Northwest River Forecast Center, "GCDW1 Streamflow and Snow Telemetry Plot," National Oceanic and Atmospheric Administration, accessed December 22, 2025, https://www.nwrfc.noaa.gov/stp/station/stpplot/stpplot.cgi?GCDW1

As shown, the December 15 forecast (red dashed line) is consistently above the 50 percent climatology (green dotted line) across the late December through February period. This indicates that, as of mid-December, expected inflows at Grand Coulee were forecast to be above median historical conditions, rather than indicating low-hydro or stress conditions.

E3's presentation indicates that the probability of resource shortfall is highest during winter periods associated with low hydro availability.[62] In this context, the December 15, 2025, forecast for Grand Coulee does not reflect low-hydro conditions during the critical winter months. Instead, both forecasts project inflows at or above median historical levels for much of the January–February period. As a result, the hydrologic conditions reflected in these forecasts reduce the likelihood of the most constraining near-term scenarios identified by E3, particularly during winter peak months when cold-weather events can drive elevated demand.

Bonneville Power Administration and Puget Sound Energy Planning Documents Short-Term Findings

As previously noted, the planning assessments of Puget Sound Energy (Puget) and the Bonneville Power Administration are relevant for evaluating resource adequacy in the Pacific Northwest. Puget is the largest electric and gas utility in Washington and was the largest offtaker of energy from the Centralia plant. BPA is the region's largest balancing authority and transmission owner, and Centralia is surrounded by (but not a part of) BPA's balancing authority area. Together, the planning documents produced by Puget and BPA provide the most direct insight into near-term and medium-term resource adequacy conditions relevant to Centralia, and they present no indication of a resource adequacy crisis in 2026 or early 2027.

Puget's published its most recent update to its IRP in 2023.[63] In that filing, Puget's resource adequacy analysis, conducted by E3, finds that the utility maintains a winter planning reserve margin exceeding 20 percent in 2027 under its preferred portfolio.[64] The analysis explicitly incorporates the retirement of the Centralia plant. Puget is currently developing its 2027 Integrated System Plan (formerly the Integrated Resource Plan) and has again retained E3 to perform the resource adequacy assessment. Puget presented its initial results in September 2025 and described several methodological updates, including changes to the load forecast, operating reserve requirements, resource accreditation, and market availability assumptions.[65] Neither the

[62] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," slide 11, E3, Sept. 22, 2025, https://www.utc.wa.gov/sites/default/files/2025-10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20WA%20RA%20Meeting.pdf.
[63] "2023 Electric Progress Report", Puget Sound Energy, March 31, 2023, https://www.pse.com/en/IRP/Past-IRPs/2023-IRP. Puget Sound Energy will next publish a full Integrated System Plan in 2027.
[64] 2023 ERP Table 7.1 shows Puget Sound Energy's PRM is more than 20% in 2029 in preferred portfolio.
[65] "Resource Planning Advisory Group Meeting 2027 Integrated System Plan," page 38, Puget Sound Energy, September 30, 2025, https://irp.cdn-website.com/dc0dca78/files/uploaded/2025_0930_RPAGMeeting_Final-5b0bf24b.pdf.

2023 IRP nor the preliminary 2027 results identify emergency resource adequacy concerns in 2026 or 2027.

The Bonneville Power Administration's most recent long-term planning assessments are presented in its 2025 Pacific Northwest Loads and Resources Study (also known as the "White Book") and its 2024 Resource Program, which, together, evaluate the adequacy of BPA's resource portfolio under a range of hydrological and operating conditions.[66]

BPA finds that, assuming the availability of market purchases and independent power producers, the Pacific Northwest is projected (in annual energy terms) to have firm energy surpluses in the first two operating years.[67] BPA further concludes that, under median water conditions, the federal system is capable of meeting demand during extreme winter weather events.[68] To the extent that resource adequacy challenges emerge in BPA's analysis, they occur in later years and are intended to signal the need for additional resource development, consistent with standard long-term planning practice, rather than indicating near-term emergency conditions.

Consistent with long-standing practice across the region, both Puget and BPA rely on interregional transmission access and short-term market purchases to meet resource adequacy needs and minimize system costs. Puget explains that purchasing energy from the regional power market has historically been a cost-effective means of meeting demand.[69] In other words, the region's strong interregional transmission capacity and surplus generation across the West allowed for relatively efficient balancing of supply and demand, even if a particular utility had a "shortfall" in owned resources within their own portfolio.

Puget and BPA's planning assessments do not support the finding of an imminent resource adequacy or reliability emergency. The studies identify manageable planning challenges in later years, but they do not indicate near-term operational shortfalls in 2026 or early 2027, even under conservative assumptions and stress-test scenarios.

Analysis of Medium-Term (2027-2031) Findings

Summary of medium-term (2027-2031) findings: The medium-term planning horizon is the most consequential for resource adequacy assessments, as it is the period in which emerging risks can still be addressed by state, regional, and private actors through established planning and investment processes. In addition to the 2024 Western Assessment of Resource Adequacy, E3, and Puget/BPA planning documents, we also analyze the Northwest Power and Conservation Council 2029 Resource Adequacy Assessment to assess RA conditions in the medium-term (2027-2031).

[66] "2025 Pacific Northwest Loads and Resources Study," Bonneville Power Administration (BPA), May 2025, https://www.bpa.gov/-/media/Aep/power/white-book/2025-whitebook.pdf; "2024 Resource Program," page 7, Bonneville Power Administration, February 21, 2025, https://www.bpa.gov/-/media/Aep/power/resource-program/2024-rp-document.pdf.
[67] "2025 Pacific Northwest Loads and Resources Study," BPA, page 32.
[68] "2025 Pacific Northwest Loads and Resources Study," BPA, Tables 3-7.
[69] "2023 Electric Progress Report", Puget Sound Energy, page 7-1, March 31, 2023, https://www.pse.com/en/IRP/Past-IRPs/2023-IRP.

The Northwest Power and Conservation Council assessment is notable as the council is required, per Congressional mandate, "to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply."[70]

The most significant risks CEG identify in the reviewed studies arise in the medium-term and are driven primarily by rapid load growth rather than coal retirements. Growing electrification, new industrial load, and data center development have increased peak and annual energy needs more quickly than in past years. These conditions place greater pressure on the timely development of new resources, transmission expansion, and demand-side programs. While risks increase later in the decade if new resources are not built on schedule, the current conditions do not constitute a crisis, nor do they justify suspending long-planned coal retirements, and planning entities are appropriately adjusting their expectations. The retirement of Centralia is not a primary driver of any identified shortfall, and none of the reviewed studies suggest that extending its operation would materially improve resource adequacy. Table 4 summarizes our findings for the medium-term analysis.

Western Electricity Coordinating Council's Western Assessment of Resource Adequacy Medium-Term Results

In its 2024 Western Assessment of Resource Adequacy, the Western Electricity Coordinating Council finds that medium-term resource adequacy risks are concentrated in later years, particularly under scenarios where planned generation is delayed or import capability is constrained.[71] Across all scenarios, modeled demand-at-risk hours increase over time, with the highest risk observed in a scenario in which only 55% of planned resources are deployed. While the assessment identifies emerging and increasing challenges under adverse assumptions, the Western Electricity Coordinating Council does not characterize this as evidence of a crisis. Instead, it is characterized as a signal for additional prioritization of reliability in (as well as generic improvement of) planning processes.[72]

The Western Assessment of Resource Adequacy finds that load growth is the primary driver of the increasing risk,[73] with an expected 20.4% increase in energy demand between 2025 and 2034, and a 17.2% increase in peak demand over same period[74] - approximately four times the growth rate between 2013 and 2022.[75] In the Northwest region specifically, the 2024 Western Assessment of

[70] Northwest Power and Conservation Council 2024 Annual Report to Congress
[71] "Western Assessment of Resource Adequacy 2024: Risks to Planned Resource Additions," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.
[72] Western Assessment of Resource Adequacy 2024: Summary," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.
[73] Western Assessment of Resource Adequacy 2024: Summary," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.
[74] Western Assessment of Resource Adequacy 2024: Summary," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.
[75] Western Assessment of Resource Adequacy 2024: Summary," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.

Resource Adequacy projects a 20% increase in energy needs from 2025 through 2034 (250 TWh to 299 TWh).[76]

Consistent with the short-term findings, the 2024 Western Assessment of Resource Adequacy demonstrates that the region has been planning for plant retirements and load growth by increasing planned builds, adding unprecedented levels of new capacity (~15GW of new batteries and ~3GW of new natural gas by 2027)[77] and moderating previously-assumed retirements downwards as compared to 2022.[78] Generation additions across the WECC subregions (including WECC-Northwest) appear to be on track with the 2024 assessment's expectations, with ~9.5GW of new batteries, ~6GW of solar, ~1.7GW of gas, and ~2GW of wind, deployed across the interconnection in 2025, more than 1.6GW of which was deployed in Washington, Oregon, Idaho, and Montana.[79]

The study does not identify retirements as a primary cause of future reliability risks. Instead, the analysis finds that the principal risks stem from insufficient new generation and constraints on imports, both of which could be exacerbated by supply chain challenges, interconnection backlogs, siting and permitting delays, and cost pressures.

According to the Western Assessment of Resource Adequacy, imports play a critical role in maintaining short-term reliability, and the timely completion of new generation is the key medium-term requirement for maintaining resource adequacy.[80] Although the 55% build out scenario is a useful planning exercise to stress-test the system, it appears unlikely based on historical data. The assessment notes that the 2018-2023 average project completion rate was closer to 76%, a period that included significant inflation and the supply chain disruptions from the Covid pandemic.[81]

A consistent theme in the 2024 Western Assessment of Resource Adequacy is the need to continue and improve upon existing state, regional, and private planning processes. The assessment highlights recent changes to utility forecasting methodologies, new long-term transmission planning efforts (*e.g.*, efforts pursuant to FERC Order 1920), and the development of the Western Resource Adequacy Program as positive planning developments.[82] In other words, the

[76] WARA 2024 Annual Demand by Subregion (figure 6)
[77] Western Assessment of Resource Adequacy 2024: Additions," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.
[78] Western Assessment of Resource Adequacy 2024: Retirements," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/; "WARA 2024 Annual Demand by Subregion," Figure 6, Western Electricity Coordinating Council, accessed December 16, 2025 https://www.wecc.org/wecc-document/17061.
[79] "Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)," December 2024 and October 2025 data, U.S. Energy Information Administration, accessed December 16, 2025, https://www.eia.gov/electricity/data/eia860m/.
[80] "WARA 2024 Import Scenarios," page 6, Western Electricity Coordinating Council, December 3, 2024, https://www.wecc.org/wecc-document/17081.
[81] Western Assessment of Resource Adequacy 2024: Historical Resource Additions," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.
[82] Western Assessment of Resource Adequacy 2024: Resource Planning," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.

assessment calls for incremental improvement to established planning for and proportional responses to medium-term challenges, not extraordinary measures outside of the planning process.

E3 Study Medium-Term Results

By 2030, E3 finds a significant resource shortfall of ~9,000 MW for the Greater Northwest region.[83] E3 attributes the projected shortfall primarily to load growth, driven predominantly by the rapid interconnection of data centers.[84] While peak demand increases modestly due to population growth, increased air-conditioning adoption, and electric vehicle uptake, E3 finds that data center development accounts for the largest share of incremental demand in the region. E3 also identifies planned generator retirements and limited replacement capacity as contributing factors to its modeled 2030 shortfall.

The magnitude and timing of the projected medium-term shortfall is sensitive to several key assumptions. First, E3 did not consider large load flexibility, which Sylvan Energy Analytics finds could mitigate most or all the near-term winter resource needs under most load scenarios.[85] Second, E3 treated the Centralia coal plant as retired throughout the study period, and did not include a corresponding replacement resource, as the analysis preceded TransAlta's announcement of a coal-to-gas conversion beginning in 2028. Including the announced conversion would reduce the shortfall by approximately 670 MW of accredited capacity.

As in the Short-Term 2026 analysis, E3's medium-term results remain sensitive to assumptions related to achievable import levels, rate of new resource additions, Canadian entitlement obligations, and the implied reserve margin associated with the selected reliability criterion. These factors continue to play a material role in determining whether resource shortfalls emerge in the study.

Finally, even within E3's own presentation, the identified medium-term shortfalls appear likely to be resolved by the completion of resource additions that utilities have already planned and reflected in their Integrated Resource Plans,[86] which underscores the function of the E3 presentation as a planning signal rather than evidence of an unaddressed reliability gap.

[83] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," pages 9, E3, Sept. 22, 2025, https://www.utc.wa.gov/sites/default/files/2025-10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20WA%20RA%20Meeting.pdf.

[84] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," pages 7, E3, Sept. 22, 2025, https://www.utc.wa.gov/sites/default/files/2025-10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20WA%20RA%20Meeting.pdf.

[85] Hart, Elaine. "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." slide 11, Sylvan Energy Analytics, January 2026. https://gridlab.org/portfolio-item/pnw_nearterm_winterra/.

[86] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," pages 21, E3, Sept. 22, 2025, https://www.utc.wa.gov/sites/default/files/2025-

Accordingly, the identification of a medium-term shortfall should be understood as a planning signal rather than an indication of an imminent or existing reliability emergency. Results of this magnitude underscore the need for continued and timely development of new resources, refinement of load and reliability assumptions, and improvements in regional coordination and transmission capability. Viewed in this context, the findings highlight the importance of sustained planning and investment through state, regional, and private processes, rather than the presence of a near-term crisis.

Northwest Power and Conservation Council's Medium-Term Results

The Northwest Power and Conservation Council's 2029 Resource Adequacy Assessment is the most comprehensive look at the Northwest region's power needs and risks in the medium-term. The Council was created by Congress with a mandate to improve electricity system planning for the Northwest and Columbia River Basin.[87] The Northwest Power and Conservation Council's annual Resource Adequacy Assessment is one of several planning efforts undertaken by the Council and provides a five-year evaluation of the region's resource adequacy. As the Council explains, the assessment "summarizes the . . . aggregate regional power supply's adequacy for the 2029 operating year (October 2028 through September 2029)."[88]

The Northwest Power and Conservation Council is one of the country's only Congressionally mandated regional coordination efforts on energy planning. The Council forecasts demand and recommends resource plans. The eight-member Council is made of two governor-appointed members from each member state (Oregon, Washington, Idaho, and Montana) who work with support staff and technical committees, and is required to consult with utilities, state and local governments, tribes, and customers "to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply."[89]

The 2029 Assessment uses the Council's own GENESYS model to evaluate system reliability across multiple metrics, providing information about the frequency, duration, and magnitude of potential shortfall events.[90] The Assessment analyzes:

- Loss of load Events (LOLE), which measures the frequency of shortfalls.
- Duration Value at Risk, which measures shortfall duration.
- Peak Value at Risk, which measures maximum hourly shortfalls; and

10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20WA%20RA%20Meeting.pdf.

[87] "2024 Annual Report to Congress," page 3, Northwest Power and Conservation Council, accessed December 16, 2025, https://storymaps.arcgis.com/stories/3c12b13cd3a9487ab44120f5beffe128.

[88] "Pacific Northwest Power Supply Adequacy Assessment for 2029," page 5, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.

[89] "2024 Annual Report to Congress," page 3, Northwest Power and Conservation Council, accessed December 16, 2025, https://storymaps.arcgis.com/stories/3c12b13cd3a9487ab44120f5beffe128.

[90] "Pacific Northwest Power Supply Adequacy Assessment for 2029," page 6, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.

- Energy Value at Risk, which measures the annual energy shortfall.[91]

The Northwest Power and Conservation Council's model is also intentionally conservative. For example, the assessment limits the use of emergency measures that would be employed in actual emergency situations (e.g., targeted brownouts, emergency backup generation).[92]

The 2029 Assessment evaluates three scenarios: (1) a reference case (planned buildouts and demand growth), (2) a reduced energy efficiency case (1000MW vs. 1300MW), and (3) higher data center demand case (3976MW by 2029 vs. 2386 MW) to test and quantify specific reliability threats. Scenarios two and three are, in effect, assuming higher electricity demand. Scenario two does so by removing a portion of the anticipated energy demand savings due to energy efficiency programs, increasing total demand needing to be served in 2029. Scenario three does so explicitly by increasing data center loads.

The 2029 Assessment finds that there is no resource adequacy threat in the reference scenario in 2029 (the analyzed year). The Council concludes that even with substantial load growth the 2021 Power Plan strategy—achieving energy efficiency consistent with the high end of the Council's target, 6,600 MW of new renewables by 2029, and sufficient balancing resources and demand response is adequate to meet regional needs.[93] The Council's findings include modeling the full retirement of the Centralia Plant.[94]

The Northwest Power and Conservation Council's analysis finds that risks only begin to emerge in the two sensitivity scenarios tested: one where energy efficiency deployment is lower than expected (1000MW vs. 1300MW by 2029), and another where data center growth is much larger than anticipated (3976MW by 2029 vs. 2386 MW).[95,96] The table below shows the results of the reliability analysis. Unsurprisingly, significant and unplanned for additional load led to greater adequacy metric violations.[97]

[91] "Pacific Northwest Power Supply Adequacy Assessment for 2029," page 10, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.
[92] "Pacific Northwest Power Supply Adequacy Assessment for 2029," pages 9-14, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.
[93] "Pacific Northwest Power Supply Adequacy Assessment for 2029," page 26, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.
[94] "Pacific Northwest Power Supply Adequacy Assessment for 2029," page 19, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.
[95] "Pacific Northwest Power Supply Adequacy Assessment for 2029," page 6, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.
[96] "Pacific Northwest Power Supply Adequacy Assessment for 2029," page 26, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.
[97] "Pacific Northwest Power Supply Adequacy Assessment for 2029," table 7, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.

Table 3: Northwest Power and Conservation Council Adequacy Metric Results

Type	Metric	Threshold	Reference	Low End EE	Higher Data Center
Frequency	Winter LOLEV	0.1	0.022	0.350	1.294
Frequency	Summer LOELV	0.1	0.017	0.033	0.3
Duration	Duration VaR 97.5	8 hours	0	1.5	20.6
Magnitude	Peak VaR 97.5	1,200 MW	0	1,567	3,076
Magnitude	Energy VaR 97.5	9,600 MWh	0	4,196	196,324

Despite the risks in the sensitivity scenarios, the Northwest Power and Conservation Council does not characterize the findings as a crisis or as evidence that generator retirements threaten reliability. Rather, the reports finds that the best actions to mitigate risks are continuing development of energy efficiency, renewable energy, coal to gas conversions, and new transmission.[98] The Council frames these results as "early warnings" that reinforce the need for sustained planning, including work underway for the 2026 Power Plan.[99] The Council's decision not to characterize these results as a crisis reflects the fact that the modeled risks arise only under sensitivity scenarios and can be addressed through established planning mechanisms already contemplated in the Council's power planning process.

BPA/Puget Sound Energy Medium-Term Results

Neither Puget nor BPA present a picture of a reliability crisis in the 2027-2031 timeframe. Instead, both identify rapid load growth as the primary driver of increasing system needs and the principal source of potential reliability risk if additional resources and measures are not developed in a timely manner. BPA explains that, under firm water conditions, the Pacific Northwest is projected to have an annual energy surplus of up to 960 average megawatts in operating year 2026, declining steadily over time to an annual energy deficit of approximately 3,026 average megawatts by operating year 2034, driven primarily by increasing regional retail load.[100]

In response to these conditions, both entities emphasize the need for timely development of new generation, expanded demand-side resources, regional coordination, and transmission investment.

[98] "Pacific Northwest Power Supply Adequacy Assessment for 2029," pages 18-21 and 26, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.
[99] "Pacific Northwest Power Supply Adequacy Assessment for 2029," page 6, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.
[100] "2025 Pacific Northwest Loads and Resources Study," page v, Bonneville Power Administration, May 2025, https://www.bpa.gov/-/media/Aep/power/white-book/2025-whitebook.pdf.

BPA's least-cost portfolio relies on energy efficiency, demand response, and market purchases to meet its obligations and requires only modest resource additions over the long-term.[101] BPA's sensitivity analyses show little-or-no unserved energy in most cases, with notable shortfalls occurring only in extreme scenarios that assume the complete loss of market imports.[102]

Puget projects demand growth in its territory, reaching a median winter peak load of over 5GW by 2029.[103] Puget also identifies the total resource need based on the median peak load and a five percent LOLP target. Assuming the total resource need is met, Puget will have a PRM of 26-28% in 2029 and 2034. [104] Table 4 shows these results.

Table 4: Puget Sound Energy 2023 IRP Total Resource Need and Planning Reserve Margin (MW)

Resource(s)	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Median Peak Load	5,004	5,382	4,171	4,831
Total Resource Need	6,319	6,771	5,329	6,107
Planning Reserve Margin	**26%**	**26%**	**28%**	**26%**

Puget also estimated the additional resource development needed to meet the projected total resource need. Using an updated ELCC method for existing and new resources, Puget identifies a need for additional "perfect capacity" (i.e., new resources). Table 5 shows the ELCC-adjusted capacity of existing resources and the addition "perfect capacity" required. [105] Puget's modeling shows this need will be met through wind, solar, storage, peaking capacity, demand-side, and distributed resources in its preferred, least-cost, portfolio.[106]

[101] "2024 Resource Program," page 70, Bonneville Power Administration, February 21, 2025, https://www.bpa.gov/-/media/Aep/power/resource-program/2024-rp-document.pdf.
[102] "2024 Resource Program," pages 57-58, Bonneville Power Administration, February 21, 2025, https://www.bpa.gov/-/media/Aep/power/resource-program/2024-rp-document.pdf.
[103] "2023 Electric Progress Report," Table 7.10, Puget Sound Energy, March 31, 2023, https://www.pse.com/en/IRP/Past-IRPs/2023-IRP.
[104] "2023 Electric Progress Report," Table 7.10, Puget Sound Energy, March 31, 2023, https://www.pse.com/en/IRP/Past-IRPs/2023-IRP.
[105] "2023 Electric Progress Report," Table 7.10, Puget Sound Energy, March 31, 2023, https://www.pse.com/en/IRP/Past-IRPs/2023-IRP.
[106] "2023 Electric Progress Report," Table 1.1, Puget Sound Energy, March 31, 2023, https://www.pse.com/en/IRP/Past-IRPs/2023-IRP.

Table 5: Puget Sound Energy 2023 IRP Total Resource Need by Resource Type (MW)

Resource(s)	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Thermal Plants	2,050	2,050	1,688	1,688
Mid-C Hydro	560	560	560	560
Wind, Solar, Baker, Other Contracts	997	981	244	252
Market Purchases	1,440	1,434	961	751
Total Existing Resource Capacity (ELCC-adjusted)	**5,047**	**5,025**	**3,453**	**3,251**
Total Resource Need	**6,319**	**6,771**	**5,329**	**6,107**
Additional Perfect Capacity Needed	**1,272**	**1,746**	**1,875**	**2,856**

Both Puget and BPA conduct resource adequacy analyses consistent with their balancing authority responsibilities and regional requirements, including participation in the Western Resource Adequacy Program and alignment with broader Western Electricity Coordinating Council and NERC planning efforts. While each identifies similar medium-term risks—such as delays in resource development, reduced import availability, and retirements of independent power producers—neither calls for extraordinary measures or for delaying planned plant retirements, including Centralia (from which both Puget and BPA used to purchase power). Each study, and taken together, reflects manageable planning challenges rather than a medium-term reliability crisis.

Review of Recent Washington State Assessment

Our assessment that the regional resource adequacy studies do not identify an imminent emergency is supported by the two Washington state agencies charged by the state legislature to conduct annual resource adequacy meetings. The Washington State Utilities and Transportation Commission and the Washington Department of Commerce concluded their 2025 Long-term Resource Adequacy Meetings in November 2025.

On December 31, 2025, the two state agencies transmitted a letter to the Washington Legislature and the Governor summarizing the findings of the November 4, 2025 Winter Preparedness Resource Adequacy Meeting.[107] The Agencies concluded that the "[w]inter reliability assessments, presented by regional resource adequacy experts, the North American Electric Reliability Corporation and Western Electricity Coordinating Council, indicate the Northwest's electric grid

[107] Summary of the 2025 Winter Preparedness Resource Adequacy Meeting, Letter from Chair Brian J. Rybarik and Assistant Director, Energy Division, Jennifer Grove to Governor Bob Ferguson, Secretary of Senate Sarah Bannister, and Chief Cler of the House of Representatives Bernard Dean. December 31, 2025, available at https://www.utc.wa.gov/casedocket/2021/210096/docsets

meets national resource adequacy criteria under normal conditions this winter."[108] The Agencies further reported that neither the Bonneville Power Administration nor Washington utilities forecast outages during the upcoming winter season. Finally, the Agencies shared that the utilities reported they have maximized hydro and natural gas storage ahead of winter and ensured facilities are operating properly, and at least two utilities noted voluntary the availability of customer curtailment programs designed to reduce demand if system conditions were to tighten.

The near-term findings are consistent with the Agencies' broader conclusions from the 2025 Long-Term Resource Adequacy Meetings. In a November 2025 summary of the three meetings on resource adequacy to the Washington Legislature and Governor, the state agencies reported that the,

> *Reliability assessments presented...indicated that the Northwest's electric grid meets national resource adequacy criteria over the near and medium terms under a broad range of operating conditions. As a region assessed as "normal risk" the Northwest has a low likelihood of electricity supply shortfall.*[109]

The Agencies cautioned that "normal risk" is not the same as "no risk" and that the presentations emphasized that no electric system is 100% risk-free and no resource provides perfect capacity.[110] Utilities, policymakers, grid operators, and planners must balance the level of reliability risk with the added cost to achieve that level of reliability. There is no perfect reliability metric or reliability target. For example, one expert may conclude a 16% planning reserve margin is optimal, while another may conclude a lower PRM of 15% better balances risk and costs. These differences reflect professional judgment, input assumptions, and tolerance for risk—all of which are the traditional province of state, regional, and utility planners and decision-makers.

The Agencies also cautioned that if significant new electricity usage materializes and more extreme weather continues, the grid could face reliability challenges. With respect to the medium-term outlook, the Agencies wrote that the "utilities and policy makers must increase efforts to make customer energy demand more flexible, reduce delays in siting and interconnecting new clean energy projects, expand regional transmission capacity, and improve transparency and accuracy of

[108] Summary of the 2025 Winter Preparedness Resource Adequacy Meeting, Letter from Chair Brian J. Rybarik and Assistant Director, Energy Division, Jennifer Grove to Governor Bob Ferguson, Secretary of Senate Sarah Bannister, and Chief Cler of the House of Representatives Bernard Dean, page 1, December 31, 2025, available at https://www.utc.wa.gov/casedocket/2021/210096/docsets

[109] Summary of the 2025 Long-term Resource Adequacy Meeting, Letter from Chair Brian J. Rybarik and Assistant Director, Energy Division, Jennifer Grove to Governor Bob Ferguson, Secretary of Senate Sarah Bannister, and Chief Cler of the House of Representatives Bernard Dean. November 19, 2025, available at https://www.utc.wa.gov/casedocket/2021/210096/docsets.

[110] Summary of the 2025 Long-term Resource Adequacy Meeting, Letter from Chair Brian J. Rybarik and Assistant Director, Energy Division, Jennifer Grove to Governor Bob Ferguson, Secretary of Senate Sarah Bannister, and Chief Cler of the House of Representatives Bernard Dean. November 19, 2025, available at https://www.utc.wa.gov/casedocket/2021/210096/docsets.

load forecasts and planned resource additions."[111] Meanwhile, federal intervention into an established and functioning regional planning process introduces uncertainty and may complicate ongoing efforts to bring new resources online in a timely manner. Broadly, the 2024 Western Assessment of Resource Adequacy notes that resource adequacy is related to policy decisions, and that shifts in policymaking can "introduce significant risks to reliability."[112]

Continued investments to strengthen the Pacific Northwest's reliability position – while accounting for Centralia's retirement – have been planned for over many years. This activity is expected to continue and can be further aided through policy certainty (and avoidance of unneeded extraordinary interventions) at the federal level.

DOE's July Resource Adequacy Report

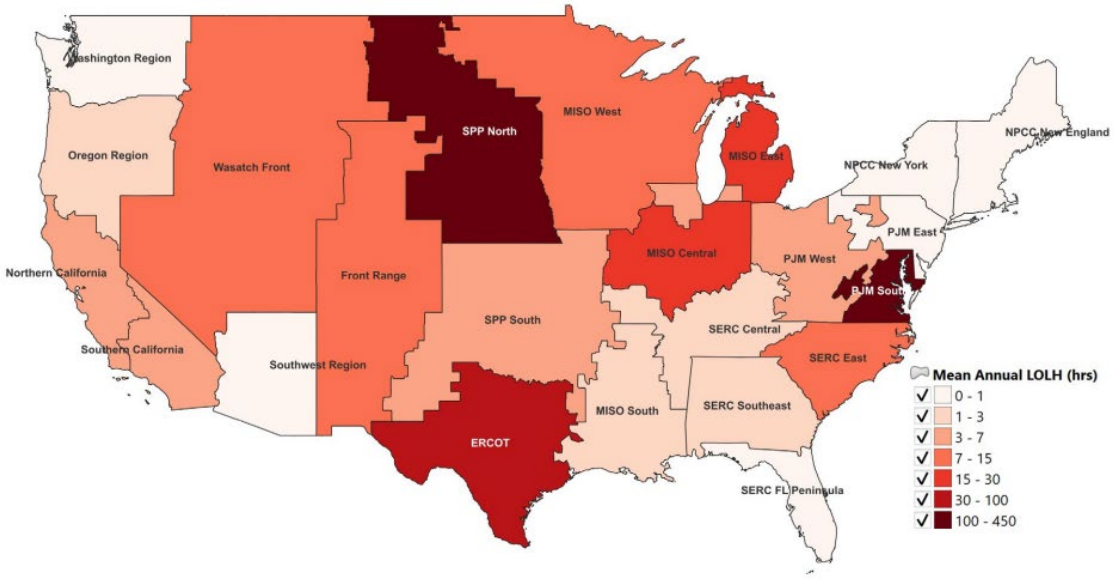
In July 2025, the Department of Energy released a resource adequacy report, analyzing the impacts of planned retirements on resource adequacy.[113] DOE references the July report in Order 202-25-11.[114] The July report analyzes several resource adequacy and reliability measures in 2030 across the nation, with findings for specific regions and states. DOE acknowledged that its study "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[115]

The DOE study found that plant retirements have essentially no impact on Washington state, limited impacts on Oregon, and moderate impacts on other Western subregions, even when relying

[111] Summary of the 2025 Long-term Resource Adequacy Meeting, Letter from Chair Brian J. Rybarik and Assistant Director, Energy Division, Jennifer Grove to Governor Bob Ferguson, Secretary of Senate Sarah Bannister, and Chief Cler of the House of Representatives Bernard Dean. November 19, 2025, available at https://www.utc.wa.gov/casedocket/2021/210096/docsets.
[112] Western Assessment of Resource Adequacy 2024: Additional Considerations," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.
[113] "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," U.S. Department of Energy, July 2025, https://www.energy.gov/topics/reliability.
[114] DOE Order No 202-25-9 at 6-7
[115] "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," page i, U.S. Department of Energy, July 2025, https://www.energy.gov/topics/reliability.

on DOE's highly unusual assumption that no Tier 2[116] or Tier 3[117] generation resources are built by 2030. [118, 119] Figure 6 shows loss of load hours by region in DOE's report.

Figure 61: DOE's July 2025 Report Mean Annual LOLH by Region (2030) – Plant Closures[120]



DOE's scenarios can be understood as a thought exercise, testing an unlikely hypothetical scenario in which plants are retired but where utilities do not procure additional generation per typical planning processes and requirements. Even in this hypothetical, DOE does not appear to find that Washington and Oregon violate its chosen reliability metrics.[121] DOE found that, even regionally, the non-CAISO West region had the least normalized unserved energy of all regions analyzed.[122]

[116] NERC defines Tier 2 resources as those having made tangible progress (e.g., completion of feasibility or system impacts studies) but are less developed than Tier 1 resources. 2024 Long-Term Reliability Assessment, NERC, July 11, 2025, https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[117] NERC defines Tier 3 resources as "units in an interconnection queue that do not meet the Tier 2 requirement." 2024 Long-Term Reliability Assessment, NERC, July 11, 2025, https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[118] "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," page 7 and 37, U.S. Department of Energy, July 2025, https://www.energy.gov/topics/reliability.
[119] "Request for Rehearing Of The Clean Energy Organizations," American Clean Power Association, Advanced Energy United, American Council on Renewable Energy, August 6, 2025, https://cleanpower.org/wp-content/uploads/2025/08/2025-08-06-Resource-Adequacy-Rehearing-Request-FINAL.pdf.
[120] "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," page 6, U.S. Department of Energy, July 2025, https://www.energy.gov/topics/reliability.
[121] "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," page 37, U.S. Department of Energy, July 2025, https://www.energy.gov/topics/reliability.
[122] "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," pages 8 and 37, U.S. Department of Energy, July 2025, https://www.energy.gov/topics/reliability.

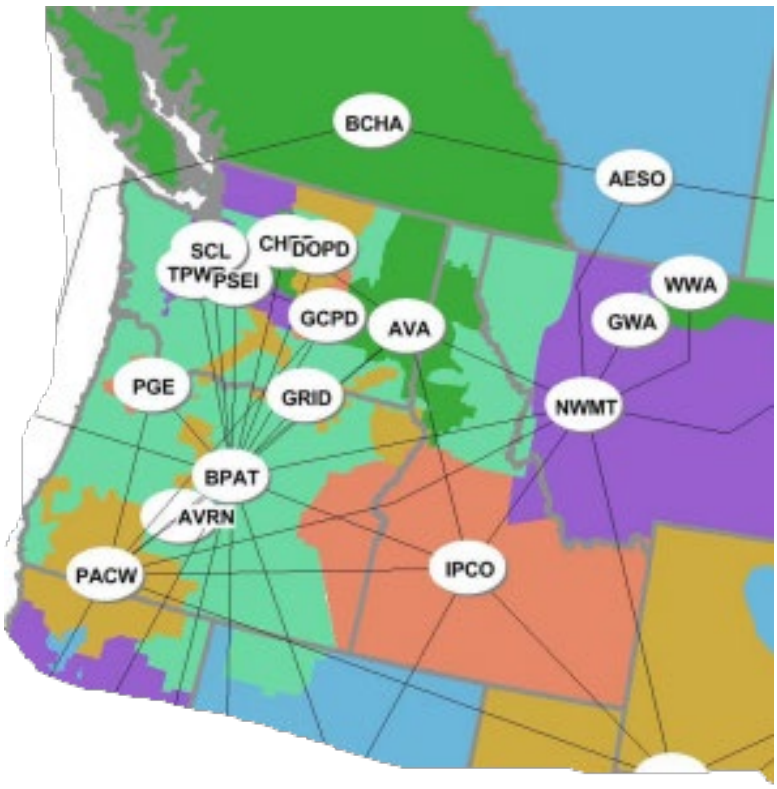
Balancing Authorities and Real-Time System Operations

As previously discussed, Resource Adequacy is generally forward-looking and distinct from real-time system operations. In addition to the extensive resource adequacy planning efforts discussed above, there is also a suite of tools available to manage the power system in real-time when challenged by extreme weather, load conditions, or other occurrences. Balancing Authorities are required by NERC and other entities to have extensive operational plans in response to threats as wide-ranging as natural disasters, winter storms, or squirrels.

Balancing Authorities are the entities responsible for managing power system operations (e.g., balancing supply and demand) and ensuring the real-time reliability of the electric system within a specific geographic area.[123] The Western Interconnection, which spans into Mexico and Canada, has 34 Balancing Authorities in the United States. Approximately 15 of those Balancing Authorities are located in the Northwest region, depending on the definition of the Northwest footprint, as shown in the figure below.

[123] "How it Works: The Role of a Balancing Authority ," U.S. Department of Energy, accessed December 16, 2025, https://www.energy.gov/sites/default/files/2023-08/Balancing%20Authority%20Backgrounder_2022-Formatted_041723_508.pdf.

Figure 7: Pacific Northwest Balancing Authorities as of October 2019[124]



The outputs of Resource Adequacy planning ultimately inform, but do not replace, the real-time reliability responsibilities of Balancing Authorities. A Balancing Authority maintains real-time balance by ensuring that generation, load and transmission interchanges align at all times. Although generators may be owned and operated by different utilities, the Balancing Authority is responsible for ensuring that each resource's schedules and actual output support system balance and comply with reliability requirements. The Balancing Authority does not economically dispatch resources it does not control. Rather, the Balancing Authority oversees scheduling and deploys its own balancing reserves to ensure the area remains in compliance with NERC reliability standards. The Bonneville Power Administration (shown as BPAT in the figure above) is the Balancing Authority for portions of Washington, Oregon, Idaho, and Montana.[125]

Balancing Authorities are responsible for developing, maintaining, and executing emergency procedures in extreme conditions. NERC Reliability Standard EOP-011 sets the requirements for

[124] "Balancing Authority Areas As of October 2019," NERC, accessed December 16, 2025, https://www.nerc.com/globalassets/programs/rapa/ra/ba-bubble-map-20191106.pdf.
[125] "Balancing Authority Area Services," Bonneville Power Administration, accessed December 16, 2025, https://www.bpa.gov/energy-and-services/transmission/interconnection/balancing-authority-area.

Balancing Authorities and Reliability Coordinators.[126] The current NERC requirements (approved by FERC in 2024) require Balancing Authorities to have operations plans for energy and capacity-based emergencies and prescribe actions regarding records keeping and communications for Balancing Authorities. NERC also defines Energy Emergency Alert (EEA) levels reflecting conditions in a Balancing Authority as shown in the table below.[127] The Western Electricity Coordinating Council provides further information on best practices for adhering to NERC guidelines and potential actions to take in an emergency situation.[128]

Table 6: NERC Energy Emergency Alert (EEA) Level Descriptions [129]

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required operating reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum operating reserve requirements.
EEA 3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum operating reserve requirements.

Balancing Authorities develop plans in response to the NERC (or other) requirements. For example, Puget's Energy System Restoration Plan sets criteria and procedures for different types of incidents (including extreme cold) depending on severity, defining chains of command and responsibilities for

[126] "EOP-011-4 – Emergency Operations," NERC, accessed December 16, 2025, https://www.nerc.com/globalassets/standards/reliability-standards/eop/eop-011-4.pdf.
[127] "2025–2026 Winter Reliability Assessment," Table 4, NERC, November 2025, https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.
[128] "Best Practices for Energy Emergency Alerts," Western Electricity Coordinating Council, March 28, 2022, https://www.wecc.org/sites/default/files/documents/meeting/2024/07%20-%20Park%20G%20-%20Best%20Practices%20for%20EEAs_July%202024.pdf.
[129] "2025–2026 Winter Reliability Assessment," Table 4, NERC, November 2025, https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

various entities.[130] The NERC rules allow for Balancing Authorities to develop plans to flexibly and proportionally respond to challenges or crises such as unplanned outages, extreme conditions, natural disasters, or other scenarios. In other words, Balancing Authorities are required to maintain a variety of options to respond to emergencies based on localized conditions.

Disclaimer

This report was prepared by Current Energy Group (CEG). It is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors using currently available information and does not necessarily reflect those of any other entity associated with this work.

[130] "Energy System Restoration Plan," Puget Sound Energy, August 30, 2024, https://www.pse.com/en/safety/first-responders/emergency-operations.



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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-02:
Declaration of Nancy Hirsch

DECLARATION OF NANCY HIRSH

I, Nancy Hirsh, declare and state as follows:

1. I was employed at the NW Energy Coalition (NWEC) from April 1996 through August 2025. For the first eighteen years I was the policy director and then in 2015, I became the NWEC executive director.

2. I have a Bachelor of Science in Natural Resource Policy from the University of Michigan's School of Natural Resources and the Environment.

3. During my tenure at NWEC, I analyzed utility and regional resource planning and engaged in regulatory proceedings, utility rate cases, and utility program reviews. I worked with state policymakers and state agency staff on clean energy development, state energy strategy, and greenhouse gas emissions and air pollution reduction approaches.

4. I have reviewed the Department of Energy's Order No. 202-25-11 and have consulted with former colleagues from Sierra Club, NW Energy Coalition, and Climate Solutions.

Introduction

5. In this declaration, I address the following topics: (1) the impetus for negotiations to close the Centralia coal plant; (2) the key features of the negotiated deal; (3) the codification of the deal by the State of Washington; (4) how the shutdown agreement was incorporated into Washington State's clean energy and greenhouse gas emission reduction policies; and (5) how the TransAlta closure agreement has been implemented, including measures to address impacts on workers and the community.

Impetus for the Negotiations

6. In 2009-2010, the Washington Department of Ecology released a proposed permit and reached a proposed settlement with TransAlta, ultimately leading to an air permit addressing mercury and nitrogen oxide (NOx) emissions from Centralia. *See, e.g.,* Ex. 1-104 – Ecology BART Order 6426 for Centralia (June 18, 2010). There was widespread objection to the agreement and permit because they did not sufficiently reduce nitrogen oxide (NOx), mercury, or carbon dioxide emissions. In particular, Ecology was not requiring Selective Catalytic Reduction (SCR) technology, which is the most effective NOx control technology available. The Sierra Club and other environmental organizations challenged this permit in various adjudicative forums. *See, e.g., Sierra Club v. Southwest Clean Air Agency and TransAlta Centralia Generation, LLC*, PCHB No. 09-108, and No. 409-17-8-II (Wash. Ct. App., Div. II).

7. While challenges over the Title V permit continued throughout 2009, Washington Governor Gregoire issued Executive Order 09-05, in May 2009, directing the Department of Ecology to work to obtain TransAlta's commitment to have the Centralia plant meet the State's greenhouse gas emissions performance standard in RCW 80.80.040(1) by the

end of 2025. Ex. 1-114 - Executive Order 09-05 (May 21, 2009). This would, in practice, require closure of the plant. At the time, the Centralia plant was the largest single source of greenhouse gas emissions in Washington State, accounting for 10% of state emissions.[1] Without an earlier closure date, Washington would not meet its 2020 climate goal as established in 2008 in RCW 70A.45.020. In addition, the Centralia plant was and continues to be the single largest source of Nitrogen Oxides (NOx) in the State.[2] NOx is a significant source of haze pollution. In 2011 the Centralia plant emitted 6635 tons of NOx per year and the next largest emitter produced 1100 tons per year. In 2023, the Centralia plant emitted 3955 tons per year compared to the next largest emitter that produced 2161 tons of NOx per year. On behalf of NWEC, I joined other advocates to bring a 2015 or 2020 closure date proposal to informal discussions with Governor Gregoire's team and state policymakers.

8. During 2010, on behalf of the NW Energy Coalition, I helped lead ongoing conversations between environmental advocates and representatives of the Governor's policy office about legislative and/or policy options to develop a comprehensive clean up and/or closure strategy that accelerated the Governor's executive order timeline and expanded clean energy and local economic development. Pressure was mounting on TransAlta, first regarding immediate installation of toxic mercury controls (TransAlta was planning new mercury controls by the end of 2012), and second as U.S. Environmental Protection Agency was considering requiring installation of SCR technology. TransAlta indicated that it would consider investment in SCR along with a firm commitment to extend the life of the plant to recoup its investment.

9. In January 2011, I met with Governor Gregoire and other members of the Environmental Priorities Coalition, which includes Climate Solutions, NWEC, Sierra Club, and Washington Environmental Council (now Washington Conservation Action) to discuss potential legislation that would require Centralia's compliance with the state greenhouse gas emissions performance standard by 2015, elimination of the sales and use tax exemptions for purchase and use of coal, and state support for worker and economic development in Lewis County, where Centralia is located.

Negotiations with TransAlta, Governor Gregoire's Policy Advisors, and Public Interest Leaders

10. The Washington legislature considered two bills in early February 2011, (HB 1825 sponsored by Rep. Liias and SB 5769 sponsored by Senator Rockefeller) to require Centralia's compliance with the greenhouse gas emissions performance standard. HB1825 had a 2015 compliance date, and SB 5769 had a 2020 compliance date.

---

[1] https://ecology.wa.gov/regulations-permits/compliance-enforcement/transalta; https://data.wa.gov/Natural-Resources-Environment/Total-Emissions-by-Reporter-Excluding-Biogenic-CO2/2ci3-df4x

[2] https://ecology.wa.gov/air-climate/air-quality/air-quality-targets/air-emissions-inventory

11. On February 21, 2011, Governor Gregoire brought together TransAlta representatives and key environmental leaders from NW Energy Coalition, Sierra Club, Washington Environmental Council (now Washington Conservation Action) and Climate Solutions, with her policy advisors to explore a compromise package that reduced emissions, supported workers, and provided appropriate financial stability to the Company.

12. I represented NWEC during the negotiations.

13. After almost a week of negotiations, the parties agreed to near-term application of mercury controls, selective non-catalytic reduction (SNCR) controls to reduce NOx emissions, closure of Unit #1 by the end of 2020, closure of Unit #2 by the end of 2025, a $55 million coal transition fund, extension of sales and use tax exemption for coal purchases and use as long as air pollution conditions were met, support for the company to continue selling electricity until closure, and support to forestall requiring SCR installation if the closure agreement was codified and implemented.

Codification of the deal and subsequent Memorandum of Agreement

14. This agreement was then turned into legislative language and was offered as a striking amendment to SB 5769. With minor amendments, this bill, the Coal-Fired Electric Generation Facilities Act, passed the legislature on April 22, 2011, and was signed by Governor Gregoire on April 29, 2011. A very controversial aspect of the legislation provided that the State could not impose any further greenhouse gas emissions standards on this facility or on a utility purchasing Coal Transition Power from Centralia. RCW 80.80.110.

15. The legislation required the Governor to enter into a Memorandum of Agreement (MOA) with TransAlta to:

    - establish a process for installation of SNCR emissions control technology by January 2013; and
    - develop a strategy for TransAlta to contribute $55 million in financial assistance to the community ($30 million for energy efficiency and economic development and $25 million for energy technologies).

16. At the end of 2011, TransAlta and Governor Gregoire signed the MOA. Ex. 1-106 – Washington-TransAlta Shutdown Memorandum of Agreement (Dec. 23, 2011).

17. As part of TransAlta having the opportunity to be financially healthy during the transition period, the Company was allowed to continue to sell at least 500 megawatts of what was called “coal transition power” to a Washington based utility or the Bonneville Power Administration. Such a power purchase agreement (PPA) could last until 2025 and would be granted an exemption from the Greenhouse Gas Emissions Performance Standard. During the legislative drafting and negotiations, utilities that were considering such a PPA argued that a simple Emissions Performance Standard exemption was not enough for them to endure the public outcry over a coal-fired power purchase. The legislature

authorized the Utilities and Transportation Commission to allow a utility to earn the equity portion of its authorized rate of return.[3] Traditional utility regulation does not allow shareholder earnings on a PPA, because the utility does not hold the capital risk. This 2011 law was groundbreaking in that regard.

18. The legislation and the MOA maintained the existing sales and use tax exemptions for the facility if it met the air pollution requirements in the Memorandum of Agreement. The tax exemptions made TransAlta's commitment of financial assistance for the community, workers, economic development and clean energy an easier commitment to make.

The shutdown agreement has been the predicate of the state's clean energy and climate laws since, as well as planning for resource adequacy for the region and alternatives.

19. The exemption from any future greenhouse gas emission reduction requirement for Centralia and a utility purchasing coal transition power from it undergirded climate legislation and state planning for the next 15 years.

20. Washington State has passed three significant clean energy and climate pollution control policies since the 2011 adoption of the Coal-Fired Electric Generation Facilities Act and in each of these new laws, specific exemptions were included for TransAlta and Puget Sound Energy until the dates Centralia was scheduled to shut down each of its units. In addition, regional power planning agencies, such as the Northwest Power and Conservation Council, have assumed closure of the Centralia plant as part of their regional resource adequacy assessments and its 5-to-20-year power planning for the region.

21. I was a lead drafter of the voter approved Energy Independence Act (2006) that established clean energy standards for electric utilities and required investments in energy efficiency and new renewable energy generation. In 2013, State Senator Braun, representing the district in which Centralia resides, advanced a bill to specifically allow an exemption from the renewable energy standard. This exemption applied to an electric utility purchasing "coal transition power." RCW 19.285.040 (2)(d). No other exemption for fossil fuels was allowed in the statute.

22. As policymakers were developing the Clean Energy Transformation Act (CETA) in 2019 (SB 5116) to phase out fossil fuel use in electricity production for consumption in Washington, they consulted with the environmental organizations that had negotiated the Centralia closure deal with the Governor's office in 2011. We acknowledged that TransAlta was adhering to the terms of the original closure legislation and supported policymaker's decision to incorporate the 2025 closure date into the law, which required all utilities in Washington State to end use of coal-fired electricity to serve their customers by December 31, 2025. This date was intentionally adopted to allow Puget Sound Energy and TransAlta to operate under their power purchase contract. RCW

[3] SB 5769 §§ 304 (4), (6)

19.405.030 (1)(a). CETA also contains a penalty on electric utilities for non-compliance with the elimination of coal from electricity supply. The penalty is $100 x 1.5 per mega-watt-hour of coal-fired electricity used to serve customers. RCW 10.405.090(1)(a)(i).

23. In 2021, the Climate Commitment Act (CCA) was passed by the Washington legislature to cap greenhouse gas emissions and invest allowance revenue in clean energy and emission reduction programs. RCW 70A.65. The pace of the ramp-down of greenhouse gas emissions accounted for the timeline for closure of the Centralia coal plant at the end of 2025. In addition, TransAlta was exempt until closure from purchasing emission allowances for greenhouse gas emissions from the plant and Puget Sound Energy was exempt from purchasing emission allowances for the coal transition power it purchased from TransAlta.

Agreement implementation and its impact on workers and the community

24. Two important aspects of the closure deal were the agreement for TransAlta to install SNCR pollution control technology to address haze and NOx rather than face potential EPA requirements to install the more effective (and costlier) SCR technology. And the agreement to allow an exemption from the State's greenhouse gas emissions performance standard for Centralia and a Washington utility purchasing Centralia power up until the shutdown dates. After codification of the deal, the environmental negotiators signed a Memorandum of Understanding with TransAlta agreeing to support SNCR for pollution control before EPA and to support the purchase of Coal Transition Power by a Washington utility before the Washington Utilities and Transportation Commission. Ex. 1-107 – TransAlta-Conservation Organizations Shutdown Memorandum of Understanding (June 2012).

25. During negotiations with the company, a key factor influencing our decision to support the long closure timeline was the impact of the plant closure on the workers and the community. We discussed with TransAlta and the Governor's staff the need to support worker retraining opportunities and economic development investments within the community. TransAlta agreed to provide $55 million dollars toward these ends within the community and to advance clean energy within the state if the state maintained the sales and use tax credits on the coal purchases until closure.

26. The legislature provided broad details for the allocation of the $55 million. Funds from TransAlta would be split with $30 million going toward economic development, weatherization and energy efficiency in the impacted community, and $25 million going toward energy technologies that create energy, economic development, pollution reduction and environmental benefits. TransAlta would start contributing funds by January 1, 2012 and further details were left to be worked out in the MOA with the Governor.

27. I worked with the Governor's office and TransAlta to further refine the allocation of financial resources to ensure the intended impacts were realized. A key aspect of the MOA development was the sub-allocation of $10 million explicitly for energy efficiency

and weatherization with $1 million targeting weatherization for low- and moderate-income residents within Lewis and south Thurston Counties. It was also determined that the $20 million could be invested in community development as well as economic development within the affected communities. The parties also agreed to allow the $25 million for energy technologies to be invested anywhere in Washington state.

28. Initially the MOA set up three grant review boards, one for each area of investment. NWEC was named in the MOA to serve on the Weatherization Board, and I was selected to serve and began working with the Weatherization Board in late 2013. After several years of grantmaking, it became clear that with the administrative complexity of three Boards and up to 35 individuals serving on the Boards consolidation would improve effectiveness. In a motion to the Governor, TransAlta requested a modification of the MOA to collapse the three Boards into one, while maintaining the three separate financial accounts. The remaining Board, the Centralia Coal Transition Board (CCTB), consists of five employees of TransAlta and four community/outside representatives. NWEC was maintained as the sole organization from outside the affected area. I have served on the Centralia Coal Transition Board (CCTB) since its inception.

29. Within the $20 million allocated for community and economic development, the CCTB decided to set aside $9 million for the workers. Of this, $1 million was dedicated to education and retraining and $8 million for a payout for each worker who is terminated by the closures of Unit #1 at the end of 2020 and Unit #2 at the end of 2025.

30. The CCTB members will continue to evaluate grant proposals and award grants through July 2026. Almost all funds for weatherization, energy efficiency, and community and economic development have been distributed. A modest portion of the energy technology funds remains available for grants in 2026.

I declare under penalty of perjury under 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 13th day of January, 2026, in Seattle, Washington.

_____

Nancy Hirsh

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-03:
DOE 202(c) Webpage

An official website of the United States government Here's how you know

DOE's Use of Federal Power Act Emergency Authority

Under Federal Power Act (FPA) section 202(c), during the continuance of a war in which the United States is engaged or when an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy, or of facilities for the generation or transmission of electric energy, or of the fuel or water for generating facilities, or other causes, the Secretary of Energy may require by order temporary connections of facilities, and generation, delivery, interchange, or transmission of electricity as the Secretary determines will best meet the emergency and serve the public interest. 16 U.S.C. § 824a(c).

All public comments and requests related to FPA section 202(c) should be sent via email to AskCR@hq.doe.gov. Information that the sender deems sensitive and not eligible for public release should be marked accordingly, and both a public (redacted) and non-public version of such materials should be submitted. Additional information about 202(c) procedures, if necessary, will be announced on this page.

The provision of this process for submission of correspondence or comments on any pending application is for purposes of ensuring the receipt by the appropriate office and personnel within the Department. Establishment of this email address does not establish a "docket," and those submitting correspondence do not constitute parties or intervenors to any proceeding. Further, submission of correspondence to the Department does not in any way limit or prevent the ability of the Secretary to act on any application, or pursuant to section 202(c) without application, in any way and at any time as he or she deems appropriate.

202(c) Orders Issued to Date

2025 DOE 202(c) Orders

202(c) orders issued from Jan. 1, 2025 to Dec. 31, 2025

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202(c) orders issued from Jan. 1, 2024 to Dec. 31, 2024

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2023 DOE 202(c) Orders

202(c) orders issued from Jan. 1, 2023 to Dec. 31, 2023

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2022 DOE 202(c) Orders

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2021 DOE 202(c) Orders

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2020 DOE 202(c) Orders

202(c) orders issued from Jan. 1, 2020 to Dec. 31, 2020

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DOE 202(c) Orders Issued Prior to 2020

DOE 202(c) orders issued prior to 2020

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Numbering Scheme Information

Beginning in 2022, the Department modified the numbering scheme associated with its section 202(c) emergency orders. Prior to 2022, emergency orders followed a fiscal year timeline, whereas since the beginning of 2022, emergency orders have aligned with the calendar year. For example, a

202(c) emergency order issued in November 2017 is identified as Order No. 202-18-1 and an order issued in December 2022 is identified as Order No. 202-22-3.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-04:
Cooke Email to Alle-Murphy

-----Original Message-----
From: Alle-Murphy, Linda
Sent: Wednesday, December 28, 2005 9:05 AM
To: Mansueti, Lawrence
Subject: Re: Order No. 202-05-3

Dear Mr. Mansueti,

I am an associate at Schnader Harrison Segal and Lewis, working together with John Britton, who represents the City of Alexandria in the Mirant Power Plant matter. I have a few procedural questions regarding the application for rehearing.

According to Section VI.H. of Order No. 202-05-3, applications for rehearing in this matter should be addressed to you. Section VI.H. cites to 16 U.S.C. Section 825(l), which refers to the "Commission" (FERC). I am just seeking to confirm that Section 825(l) also applies to this DOE proceeding.

Also, are 10 CFR Section 1003.1 et seq., Office of Hearings and Appeals Procedural Regulations applicable to this proceeding (e.g. re service requirements, etc.) If not, are there other procedural rules that apply to this proceeding?

Thank you very much for your assistance! You may respond by return e-mail or, if that is not convenient for you, by telephone or fax.

Linda Alle-Murphy
Linda B. Alle-Murphy
Schnader Harrison Segal & Lewis LLP
1600 Market Street, Suite 3600
Philadelphia, PA 19103-7286

From: Cooke, Lot
Sent: Friday, December 30, 2005 8:51 AM
To: 'LAlle-Murphy@Schnader.com'
Subject: Rehearing procedures for DOE Order No. 202-05-3

Dear Ms. Alle-Murphy:

In response to your emailed question to Mr. Mansueti--

The DOE Organization Act transferred the authority of the Federal Power Commission to the Secretary, except for authority over rates and charges for the transmission and sale of electric energy, which was transferred to FERC. Federal Power Act (FPA) Section 202(c) emergency authority was generally and specifically given to the Secretary.

An order issued under the FPA is only reviewable pursuant to the rehearing provisions contained in section 313 of the FPA, so that is the applicable provision under which to seek rehearing of the December 20,
2005 order.

The DOE regulations on emergency orders, 10 CFR section 205.370, et seq., do not a have specific rehearing section, but a party seeking rehearing can look for procedural guidance to FERC's Rules of Practice and Procedure, 18 CFR Part 385. In particular the rehearing regulations contained at 18 CFR section 385.713 and the service requirement contained at 18 CFR section 385.2010. The Office of Hearings and Appeals procedures are not applicable as the Secretary will make the rehearing decision pursuant to FPA section 313.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-05:
DOE Rehearing Procedures

An official website of the United States government Here's how you know

U.S. DEPARTMENT of ENERGY

DOE 202(c) Order Rehearing Procedures

DOE may revise these procedures through advance written notification to the parties and posting here.

Intervention. Any person seeking to intervene to become a party must file a written motion to intervene by emailing AskCR@hq.doe.gov. A motion to intervene must state the movant's interest in sufficient factual detail to demonstrate that the movant has or represents an interest which may be directly and substantially affected by the outcome of the proceeding. A motion to intervene must be filed within 30 days after the

issuance of a section 202(c) order, which includes an original order or a renewal order. No grant of late intervention is permitted unless DOE finds good cause. The grant of party status will be expressly stated by DOE order within thirty days of filing. A motion to intervene may be combined with a motion for rehearing, answer, or other motion.

Rehearing. Pursuant to 16 U.S. Code § 825*l*, any party applying for rehearing must file a written motion for rehearing by emailing AskCR@hq.doe.gov within 30 days after the issuance of a section 202(c) order. The motion for rehearing must set forth specifically the ground or grounds upon which such motion is based and must contain a clear and concise statement of the facts and law which support the motion and the specific relief or ruling requested. Any grounds not specifically identified in such motion shall be waived. All motions for rehearing will be addressed in a consolidated proceeding and order on rehearing. Unless DOE acts upon the motion for rehearing within 30 days of filing, such motion may be deemed to have been denied.

Answers. Any party may file an answer to another party's motion by emailing AskCR@hq.doe.gov within 7 days after the motion is filed. An answer must contain a clear and concise statement of any disputed factual allegations and any law upon which the answer relies. An answer to an answer is not permitted.

Timing and Service. DOE will use best efforts to post filings here within 24 hours of receipt. Such posting constitutes service to all parties. Filing or posting due dates that fall on a federal holiday or weekend shall be extended to the next business day. Documents received after 4:30 p.m. Eastern Time are deemed filed on the next business day.

Confidentiality. DOE strongly encourages that all filings be limited to information suitable for public release. If procedures to maintain confidentiality are requested, DOE will provide them as needed at the discretion of DOE.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-06:
Groundwater Report (Jan. 2025)

2024 Annual Groundwater Monitoring Report for the Limited Purpose Landfill at the TransAlta Centralia Mine, near Centralia, Washington

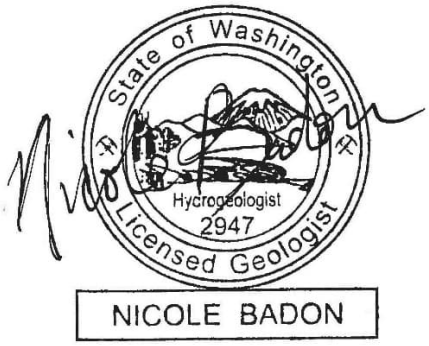
Prepared for

TransAlta Centralia Mining LLC

January 2025

Jacobs
999 W. Riverside Ave Suite 500
Spokane, WA 99201
(509) 747-2000

This report has been certified by a Hydrogeologist
licensed in the State of Washington and employed by Jacobs Engineering Group Inc.



01/30/2025

Nicole Badon, representing:

Jacobs Engineering Group

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Acronyms and Abbreviations

°C	degrees Celsius
CCR	coal combustion residuals
CCR SAP	*Groundwater Monitoring Sampling and Analysis Plan for the Limited Purpose Landfill at the TransAlta Centralia Mine*
CFR	Code of Federal Regulations
DQR	Double Quantification Rule
EPA	U.S. Environmental Protection Agency
HNO_3	nitric acid
LPLF	Limited Purpose Landfill
mg/L	milligram per liter
SSI	statistically significant increase
SWFPR	sitewide false positive rate
TCM	TransAlta Centralia Mine
UPL	Upper Prediction Limit
WAC	Washington Administrative Code

SECTION 1

Introduction

This section summarizes the 2024 annual report's purpose and objectives, the document organization, and provides the site description and the status of the monitoring program.

1.1 Purpose and Objectives

This document is the 2024 annual report for the Limited Purpose Landfill at the TransAlta Centralia Mine (TCM), as required per *CCR Groundwater Monitoring and Corrective Action* of 40 Code of Federal Regulations (CFR), 257.90(e), *Annual Groundwater Monitoring and Corrective Action Report*. Per the CCR Rule, the minimum requirements for each annual report submittal must include the following (as itemized per 40 CFR 257.90(e) [items 1 through 5]):

1. A map showing the Coal Combustion Residuals (CCR) unit (landfill) and the designated CCR groundwater monitoring network, including upgradient and downgradient wells with well identification numbers.
2. The identification of monitoring wells that were installed or decommissioned during the preceding year, along with a narrative description, and the reasons those actions were taken.
3. A summary of the groundwater samples that were collected for analysis for each upgradient (or background) and downgradient well, the dates the samples were collected, and whether the sample was required by the detection or assessment monitoring program.
4. A narrative discussion of transition between monitoring programs (the date and circumstances of transitioning from detection phase to assessment monitoring), if applicable
5. Other information required per 40 CFR 257.90 through 257.94, interpreted to include the following:
   - A map showing groundwater elevations, inferred groundwater elevation contours, and inferred groundwater flow direction from the sampling events conducted during the year.
   - A groundwater elevation hydrograph, including data over the period of record.
   - Groundwater flow rates for the semiannual events conducted during the preceding year.
   - Results from data quality review and data validation
   - A summary of the statistical method and the respective background (compliance) limits for Detection Monitoring (Appendix III) constituents
   - A summary of any Appendix III constituents that are identified as a statistically significant increase (SSI) greater than background levels.

In addition to this technical information, the annual report must also include a narrative of the following items:

- Documentation of the status of the monitoring program (that is, detection or assessment phase)
- Key actions completed for the preceding calendar year including alternative source demonstrations
- A description of problems encountered, and actions taken to resolve the problems (if needed)
- Key activities anticipated for the upcoming year

The annual reports are due by January 31 and summarize monitoring results from the preceding year. The CCR Rule requires specific reports and notifications throughout the monitoring process, with up to three forms of submittals:

- The site's operating record (40 CFR 257.105)
- Notifications to the State Director (40 CFR 257.106)
- The publicly accessible internet site (40 CFR 257.107)

1.2 Document Organization

The document is organized into the following sections:

- Section 1. Introduction. Presents the document purpose and objectives, site description, and status of monitoring program.
- Section 2. Monitoring Program Description. Summarizes the groundwater monitoring system design (well network) and the sampling program for the Limited Purpose Landfill.
- Section 3. Groundwater Monitoring Results. Summarizes the groundwater monitoring information related to background data collection and the initial compliance event and provides a map showing groundwater elevations and inferred flow direction, estimates of groundwater seepage velocity, and a summary of groundwater quality results for the initial compliance event.
- Section 4. Statistical Evaluation. Summarizes the statistical method and the compliance limits and compares the initial compliance results to the compliance limits to determine whether there is an SSI greater than background conditions for the Appendix III constituents.
- Section 5. Alternative Source Demonstration. Summarizes statistically significant exceedances, the detection monitoring results, retesting, confirmation, and documentation of an alternative source demonstration for the confirmed values.
- Section 6. Summary. Summarizes the key points of the initial annual report per the CCR regulatory requirements.
- Section 7. References. Lists the documents referenced to develop this report.

1.3 Site Description

TCM manages the Limited Purpose Landfill, which is approximately 7 miles east of Centralia, Washington (Figure 1). The Limited Purpose Landfill is north of Pit 7 in the Centralia Mine. The site is in the southern half of Section 33, Township 15N, Range 1W; Latitude 46°44'23" North, Longitude 122°49'55". The site address is 913 Big Hanaford Road, and the Property Tax Parcel (Account) Number is 023387001000. The permitted area encompassing the Limited Purpose Landfill is 57 acres, and the actual footprint of the waste disposal area is 18 acres (Figure 2). The Limited Purpose Landfill consists of the waste disposal area, and the surface impoundments immediately south of the waste disposal area to manage leachate generated at the disposal cell.

TransAlta Centralia Generation LLC operates a coal-burning power plant that is located adjacent to TCM and generates residual ash waste; the residual ash waste is disposed of into the Limited Purpose Landfill. The construction of Stage 1 began during the summer of 2009, and the Lewis County Environmental Health Department authorized TCM to begin waste disposal operations effective October 31, 2009. On December 21, 2009, the Lewis County Environmental Health Department amended the facility permit to approve the disposal of residual ash waste in Stage 1 Area A3a, in addition to Areas A1 and A2, which had been approved for disposal in the original permit. The Stage 2 Area of the Limited Purpose Landfill

was constructed in three phases from 2011 through 2014 and was subsequently approved for the receipt of ash waste material.

1.4 Status of the Groundwater Monitoring Program

The groundwater monitoring program is currently in the detection phase, as described under 40 CFR 257.94, *Detection Monitoring Program*.

In 2019, the background levels for the Appendix III constituents listed for detection monitoring were updated. The resultant Upper Prediction Limits (UPLs) represent a longer period of monitoring providing an additional 5 monitoring events. Due to the complex behavior of groundwater and need for sufficiently large sample sizes, the EPA Unified Guidance recommends that background levels should be evaluated and possibly updated every four to eight measurements.

Groundwater monitoring was conducted May 8, 2024 and October 8 and 9, 2024 for biannual monitoring. Resampling was conducted after the May 8, 2024 event on June 24, 2024 for an exceedance for boron in wells LPLF-2R and LPLF-8, and TDS in LPLF-2R. Resampling was conducted after the October 8 and 9, 2024 sampling event on November 26, 2024 for boron in wells LPLF-2R and LPLF-8, and TDS in LPLF-2R. The resampling results were used in an alternative source demonstration, as documented in Section 5 of this report. Based on the demonstrations, the SSI are determined as a result of natural variation in groundwater concentrations from the resaturated spoils beneath the facility.

SECTION 2

Monitoring Program Description

This section summarizes the CCR groundwater monitoring program for the Limited Purpose Landfill.

2.1 Monitoring Program

Groundwater is monitored in accordance with the CCR SAP (CH2M, 2016). Details regarding the site hydrogeology, the stratigraphic sequence, the uppermost aquifer, and the lower aquitard/confining unit are presented in the groundwater monitoring system design document (CH2M, 2017a) posted to the publicly available website and are not reiterated herein. Details regarding the monitoring network, sampling, and field/laboratory quality control are described in the following sections.

2.2 Monitoring Network

Effective April 17, 2015, the CCR regulations (specifically, 40 CFR 257.91, *Groundwater Monitoring Systems*) require a facility to install a detection groundwater monitoring system at appropriate locations and depths to yield groundwater samples from the uppermost aquifer and monitoring of all potential contamination pathways. At least one upgradient well must accurately represent the quality of background groundwater unaffected by potential leakage from the CCR unit. The regulations also state that at least three downgradient wells must accurately represent the quality of groundwater passing the waste boundary for the detection of potential groundwater contamination in the uppermost aquifer.

Table 1 summarizes the groundwater monitoring well network and construction details for the Limited Purpose Landfill. Figure 2 shows the designated CCR groundwater monitoring network, which consists of five wells screened in the uppermost aquifer and located around the perimeter of the ash disposal area. Monitoring wells LPLF-1 and LPLF-5 are effectively upgradient of the landfill and used to characterize background conditions unaffected by the landfill, and wells LPLF-2R, LPLF-7R, and LPLF-8 are downgradient and designated as compliance wells. As noted in Section 1.4, documentation of the CCR *Groundwater Monitoring Systems* design was submitted to the publicly available website in October 2017, as described in the *Coal Combustion Residual Groundwater Monitoring System Certification for the Limited Purpose Landfill at the Centralia Mine near Centralia, Washington* (CH2M, 2017a).

2.3 Groundwater Level Measurement

Static groundwater level measurements are collected during each monitoring event to calculate groundwater elevations, estimate groundwater flow direction, and calculate the groundwater seepage velocity. Groundwater elevations are calculated by subtracting the field measured static depth to water from the surveyed top-of-casing elevations relative to the local vertical datum (NAD 27, Washington State Plane, North 3601, Feet Intl). Field-measured groundwater levels are recorded on field forms (provided in Appendix A) and the groundwater level data are presented in Section 3.

2.4 Groundwater Sampling

Each well is equipped with dedicated tubing to facilitate low-flow sampling methods, except for LPLF-1, which is bailed to collect the sample. A peristaltic pump is used to support sampling methods required for low-flow (minimal drawdown) groundwater sampling procedures as described under *Groundwater Sampling Guidelines for Superfund and RCRA Project Managers* (EPA, 2002). In accordance with the low-flow method, purging continues until field parameters have stabilized to acceptable tolerances as outlined in the CCR SAP (CH2M, 2016b). Field parameters are measured using factory-calibrated multiparameter probe. Appendix A includes copies of field sampling forms for sampling events conducted in 2024.

Groundwater samples were collected in laboratory-provided sample containers. Below are the test methods, reporting limits, and preservatives to collect groundwater samples for the Appendix III constituents for detection monitoring.

Constituent	Analytical Test Method	Reporting Limit (mg/L)	Preservative
Boron	EPA 6010C	0.01	HNO_3
Calcium	EPA 6010C	0.05	HNO_3
Chloride	E300	2.5	Chill to 4°C
Fluoride	E300	0.5	Chill to 4°C
pH	SM 4500H B	0.1	Chill to 4°C
Sulfate	E300	10	Chill to 4°C
Total Dissolved Solids	A2540C	1	Chill to 4°C

°C = degrees Celsius
HNO_3 = nitric acid
mg/L = milligram per liter

Laboratory analyses were performed by an accredited and certified testing laboratory (ALS, in Kelso, Washington).

2.5 Field and Laboratory Quality Control

As described in the CCR SAP (CH2M, 2016b), field and laboratory quality control are guided by the field quality control procedures that included sample labeling, chain-of-custody documentation, and sealing of sample containers following sample collection. Field duplicate and matrix spike (with duplicates) samples are collected during each sampling event. Temperature and method blanks are included with each shipment.

Laboratory quality control procedures included analysis of method blanks, surrogates, duplicates, and matrix spike/matrix spike duplicates. Results from the laboratory quality control procedures are included in the analytical data packages and are included in Appendix B.

SECTION 3

Groundwater Monitoring Results

This section summarizes the groundwater monitoring results related to the dates of sampling for the monitoring events, groundwater elevations, groundwater flow direction, the estimates of groundwater seepage velocity, and the groundwater quality results from the monitoring events.

3.1 Compliance Monitoring Events

The CCR Rule requires at least eight background groundwater monitoring events before the October 17, 2017, deadline to establish background conditions. Monitoring events after the eighth background event are considered initial detection-phase compliance monitoring to determine whether there is an SSI greater than background conditions. Below is a summary of the compliance and resampling events and the respective constituent suites for the sampling events. In 2024 an additional 2 monitoring events were included in the re-evaluation and determination of groundwater conditions.

Monitoring Event Type/Purpose	Date Completed	Appendix III, Detection Monitoring Constituents	Resampled Wells
Detection/Compliance	May 8, 2024	Yes	NA
Resampling/Confirmation	June 24, 2024	2 Constituents (boron, and TDS)	LPLF-2R, LPLF-8
Detection/Compliance	October 8 and 9, 2024	Yes	NA
Resampling/Confirmation	November 26, 2024	2 Constituents (boron, and TDS)	LPLF-2R, LPLF-8

3.2 Groundwater Levels and Hydrographs

Table 2 summarizes the groundwater measurements from the 2024 groundwater monitoring program. Figure 3 shows the groundwater elevation hydrograph from the CCR network wells from the initial monitoring events conducted from November 2016 through November 2024. In general, groundwater elevations are relatively similar to historical levels. Continued monitoring will be used to assess the need to evaluate seasonal patterns, characteristics, or apparent trends in the site hydrograph.

3.3 Groundwater Flow Direction

Figures 4 and 5 show the elevation contours and inferred flow direction for the groundwater conditions at the site for May and October 2024, respectively. The groundwater in the uppermost aquifer beneath the Limited Purpose Landfill generally flows to the southwest. Well, LPLF-5 was dry during the October 8, 2024 sampling event (the elevation of the lowest measured groundwater level in LPLF-5 was used for contouring). A flow direction to the southwest is consistent with historical groundwater monitoring results.

3.4 Groundwater Flow Velocity Estimates

The estimated groundwater seepage velocity is 5 feet per year, which is based on the following equation and hydraulic assumptions and groundwater elevations in the uppermost aquifer:

$$v = \frac{K_a i}{n_e}$$ Equation from Fetter, 1994

where:

v	=	groundwater velocity (seepage velocity)
K_a	=	average horizontal hydraulic conductivity
i	=	horizontal hydraulic gradient
n_e	=	effective porosity

- An average hydraulic conductivity estimate of 0.11 to 0.17 feet per day (equivalent to 3.88 x 10^{-5} to 5.82x 10^{-5} centimeters per second), which is based on slug test analyses and as summarized in the *Coal Combustion Residual Groundwater Monitoring System Certification for the Limited Purpose Landfill at the Centralia Mine Site near Centralia, Washington* (CH2M, 2017a).
- Hydraulic gradient was consistently 0.02 to 0.03 feet per foot, as measured from Figures 4 and 5. This value is considered a typical but lower value based on previous monitoring performed under the pre-existing WAC program since 2007.
- Effective porosity of 0.15 (assumed value generally representative of mine spoils)

3.5 Groundwater Quality Results

Table 3 presents the groundwater quality results for the Appendix III constituents from the 2024 groundwater monitoring and resampling events. Groundwater data from the monitoring events are compared to the background conditions per the selected statistical method to determine whether the initial compliance values exceed background concentrations, as presented in Section 4. Resampling was conducted to confirm parameters that represented statistically significant exceedances for those wells and parameters identified.

3.6 Data Quality Assessment

The groundwater quality data were reviewed to assess the representativeness and usability of data before performing statistical evaluations as presented in Section 4. The method for performing the data quality review is documented in the CCR SAP (CH2M, 2016b) and follows procedures in the U.S. Environmental Protection Agency (EPA) *National Functional Guidelines for Inorganic Superfund Methods Data Review* (EPA, 2016).

Table 4 is a summary of the data validation that was conducted for each sampling and analysis event. The summary includes review of laboratory analysis, receipt, qualifiers, laboratory method blanks, replicant sample results, and matrix spike recovery. Additionally, a field duplicate was collected for each detection monitoring event and relative percentage difference calculated for the duplicate sample. Laboratory and field duplicate values were within the data validation limits.

The data quality assessment is that analysis was consistent with the CCR SAP for the site. Based on this review, the field and laboratory methods followed the procedures specified in the CCR SAP, the completeness target/goal of 100 percent was achieved, none of the data were rejected, and data were found to satisfy the data quality objectives to be included for statistical evaluation as presented in Section 4.

SECTION 4

Statistical Evaluation

This section summarizes the CCR regulatory requirements for statistical evaluation under the detection phase, as well as the selected statistical method, and compares the 2024 monitoring data to determine if monitoring values exceed compliance limits.

4.1 Statistical Evaluation Regulatory Requirements

The CCR Rule specifically lists four methods acceptable for statistical analysis (40 CFR 257.93[f]):

1. Parametric or nonparametric analysis of variance
2. Tolerance intervals
3. Prediction intervals (limits)
4. Control charts

Another statistical test method also may be considered if it meets the performance standards listed in 40 CFR 297.93(g). Per the CCR Rule, the selected statistical method was posted to the publicly available website by the October 17, 2017, deadline.

4.2 Statistical Evaluation Methods and Compliance Limits

Based on the site-specific groundwater conditions and results from an exploratory evaluation of the background data, the selected statistical method for evaluating groundwater detection monitoring data is a prediction interval (limit) method, which is a statistical method option, per 40 CFR 257.93(f)(3). The prediction interval method will be used separately for each well-constituent pair and was selected because the Appendix III constituents exhibited significant spatial variability, making an upgradient versus downgradient, also known as interwell, comparison infeasible. The method for six of the seven Appendix III constituents (including boron, calcium, chloride, pH, sulfate, and TDS) is an intra-well Prediction Limit; the seventh constituent, fluoride, is handled separately via the Double Quantification Rule (DQR). Per EPA *Unified Guidance* (2009), the DQR is applicable to constituents that exhibit 100 percent no-detect characteristics, and fluoride is 100 percent nondetect during the background period. The DQR method, which is applicable to fluoride only, assumes that a SSI is confirmed if both the original and retest values are confirmed to be detected values. Supplemental details and rationale for method selection are presented in *Coal Combustion Residual Statistical Method for the Limited Purpose Landfill at the Centralia Mine near Centralia, Washington* (CH2M, 2017b), which has been posted to the CCR public website prior to the October 17, 2017, deadline.

EPA's *Unified Guidance* (2009) recommends that prediction limits be combined with retesting for maintaining a low sitewide false positive rate (SWFPR) while providing high statistical power. The exploratory analysis confirmed a "1-of-2" retesting strategy is acceptable and will be used to verify an apparent SSI (that is, an initial SSI for Appendix III constituents). Retesting is an integral part of the statistical methodology for controlling the SWFPR when multiple monitoring locations and parameters are being evaluated. Assuming the "1-of-2" retesting approach, an apparent SSI cannot be confirmed or denied until the results of the resampling event have been obtained.

Following the prediction interval method, the compliance limits were calculated on the CCR Appendix III constituents for the three downgradient compliance wells (LPLF-2R, LPLF-8, and LPLF-7R). The calculation of intra-well prediction limits is used for six of the seven CCR constituents, including boron, calcium, chloride, pH, sulfate, and TDS; fluoride is evaluated separately via the DQR as a result of the 100 percent nondetects during background period. Assuming that sample background data are normally

distributed, or assuming that they can be transformed to fit a normal distribution, then the parametric upper prediction limit (UPL) is based on equation (1) as follows:

$$UPL = \overline{x} + Ks \quad (1)$$

where:

$\overline{x}$ is the sample mean,

s is the sample standard deviation, and

K is a multiplier factor that is chosen based on the evaluation schedule (nE), number of constituents (nc), number of wells (nw), number of background observations (n), overall SWFPR, and the specific retesting scheme selected.

For constituents such as pH, which require both lower and upper prediction limits, equation (2) is used:

$$LPL, UPL = \overline{x} \pm Ks \quad (2)$$

Table 5 presents the background (compliance) limits for each Appendix-III constituent derived from the equations above. For selected constituents exhibiting trends during background period, the background data were detrended before determining the background levels. As shown in Table 5, the constituents in which trends will be accounted for include boron, calcium, and TDS at well LPLF-2R; chloride, sulfate, and TDS at well LPLF-7R; and calcium, sulfate, and TDS at well LPLF-8. For the cases listed as 'no' for trend removal, the UPLs and lower prediction levels are the fixed compliance values to directly compare against future detection monitoring data to determine a SSI above compliance, and will be the levels to use until background is updated in the future. However, for cases listed as 'yes' for trend removal, the UPL is a calculated value dependent on time of sampling using equation (3) as follows:

Trend accounting UPL = Intercept + slope(time, in days) + residual value* (3)

Note that the trendline equations and variables for intercept, slope, time, and residual values are shown in Table 5; these UPLs are listed as 'calculated' as they are dependent upon the time when the compliance data were obtained. The time (in days) is assumed as the number of days starting from the initial background event (which was collected on November 14, 2016) to when the compliance data in question were collected (example May 8, 2024, which is 2732 days following the initial event on November 14, 2016). For TDS at well LPLF-2R, transformation was performed using the Tukey power transformation to convert it into a normal distribution before applying the simple regression to determine an appropriate relationship for trend removal.

4.3 Statistical Evaluation Results

Table 6 summarizes the monitoring results determined to be confirmed SSI after retesting and therefore identified for further evaluation. The 2024 groundwater monitoring results were less than or within the respective compliance limits, except for the following six cases, boron in LPLF-2R (spring and fall) and LPLF-8 (spring and fall), and total dissolved solids (TDS) in LPLF-2R (spring and fall).

Resampling and confirmation testing were conducted within 90 days after validation of monitoring results and evaluated for potential detection or applicability of an alternative source demonstration. Resampling confirmed the values for boron in LPLF-2R and LPLF-8, and TDS in LPLF-2R. Therefore, resulting in a total of six SSIs.

The remaining detections were determined that an alternative source demonstration was appropriate for the six results. Section 5 discusses the alternative source demonstration and applicability to these confirmed SSI results. It is anticipated that these results will be included in a review of site conditions and groundwater quality variability under changing groundwater elevations.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-07:
Cleanup Site Details (Oct. 2025)

Cleanup Site Details

Cleanup Site ID: 17302

Cleanup Site ID: 17302 **Facility/Site ID:** 94772166 **UST ID:** 8710 Site Page | Site Documents | View Map

Cleanup Site Name: TransAlta Centralia Glossary

Alternate Names: CENTRALIA STEAM PLANT, TransAlta, TransAlta Centralia

LOCATION

Address: 913 BIG HANAFORD RD **City:** CENTRALIA **Zip Code:** 98531 **County:** Lewis

Latitude: 46.75487 **Longitude:** -122.86360 **WRIA:** 23 **Legislative District:** 20 **Congressional District:** 3 **TRS:** 15N 1W 30

DETAIL

Status: Awaiting Cleanup **NFA Received?** No **Is PSI site?** No

Statute: MTCA **NFA Date:** N/A **Current VCP?** No **Past VCP?** No

Site Rank: N/A **NFA Reason:** N/A **Brownfield?** No

Site Manager: Middleton, Tom **Responsible Unit:** Southwest **Active Institutional Control?** No

CLEANUP UNITS

Cleanup Unit Name	Unit Type	Unit Status	Resp Unit	Unit Manager	Current Process
TransAlta	Upland	Awaiting Cleanup	SW	Middleton, Tom	Ecology-supervised or conducted
TransAlta Sediment	Sediment	Awaiting Cleanup	SW	Middleton, Tom	Ecology-supervised or conducted

ACTIVE INSTITUTIONAL CONTROLS

Instrument Type	Restriction Media	Restrictions/Requirements	Date	Recording Number	Recording County	Tax Parcel
There are no current Institutional Controls in effect for this site.						

AFFECTED MEDIA & CONTAMINANTS

	MEDIA					
Contaminant	**Soil**	**Groundwater**	**Surface Water**	**Sediment**	**Air**	**Bedrock**
Arsenic	C	C				
Dioxins/Furans	B					
Halogenated Solvents		C				
Mercury				C		
Metals - Other	C	C		C		
Petroleum-Diesel		C				
Petroleum-Other		B				

Key:
B - Below Cleanup Level C - Confirmed Above Cleanup Level RA - Remediated-Above
S - Suspected R - Remediated RB - Remediated-Below

SITE ACTIVITIES

Activity	Status	Start Date	End Date/ Completion Date
Site Discovery/Release Report Received	Completed		5/14/2025
Initial Investigation / Federal Preliminary Assessment	Completed		6/2/2025
Early Notice Letter(s)	Completed		8/13/2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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Exhibit 1-06:
Groundwater Report (Jan. 2025)

2024 Annual Groundwater Monitoring Report for the Limited Purpose Landfill at the TransAlta Centralia Mine, near Centralia, Washington

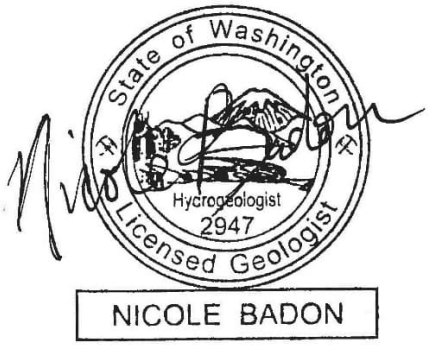
Prepared for

TransAlta Centralia Mining LLC

January 2025

Jacobs
999 W. Riverside Ave Suite 500
Spokane, WA 99201
(509) 747-2000

This report has been certified by a Hydrogeologist
licensed in the State of Washington and employed by Jacobs Engineering Group Inc.



01/30/2025

Nicole Badon, representing:

Jacobs Engineering Group

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SECTION 1

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- Section 1. Introduction. Presents the document purpose and objectives, site description, and status of monitoring program.
- Section 2. Monitoring Program Description. Summarizes the groundwater monitoring system design (well network) and the sampling program for the Limited Purpose Landfill.
- Section 3. Groundwater Monitoring Results. Summarizes the groundwater monitoring information related to background data collection and the initial compliance event and provides a map showing groundwater elevations and inferred flow direction, estimates of groundwater seepage velocity, and a summary of groundwater quality results for the initial compliance event.
- Section 4. Statistical Evaluation. Summarizes the statistical method and the compliance limits and compares the initial compliance results to the compliance limits to determine whether there is an SSI greater than background conditions for the Appendix III constituents.
- Section 5. Alternative Source Demonstration. Summarizes statistically significant exceedances, the detection monitoring results, retesting, confirmation, and documentation of an alternative source demonstration for the confirmed values.
- Section 6. Summary. Summarizes the key points of the initial annual report per the CCR regulatory requirements.
- Section 7. References. Lists the documents referenced to develop this report.

1.3 Site Description

TCM manages the Limited Purpose Landfill, which is approximately 7 miles east of Centralia, Washington (Figure 1). The Limited Purpose Landfill is north of Pit 7 in the Centralia Mine. The site is in the southern half of Section 33, Township 15N, Range 1W; Latitude 46°44'23" North, Longitude 122°49'55". The site address is 913 Big Hanaford Road, and the Property Tax Parcel (Account) Number is 023387001000. The permitted area encompassing the Limited Purpose Landfill is 57 acres, and the actual footprint of the waste disposal area is 18 acres (Figure 2). The Limited Purpose Landfill consists of the waste disposal area, and the surface impoundments immediately south of the waste disposal area to manage leachate generated at the disposal cell.

TransAlta Centralia Generation LLC operates a coal-burning power plant that is located adjacent to TCM and generates residual ash waste; the residual ash waste is disposed of into the Limited Purpose Landfill. The construction of Stage 1 began during the summer of 2009, and the Lewis County Environmental Health Department authorized TCM to begin waste disposal operations effective October 31, 2009. On December 21, 2009, the Lewis County Environmental Health Department amended the facility permit to approve the disposal of residual ash waste in Stage 1 Area A3a, in addition to Areas A1 and A2, which had been approved for disposal in the original permit. The Stage 2 Area of the Limited Purpose Landfill

was constructed in three phases from 2011 through 2014 and was subsequently approved for the receipt of ash waste material.

1.4 Status of the Groundwater Monitoring Program

The groundwater monitoring program is currently in the detection phase, as described under 40 CFR 257.94, *Detection Monitoring Program*.

In 2019, the background levels for the Appendix III constituents listed for detection monitoring were updated. The resultant Upper Prediction Limits (UPLs) represent a longer period of monitoring providing an additional 5 monitoring events. Due to the complex behavior of groundwater and need for sufficiently large sample sizes, the EPA Unified Guidance recommends that background levels should be evaluated and possibly updated every four to eight measurements.

Groundwater monitoring was conducted May 8, 2024 and October 8 and 9, 2024 for biannual monitoring. Resampling was conducted after the May 8, 2024 event on June 24, 2024 for an exceedance for boron in wells LPLF-2R and LPLF-8, and TDS in LPLF-2R. Resampling was conducted after the October 8 and 9, 2024 sampling event on November 26, 2024 for boron in wells LPLF-2R and LPLF-8, and TDS in LPLF-2R. The resampling results were used in an alternative source demonstration, as documented in Section 5 of this report. Based on the demonstrations, the SSI are determined as a result of natural variation in groundwater concentrations from the resaturated spoils beneath the facility.

SECTION 2

Monitoring Program Description

This section summarizes the CCR groundwater monitoring program for the Limited Purpose Landfill.

2.1 Monitoring Program

Groundwater is monitored in accordance with the CCR SAP (CH2M, 2016). Details regarding the site hydrogeology, the stratigraphic sequence, the uppermost aquifer, and the lower aquitard/confining unit are presented in the groundwater monitoring system design document (CH2M, 2017a) posted to the publicly available website and are not reiterated herein. Details regarding the monitoring network, sampling, and field/laboratory quality control are described in the following sections.

2.2 Monitoring Network

Effective April 17, 2015, the CCR regulations (specifically, 40 CFR 257.91, *Groundwater Monitoring Systems*) require a facility to install a detection groundwater monitoring system at appropriate locations and depths to yield groundwater samples from the uppermost aquifer and monitoring of all potential contamination pathways. At least one upgradient well must accurately represent the quality of background groundwater unaffected by potential leakage from the CCR unit. The regulations also state that at least three downgradient wells must accurately represent the quality of groundwater passing the waste boundary for the detection of potential groundwater contamination in the uppermost aquifer.

Table 1 summarizes the groundwater monitoring well network and construction details for the Limited Purpose Landfill. Figure 2 shows the designated CCR groundwater monitoring network, which consists of five wells screened in the uppermost aquifer and located around the perimeter of the ash disposal area. Monitoring wells LPLF-1 and LPLF-5 are effectively upgradient of the landfill and used to characterize background conditions unaffected by the landfill, and wells LPLF-2R, LPLF-7R, and LPLF-8 are downgradient and designated as compliance wells. As noted in Section 1.4, documentation of the CCR *Groundwater Monitoring Systems* design was submitted to the publicly available website in October 2017, as described in the *Coal Combustion Residual Groundwater Monitoring System Certification for the Limited Purpose Landfill at the Centralia Mine near Centralia, Washington* (CH2M, 2017a).

2.3 Groundwater Level Measurement

Static groundwater level measurements are collected during each monitoring event to calculate groundwater elevations, estimate groundwater flow direction, and calculate the groundwater seepage velocity. Groundwater elevations are calculated by subtracting the field measured static depth to water from the surveyed top-of-casing elevations relative to the local vertical datum (NAD 27, Washington State Plane, North 3601, Feet Intl). Field-measured groundwater levels are recorded on field forms (provided in Appendix A) and the groundwater level data are presented in Section 3.

2.4 Groundwater Sampling

Each well is equipped with dedicated tubing to facilitate low-flow sampling methods, except for LPLF-1, which is bailed to collect the sample. A peristaltic pump is used to support sampling methods required for low-flow (minimal drawdown) groundwater sampling procedures as described under *Groundwater Sampling Guidelines for Superfund and RCRA Project Managers* (EPA, 2002). In accordance with the low-flow method, purging continues until field parameters have stabilized to acceptable tolerances as outlined in the CCR SAP (CH2M, 2016b). Field parameters are measured using factory-calibrated multiparameter probe. Appendix A includes copies of field sampling forms for sampling events conducted in 2024.

Groundwater samples were collected in laboratory-provided sample containers. Below are the test methods, reporting limits, and preservatives to collect groundwater samples for the Appendix III constituents for detection monitoring.

Constituent	Analytical Test Method	Reporting Limit (mg/L)	Preservative
Boron	EPA 6010C	0.01	HNO_3
Calcium	EPA 6010C	0.05	HNO_3
Chloride	E300	2.5	Chill to 4°C
Fluoride	E300	0.5	Chill to 4°C
pH	SM 4500H B	0.1	Chill to 4°C
Sulfate	E300	10	Chill to 4°C
Total Dissolved Solids	A2540C	1	Chill to 4°C

°C = degrees Celsius
HNO_3 = nitric acid
mg/L = milligram per liter

Laboratory analyses were performed by an accredited and certified testing laboratory (ALS, in Kelso, Washington).

2.5 Field and Laboratory Quality Control

As described in the CCR SAP (CH2M, 2016b), field and laboratory quality control are guided by the field quality control procedures that included sample labeling, chain-of-custody documentation, and sealing of sample containers following sample collection. Field duplicate and matrix spike (with duplicates) samples are collected during each sampling event. Temperature and method blanks are included with each shipment.

Laboratory quality control procedures included analysis of method blanks, surrogates, duplicates, and matrix spike/matrix spike duplicates. Results from the laboratory quality control procedures are included in the analytical data packages and are included in Appendix B.

SECTION 3

Groundwater Monitoring Results

This section summarizes the groundwater monitoring results related to the dates of sampling for the monitoring events, groundwater elevations, groundwater flow direction, the estimates of groundwater seepage velocity, and the groundwater quality results from the monitoring events.

3.1 Compliance Monitoring Events

The CCR Rule requires at least eight background groundwater monitoring events before the October 17, 2017, deadline to establish background conditions. Monitoring events after the eighth background event are considered initial detection-phase compliance monitoring to determine whether there is an SSI greater than background conditions. Below is a summary of the compliance and resampling events and the respective constituent suites for the sampling events. In 2024 an additional 2 monitoring events were included in the re-evaluation and determination of groundwater conditions.

Monitoring Event Type/Purpose	Date Completed	Appendix III, Detection Monitoring Constituents	Resampled Wells
Detection/Compliance	May 8, 2024	Yes	NA
Resampling/Confirmation	June 24, 2024	2 Constituents (boron, and TDS)	LPLF-2R, LPLF-8
Detection/Compliance	October 8 and 9, 2024	Yes	NA
Resampling/Confirmation	November 26, 2024	2 Constituents (boron, and TDS)	LPLF-2R, LPLF-8

3.2 Groundwater Levels and Hydrographs

Table 2 summarizes the groundwater measurements from the 2024 groundwater monitoring program. Figure 3 shows the groundwater elevation hydrograph from the CCR network wells from the initial monitoring events conducted from November 2016 through November 2024. In general, groundwater elevations are relatively similar to historical levels. Continued monitoring will be used to assess the need to evaluate seasonal patterns, characteristics, or apparent trends in the site hydrograph.

3.3 Groundwater Flow Direction

Figures 4 and 5 show the elevation contours and inferred flow direction for the groundwater conditions at the site for May and October 2024, respectively. The groundwater in the uppermost aquifer beneath the Limited Purpose Landfill generally flows to the southwest. Well, LPLF-5 was dry during the October 8, 2024 sampling event (the elevation of the lowest measured groundwater level in LPLF-5 was used for contouring). A flow direction to the southwest is consistent with historical groundwater monitoring results.

3.4 Groundwater Flow Velocity Estimates

The estimated groundwater seepage velocity is 5 feet per year, which is based on the following equation and hydraulic assumptions and groundwater elevations in the uppermost aquifer:

$$v = \frac{K_a i}{n_e}$$ Equation from Fetter, 1994

where:

v	=	groundwater velocity (seepage velocity)
K_a	=	average horizontal hydraulic conductivity
i	=	horizontal hydraulic gradient
n_e	=	effective porosity

- An average hydraulic conductivity estimate of 0.11 to 0.17 feet per day (equivalent to 3.88 x 10^{-5} to 5.82x 10^{-5} centimeters per second), which is based on slug test analyses and as summarized in the *Coal Combustion Residual Groundwater Monitoring System Certification for the Limited Purpose Landfill at the Centralia Mine Site near Centralia, Washington* (CH2M, 2017a).
- Hydraulic gradient was consistently 0.02 to 0.03 feet per foot, as measured from Figures 4 and 5. This value is considered a typical but lower value based on previous monitoring performed under the pre-existing WAC program since 2007.
- Effective porosity of 0.15 (assumed value generally representative of mine spoils)

3.5 Groundwater Quality Results

Table 3 presents the groundwater quality results for the Appendix III constituents from the 2024 groundwater monitoring and resampling events. Groundwater data from the monitoring events are compared to the background conditions per the selected statistical method to determine whether the initial compliance values exceed background concentrations, as presented in Section 4. Resampling was conducted to confirm parameters that represented statistically significant exceedances for those wells and parameters identified.

3.6 Data Quality Assessment

The groundwater quality data were reviewed to assess the representativeness and usability of data before performing statistical evaluations as presented in Section 4. The method for performing the data quality review is documented in the CCR SAP (CH2M, 2016b) and follows procedures in the U.S. Environmental Protection Agency (EPA) *National Functional Guidelines for Inorganic Superfund Methods Data Review* (EPA, 2016).

Table 4 is a summary of the data validation that was conducted for each sampling and analysis event. The summary includes review of laboratory analysis, receipt, qualifiers, laboratory method blanks, replicant sample results, and matrix spike recovery. Additionally, a field duplicate was collected for each detection monitoring event and relative percentage difference calculated for the duplicate sample. Laboratory and field duplicate values were within the data validation limits.

The data quality assessment is that analysis was consistent with the CCR SAP for the site. Based on this review, the field and laboratory methods followed the procedures specified in the CCR SAP, the completeness target/goal of 100 percent was achieved, none of the data were rejected, and data were found to satisfy the data quality objectives to be included for statistical evaluation as presented in Section 4.

SECTION 4

Statistical Evaluation

This section summarizes the CCR regulatory requirements for statistical evaluation under the detection phase, as well as the selected statistical method, and compares the 2024 monitoring data to determine if monitoring values exceed compliance limits.

4.1 Statistical Evaluation Regulatory Requirements

The CCR Rule specifically lists four methods acceptable for statistical analysis (40 CFR 257.93[f]):

1. Parametric or nonparametric analysis of variance
2. Tolerance intervals
3. Prediction intervals (limits)
4. Control charts

Another statistical test method also may be considered if it meets the performance standards listed in 40 CFR 297.93(g). Per the CCR Rule, the selected statistical method was posted to the publicly available website by the October 17, 2017, deadline.

4.2 Statistical Evaluation Methods and Compliance Limits

Based on the site-specific groundwater conditions and results from an exploratory evaluation of the background data, the selected statistical method for evaluating groundwater detection monitoring data is a prediction interval (limit) method, which is a statistical method option, per 40 CFR 257.93(f)(3). The prediction interval method will be used separately for each well-constituent pair and was selected because the Appendix III constituents exhibited significant spatial variability, making an upgradient versus downgradient, also known as interwell, comparison infeasible. The method for six of the seven Appendix III constituents (including boron, calcium, chloride, pH, sulfate, and TDS) is an intra-well Prediction Limit; the seventh constituent, fluoride, is handled separately via the Double Quantification Rule (DQR). Per EPA *Unified Guidance* (2009), the DQR is applicable to constituents that exhibit 100 percent no-detect characteristics, and fluoride is 100 percent nondetect during the background period. The DQR method, which is applicable to fluoride only, assumes that a SSI is confirmed if both the original and retest values are confirmed to be detected values. Supplemental details and rationale for method selection are presented in *Coal Combustion Residual Statistical Method for the Limited Purpose Landfill at the Centralia Mine near Centralia, Washington* (CH2M, 2017b), which has been posted to the CCR public website prior to the October 17, 2017, deadline.

EPA's *Unified Guidance* (2009) recommends that prediction limits be combined with retesting for maintaining a low sitewide false positive rate (SWFPR) while providing high statistical power. The exploratory analysis confirmed a "1-of-2" retesting strategy is acceptable and will be used to verify an apparent SSI (that is, an initial SSI for Appendix III constituents). Retesting is an integral part of the statistical methodology for controlling the SWFPR when multiple monitoring locations and parameters are being evaluated. Assuming the "1-of-2" retesting approach, an apparent SSI cannot be confirmed or denied until the results of the resampling event have been obtained.

Following the prediction interval method, the compliance limits were calculated on the CCR Appendix III constituents for the three downgradient compliance wells (LPLF-2R, LPLF-8, and LPLF-7R). The calculation of intra-well prediction limits is used for six of the seven CCR constituents, including boron, calcium, chloride, pH, sulfate, and TDS; fluoride is evaluated separately via the DQR as a result of the 100 percent nondetects during background period. Assuming that sample background data are normally

distributed, or assuming that they can be transformed to fit a normal distribution, then the parametric upper prediction limit (UPL) is based on equation (1) as follows:

$$UPL = \overline{x} + Ks \quad (1)$$

where:

$\overline{x}$ is the sample mean,

s is the sample standard deviation, and

K is a multiplier factor that is chosen based on the evaluation schedule (nE), number of constituents (nc), number of wells (nw), number of background observations (n), overall SWFPR, and the specific retesting scheme selected.

For constituents such as pH, which require both lower and upper prediction limits, equation (2) is used:

$$LPL, UPL = \overline{x} \pm Ks \quad (2)$$

Table 5 presents the background (compliance) limits for each Appendix-III constituent derived from the equations above. For selected constituents exhibiting trends during background period, the background data were detrended before determining the background levels. As shown in Table 5, the constituents in which trends will be accounted for include boron, calcium, and TDS at well LPLF-2R; chloride, sulfate, and TDS at well LPLF-7R; and calcium, sulfate, and TDS at well LPLF-8. For the cases listed as 'no' for trend removal, the UPLs and lower prediction levels are the fixed compliance values to directly compare against future detection monitoring data to determine a SSI above compliance, and will be the levels to use until background is updated in the future. However, for cases listed as 'yes' for trend removal, the UPL is a calculated value dependent on time of sampling using equation (3) as follows:

Trend accounting UPL = Intercept + slope(time, in days) + residual value* (3)

Note that the trendline equations and variables for intercept, slope, time, and residual values are shown in Table 5; these UPLs are listed as 'calculated' as they are dependent upon the time when the compliance data were obtained. The time (in days) is assumed as the number of days starting from the initial background event (which was collected on November 14, 2016) to when the compliance data in question were collected (example May 8, 2024, which is 2732 days following the initial event on November 14, 2016). For TDS at well LPLF-2R, transformation was performed using the Tukey power transformation to convert it into a normal distribution before applying the simple regression to determine an appropriate relationship for trend removal.

4.3 Statistical Evaluation Results

Table 6 summarizes the monitoring results determined to be confirmed SSI after retesting and therefore identified for further evaluation. The 2024 groundwater monitoring results were less than or within the respective compliance limits, except for the following six cases, boron in LPLF-2R (spring and fall) and LPLF-8 (spring and fall), and total dissolved solids (TDS) in LPLF-2R (spring and fall).

Resampling and confirmation testing were conducted within 90 days after validation of monitoring results and evaluated for potential detection or applicability of an alternative source demonstration. Resampling confirmed the values for boron in LPLF-2R and LPLF-8, and TDS in LPLF-2R. Therefore, resulting in a total of six SSIs.

The remaining detections were determined that an alternative source demonstration was appropriate for the six results. Section 5 discusses the alternative source demonstration and applicability to these confirmed SSI results. It is anticipated that these results will be included in a review of site conditions and groundwater quality variability under changing groundwater elevations.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-09:
Ecology 2018-2028 Regional Haze Plan



State Implementation Plan Revision

Second Regional Haze Plan (2018 – 2028)

By

Air Quality Program

Washington State Department of Ecology
Olympia, Washington

January 2022
Publication 22-02-005

Publication Information

This document is available on the Department of Ecology's website at:
https://apps.ecology.wa.gov/publications/summarypages/22-02-005.html

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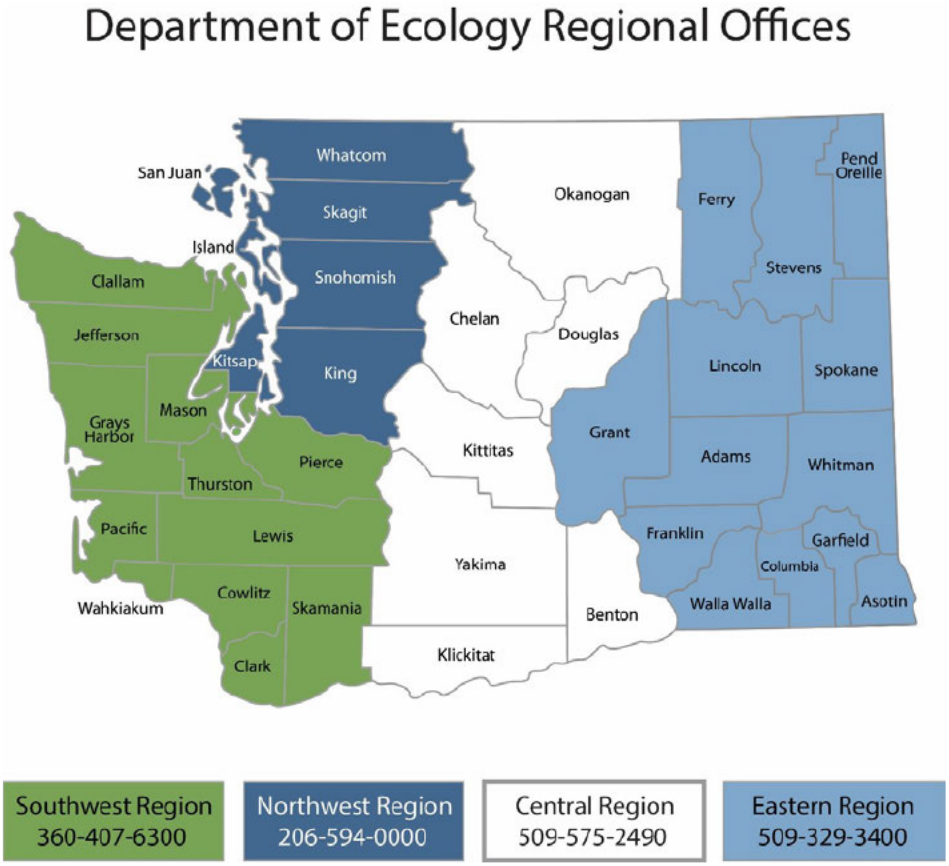
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Eastern	Adams, Asotin, Columbia, Ferry, Franklin, Garfield, Grant, Lincoln, Pend Oreille, Spokane, Stevens, Walla Walla, Whitman	4601 North Monroe Spokane, WA 99205	509-329-3400
Headquarters	Statewide	P.O. Box 46700 Olympia, WA 98504	360-407-6000

State Implementation Plan Revision

Second Regional Haze Plan (2018 – 2028)

Air Quality Program
Washington State Department of Ecology
Headquarters

Olympia, WA



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Due to document size constraints, all appendices are available as separate documents. Note that some of the content was not drafted by Ecology and cannot meet Ecology's document accessibility requirements.

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Acknowledgements

The authors of this report thank the following people for their contribution for their contribution and assistance in preparing this implementation plan:

Tim Allen, U.S. Fish and Wildlife Service
Bret Anderson U.S. Forest Service
Rick Graw, U.S. Forest Service
Jeff Hunt, EPA
Kirsten King, National Park Service
Debra Miller, National Park Service
Tom Moore, Western Regional Air Partnership
Melanie Peters, National Park Service
Janice Peterson, U.S. Forest Service
Don Shepherd, National Park Service
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Acronyms, Abbreviations, and Terms

Anthropogenic	Caused or produced by humans
ARS	Air Resource Specialist, Inc.
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Btu	British thermal unit
CAA	Clean Air Act
CAMx	Comprehensive Air Quality Model with Extensions
CD	Clearest days
CFR	Code of Federal Regulations
CIRA	Cooperative Institute for Research in the Atmosphere
CISWI	Commercial and Industrial Solid Waste Incineration Units
CM	Coarse Matter
CMAQ	Community Multi-Scale Air Quality Model
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DNR	Washington Department of Natural Resources
dv	Deciview; a measure of light extinction
EC	Elemental Carbon
Ecology	Washington State Department of Ecology
EGU	Electric Generating Unit
EI	Emission Inventory
EPA	US Environmental Protection Agency
FCCU	Fluid Catalytic Cracking Unit
FIP	Federal Implementation Plan
FLM	Federal Land Manager
GCVTC	Grand Canyon Visibility Transport Commission
GHG	Greenhouse Gas
Glidepath	The rate of improvement sufficient to attain natural conditions by 2064
HI	Haze Index
IMPROVE	Interagency Monitoring of Protected Visual Environments
LTS	Long Term Strategy
MARPOL VI	Maritime Pollution Annex VI
MID	Most Impaired Days
Mm^{-1}	Inverse megameter; a measure of light extinction
MM	Million
MM5	Meteorological Mesoscale 5
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	Ammonia
$(NH_4)2SO_4$	Ammonium Sulfate
NO_2	Nitrogen Dioxide
NO_3	Ammonium Nitrate or NH4NO3
NOx	Nitrogen Oxides

NPCA	National Parks Conservation Association
NPDES	National Pollutant Discharge Elimination System
NPS	National Park Service
NSPS	New Source Performance Standards
NSR	New Source Review
NTEC	National Tribal Environmental Council
NWPPA	Northwest Pulp and Paper Association
O_3	Ozone
OC	Organic Carbon
ODEQ	Oregon Department of Environmental Quality
OM	Organic Mass
OMC	Organic Mass of Carbon
PM	Particulate Matter
$PM_{2.5}$	Fine Particles or Particulate Matter with an aerodynamic diameter of 2.5 microns or less
PM_{10}	Coarse Particles or Particulate Matter with an aerodynamic diameter of 10 microns or less
POA	Primary Organic Aerosol
ppm	parts per million
PSAT	Particulate Matter Source Apportionment Technology
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RAVI	Reasonably Attributable Visibility Impairment
RH	Regional Haze
RHR	Regional Haze Rule
RPG	Reasonable Progress Goal
RPO	Regional Planning Organization
RRF	Relative Response Factors
SIP	State Implementation Plan
SMOKE	Sparse Matrix Operator Kernel Emissions
SMP	Smoke Management Plan
SOIL	Fine Soil
SO_2	Sulfur Dioxide
SO_4	Ammonium Sulfate or $(NH_4)_2SO_4$
SOx	Sulfur Oxides
TIP	Tribal Implementation Plan
TSS2	Technical Support System
URP	Uniform Rate of Progress
USDA FS	U.S. Department of Agriculture – Forest Service
USDI FWS	U.S Department of the Interior – Fish and Wildlife Service
USDI NPS	U.S. Department of the Interior – National Park Service
USGS	U.S. Geological Survey
VOC	Volatile Organic Compound
WAC	Washington Administrative Code

WEP	Weighted Emissions Potential
WESTAR	Western States Air Resources Council
WRAP	Western Regional Air Partnership

Executive Summary

This report is Washington's second Regional Haze State Implementation Plan covering 2018 through 2028 and the progress report for 2014 through 2018. The Regional Haze Rule requires Washington to meet natural visibility conditions (no human-caused haze) in our eight mandatory Class 1 federal Areas by 2064.

The plan must:

- Establish goals to improve visibility in Washington's three national parks and five wilderness areas (mandatory Class 1 federal Areas).
- Develop long-term strategies to reduce air pollution that causes poor visibility:
  - Improve visibility on the 20 percent most polluted days;
  - Protect current visibility on the 20 percent clearest days;
  - Identify and reduce Washington's air impacts to mandatory Class 1 federal Areas outside Washington.

Ecology identified that:

- Two mandatory Class 1 federal Areas (Goat Rocks Wilderness and Mount Adams Wilderness) are forecast to meet natural conditions (EPA's visibility goals) by 2028.
- Emissions from transportation are the largest source of air pollution that causes poor visibility. We have started rulemaking to reduce transportation emissions:
  - Chapter 173-423 WAC, Clean Vehicles Program, which adopts California's more protective vehicle emission standards;
  - Chapter 173-424 WAC, Clean Fuels Program Rule, which reduces pollution from vehicle fuels.
- Emissions from petroleum refineries contribute to poor visibility. We plan to identify emission controls, if any, to reduce emissions from refineries. After we have identified and scheduled installation of controls, we will amend this plan.

Washington's second Regional Haze State Implementation Plan:

- Establishes 2028 visibility goals for Washington's mandatory Class 1 federal Areas.
- Develops a long-term strategy to improve visibility.
- Provides inventories of emissions causing a visibility problem.
- Analyzes sources of haze in Washington's mandatory Class 1 federal Areas.
- Selects and evaluates the largest emitting stationary sources for potential emission controls.
  - Determines reasonable controls using a reasonability analysis.
  - Determines the emission controls that sources must install to improve visibility.

Chapter 1. Regional Haze Program Overview and Plan Development

1.1 Background

In 1977, Congress amended the Clean Air Act (CAA), 42 U.S.C. 7401 et seq., to include provisions to protect scenic vistas in certain Class 1 Areas. In these amendments, Congress declared a national visibility goal:

> *"The prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." (CAA Section 169A)*

In 1979, EPA, in consultation with the Secretary of the Interior, established 156 mandatory class 1 federal Areas (Class 1 Areas) in which they determined visibility was an important factor. EPA designated eight Class 1 Areas in Washington.

EPA promulgated reasonably attributable visibility impairment (RAVI) regulations in 1980 to address the national visibility goal. RAVI regulations address distinct plumes (called "plume blight") caused by large stationary sources. RAVI regulations represented the first phase in addressing visibility impairment. Each state must develop visibility plans as part of the larger air quality State Implementation Plan (SIP). The SIP is a large body of federally-enforceable state regulations, programs, and permits that implement, maintain, and enforce federal ambient air quality standards and the Regional Haze Program.

The Washington State Department of Ecology (Ecology) revised the SIP for the purpose of visibility protection (Visibility SIP) and submitted it to EPA in March 1985. EPA formally approved the Visibility SIP on May 4, 1987. Ecology reviewed and revised the Visibility SIP several times since then.

Washington's Visibility SIP addressed the distinct plumes from large stationary sources and silvicultural smoke. Although we do not consider prescribed burning from forestry activities a stationary source, prescribed burning has a significant impact on visibility. Because of this, Washington addressed this source in its Visibility SIP. Specifically, Ecology coordinated with the Washington Department of Natural Resources (DNR) to include visibility protections in the 1998 Smoke Management Plan (SMP). Ecology submitted a RAVI SIP — including the 1998 SMP —that focused on silvicultural (forest) smoke management in addition other sources that affect haze. Ecology submitted the 1999 RAVI SIP to EPA on November 5, 1999; EPA approved it June 11, 2003.[1]

EPA adopted the Regional Haze Rule (RHR) in 1999. The RHR addressed visibility impairment from widespread haze caused by emissions from multiple sources. These emissions often mix and

[1] Final Federal Register Notice: 68 FR 34821, June 11, 2003. https://www.govinfo.gov/content/pkg/FR-2003-06-11/pdf/03-14573.pdf#page=1; Proposal Federal Register Notice: 67 FR 65077, October 23, 2002. https://www.govinfo.gov/content/pkg/FR-2002-10-23/pdf/02-26992.pdf

disperse over long distances. The RHR established a comprehensive visibility protection program for the 156 Class 1 Areas.

In 2010, Ecology developed its first Regional Haze SIP (Ecology, 2010, revised 2012). It identified key sources of air pollution and defined a strategy to improve visibility in Washington's Class 1 Areas during the first planning period from 2005 through 2018. Ecology submitted the required Regional Haze Five Year Progress Report for the state (Ecology, 2017) in 2017. This document is the second Regional Haze SIP and covers the 10-year period from 2018 through 2028. It also serves as the progress report for 2014 through 2018.

For information on Washington's Regional Haze program, visit Ecology's Regional Haze website (Ecology, 2021).[2]

1.2 Regional Haze Rule

The objectives of the RHR are:

- Improve existing visibility in all 156 Class 1 Areas;
- Prevent future impairment of visibility by anthropogenic sources; and
- Meet the national goal of natural visibility conditions by 2064.

The RHR requires each state to adopt a RH SIP that focuses on improving visibility in the 20 percent most impaired days (MID), and protecting visibility in the 20 percent clearest days. A state's RH SIP must provide a comprehensive analysis of natural and anthropogenic sources of haze in each Class 1 Area within the state and contain strategies to control and reduce emissions that contribute to haze. For each Class 1 Area, the state must establish reasonable progress goals (RPGs) for each implementation period towards achieving natural visibility conditions. The RPGs must provide an improvement in visibility for the most impaired days over the period of the implementation plan and maintain the visibility for the clearest days over the same period. The SIP must also address Class 1 Areas outside of the state that we anticipate emissions from within the state might affect.

The RHR breaks the regional haze program into several planning periods from 2005 to 2064. The first RH SIP covered the initial planning period from 2005 - 2018. That SIP established the basis for future RH SIP revisions and initiated the process of making reasonable progress toward the 2064 goal. This second RH SIP covers the planning periods from 2018 - 2028.

In 2017, EPA revised the RHR. EPA clarified the relationship between long-term strategies and RPGs in state plans and the long-term strategy obligations of all states. EPA reiterated that the CAA requires states to consider four statutory factors in each implementation period to determine the rate of progress towards natural visibility conditions that is reasonable for each Class 1 Area. Those four factors are:

- Costs of compliance;
- Time necessary for compliance;
- Energy and non-air quality environmental impacts; and

[2] https://ecology.wa.gov/Air-Climate/Air-quality/Air-quality-targets/Regional-haze

- Remaining useful life of the facility.

The 2017 RHR revisions also addressed other issues, including:

- Described the way in which we select a set of days during each year for purposes of tracking progress towards natural visibility conditions;
- Revised some requirements for the content of progress reports;
- Updated, simplified, and extended to all states the provisions for reasonably attributable visibility impairment;
- Revoked federal implementation plans adopted in the 1980s that require EPA to assess and address any existing RAVI situations in some states;
- Revised the requirement for states to consult with the federal land managers (FLMs);
- Adjusted the due date for the next SIP from 2018 to 2021;
- Revised the due dates for progress reports; and
- Changed the requirement that states submit progress reports as formal SIP revisions to documents that need not comply with the procedural requirements of 40 CFR 51.102, 40 CFR 51.103, and Appendix V to Part 51.

Changes to FLM consultation requirements will bring the expertise and perspective of these officials into the state plan development process early enough that they can meaningfully contribute to the state's deliberations.

1.3 Progress report requirements

This RH SIP revision also serves as a progress report that demonstrates Washington's progress towards the 2018 Reasonable Progress Goals (RPGs) during the period since the previous progress report. To serve as a progress report, the 2021 Regional Haze Plan revision must address the *Requirements for periodic comprehensive revisions of implementation plans for regional haze in* 40 CFR 51.308(f) and (g). Each state must analyze the following elements in evaluating progress towards intermediate visibility goals. These elements include:

- A status update of all controls that were implemented and relied on to achieve the RPGs;
- A summary of the emissions reductions;
- A current conditions analysis including the clearest and most impaired days;
- Any changes to the speciated analysis at each Class 1 Area to identify if there are changes to which pollutants impact visibility in each Class 1 Area;
- Updated emissions inventory and any changes in emissions and sources;

EPA also specifies that the evaluation period should only cover the period since the last progress report, and include the most recent five years of available data.

In October 2017, Ecology submitted to EPA the progress report (Ecology, 2017). The report was originally due to EPA in 2015, using the data from 2009 – 2013. However, due to the delay in submitting the report, we reviewed intermediate progress based on the data collected during the 2009 - 2013 period as well as 2010 – 2014. The 2017 Progress Report addressed the following:

- Status of RH Plan state strategy
- Emissions reductions from RH Plan control strategies

- Visibility progress and emission inventory trends
- Assessment of changes impeding visibility progress
- Review of visibility monitoring strategy
- RH Plan adequacy determination
- FLM comments

We concluded in our 2017 Progress Report that visibility in Washington's Class 1 Areas improved since the 2000 – 2004 baseline period, and the visibility measured in the 2010–2014 period met or exceeded the 2018 visibility goals.

In the current 2021 RH SIP revision, however, EPA recalculated visibility metrics. At the time of the preparation of this RH SIP revision, the most recent data available for the analysis was for the 2014 – 2018 five-year period.

Preliminary raw Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data for 2019 was presented via the FLMs Environmental Database website to the public in February 2021.[3] However, we did not use this raw data for this progress report because it could be incomplete and any missing data substitutions would influence progress report analysis.

Table 1-1 describes each of the progress report elements required by EPA and references relevant chapters in this RH SIP revision where it addresses each element.

Table 1-1: EPA required elements of the Progress Report and the corresponding references in relevant chapters.

Progress Report Element	Chapter where Addressed
40 CFR 51.308(g)(1) A description of the status of implementation of all measures included in the implementation plan for achieving reasonable progress goals for mandatory Class 1 Federal areas both within and outside the State	Chapter 9. Reasonable Progress Goals.
40 CFR 51.308(g)(2) A summary of the emissions reductions achieved throughout the State through implementation of the measures described in paragraph (g)(1) of this section.	Chapter 4. Emissions Inventory.
40 CFR 51.308(g)(3) For each mandatory Class 1 Federal area within the State, the State must assess the following visibility conditions and changes, with values for most impaired, least impaired and/or clearest days as applicable expressed in terms of 5-year averages of these annual values. The period for calculating current visibility conditions is the most recent 5-year period preceding the required date of the progress report for which data are available as of a date 6 months preceding the required date of the progress report.	Chapter 3. Current Visibility Conditions in Washington's Class 1 Areas.

[3] http://vista.cira.colostate.edu/Improve/aqrv-summaries/

Progress Report Element	Chapter where Addressed
40 CFR 51.308(g)(4) An analysis tracking the change over the period since the period addressed in the most recent plan required under paragraph (f) of this section in emissions of pollutants contributing to visibility impairment from all sources and activities within the State. Emissions changes should be identified by type of source or activity. With respect to all sources and activities, the analysis must extend at least through the most recent year for which the state has submitted emission inventory information to the Administrator in compliance with the triennial reporting requirements of subpart A of this part as of a date 6 months preceding the required date of the progress report. With respect to sources that report directly to a centralized emissions data system operated by the Administrator, the analysis must extend through the most recent year for which the Administrator has provided a State-level summary of such reported data or an internet-based tool by which the State may obtain such a summary as of a date 6 months preceding the required date of the progress report. The State is not required to backcast previously reported emissions to be consistent with more recent emissions estimation procedures, and may draw attention to actual or possible inconsistencies created by changes in estimation procedures.	Chapter 3. Current Visibility Conditions in Washington's Class 1 Areas. Chapter 4. Emissions Inventory. Chapter 5. Western Regional Air Partnership Modeling. Chapter 7. Source Apportionment and Impacted Class 1 Areas. Chapter 9. Reasonable Progress Goals.
40 CFR 51.308(g)(5) An assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred since the period addressed in the most recent plan required under paragraph (f) of this section including whether or not these changes in anthropogenic emissions were anticipated in that most recent plan and whether they have limited or impeded progress in reducing pollutant emissions and improving visibility.	Chapter 4. Emissions Inventory.

The current implementation plan elements and strategies are sufficient to enable Washington or other states with Class 1 Areas affected by emissions from Washington, to meet all established RPGs for the period covered by the first implementation plan. All Washington Class 1 Area 2018 RPGs were below the uniform rate of progress and Washington remains on track to meet the long-term goal of natural conditions by 2064.

1.4 Regional haze state implementation plan development

Regional haze planning requires a regional approach to visibility impairment. This section provides background on:

- Regional planning to address regional haze.
- The role of the Western Regional Air Partnership (WRAP) in the development of this second regional haze State Implementation Plan (RH SIP).

Regional planning

Haze-causing pollutants originate from numerous sources located in different geographic areas and can transport over long distances. In recognition of this, EPA encouraged states to create regional planning organizations (RPOs) to coordinate regional activities related to the Regional Haze Rule (RHR). States formed—and EPA funded—five RPOs, which collectively cover the 48 contiguous states, Alaska, and Hawaii (Figure 1–1).



Figure 1–1: Regional Planning Organizations

Western Regional Air Partnership

The Western Regional Air Partnership (WRAP) is a voluntary organization of western states, tribes, and federal agencies that work collaboratively to address visibility impairment in Class 1 Areas. WRAP formed in 1997 as the successor to the Grand Canyon Visibility Transport Commission (GCVTC). The 1990 Amendments to the CAA authorized the formation of visibility transport commissions and required EPA to establish the GCVTC.

WRAP promoted, supported, and monitored the implementation of the GCVTC's June 1996 recommendations for improving visibility in the 16 national parks and wilderness areas on the Colorado Plateau. The recommendations developed by the GCVTC represented a significant milestone in the study of regional haze. The GCVTC's technical analysis found the customary focus on mitigating visibility impairment from stack plumes associated with stationary point sources insufficient to address the wide range of pollutants and sources that caused or contributed to visibility impairment across the Colorado Plateau. The GCVTC's air quality monitoring and modeling showed that the long-range transport (more than 100 miles) of emissions from numerous and widespread sources contributed to regional haze.

The RHR expanded the focus of regional visibility planning processes in the West from the Colorado Plateau to all western Class 1 Areas. WRAP embraced this geographic expansion by expanding its role to address regional haze in all 13 contiguous western states, Alaska, and Hawaii.

The focus of WRAP for this second RH SIP is technical analysis. WRAP has engaged in compilation of ambient monitoring, emission inventories, air quality modeling, and data analysis. The result is a regionally consistent body of technical data and analysis to address regional haze in the west. WRAP also provides a forum for coordination and consultation between states, tribes, and FLMs.

WRAP staff work through committees, and workgroups composed of states, tribes, FLMs, and EPA. Various state and federal agencies provide additional staff time. WRAP also contracts with environmental consulting firms for analysis of air pollution data, compilation and preparation of emissions inventory data, photochemical modeling, and analyses of natural and/or uncontrollable air pollution sources.

Washington's consultation with other states, tribes, and FLMs.

Addressing regional haze requires communication between states, tribes, EPA, and FLMs. Communications can be both informal and formal. The RHR has requirements for a state to consult with the FLMs administering Class 1 Areas within a state. This section discusses the role of consultation between the state of Washington and other states, tribes, and FLMs in the development of the second RH SIP.

Consultation with other states

The RHR requires consultation between states on the development of coordinated emission management strategies. This requirement applies both to Class 1 Areas within Washington, and to Class 1 Areas outside Washington, where we anticipate emissions from Washington contribute to visibility impairment.

Coordination facilitates completion of technical tasks and policy decisions in areas such as:

- Monitoring
- Emissions
- Source attribution
- Modeling
- Control measures

This extensive coordination results in an RH SIP that reflects Washington's implementation of a regionally consistent approach to addressing visibility impairment in the west.

Washington held several conference calls with neighboring states (Alaska, Idaho and Oregon) from 2019 through 2021 to discuss the progress of regional haze plan development, including discussions on the RACT/four factor analysis and control strategies (Appendix R). Our participation in WRAP also fostered a regionally consistent approach to regional haze planning in the western states and provided a sound mechanism for consultation (Appendix K). Consultation among the fifteen western states within WRAP continues through conference calls and WRAP sponsored working group updates and results meetings.

Tribal notification

Although the RHR does not have a requirement for formal consultation with the tribes, Washington notified tribes in Washington, and federally recognized tribes in Oregon, and Idaho closest to Washington, of the development of the RH SIP. This was an informative letter to the chairpersons of the tribes in Washington. We followed up with invitations to chairpersons, natural resource managers, and tribal historic preservation officers to public meetings held in December of 2020 and January 2021 and several participated in those meetings.

Consultation with federal land managers

The RHR requires consultation between Washington and FLMs on development and implementation of the RH SIP. The RHR specifies that the consultation must provide an opportunity for affected FLMs to comment on the state's assessment of visibility impairment in each Class 1 Area and provide recommendations on the reasonable progress goals and the development and implementation of visibility control strategies to address visibility impairment. Ecology provided FLMs with an opportunity to comment on the long-term strategy, reasonable progress goals, source selection, and four-factor analysis to identify reasonable controls of haze causing emissions more than 120 days prior to the start of a public hearing or other public comment opportunity.

Formal consultation requirements do not preclude informal consultation. Ecology had informal consultation opportunities and other public comment opportunities during SIP development. These were conference calls with representatives of the U.S. Forest Service, the National Park Service, and the U.S. Fish and Wildlife Service. The major focus of these meetings was Ecology's source selection. Ecology used the EPA recommended Q/d (emissions over distance to the nearest Class 1 Area) method to determine the sources we analyzed, the four-factor analyses, and suggested control strategies. These discussions were helpful for both Ecology and the FLMs. Ecology used the discussions and informal written comments from FLMs to review the Q/d determinations.

Appendix A contains information on Ecology's early and formal consultation with the FLMs for this RH SIP. It includes the written comments submitted to Ecology along with a synopsis of FLM comments accompanied by Ecology's responses, as well as a summary of our meetings.

1.5 Environmental justice considerations

Introduction

Ecology incorporates environmental justice (EJ) into their planning process. EJ envisions and captures the need for change and defines actions the agencies may take to remove disparities. In general, EJ includes two main components:

- Fair treatment means that no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental, and commercial operations or policies
- Meaningful involvement means that the public has a fair opportunity to participate in decisions about activities that may affect their environment and/or health; can influence the regulatory agency's decision; and the decision-makers seek out and facilitate the involvement of those potentially affected early and throughout the process.

Ecology EJ actions

Ecology consulted with our EJ coordinator to determine how best to address EJ concerns within the constraints of the Regional Haze Rule and guidance. Based upon her guidance and the use of EJSCREEN, we took the following actions:

- Identify the population characteristics of the people affected by the action (such as minority populations, low-income populations, non-English speaking populations, and tribes).
- Assess and address disproportionately high and adverse human health or environmental effects on minority populations and low-income populations.
- Plan for and facilitate the meaningful involvement of affected communities in the processes.
- Ensure that potentially affected populations have appropriate opportunity to learn about, participate in, and influence Ecology's decisions and actions.

To ensure that all people, regardless of their social, racial, geographical, or able-bodied status could participate in the review and decision making about the second Regional Haze SIP, we:

- Provided public notices that meet online accessibility requirements and notified interested public via emails and newspaper publications.
- Translated the notices into the priority minority languages in Washington:
    - Spanish
    - Korean
    - Vietnamese
    - Chinese
- Notified the leaders of the tribal communities in Washington and offered Government-to-Government consultation in addition to inviting the tribal members to attend public meetings.

- Held accessible online webinars to discuss various aspects of the program.
- Provided 45 days for the public to submit comments.
- Held a virtual public hearing.
- Simplified and formatted the Public Review Draft (text and graphics) to ensure it is compatible with available text-to-speech readers.

The long-term strategy in this regional haze SIP revision includes emission reductions from permits and state rules. The visibility benefits of these controls provide co-benefits to the communities that are in the vicinity where emission reductions occur. An example of such controls would be federal fuel and engine rules that have resulted in large reductions in mobile source air pollution and improvements in visibility.

Grant programs to reduce mobile source emissions and diesel pollution in disproportionately impacted communities

There are several emission control grant programs in Washington that take into account EJ concerns in awarding grants or have co-benefits for nearby disadvantaged communities. These include the woodstove buy-back and exchange program (Chapter 173-433 WAC), the low emission vehicles 2021 rulemaking to reduce emissions around ports, distribution centers, and freight corridors (which tend to be located within disadvantaged communities), and the Volkswagen enforcement action grants that prioritizes projects in or near communities disproportionately impacted by diesel fumes.

1.6 Meaningful public participation

Summary of changes to the public review draft

Ecology made the following changes to the public review draft SIP:

- In Chapter 7, changed all occurrences of “All controls identified as reasonable in the reasonability analysis will be installed and operated as an enforceable requirement consistent with the RHR” to “All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR.”
- In Chapter 7, in the conclusion to the Marathon Petroleum Company changed the following sentence “To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls will likely occur in the next implementation period” to “To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls may occur in the next implementation period.”
- In Table 7-19, a footnote was added to the BART 2008 $/ton column that stipulates: “FCCU is SNCR, others LNB.”
- In the Executive summary, “Emissions from petroleum refineries cause poor visibility” was changed to “Emissions from petroleum refineries contribute to poor visibility.”
- Added the following paragraphs to Section 6.8:

The PSAT identified sulfate contributions from non-EGU point sources in Washington, originating from the 12,053 tons of non-EGU SO2 emissions included in the model (see Chapter 6). However, 64 percent of those modeled SO2 emissions (7,729 tons) are from the two aluminum facilities in Washington (Alcoa Wenatchee and Alcoa Intalco). WRAP modeled these facilities using historical emissions data and with no assumed emissions reductions. The Alcoa Wenatchee facility curtailed in 2015, going to zero emissions, and announced on December 13, 2021, that it will permanently close. The Alcoa Intalco facility curtailed in 2020 and went to zero emissions. Ecology and Intalco entered into an Agreed Order in January 2021 requiring Intalco to conduct a four-factor analysis before restarting (see Chapter 7 and appendix Q for more details).

As a result of the above analysis, we have determined that sources in Washington do not have significant impacts in other States' mandatory Class 1 Areas beyond the measures already addressed in this SIP submittal. Ecology did not receive any request for additional reductions from neighboring states during our consultations with them.

- Ecology received a comment noting that we did not include a facility with a Q/d greater than 10 in the four-factor analysis. The McKinley Paper Plant is a recycled paper mill and is not a chemical pulping facility, which is why it was not included with the other chemical pulp and paper facilities for whom we requested a four-factor analysis. Our original intent was to have the McKinley facility included with other non-chemical paper mills in future implementation periods. However, the McKinley facility does have a Q/d of 83.1, which exceeds the selection criteria of 10. Ecology will start the four-factor analysis process with McKinley and include the results in an update to the SIP.

Ecology's response to comments on the public review draft

Please see Appendix U and V for the individual comments and Appendix W for Ecology's responses.

1.7 Organization of the second regional haze plan (2018 -2028)

The RH SIP is organized as follows:

Chapter 1

- Overview of the RHR and the development of the RH SIP.
- This includes the role of regional planning, the Western Regional Air Partnership (WRAP), and consultation with FLMs, tribes, and other states.
- It also includes a description of where the progress report elements are found in the document.

Chapter 2

- Primer on visibility
- Describes Washington's eight Class 1 Areas
- Describes visibility monitoring for these area at the Interagency Monitoring of Protected Visual Environments (IMPROVE) sites.

Chapter 3

- Describes current conditions in the Class 1 Areas.
- Describes the uniform rate of progress (URP) in visibility improvement needed to achieve the 2064 natural conditions.

Chapter 4

- Discusses the visibility baseline and 2018 statewide emissions inventories that Ecology developed and used to prepare this plan.

Chapter 5

- Describes the modeling used by the WRAP that Washington relied upon for this plan.

Chapter 6

- Discusses the significant in-state and regional sources of haze that affect Washington's Class 1 Areas and will likely affect visibility conditions in 2028.
- Discusses the Class 1 Areas in adjacent states that Washington emissions significantly affect.

Chapter 7

- Describes the source selection process and the four-factor analysis to determine the reasonableness of additional emission controls for inclusion in the long-term strategy.

Chapter 8

- Describes the long-term strategy to address regional haze visibility impairment in Washington's Class 1 Areas.
- Identify and reduce Washington's air impacts to mandatory Class 1 federal Areas outside of Washington.

Chapter 9

- Defines the reasonable progress goal for each of the eight Class 1 Areas in Washington.

Chapter 10

- Describes future planning.
- Summarizes the Washington RH SIP.

Chapter 2. Visibility and Visibility Monitoring in Washington's Class 1 Areas

2.1 Natural sources of visibility impairment

Natural sources of visibility impairment are emissions not attributed to anthropogenic (human-caused) emissions, and they can be major contributors to visibility impairment. Natural sources include:

- Volcanos
- Wildfire
- Windblown dust
- Certain wildland prescribed fire

Even when there is an absence of emissions, the scattering of light by air molecules can degrade visibility. We refer to this as "Rayleigh scattering". The air molecules' temperature and density can cause this effect.

We cannot control these sources. We focus control strategies for visibility improvement on what we can control, anthropogenic sources. Current analysis methods for monitoring data do not provide a clear distinction between natural and anthropogenic emissions, but certain pollutant species, such as sulfur dioxide (SO_2) and nitrogen oxides (NOx) are more representative of anthropogenic sources, while organic mass (OM) and coarse particulate matter (PM_{10}) are usually more representative of natural sources such as wildfire and dust, respectively.

2.2 Anthropogenic sources of visibility impairment

Anthropogenic sources of visibility impairment include everything attributable to human activities that produces emissions of visibility impairing pollutants. Some examples include:

- Industrial activities
- Transportation
- Agricultural activities
- Residential heating
- Managed outdoor burning

Anthropogenic sources can be of local, regional, or international nature. Only anthropogenic sources and emissions within the boundaries of the United States can be controlled. Some anthropogenic sources of emission are beyond the scope of Washington's SIP. Emissions from Mexico, Canada, other international emissions, and offshore marine shipping emissions in the Pacific Ocean are examples of anthropogenic sources that contribute to visibility impairment in Washington, but are beyond the scope of this planning document.

2.3 Emissions

Natural sources and anthropogenic sources emit visibility-impairing pollutants. Particle and gas emissions may go through chemical changes before an air monitor captures them. For this reason, the chemical species causing visibility impairment may not be the same species emitted by a pollution source.

2.4 The IMPROVE program for visibility monitoring

The Interagency Monitoring of Protected Visual Environments (IMPROVE) program is a multi-agency cooperative effort with the primary purposes of protecting visibility in Class 1 Areas and characterizing regional haze. The objectives of IMPROVE program are to:

- Establish current visibility and aerosol conditions in Class 1 Areas.
- Identify chemical species and emission sources responsible for visibility impairment.
- Document long-term trends for assessing progress towards the national visibility goal.
- Provide regional haze monitoring representing visibility in Class 1 Areas, where practical, in support of the Regional Haze Rule (RHR).

A formal cooperative relationship operates and maintains the IMPROVE monitoring sites. This cooperative includes:

- EPA
- National Parks Service (NPS)
- Fish and Wildlife Service (USFWS)
- Bureau of Land Management (BLM)
- Forest Service (USFS)

IMPROVE monitors obtain a complete signature of the composition of the airborne particles affecting visibility. Each IMPROVE monitor collects a 24-hour sample of these particles onto a set of filters every three days to determine the standard chemical components causing visibility impairment at that site.

To facilitate the data analysis, we group together some elemental particles and compounds (based on scientific principles) into seven standard components that cause light extinction.

Table 2-1 lists the seven standard aerosol components of light extinction along with the default color used in graphics throughout this document.

Table 2-1: Monitor Aerosol Composition

Aerosol Component	Abbreviation (Color)
Ammonium Sulfate	$(NH_4)_2SO_4$ (yellow)
Ammonium Nitrate	NH_4NO_3 (orange)
Organic Mass	OM (green)
Elemental Carbon	EC (black)
Fine Soil	Soil (maroon)
Coarse Mass	CM (gray)
Sea Salt	Sea Salt (light blue)

The IMPROVE website (IMPROVE) has detailed information regarding the IMPROVE program, including history, sampling protocols, standard operating procedures, and data availability.

Data collected at the IMPROVE monitoring sites is used by:

- Land managers
- Industry planners
- Scientists
- Public interest groups
- Air quality regulators

2.5 The revised IMPROVE equation and measuring visibility impairment

Some of the particles that compose aerosols absorb light, while others reflect or scatter light. Both absorption and scattering of light result in light extinction. Light extinction is the technical term for visibility impairment between the viewer and the light source.

Each of the key components of particulate aerosols affect light extinction in different ways. The first IMPROVE equation underestimated the highest extinction values and overestimated the lowest extinction values. The revised algorithm was developed by Pitchford et al., 2007 (Marc Pitchford, 2007). The revised algorithm is relatively simple, it produces consistent estimates of light extinction for all IMPROVE aerosol monitoring sites, and it permits the individual particle component contributions to light extinction to be separately estimated (see

Figure 2–1). The revised IMPROVE equation also accounts for site-specific Rayleigh scattering values based on altitude. Rayleigh scattering is the scattering of light by molecules of air.

$b_{ext} \approx$	2.2 x fs(RH) x [Small Sulfate] + 4.8 x fL(RH) x [Large Sulfate] + 2.4 x fs(RH) x [Small Nitrate] + 5.1 x fL(RH) x [Large Nitrate] + 2.8 x [Small Organic Mass] + 6.1 x fL(RH) x [Large Organic Mass] + 10 x [Elemental Carbon] + 1 x [Fine Soil] + 1.7 x fs(RH) x [Sea Salt] + 0.6 x [Coarse Mass] + Rayleigh Scattering (site specific) + 0.33 x [NO2 (ppb)]

Figure 2–1: Revised Interagency Monitoring of Protected Visual Environments Equation

The result of the revised IMPROVE equation is referred to as the reconstructed light extinction (denoted as b_{ext}). It represents the light extinction due to the aerosol particulates measured at the IMPROVE monitor and is proportional to the mass measured at the monitor.

We express reconstructed light extinction in units of inverse megameters (Mm^{-1}). The RHR requires the tracking of visibility conditions in terms of the haze index metric expressed in the deciview (dv) unit (40 CFR 51.308(f)(1)(i)). Generally, we consider a one-dv change in the haze index a humanly perceptible change under ideal conditions, regardless of background visibility conditions. Figure 2–2 shows the relationship between extinction, Mm^{-1}, dv, and visual range (km).

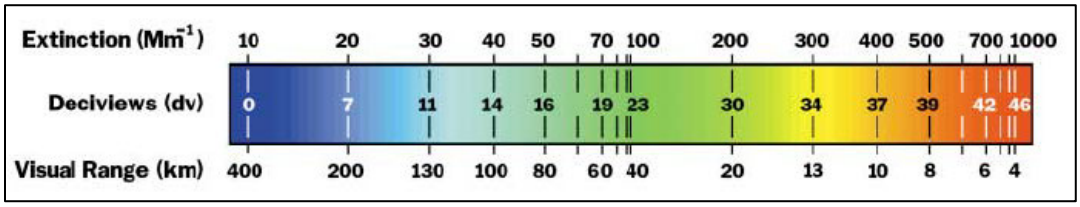


Figure 2–2: Comparison of extinction, deciview, and visual range
Source: (Malm, 2018).

2.6 Baseline conditions

The RHR requires the calculation of baseline conditions for each Class 1 Area. EPA has defined baseline conditions as the five-year average (annual values for 2000 - 2004) of IMPROVE monitoring data (expressed in dv) for the most impaired days (MID) and the clearest days. In the first regional haze plan, we defined the baseline conditions as reference points against which we tracked visibility improvement.

2.7 Natural conditions

The visibility under natural conditions (absent any anthropogenic impairment) could vary daily, based on the contribution of natural sources and meteorological conditions. Therefore, natural conditions consist of a level of visibility (in dv) for both the most impaired and clearest days.

Since no visibility monitoring data exists from the before anthropogenic impairment period, we base these estimates of natural conditions on EPA guidance (EPA, 2003) on how to estimate natural conditions.

2.8 Uniform rate of progress

The uniform rate of progress (URP) is the calculation of the uniform slope, or glidepath, of the line between baseline visibility conditions and natural visibility conditions over the 60-year period. For the first regional haze plan, the benchmark was the dv level that we planned to meet in 2018 (Figure 2–3). This was the 2018 milestone, and it applied to both the most impaired and clearest days. For the second regional haze planning period, the benchmark is the dv level achieved by 2028 (Figure 2–3).

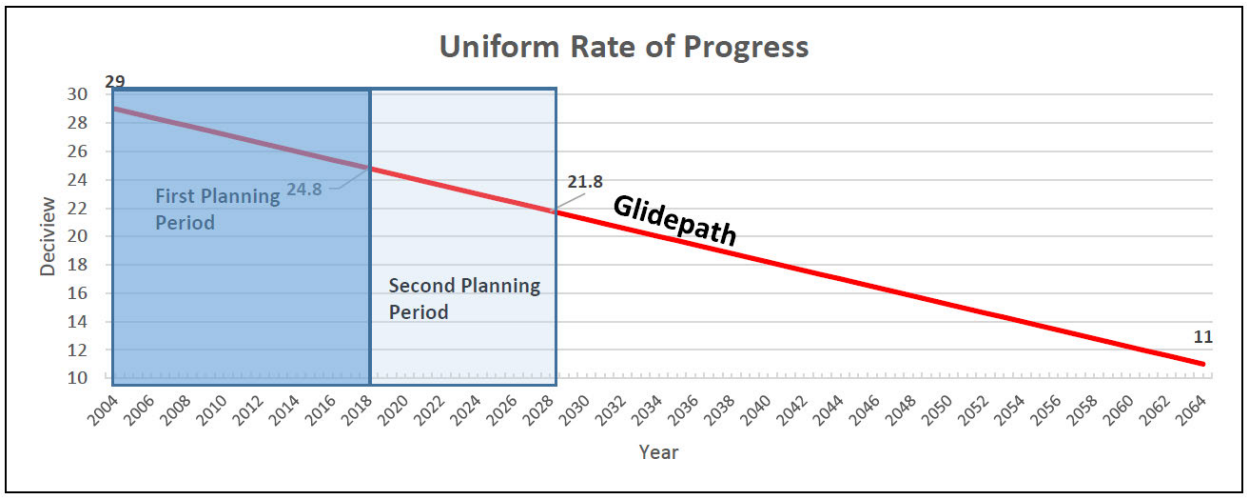


Figure 2–3: Example of How Uniform Rate of Progress is Determined Source: EPA Guidance for Setting Reasonable Progress Goals under the Regional Haze Program

The difference between baseline conditions and natural conditions represents the amount of progress needed to reach natural visibility conditions. In this example (not actual data), the State has determined that the baseline for the most impaired days for the Class 1 Area is 29 dv and estimated that natural background is 11 dv, a difference of 18 dv.

The annual average visibility improvement needed to reach natural conditions by 2064 is the total amount of improvement needed divided by 60 years (the period between 2005 and 2064). The visibility improvement per year is the uniform rate of progress (URP) expressed in dv per year. In this example, the average improvement needed is 0.3 dv/yr.

URP = [Baseline Condition - Natural Condition]/60 years

Multiply the annual average visibility improvement needed by the number of years in the first planning period (14 years from 2005 until 2018). In this example, this value is 4.2 dv. This is the visibility improvement that we would need during the first planning period to attain natural visibility conditions by 2064.

Calculate the visibility improvement needed to maintain a uniform rate of progress to 2028 (i.e. the amount of reduction in dv necessary for the second planning period) by multiplying the URP value by the number of years between the baseline period and the end of the second planning period (24 years). In this example, the value is 7.2 dv.

Visibility improvement from the baseline to 2018 = [uniform rate of progress] x [14 years]

Visibility improvement from the baseline to 2028 = [uniform rate of progress] x [24 years]

2.9 Washington's Class 1 Areas and visibility monitoring

Washington's Class 1 Areas

Washington has eight Class 1 Areas: three national parks and five wilderness areas. Visibility in the Class 1 Areas is monitored at the interagency monitoring of protected visual environments (IMPROVE) sites. Figure 2–4 shows Washington's eight Class 1 Areas along with the locations of the IMPROVE monitors for the Class 1 Areas.

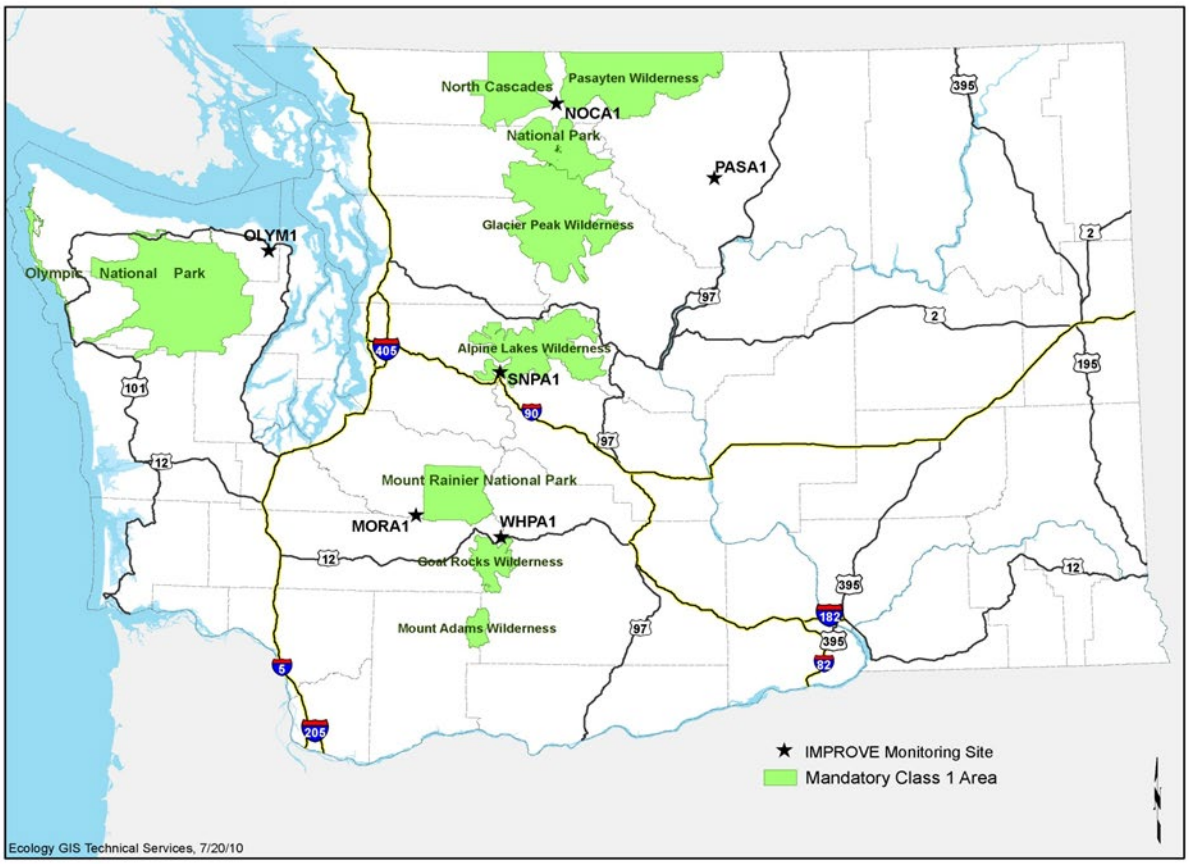


Figure 2–4: Washington's Class 1 Areas and visibility monitoring sites

Table 2-2 provides information on the size of and the federal agency that manages each Class 1 Area, as well as the name of the IMPROVE monitor for each area. The acreages are from 40 CFR 81.434. They may not match the current acreages of the national park or wilderness area for reasons including more accurate surveys or expansion of the area.

Table 2-2: Washington's Class 1 Areas

Class 1 Area	Acreage	Federal Land Manager	IMPROVE monitor
Olympic National Park	892,578	USDI-NPS	OLYM1
North Cascades National Park	503,277	USDI-NPS	NOCA1
Glacier Peak Wilderness	464,258	USDA-FS	NOCA1
Alpine Lakes Wilderness	303,508	USDA-FS	SNPA1
Mt. Rainier National Park	235,239	USDI-NPS	MORA1
Goat Rocks Wilderness	82,680	USDA-FS	WHPA1
Mt. Adams Wilderness	32,356	USDA-FS	WHPA1
Pasayten Wilderness	505,524	USDA-FS	PASA1
Total Acres	3,019,420		

The sections below briefly describe Washington's Class 1 Areas. Maps of these areas are included later in this chapter.

Olympic National Park

Olympic National Park includes a significant portion of the Olympic Peninsula in northwestern Washington. It consists of two segments: the Olympic Mountains, which form the mountainous core of the park, and a coastal strip, stretching for 90 km (56 mi) along the Pacific coast. Thirteen major rivers are flowing from the Olympic Mountains in all directions. Ninety-five percent of the park is designated wilderness.

Elevations range from sea level to 2,428 m (7,965 ft) at the crest of Mt. Olympus near the center of the peninsula. The area has the greatest precipitation gradient in the world for temperate latitudes. Annual precipitation is near 400 cm (150 in) in the western valleys and 500 cm (200 in) at the summit of Mt Olympus but as little as 41 cm (16 in) on the northeast shore of the peninsula in the rain shadow of the Olympic Mountains.

North Cascades National Park

North Cascades National Park is set in the rugged mountains and the beautiful scenery of the Cascade Mountain Range in northcentral Washington, about 80 km (50 mi) east of Bellingham. The area was set aside to preserve dramatic mountain scenery, alpine areas, and glaciers. Mountain summits rise abruptly 1,800-2,600 m (5,900-8,530 ft) above the valley floor. Approximately 93 percent of the park is designated wilderness.

North Cascades National Park lies less than 150 km (95 mi) from major metropolitan areas, most notably, Seattle, Washington and Vancouver, British Columbia.

Glacier Peak Wilderness

Glacier Peak Wilderness includes more than 200 lakes, many unnamed and tremendously difficult to access, in various cirques and hidden basins. The wilderness straddles the northern Cascade Range roughly between Suiattle River on the west and Lake Chelan on the east. North Cascades National Park is adjacent to the northern border.

The dominant topographic feature is Glacier Peak, a 3,214 m (10,541 ft) high volcanic cone. Other mountain summits are 2,500 m (8,200 ft) or lower in elevation. Most terrain lies below 2,000 m (6,500 feet) elevation.

Glacier Peak Wilderness drains on the west side of the Cascade crest to the Suiattle and Sauk Rivers, tributaries to the Skagit River, which flows into northern Puget Sound. East of the Cascade crest, streams flow to Lake Chelan and the Columbia River basin. The lowest elevations where streams exit the wilderness on the west side are around 400 m (1,300 ft). The lowest elevations east of the Cascade crest are 350 to 400 m (1,200 to 1,300 ft), close to the 335 m (1,099 ft) elevation of Lake Chelan.

Alpine Lakes Wilderness

When Congress passed the 1976 Alpine Lakes Wilderness Act to protect the area in its unique natural state they created the Alpine Lakes Wilderness. The name Alpine Lakes takes its origin from the nearly 700 small mountain lakes nestled among the high rock peaks and forested valleys of the region. The Mt. Baker-Snoqualmie National Forest and the Okanogan-Wenatchee National Forest jointly administer the wilderness.

Alpine Lakes Wilderness is located in the rugged central Cascade Range. It is accessible by 47 trailheads and 990 km (615 mi) of trail on both sides of the crest of the Cascade Range between Stevens Pass (US Hwy 2) on the north and Snoqualmie Pass (I-90) on the south.

Mount Rainier National Park

Mount Rainier National Park became the nation's fifth national park in 1899. The Park was set aside to protect timber, minerals, and other natural resources. One hundred kilometers (62 mi) southeast of Seattle, Mount Rainier is the highest of the chain of volcanoes comprising the Cascade Range. At 4,392 m (14,410 ft), Mount Rainier is the fifth tallest peak in the contiguous 48 states. The massive mountain occupies more than one-fourth of the park's area. The 27 major glaciers on its slopes form the largest mass of year-round ice in the United States outside of Alaska.

Mount Rainier National Park lies within 64 km (40 mi) of Puget Sound. The lowlands along the eastern shore of Puget Sound are the most populated and industrialized area of Washington.

Goat Rocks Wilderness

The Goat Rocks Wilderness is a portion of the volcanic Cascade Range in southwestern Washington located between Mount Rainier and Mount Adams. The Goat Rocks are remnants of a large volcano, which has been extinct for some two million years. The cluster of rocks and

peaks in this area earned the title “Goat Rocks” because of the bands of mountain goats that live there. The wilderness lies in both the Gifford Pinchot National and the Okanogan-Wenatchee National Forests.

Glaciation and erosion have worn away the terrain and left moderate summits east and west of the crest of the Cascades. Elevation in the Goat Rocks range from 900 m (3,000 ft) to 2,450 m (8,201 ft) at Gilbert Peak. The deep east-west drainages below the ridges often open into park-like alpine meadows dotted with small lakes and even smaller ponds.

Mount Adams Wilderness

Congress designated the Mount Adams Wilderness in 1964. The wilderness lies in the Gifford Pinchot National Forest on the crest of the Cascade Range in southwestern Washington. Second in height only to Mount Rainier statewide, 3,742 m (12,276 ft) Mount Adams looms over at least 10 glaciers and a wilderness of forested slopes and subalpine meadows. The huge volcanic bulk of the mountain takes up a considerable portion of the Wilderness. Since the eruption of Mount St. Helens, Mount Adams has become a popular attraction for mountain climbers.

Pasayten Wilderness

The Pasayten Wilderness stretches across the crest of the Cascade Range in northern Washington. The wilderness is bordered on the north by 80 km (50 mi) of the Canadian border and on the west by the Ross Lake National Recreation Area. The Pasayten Wilderness is located in both the Okanogan-Wenatchee and the Mount Baker-Snoqualmie National Forests.

The terrain of the western Pasayten is a series of high ridges that flatten out in the eastern portion to high plateaus. Almost 150 peaks in the Pasayten have elevations above 2,300 m (7,500 ft). The part west of the Cascade crest is in the upper Skagit River basin and drains into Ross Lake and the Skagit River and then into northern Puget Sound. From the eastern part of the wilderness, streams flow north into British Columbia or southeast into the central Columbia Plateau. The lowest elevations are around 1,000 m (3,000 ft) at the western boundary near Ross Lake and the southern boundary near Lost River Gorge.

Visibility monitoring of Washington's Class 1 Areas

Washington has six IMPROVE sites that monitor the visibility of the state's eight Class 1 Areas. Four have been combined into two clusters and one monitor is used to represent each cluster. We discuss each site briefly below. You can find additional information on nearby populations, industrial centers, and wind patterns for the sites in Appendix B.

Olympic IMPROVE site: OLYM1

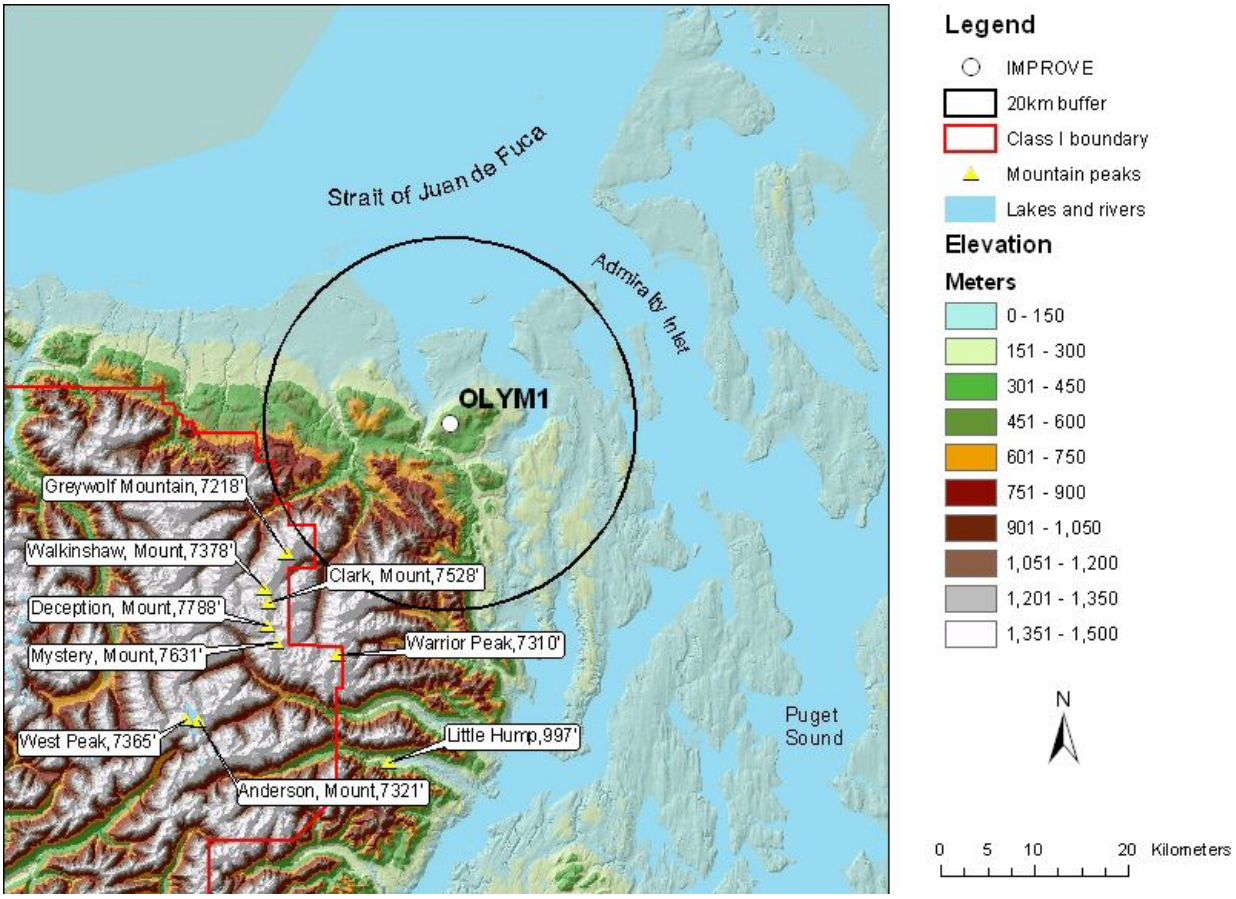


Figure 2–5: Location of the OLYM1 site
Source: Causes of Haze Assessment Descriptive Maps

The IMPROVE site representing the Olympic National Park is OLYM1, located northeast of the park boundary on an exposed hilltop (Blyn Lookout) near the northeastern extreme of the Olympic Peninsula at an elevation of 600 m (1,968 ft) (Figure 2–5).

Representativeness

OLYM1 is on the northeast shore of the peninsula near Sequim. Sequim is in the rain shadow of the Olympics, with sea level precipitation less than 50 cm (20 inches) annually. The rain shadow effect may be less severe at the OLYM1 elevation of 600 m. OLYM1 should be representative of eastern Olympic National Park areas most of the time, although at this elevation there may be periods when it is above inversion height.

Because of the size of the park, different sources may affect different areas. For the northeastern portion of the park, where the OLYM1 monitoring site is located, nearby industrial and urban emission sources that most immediately affect the area are in Port Angeles. For the western portions of the park, including the coastal section, there are no additional large source areas, although there may be timber and shipping related industries.

North Cascades IMPROVE Site: NOCA1

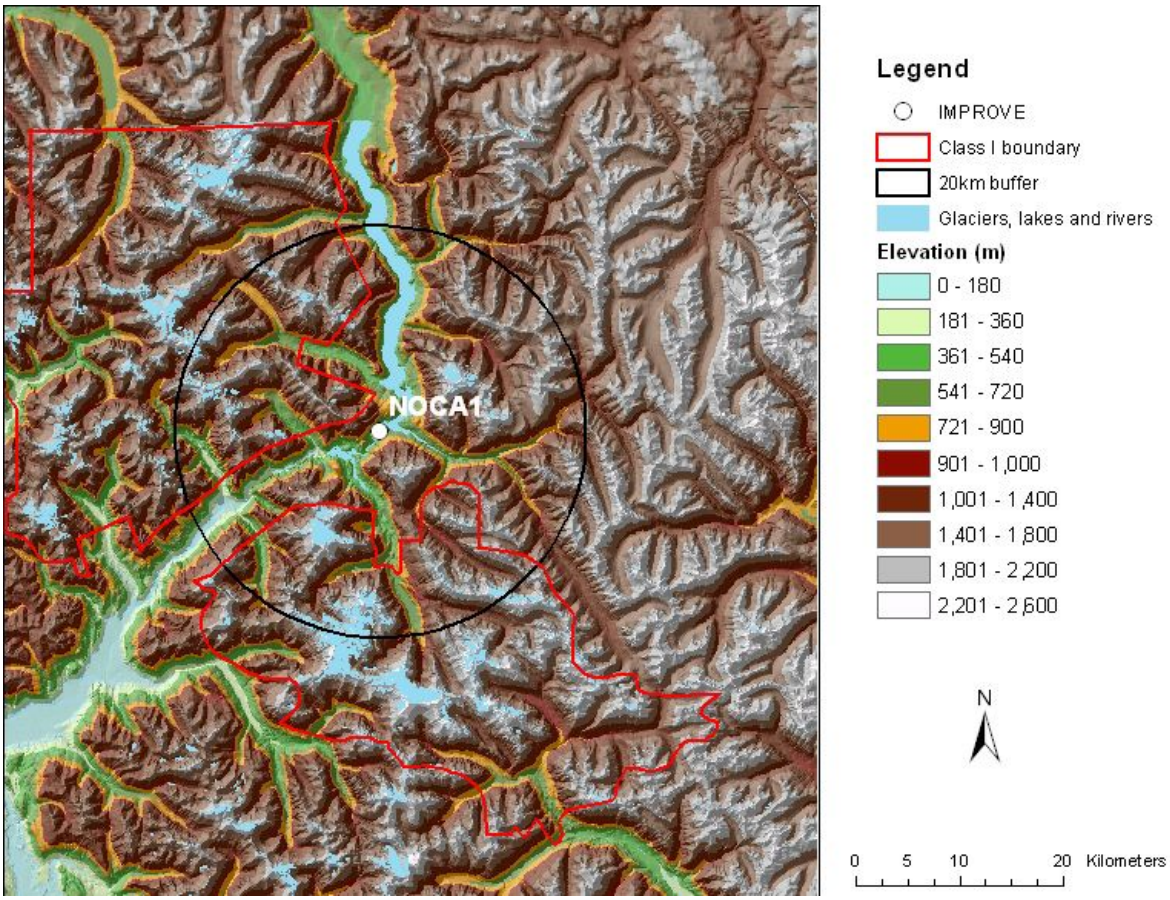


Figure 2–6: Location of the NOCA1 Site
Source: Causes of Haze Assessment Descriptive Maps

The NOCA1 IMPROVE site is the monitoring site for two Class 1 Areas, North Cascades National Park and Glacier Peak Wilderness. NOCA1 is located near Ross Lake on the upper reaches of the Skagit River just outside of the eastern boundary of the northern park section, located north of the Skagit River (Figure 2–6). The monitor is situated at an elevation of 576 m (1,889 ft) and is 87 m (285 ft) above the level of Ross Lake and about 200 m (650 ft) below the surrounding ridge tops.

Representativeness

The NOCA1 IMPROVE site is within the Skagit River Valley near Ross Lake and is in the lower slopes of a valley. It may at times be within surface-based valley inversions. The monitor is representative of the lower elevation air shed.

Snoqualmie Pass IMPROVE site: SNPA1

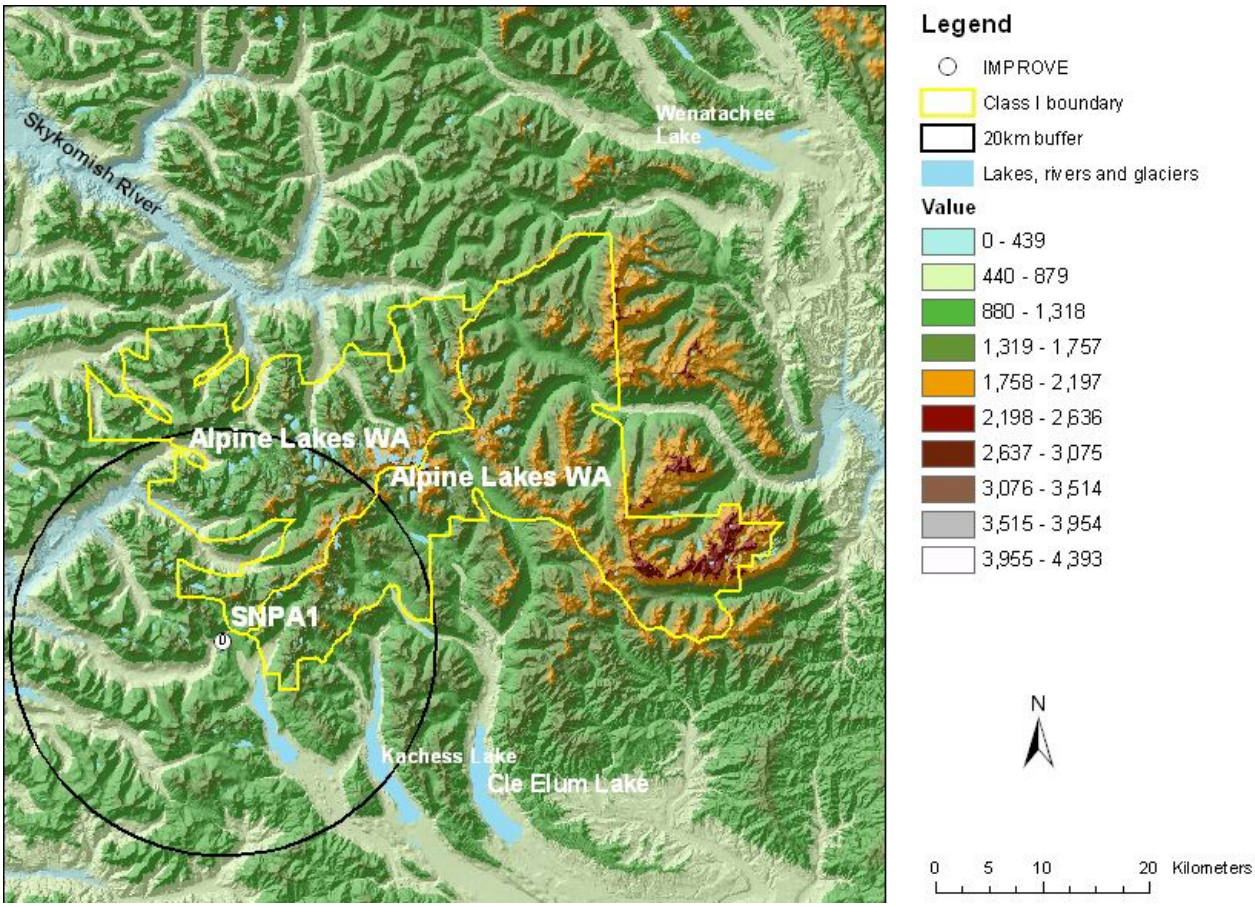


Figure 2–7: Location of the SNPA1 site
Source: Causes of Haze Assessment Descriptive Maps

SNPA1 is the IMPROVE site representing the Alpine Lakes Wilderness. SNPA1 is located near the southwest boundary of the wilderness in Snoqualmie Pass, a pass over the Cascade Range (Figure 2–7). The monitoring site elevation of 1,160 m (3,805 ft) is 239 m (784 ft) above the Snoqualmie Pass elevation of 921 m (3,022 ft). SNPA1 is located near a ski area on Snoqualmie Pass.

Representativeness

SNPA1 is at a well-exposed ridge crest location and should be very representative of the particulate aerosol concentration and composition at similarly exposed locations in the Alpine Lakes Wilderness. The elevation of SNPA1 is at the lower end of the range of elevations of the wilderness.

The mountain pass location of SNPA1 is representative of transport flow across the Cascade crest. Due to its location at a ridge crest, SNPA1 is probably above trapping inversions that may develop at valley bottom locations west and east of the Cascade crest.

Mount Rainier IMPROVE site: MORA1

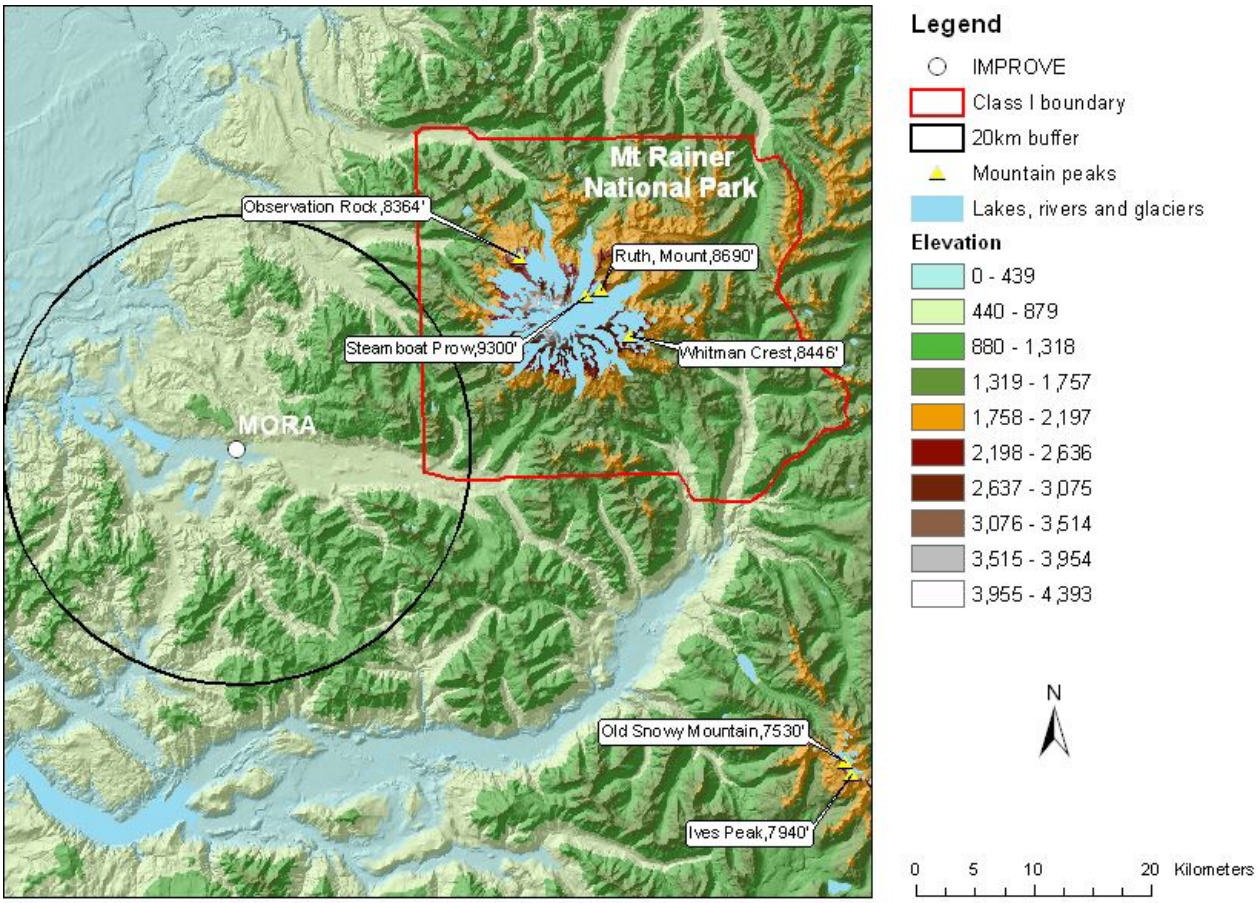


Figure 2–8: Location of the MORA1 site
Source: Causes of Haze Assessment Descriptive Maps

The IMPROVE site representing Mount Rainier National Park, MORA1, is situated southeast of the park at the Tahoma Woods park headquarters. MORA1 is located within the Nisqually River Valley at an elevation of 439 m (1,440 ft). The monitor is some 30 km (18.5 mi) west-southwest from the summit of Mount Rainer (Figure 2–8) as shown above.

The orientation of the drainage is east to west, with an elevation drop of about 60 ft/mile. Where the Nisqually River empties into Alder Lake Reservoir (5 km or 3 miles) west of the site the river elevation is 367 m (1,204 ft).

The valley bottom at the monitoring site is about 1.5 km (0.9 mi) wide. The monitoring site is at the northern edge of the valley bottom. Elevations rise to 450 m (1,475 ft) at a distance of 2 km (1.25 mi) north and 3 km (1.9 mi) south from the monitoring site. Regional ground cover is predominantly fir and pine forest.

Representativeness

The valley where the IMPROVE site is located may be subject to inversion and trapping of pollutants during periods of high pressure and stagnation. In those cases, the trapped stable

layer would contain the monitoring site. In those instances, the monitor would only be representative of the lower portions of the park.

Generally, wind directions at MORA1 channel to an east/west direction with characteristic mountain/valley circulations of easterly nighttime drainage flow and westerly daytime upslope flow in the valley.

White Pass IMPROVE site: WHPA1

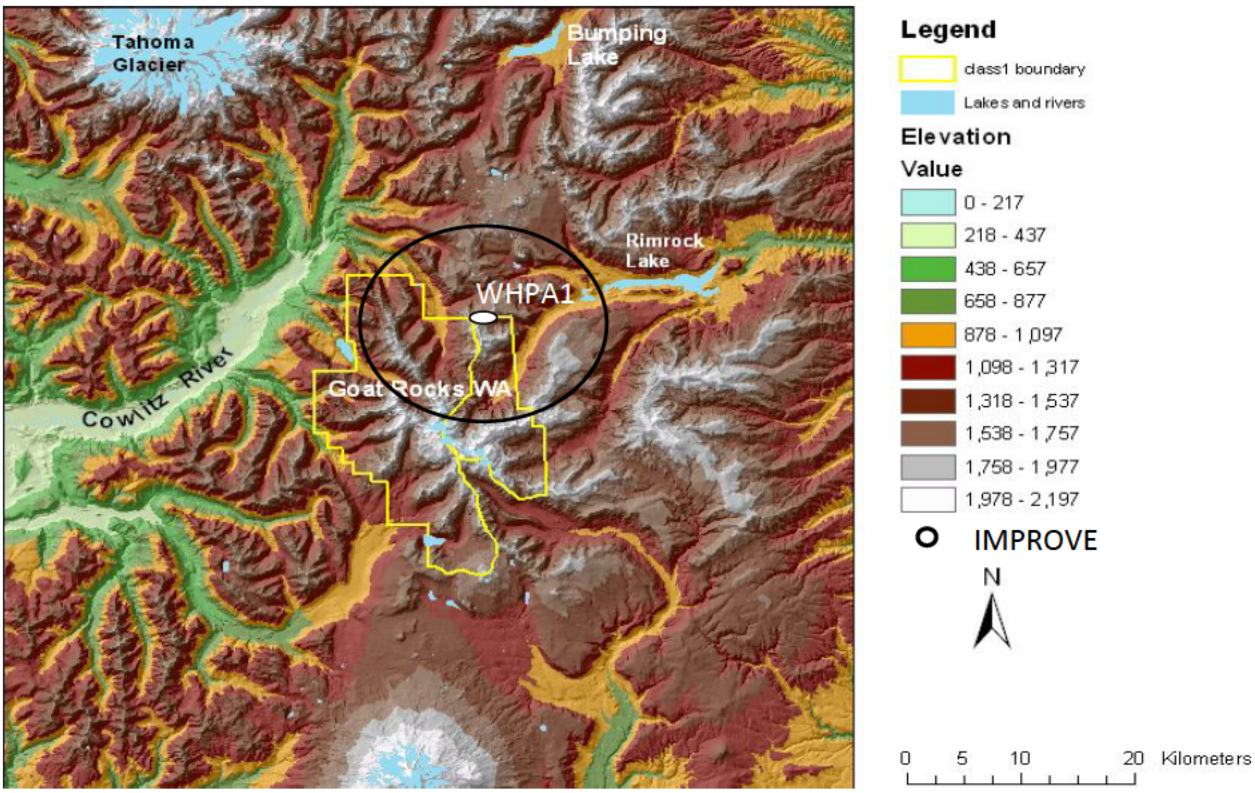


Figure 2–9: Location of the WHPA1 site
Source: Causes of Haze Assessment Descriptive Maps

The IMPROVE site representing Goat Rocks and Mount Adams Wilderness Areas, WHPA1, is located on the crest of the Cascade Range at the northern Goat Rocks Wilderness boundary at White Pass Ski Resort near White Pass Washington (Figure 2–9). The monitoring site elevation is 1,830 m (6,002 ft).

Representativeness

WHPA1 is at a ridge crest location well exposed to upper airflows and to aerosols transported aloft from upwind sources. WHPA1 should be representative of aerosol concentration and composition at similarly exposed locations in the Goat Rocks and Mount Adams Wilderness Areas. Its elevation and exposure should also make it representative of regional characteristics and transport from distant source regions at pressure heights near 850 mb that are relatively unperturbed by terrain effects.

Pasayten IMPROVE site: PASA1

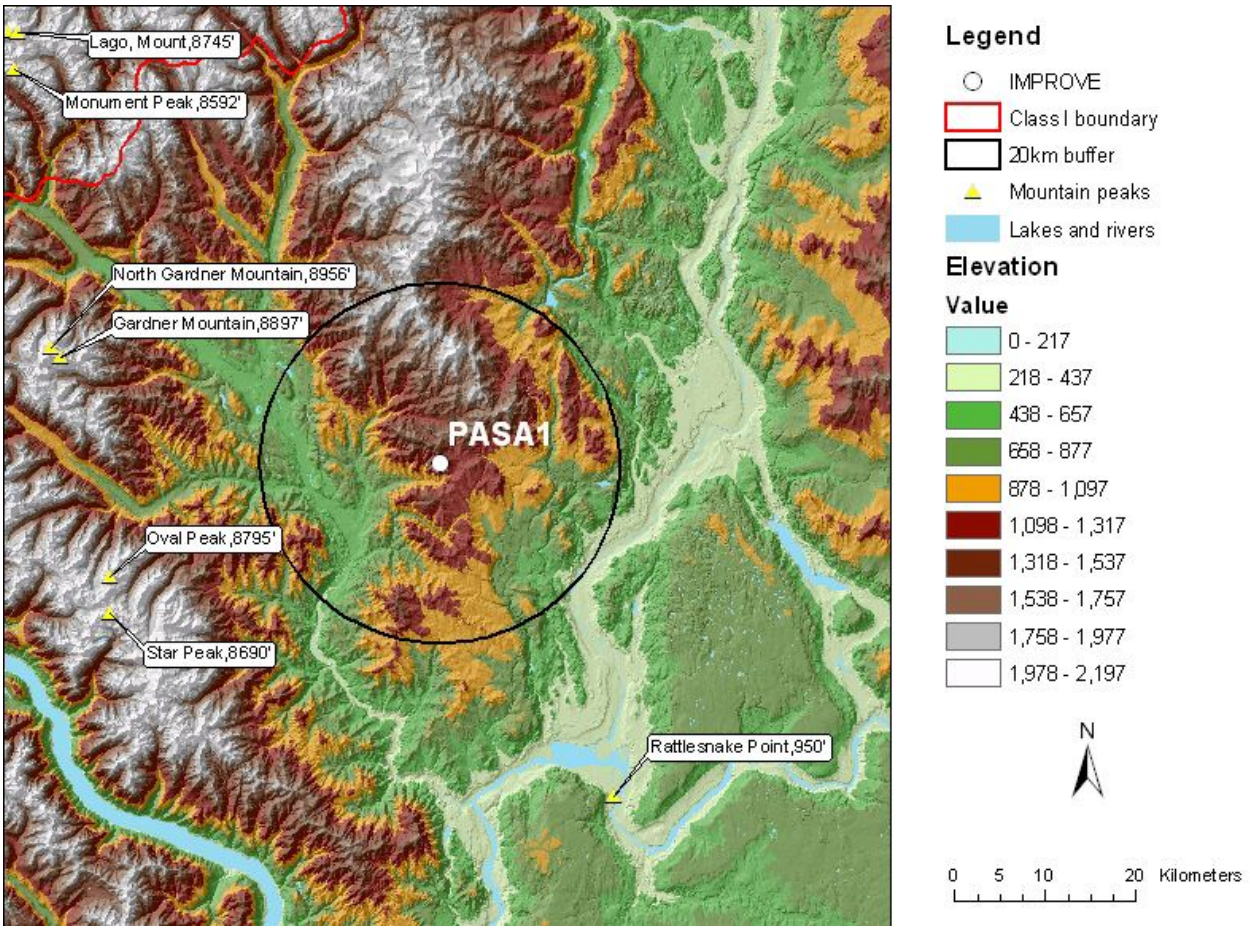


Figure 2–10: Location of the PASA1 site
Source: Causes of Haze Assessment Descriptive Maps

The IMPROVE site representing Pasayten Wilderness, PASA1, is situated near the crest of Little Buck Mountain, 50 km (30 mi) south and east of the wilderness boundary (Figure 2–10). PASA1 is located at an exposed elevation of 1,634 m (5,360 ft).

Representativeness

The PASA1 IMPROVE site is at a well-exposed ridge top location and is somewhat representative of regional conditions including high elevation locations in the Pasayten Wilderness. It is more representative of upper level (850 mb) aerosol characteristics of the central Columbia Plateau and Basin. This monitor is further away from the Class 1 Area it represents than any others in Washington. The PASA1 monitor is in an area that has frequent prescribed burning that may not actually impact the Pasayten Wilderness. Prescribed burning near the PASA1 monitor does not typically impact visibility in the Pasayten Wilderness because prevailing westerly winds and terrain limit the transport of smoke from the Columbia Plateau to the Cascade mountains.

The North Cascades National Park IMPROVE site, NOCA1, may be more representative of low elevations of the Pasayten Wilderness east of the Cascade crest.

Chapter 3.Current Visibility Conditions in Washington's Class 1 Areas

3.1 Overview of visibility conditions in Washington

3.1.1 Introduction

Washington Department of Ecology (Ecology) analyzed current visibility conditions in Washington's eight mandatory Class 1 Federal Areas (Class 1 Areas) as required by the Regional Haze Program (40 CFR 51.308(f)(1)). We compared current visibility conditions to both the historical baseline and natural conditions. The five-year period (2014 - 2018) is the most recent monitoring dataset available for regulatory use and is the period we refer to as "current conditions" throughout this document. The first Regional Haze State Implementation Plan (RH SIP) defined "baseline visibility conditions'' as the five-year period from 2000 - 2004. The Regional Haze Rule (RHR) sets the statutory deadline of 2064 to reach natural visibility conditions at all Class 1 Areas. Natural visibility represents the visibility conditions in the absence of human-caused impairment.

3.1.2 Methodology

Ecology used the monitoring data for the current conditions from the interagency monitoring of protected visual environments (IMPROVE) sites that track pollutants affecting visibility in Class 1 Areas. For more information on the pollutants, see Chapter 4 Emission Inventories. Washington has six IMPROVE sites and eight Class 1 Areas. Two of the sites cover four Class 1 Areas. Table 3-1 provides general information on the six sites[4]. For more information about the IMPROVE program see Chapter 2, Section 2.2: Visibility monitoring of Washington's Class 1 Areas.

Table 3-1: IMPROVE monitoring sites.

Site name	Site abbreviation	Site sponsor	Monitored Class 1 Area
Olympic	OLYM1	USDI-NPS	Olympic National Park
North Cascades	NOCA1	USDI-NPS	North Cascades National Park & Glacier Peak Wilderness
Snoqualmie Pass	SNPA1	USDA-FS	Alpine Lakes Wilderness
Mount Rainier	MORA1	USDI-NPS	Mount Rainier National Park
White Pass	WHPA1	USDA-FS	Goat Rocks Wilderness & Mount Adams Wilderness
Pasayten	PASA1	USDA-FS	Pasayten Wilderness

[4] See the map of the Class 1 Areas and the monitoring sites at: https://ecology.wa.gov/Air-Climate/Air-quality/Air-quality-targets/Regional-haze.

The Western Regional Air Partnership (WRAP) analyzed and compiled the IMPROVE monitoring data for consistency in planning among Western states. We used WRAP's technical data and analysis to determine current conditions. We also used the WRAP Technical Support System (TSS) online tool at https://views.cira.colostate.edu/tssv2/ to generate graphs and tables illustrating the results of the data analysis. Those interested in reviewing the data may access the observation-specific tools at https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx.

During the first planning period, we used the worst (haziest) days from the IMPROVE monitoring data to determine the baseline visibility for the worst visibility days for the 2000 - 2004 period. However, the RHR revision in 2017 changed the metric on how to select a set of the worst visibility days during each year to track progress towards natural visibility conditions. The revised metric reflects the finding that natural events such as wildfires and dust storms overwhelmingly influence the haziest days. The rule revision removed five percent of the haziest days recorded at the IMPROVE sites from the calculations to create "the most impaired days" (MID) metric. The MID are the 20 percent of the worst visibility days in a calendar year, after removing the five percent haziest days. Thus, the design of the MID metric identifies the days with the largest amounts of anthropogenic visibility impairment. Because of the rule revision, EPA and WRAP recalculated the baseline conditions for all Class 1 Areas for the second implementation period.

The RHR requires that states track progress in visibility with a metric of haze known as the deciview (dv). We use the dv because under many circumstances, a person will perceive a change in one dv to be the same on both clear and hazy days. However, the dv does not easily relate to pollutant concentrations. Therefore, species contribution analysis uses a metric directly related to pollutant concentrations, known as "light extinction," with units of inverse megameters (Mm^{-1}). Light extinction does not linearly relate to a person's perception of changes in haze, but does linearly relate to pollutant concentrations in the atmosphere.

The glidepath from the baseline visibility conditions for the MID to the natural conditions over a 60-year period depicts the uniform rate of progress (URP). The uniform rate of visibility improvement for the MID is measured in deciviews of improvement per year. We need to maintain this average rate to attain natural visibility conditions by the end of 2064 in each Class 1 Area. Thus, the URP glidepath is a planning tool to help track ongoing improvements in visibility and to gauge whether there are sufficient controls over the emission sources to meet our progress goals during this planning period and stay on track to achieve the natural condition goals by 2064.

In the first planning period, natural conditions and the URP glidepath endpoint were the same by default. However, not all human-caused impairment comes from emission sources that the state can control. In accordance with the RHR (40 CFR 51.308(f)(1)(vi)(B)), the states can propose an adjustment to the endpoint of the glidepath to account for emissions they do not control such as international emissions. In this planning period, WRAP calculated the impacts of international anthropogenic sources on Washington's visibility in each Class 1 Area.

Washington is focusing on impairments that come from the sources within the states' control and is proposing an adjustment to the endpoint of the glidepath in Chapter 9 to account for international contributions.

In this chapter, the current visibility conditions are compared to the unadjusted glidepath for each of the eight Class 1 Areas in Washington (40 CFR 51.308(f)(1)(vi)). In Chapter 9, we adjusted the endpoint of the glidepath to account for the international contributions and use the international adjusted glidepath when we project reasonable progress goals.

For each Class 1 Area, we calculated the uniform rate of progress, and reviewed the visibility during MID and clearest days during 2014 - 2018. We compared the clearest days to the baseline, and the MID to the unadjusted URP glidepath. We provided an analysis of the annual and seasonal species' contributions to the visibility impairment during the current period. We also provided a visibility trend synopsis of annual species contributions to light extinction from 2002 - 2018.

3.1.3 Summary results

Table 3-2 and Table 3-3 show a summary of the 2000 - 2004 baseline, IMPROVE 2008 - 2012, IMPROVE 2014 - 2018, and estimated natural conditions for the clearest days and MID. This is required by the RHR (40 CFR 51.308(f)(1)(i – v)).

Table 3-2: Baseline, current, and estimated natural visibility conditions for the clearest days (in dv).

Class 1 Area	IMPROVE monitor	Baseline 2000-2004	Average 2008-2012	Current conditions 2014-2018	Estimated natural conditions 2064	Difference between current and natural conditions
Olympic National Park	OLYM1	6.0	3.9	3.6	2.7	0.9
Glacier Peak Wilderness Area	NOCA1	3.4	2.9	2.5	1.9	0.6
North Cascades National Park	NOCA1	3.4	2.9	2.5	1.9	0.6
Alpine Lakes Wilderness Area	SNPA1	5.5	4.0	3.3	2.3	1.0
Mount Rainier National Park	MORA1	5.5	4.2	3.9	2.6	1.3
Goat Rocks Wilderness Area	WHPA1	1.7	1.3	1.0	0.8	0.2
Mount Adams Wilderness Area	WHPA1	1.7	1.3	1.0	0.8	0.2
Pasayten Wilderness Area	PASA1	2.7	2.1	1.6	1.2	0.4

Table 3-3: Baseline, current, and estimated future visibility conditions for the most impaired days (in dv).

Class 1 Area	IMPROVE monitor	Baseline 2000-2004	Average 2008-2012	Current conditions 2014-2018	Estimated unadjusted natural conditions 2064	Difference between current and natural conditions
Olympic National Park	OLYM1	14.9	13.5	11.9	6.9	5.0
Glacier Peak Wilderness Area	NOCA1	12.6	11.1	10.0	6.9	3.1
North Cascades National Park	NOCA1	12.6	11.1	10.0	6.9	3.1
Alpine Lakes Wilderness Area	SNPA1	15.4	13.7	12.7	7.3	5.4
Mount Rainier National Park	MORA1	16.5	14.1	12.7	7.7	5.0
Goat Rocks Wilderness Area	WHPA1	10.5	9.1	8.0	6.1	1.9
Mount Adams Wilderness Area	WHPA1	10.5	9.1	8.0	6.1	1.9
Pasayten Wilderness Area	PASA1	10.4	9.6	9.5	6.0	3.5

3.2 Olympic National Park

The baseline visibility for the Olympic National Park is 6.0 dv for the clearest days and 14.9 dv for the MID. The unadjusted URP glidepath goes from 14.9 to 6.9 dv at a rate of 0.13 dv per year (8 dv divided by 60 years), which is the rate that would need to be maintained to reach natural visibility conditions in the park by 2064.

The current conditions (2014 - 2018) calculated from OLYM1 monitoring data are 3.6 dv for the clearest days and 11.9 dv for the MID. The clearest days' visibility improved by 2.4 dv from the baseline. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 1.8 dv. The MID visibility improved by 3 dv and is under the unadjusted URP glidepath.

Figure 3–1 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at OLYM1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most recent annual average MID are below the glidepath, which indicates a rate of visibility improvement that will accomplish the 2064 natural conditions goal.

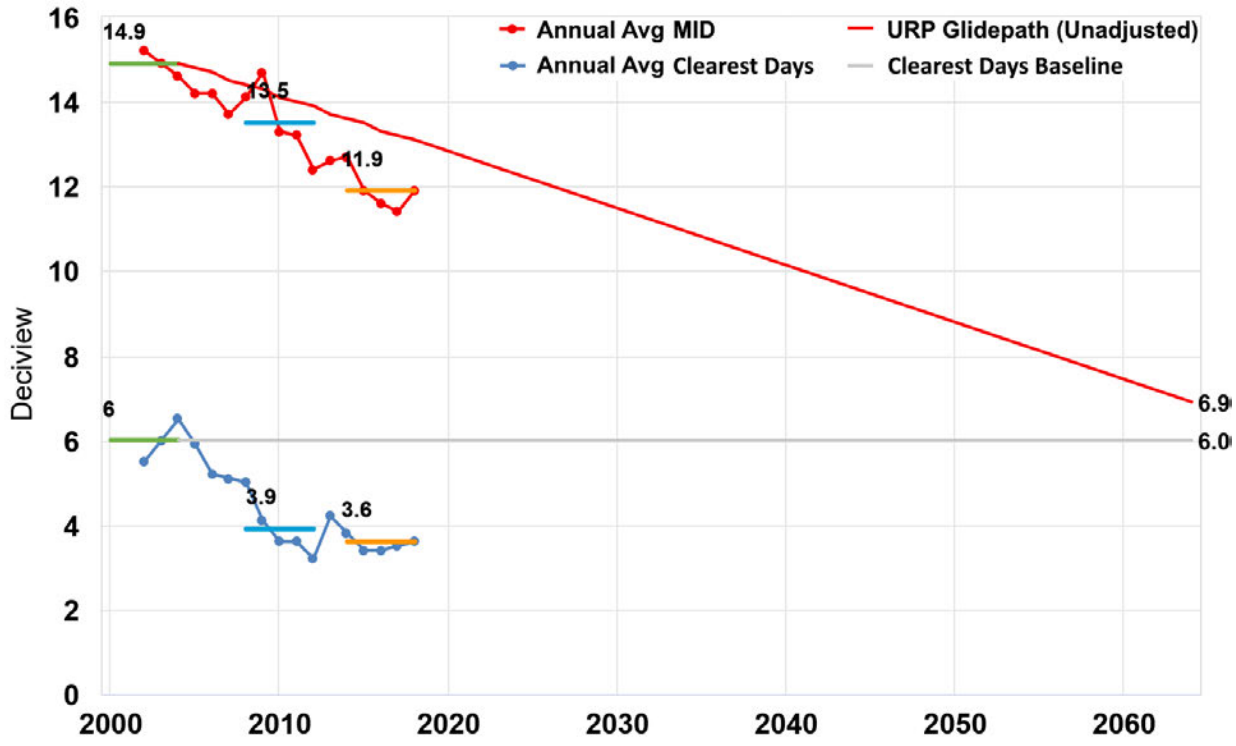


Figure 3–1: Current visibility conditions compared to the unadjusted URP glidepath and baseline (clearest days) at OLYM1.

Figure 3–2 shows the annual species contributions to light extinction from 2014 - 2018 for both MID and clearest days. Sulfates decreased in 2015 for both MID and clearest days and the decrease sustained through the rest of the five-year period. Nitrates showed very little change and organic mass showed some year-to-year variability.

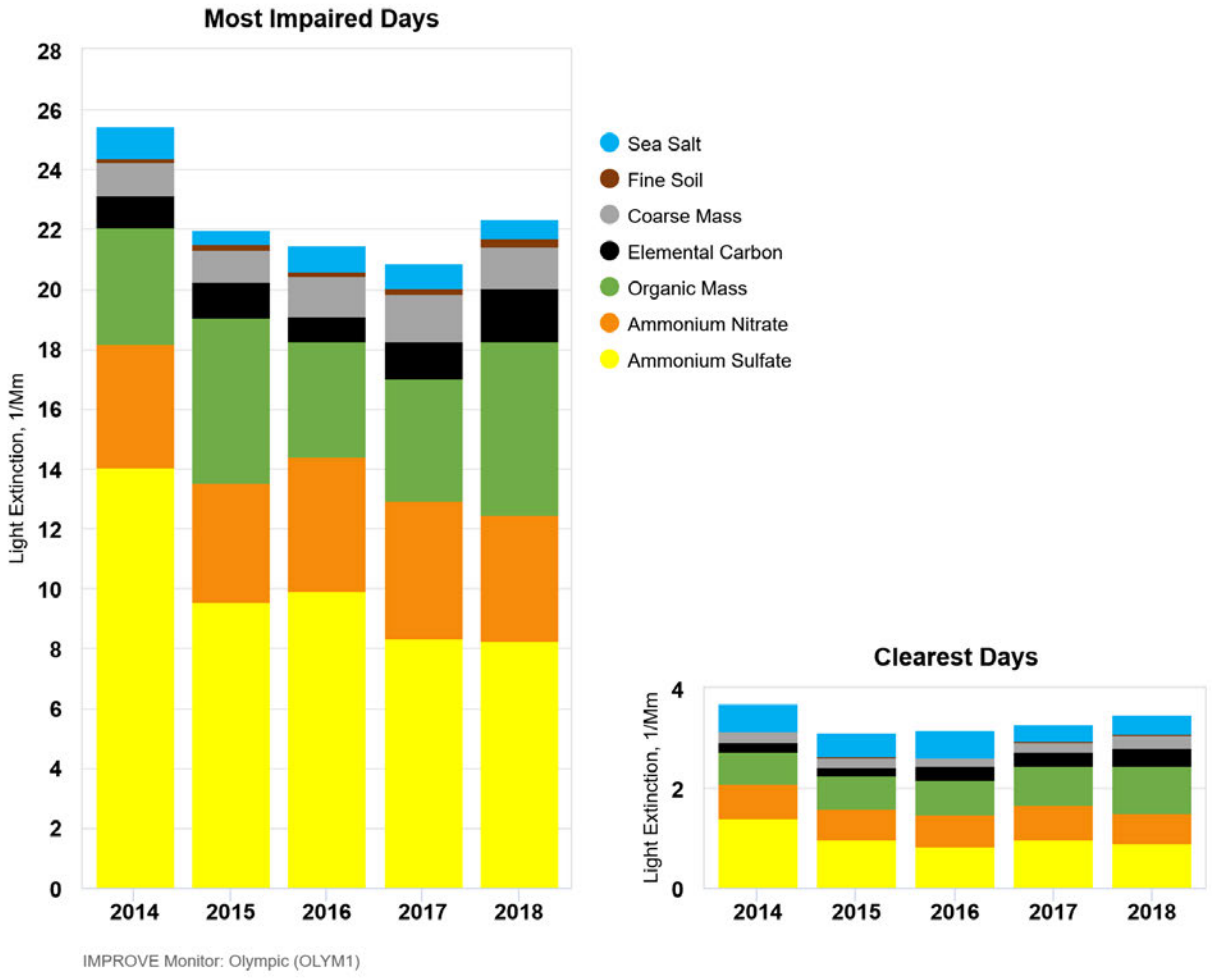


Figure 3–2: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at OLYM1.

Table 3-4 shows the annual species' contribution during the five-year period from 2014 - 2018 for the MID. Sulfates contributed nearly half of the light extinction to MID from 2014 - 2018. The percentage of organic mass increased in 2015 and 2018. During the five-year period, sulfates (44%) were the largest contributor to light extinction, followed by organic mass (21%) and nitrates (19%). Elemental carbon, coarse mass, fine soil, and sea salt had minimal contributions to light extinction.

Table 3-4: Annual species contributions to light extinction for MID from 2014 - 2018 at OLYM1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	4%	2%	4%	4%	3%	3%
Fine Soil	1%	1%	1%	1%	1%	1%
Coarse Mass	4%	5%	6%	8%	6%	6%
Elemental Carbon	4%	5%	4%	6%	8%	5%
Organic Mass	15%	25%	18%	20%	26%	21%
Ammonium Nitrate	16%	18%	21%	22%	19%	19%
Ammonium Sulfate	55%	44%	46%	40%	37%	44%

Table 3-5 shows the annual species contributions during the five-year period for the clearest days. Sulfates (30%) contributed the most to light extinction followed by organic mass (22%), nitrates (20%), and sea salt (14%).

Table 3-5: Annual species contributions to light extinction for clearest days from 2014 - 2018 at OLYM1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	15%	15%	17%	11%	11%	14%
Fine Soil	0%	1%	0%	0%	1%	0%
Coarse Mass	6%	7%	6%	6%	8%	7%
Elemental Carbon	5%	5%	8%	9%	10%	7%
Organic Mass	17%	22%	22%	23%	27%	22%
Ammonium Nitrate	19%	19%	21%	22%	17%	20%
Ammonium Sulfate	38%	31%	26%	29%	26%	30%

Table 3-6 and Table 3-7 show the seasonality of MID from 2014 - 2018. Sulfates contributed nearly half of the visibility impacts in spring, summer, and fall. Nitrates contributed a third of visibility impacts in the winter, but less for other seasons. The majority of MID occurred during the spring and summer, which is also when sulfate impacts were largest.

Table 3-6: Number of MID at OLYM1, by season, from 2014 - 2018.

Year	Winter	Spring	Summer	Fall
2014	1	7	10	6
2015	2	12	3	7
2016	1	5	14	4
2017	3	4	13	4
2018	3	8	8	5
5-yr Total	10	36	48	26

Table 3-7: Seasonal species contributions to light extinction for MID from 2014 - 2018 at OLYM1.

Species	Winter	Spring	Summer	Fall
Sea Salt	3%	3%	4%	3%
Fine Soil	1%	2%	1%	1%
Coarse Mass	4%	6%	7%	4%
Elemental Carbon	7%	6%	4%	7%
Organic Mass	22%	19%	19%	25%
Ammonium Nitrate	32%	17%	17%	21%
Ammonium Sulfate	31%	46%	49%	40%

Figure 3–3 shows the long-term trends for OLYM1. Nitrates and sulfates decreased since the baseline period for both MID and clearest days. Organic mass decreased for the clearest days over the past 17 years of observations.

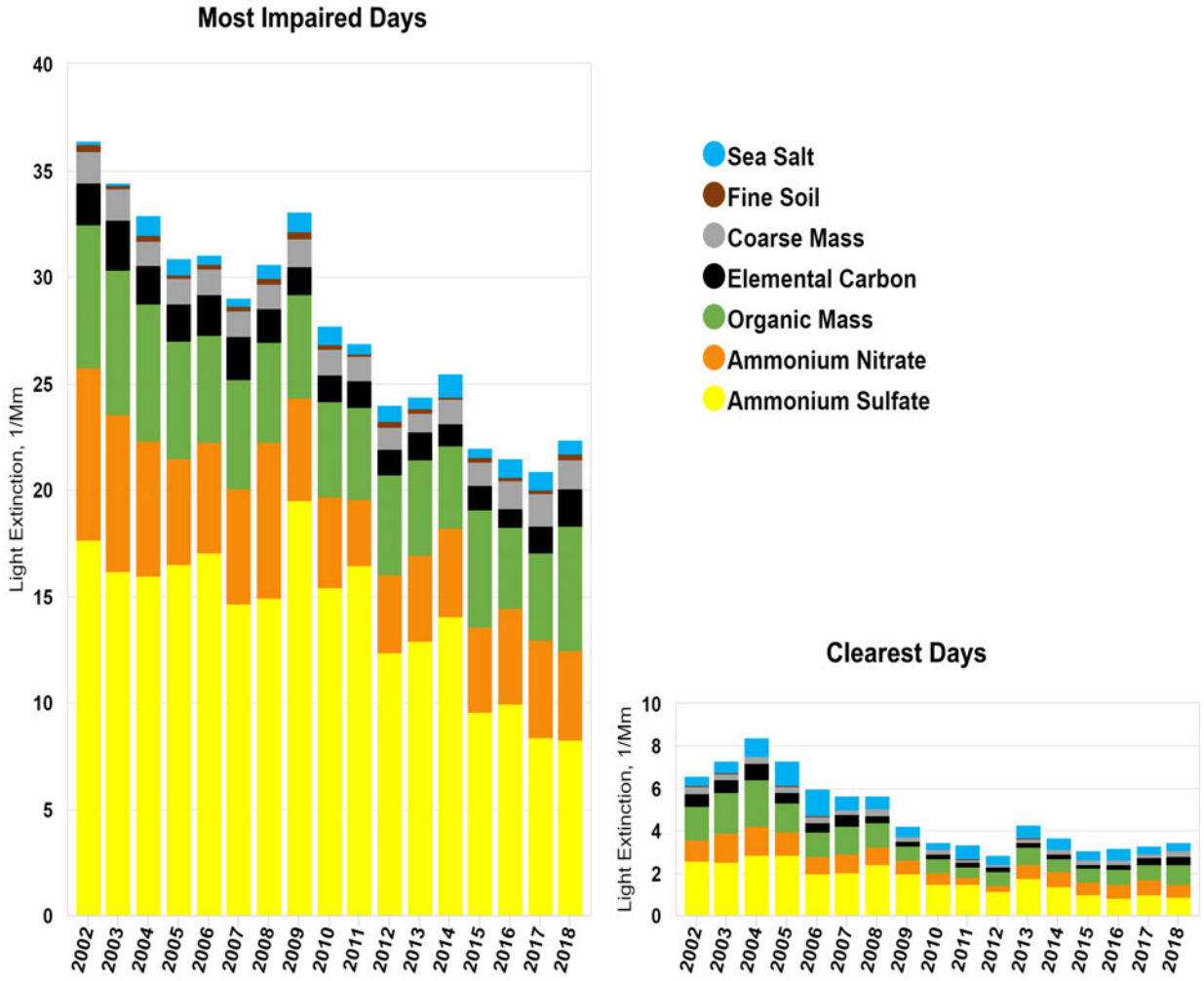


Figure 3–3: Annual species contributions to light extinction for MID and clearest days from 2002 - 2018 at OLYM1.

3.3 North Cascades National Park and Glacier Peak Wilderness

The NOCA1 monitoring site measures visibility in the North Cascades National Park and Glacier Peak Wilderness. Data for 2017 did not meet the data completeness requirements per the EPA document "Guidance for Tracking Progress under the RHR" (EPA, 2003). Twenty-three days (19% of the total) were missing for all species. WRAP performed data substitutions for 2017 using the OLYM1 IMPROVE site to address data completeness problems, due to the reasonable sulfate, elemental carbon, and organic mass correlation. See Appendix C for additional information on the WRAP data completeness memo.

The baseline visibility for the North Cascades National Park and Glacier Peak Wilderness is 3.4 dv for the clearest days and 12.6 dv for the MID. The unadjusted URP glidepath goes from 12.6 to 6.9 dv at a rate of 0.01 dv per year (5.7 dv divided by 60 years), which is the rate that needs to be maintained to reach natural visibility conditions in the park by 2064.

Based on the IMPROVE monitoring data, the 2014 – 2018 period visibility for the MID is 10.0 dv, and 2.5 dv for the clearest days. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 1.3 dv. The MID visibility improved by 2.6 dv from the baseline and is under the unadjusted URP glidepath. On the clearest days, the visibility improved by 0.9 dv.

Figure 3–4 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at NOCA1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most recent annual average MID are below the glidepath, which indicates a rate of visibility improvement that will accomplish the 2064 natural conditions goal.

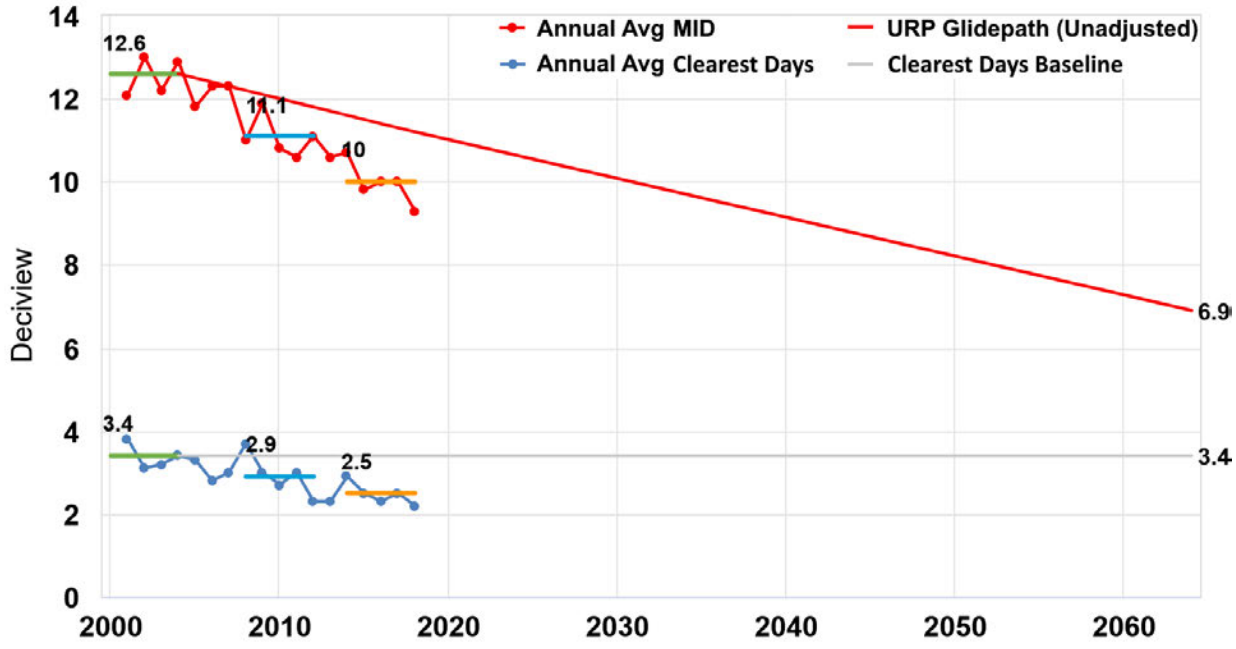


Figure 3–4: Current visibility conditions compared to the unadjusted glidepath (MID) and baseline (clearest days) at NOCA1.

Figure 3–5 shows the annual species contributions to light extinction from 2014 to 2018 for both MID and clearest days. Sulfates decreased for both MID and clearest days during the five-year period. Nitrates and organic mass showed some year-to-year variability.

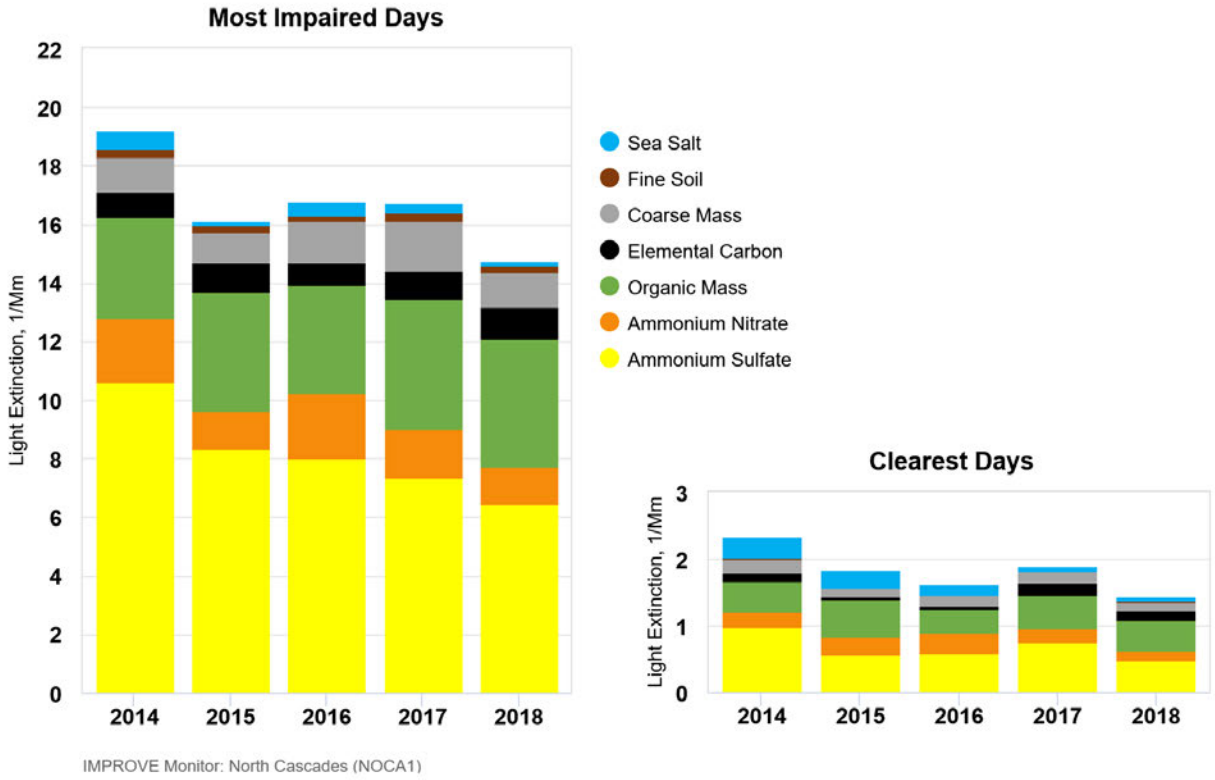


Figure 3–5: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at NOCA1.

Table 3-8 shows the annual species contributions during the five-year period for the MID. Sulfates contributed half of the light extinction to MID from 2014 - 2018. The percentage of organic mass increased in 2015, 2017, and 2018. During the five-year period, sulfates (49%) were the largest contributor to light extinction, followed by organic mass (24%), nitrates (10%), and coarse mass (8%). Elemental carbon, fine soil, and sea salt had minimal contributions to light extinction.

Table 3-8: Annual species contributions to light extinction for MID from 2014 - 2018 at NOCA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	3%	1%	3%	2%	1%	2%
Fine Soil	2%	2%	1%	2%	2%	2%
Coarse Mass	6%	7%	9%	10%	8%	8%
Elemental Carbon	4%	6%	4%	6%	7%	5%
Organic Mass	18%	25%	22%	27%	30%	24%
Ammonium Nitrate	11%	8%	13%	10%	9%	10%
Ammonium Sulfate	55%	52%	48%	44%	44%	49%

Table 3-9 shows the annual species contributions during the five-year period for the clearest days. Sulfates (36%) contributed the most to light extinction, followed by organic mass (26%). Note the relatively low contribution of nitrates for both MID and clearest days at NOCA1.

Table 3-9: Annual species contributions to light extinction for clearest days from 2014 - 2018 at NOCA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	14%	14%	10%	4%	5%	9%
Fine Soil	1%	1%	1%	1%	1%	1%
Coarse Mass	9%	7%	9%	8%	9%	8%
Elemental Carbon	5%	2%	3%	10%	9%	6%
Organic Mass	19%	30%	23%	27%	31%	26%
Ammonium Nitrate	10%	15%	19%	11%	11%	13%
Ammonium Sulfate	41%	31%	36%	39%	33%	36%

Table 3-10 and Table 3-11 show the seasonality of MID from 2014 - 2018. Sulfates contributed to the majority of light extinction for all seasons. Organic mass contributed to nearly a third of light extinction in the fall. Coarse mass contributed to 10% of the light extinction in the summer, but less for other seasons. The majority of MID occurred during the spring and summer, when nitrate and coarse mass contributions were largest.

Table 3-10: Number of MID at NOCA1, by season, from 2014 - 2018.

Year	Winter	Spring	Summer	Fall
2014	1	11	7	4
2015	2	14	4	3
2016	0	8	13	3
2017	2	7	13	2
2018	1	13	5	5
5-yr Total	6	53	42	17

Table 3-11: Seasonal species contributions to light extinction for MID from 2014 - 2018 at NOCA1.

Species	Winter	Spring	Summer	Fall
Sea Salt	0%	1%	2%	3%
Fine Soil	1%	2%	1%	1%
Coarse Mass	4%	7%	10%	6%
Elemental Carbon	6%	6%	5%	7%
Organic Mass	18%	23%	24%	29%
Ammonium Nitrate	5%	10%	12%	8%
Ammonium Sulfate	67%	50%	46%	46%

Figure 3–6 shows the long-term trends for NOCA1. Sulfates decreased since the baseline period for both MID and clearest days. Organic mass showed some year-to-year variability over the past 17 years of observations.

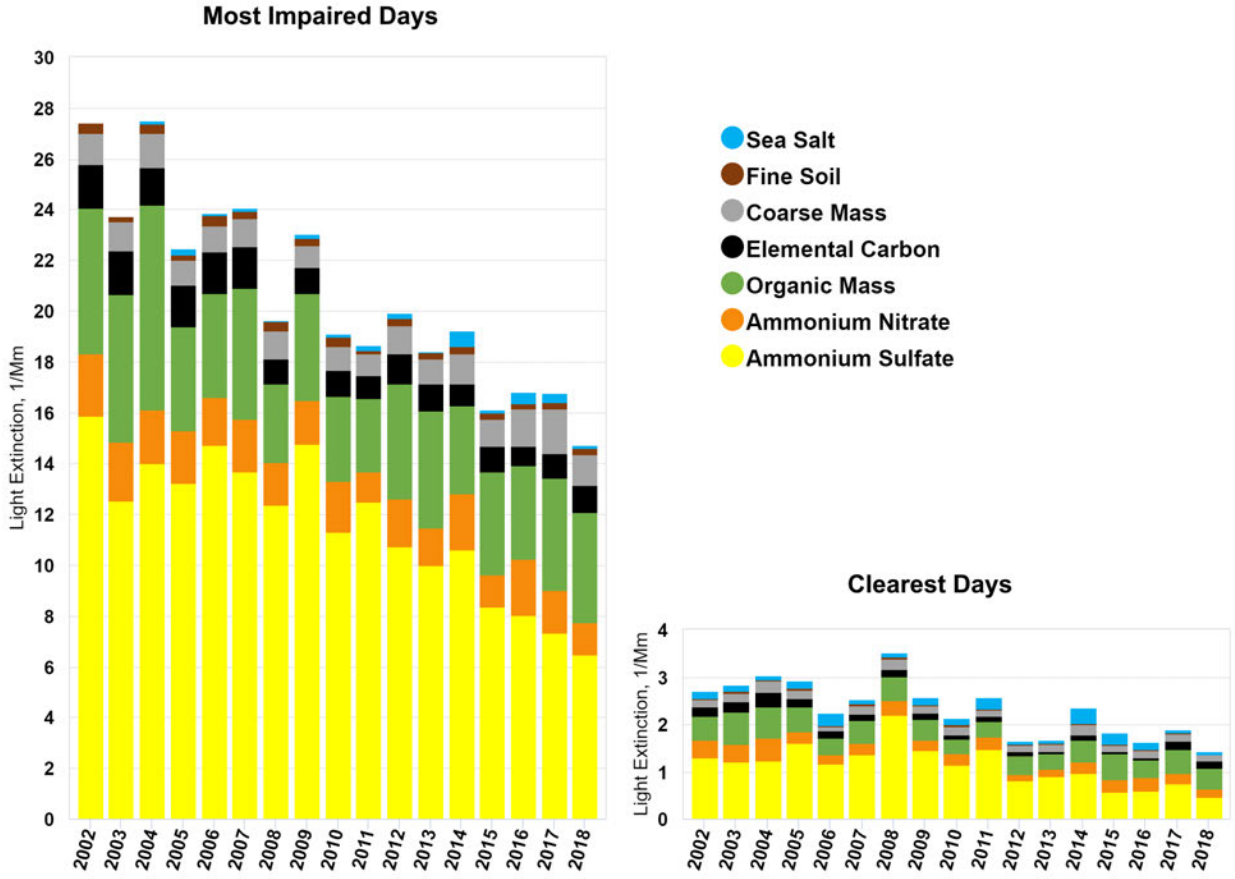


Figure 3–6: Annual species contributions to light extinction for MID and clearest days from 2002 to 2018 at NOCA1.

3.4 Alpine Lakes Wilderness

The SNPA1 monitoring site measures baseline visibility in the Alpine Lakes Wilderness for the MID and clearest days for the years 2001 - 2004. Data for 2013 did not meet the data completeness requirements per the EPA document "Guidance for Tracking Progress under the RHR." Fourteen days (12% of the total) were missing for all species. WRAP performed data substitutions for 2013 to using the MORA1 IMPROVE site to address data completeness problems, due to the strong sulfate and soil correlation, and reasonable elemental carbon, organic mass, and coarse matter correlation. See Appendix C for additional information on the WRAP data completeness memo.

The baseline visibility for the Alpine Lakes Wilderness is 5.5 dv for the clearest days and 15.4 dv for the MID. The unadjusted URP glidepath goes from 15.4 to 7.3 dv at a rate of 0.14 dv per year (8.1 dv divided by 60 years), which is the rate that would need to be maintained to reach natural visibility conditions in the park by 2064.

The current conditions (2014 – 2018) calculated from the SNPA1 monitoring data are 3.3 dv for the clearest day and 12.7 dv for the MID. The clearest days' visibility improved by 2.2 dv from the baseline. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 2.0 dv. The MID visibility improved by 2.7 dv and is below the unadjusted URP glidepath.

Figure 3–7 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at SNPA1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most recent annual average MID are below the glidepath, which indicates a rate of visibility improvement that will accomplish the 2064 natural conditions goal.

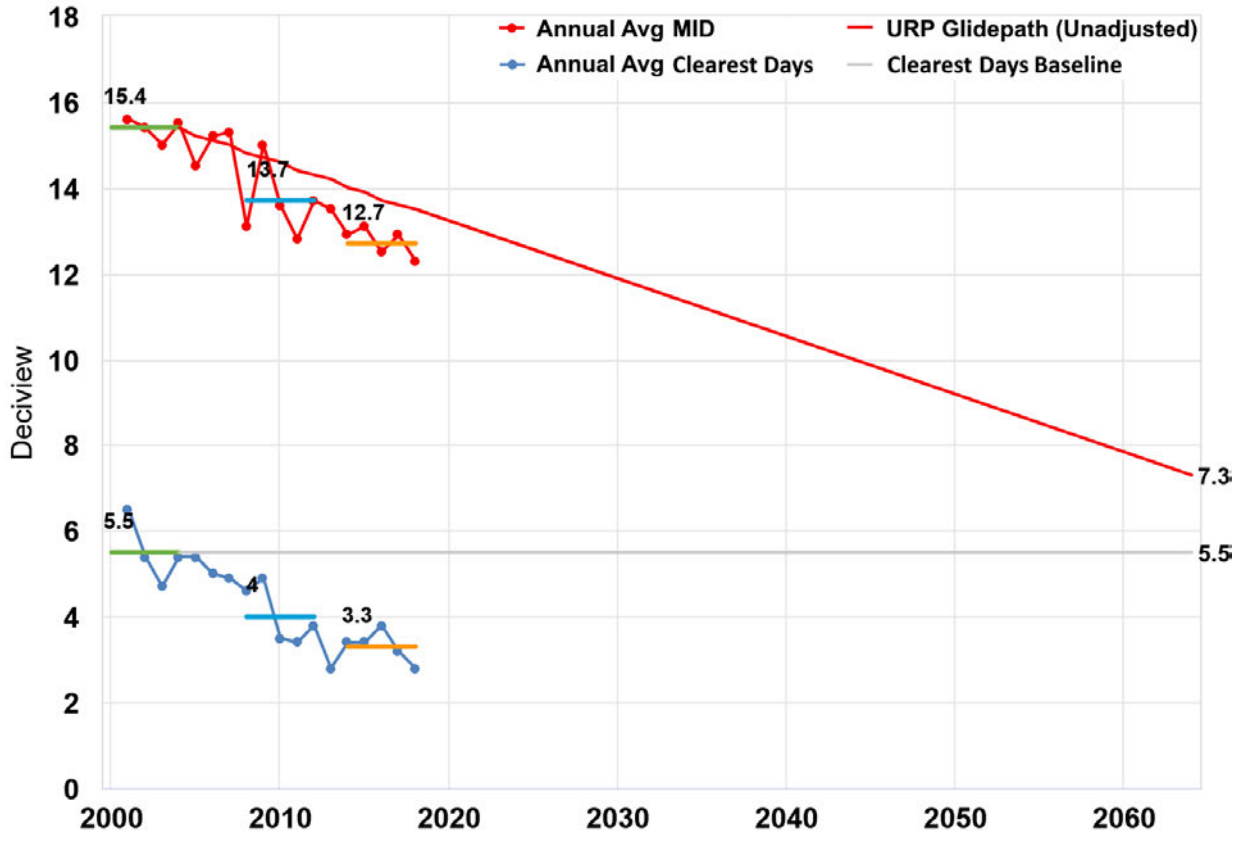


Figure 3–7: Current visibility conditions compared to the unadjusted URP glidepath and baseline (clearest days) at SNPA1.

Figure 3–8 shows the annual species contributions to light extinction from 2014 - 2018 for both MID and clearest days. Sulfates decreased for MID during the five-year period. Nitrates and organic mass showed some year-to-year variability.

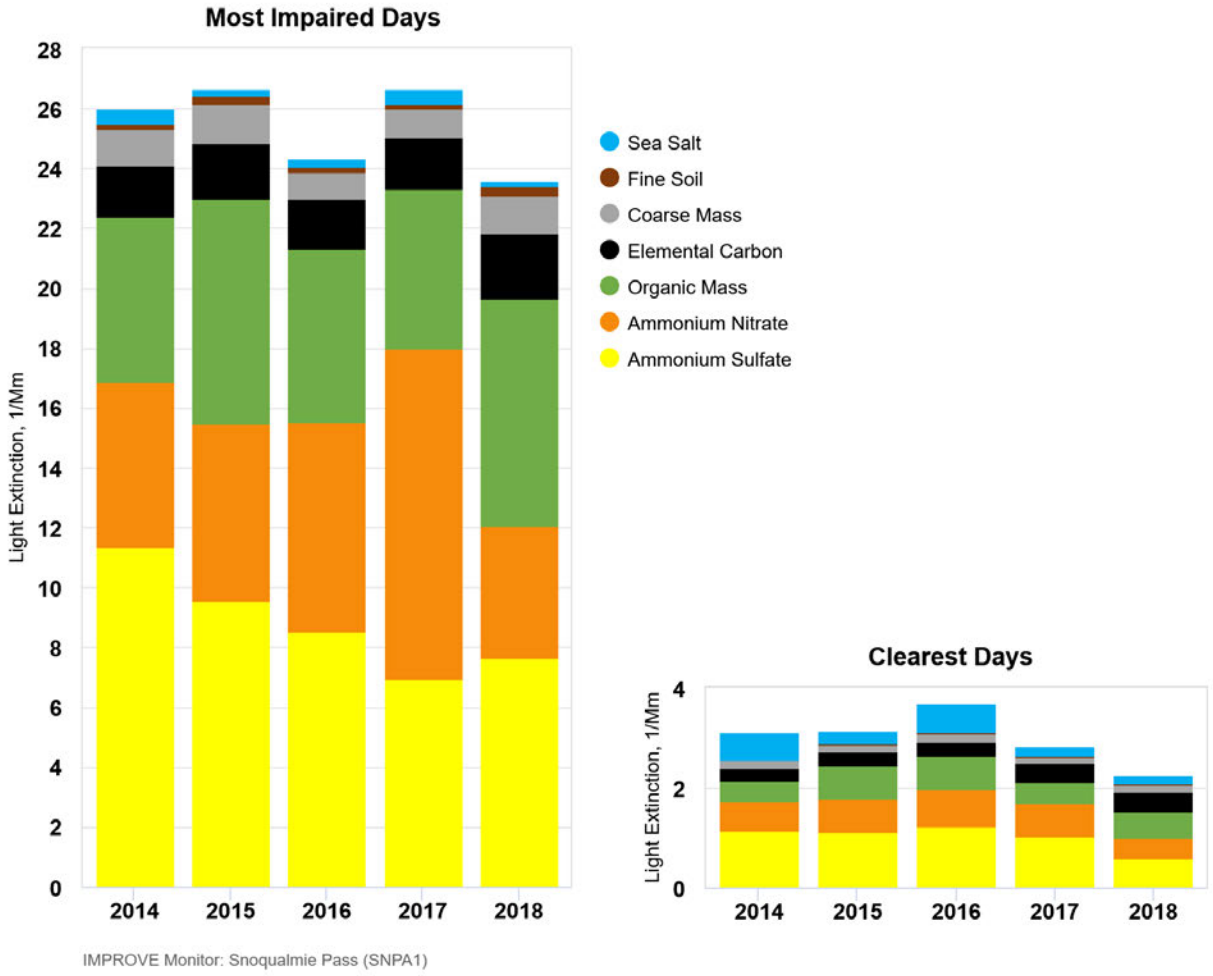


Figure 3–8: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at SNPA1.

Table 3-12 shows the annual species contribution during the five-year period for the MID. Sulfates contributed more than a third of the light extinction on MID from 2014 to 2018. The percentage of nitrates increased in 2017 while the percentage of organic mass increase in 2015 and 2018. During the five-year period, sulfates (35%) were the largest contributor to light extinction, followed by nitrates (26%) and organic mass (25%). Elemental carbon, coarse mass, fine soil, and sea salt had minimal contributions to light extinction.

Table 3-12: Annual species contributions to light extinction for MID from 2014 - 2018 at SNPA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	2%	1%	1%	2%	2%	2%
Fine Soil	1%	1%	1%	1%	1%	1%
Coarse Mass	5%	5%	4%	4%	5%	5%
Elemental Carbon	7%	7%	7%	6%	9%	7%
Organic Mass	21%	28%	24%	20%	32%	25%
Ammonium Nitrate	21%	22%	29%	41%	19%	26%
Ammonium Sulfate	44%	36%	35%	26%	32%	35%

Table 3-13 shows the annual species contributions during the five-year period for the clearest days. Sulfates (33%) contributed the most to light extinction, followed by nitrates (20%), sea salt (19%), organic mass (18%), and elemental carbon (12%).

Table 3-13: Annual species contributions to light extinction for clearest days from 2014 - 2018 at SNPA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	18%	21%	18%	14%	23%	19%
Fine Soil	1%	1%	0%	1%	1%	1%
Coarse Mass	5%	4%	5%	4%	6%	5%
Elemental Carbon	9%	9%	8%	14%	18%	12%
Organic Mass	13%	21%	18%	14%	23%	18%
Ammonium Nitrate	19%	21%	20%	23%	19%	20%
Ammonium Sulfate	36%	35%	33%	37%	26%	33%

Table 3-14 and Table 3-15 show the seasonality of MID from 2014 - 2018. Sulfates contributed nearly half of the light extinction in spring and summer. Nitrates contributed two thirds of the light extinction in winter, but much less for other seasons. Organic mass contributed to nearly a third of light extinction in the summer and fall. The majority of MID occurred in spring, summer, and fall.

Table 3-14: Number of MID at SNPA1, by season, from 2014 - 2018.

Year	Winter	Spring	Summer	Fall
2014	2	8	9	5
2015	0	10	7	6
2016	2	4	10	6
2017	5	3	10	5
2018	1	7	6	9
5-yr Total	10	32	42	31

Table 3-15: Seasonal species contributions to light extinction for MID from 2014 - 2018 at SNPA1.

Species	Winter	Spring	Summer	Fall
Sea Salt	2%	2%	1%	1%
Fine Soil	0%	2%	1%	0%
Coarse Mass	2%	6%	6%	3%
Elemental Carbon	5%	7%	7%	8%
Organic Mass	10%	22%	29%	29%
Ammonium Nitrate	66%	19%	16%	32%
Ammonium Sulfate	16%	44%	40%	27%

Figure 3–9 shows the long-term trends for SNPA1. Sulfates have decreased since the baseline period for MID. Every species decreased since the baseline period for clearest days.

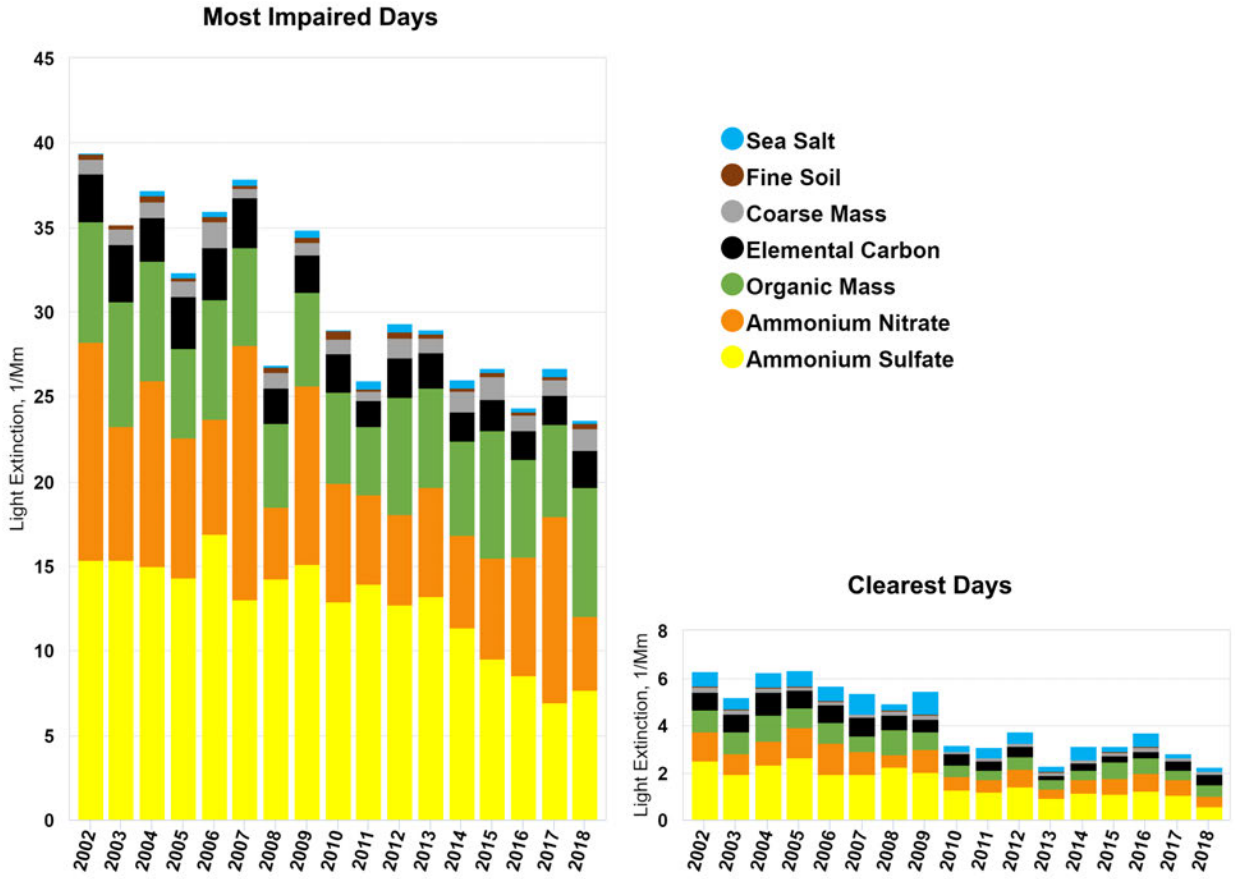


Figure 3–9: Annual species contributions to light extinction for MID and clearest days from 2002 - 2018 at SNPA1.

3.5 Mount Rainier National Park

The baseline visibility for the Mount Rainier National Park is 5.5 dv for the clearest days and 16.5 dv for the MID. The unadjusted URP glidepath goes from 16.5 to 7.7 dv at a rate of 0.15 dv per year (9.8 dv divided by 60 years), which is the rate that would need to be maintained to reach natural visibility conditions in the park by 2064.

The current conditions (2014 - 2018) calculated from the MORA1 monitoring data are 3.9 dv for the clearest days and 12.7 for the MID. The clearest days' visibility improved by 1.6 dv from the baseline. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 2.1 dv. The MID visibility improved by 3.8 dv and is under the unadjusted URP glidepath.

Figure 3–10 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at MORA1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most

recent annual average MID are below the glidepath, which indicates a rate of visibility improvement that will accomplish the 2064 natural conditions goal.

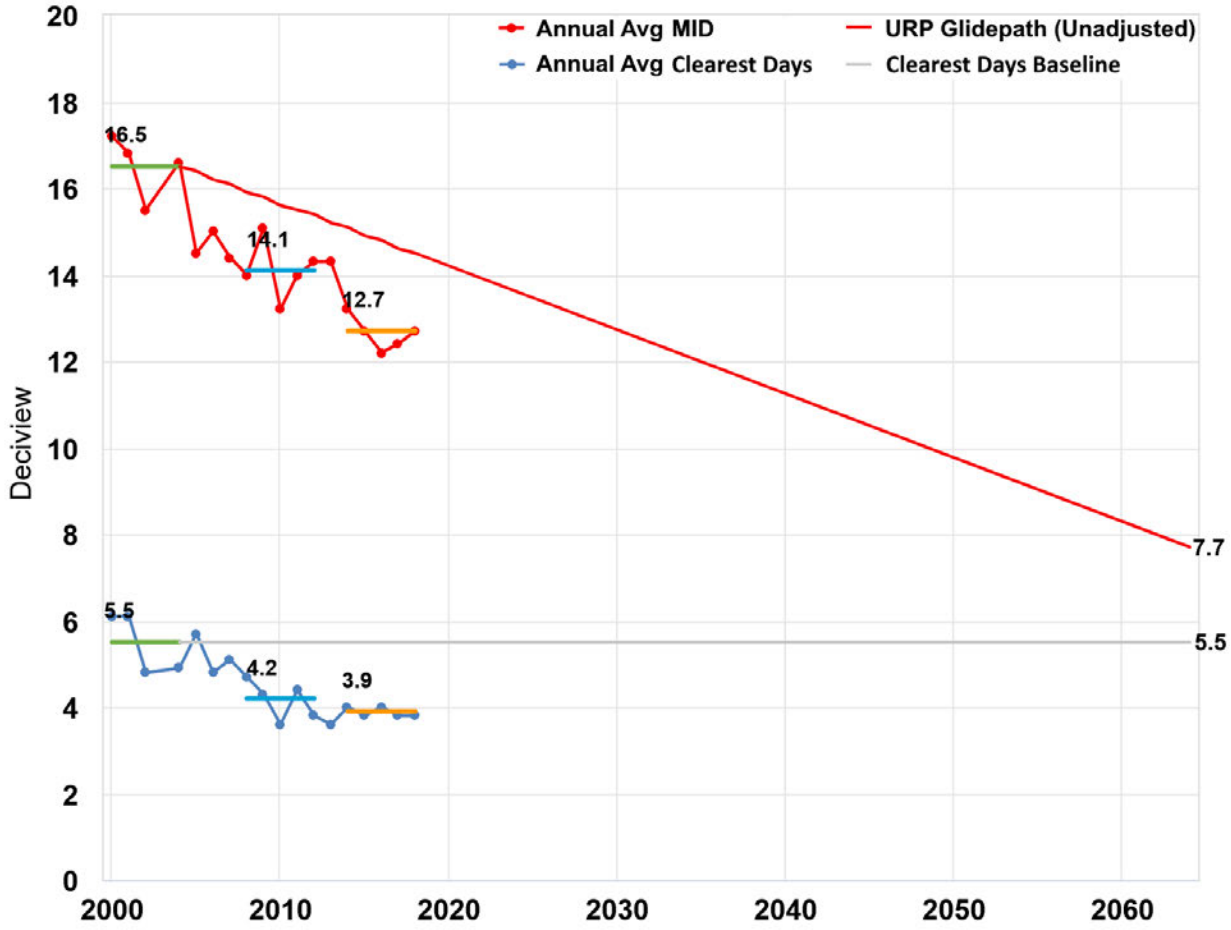


Figure 3–10: Current visibility conditions compared to the unadjusted URP glidepath and baseline (clearest days) at MORA1.

Figure 3–11 shows the annual species contributions to light extinction from 2014 - 2018 for both MID and clearest days. Sulfates decreased each year for MID. Organic mass increased in 2018 for MID. The clearest days showed very little change for all species.

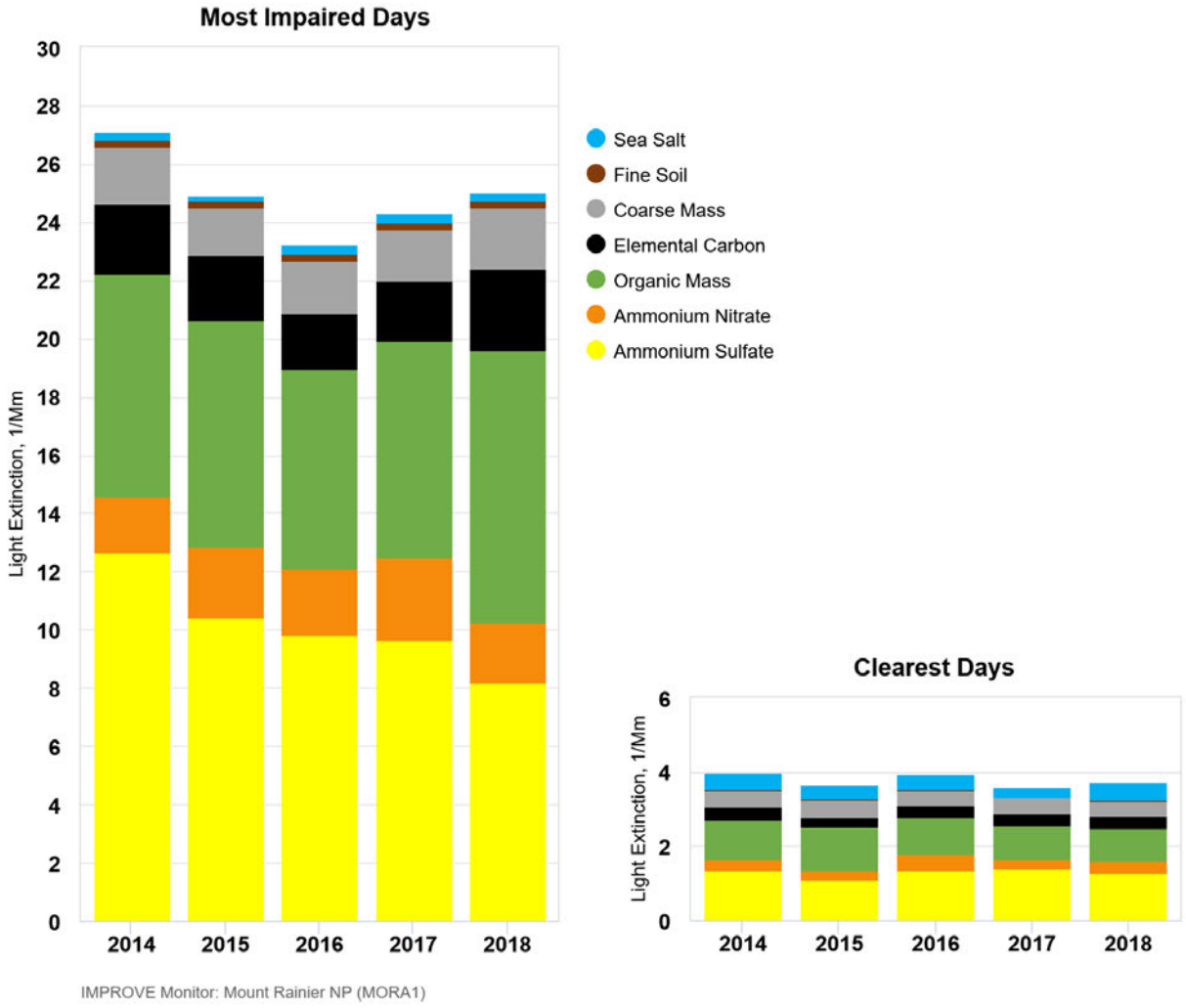


Figure 3–11: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at MORA1.

Table 3-16 shows the annual species contributions during the five-year period for the MID. Sulfates contributed more than a third of the light extinction to MID from 2014 - 2018. Organic mass contributed to nearly a third of the light extinction, but increased in 2018. During the five-year period, sulfates (41%) were the largest contributor to light extinction, followed by organic mass (31%), nitrates (9%), and elemental carbon (9%).

Table 3-16: Annual species contributions to light extinction for MID from 2014 - 2018 at MORA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	1%	0%	1%	1%	1%	1%
Fine Soil	1%	1%	1%	1%	1%	1%
Coarse Mass	7%	7%	8%	7%	8%	7%
Elemental Carbon	9%	9%	8%	8%	11%	9%
Organic Mass	28%	31%	29%	31%	38%	31%
Ammonium Nitrate	7%	10%	10%	12%	8%	9%
Ammonium Sulfate	47%	42%	42%	40%	33%	41%

Table 3-17 shows the annual species contributions during the five-year period for the clearest days. Sulfates (35%) contributed the most to light extinction, following by organic mass (26%), coarse mass (12%), and sea salt (10%).

Table 3-17: Annual species contributions to light extinction for clearest days from 2014 - 2018 at MORA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	11%	10%	11%	7%	13%	10%
Fine Soil	0%	1%	0%	1%	1%	1%
Coarse Mass	11%	13%	11%	12%	11%	12%
Elemental Carbon	10%	7%	8%	9%	9%	9%
Organic Mass	26%	32%	25%	25%	24%	26%
Ammonium Nitrate	8%	7%	11%	7%	9%	8%
Ammonium Sulfate	34%	31%	35%	39%	34%	35%

Table 3-18 and Table 3-19 show the seasonality of MID from 2014 - 2018. Sulfates contributed nearly half of the light extinction in spring and summer. Organic mass contributed more than a third of the light extinction in fall and winter. The majority of MID occurred during the spring and summer, which is also when sulfate and nitrate impacts are highest.

Table 3-18: Number of MID at MORA1, by season, from 2014 - 2018.

Year	Winter	Spring	Summer	Fall
2014	3	3	14	3
2015	3	12	5	3
2016	1	6	12	5
2017	1	3	15	4
2018	1	8	8	7
5-yr Total	9	32	54	22

Table 3-19: Seasonal species contributions to light extinction for MID from 2014 - 2018 at MORA1.

Species	Winter	Spring	Summer	Fall
Sea Salt	1%	1%	1%	1%
Fine Soil	1%	1%	1%	0%
Coarse Mass	3%	7%	8%	8%
Elemental Carbon	19%	8%	8%	12%
Organic Mass	41%	29%	31%	36%
Ammonium Nitrate	6%	10%	9%	7%
Ammonium Sulfate	29%	43%	42%	36%

Figure 3–12 shows the long-term trends for MORA1. Sulfates decreased since the baseline period for both MID and clearest days.

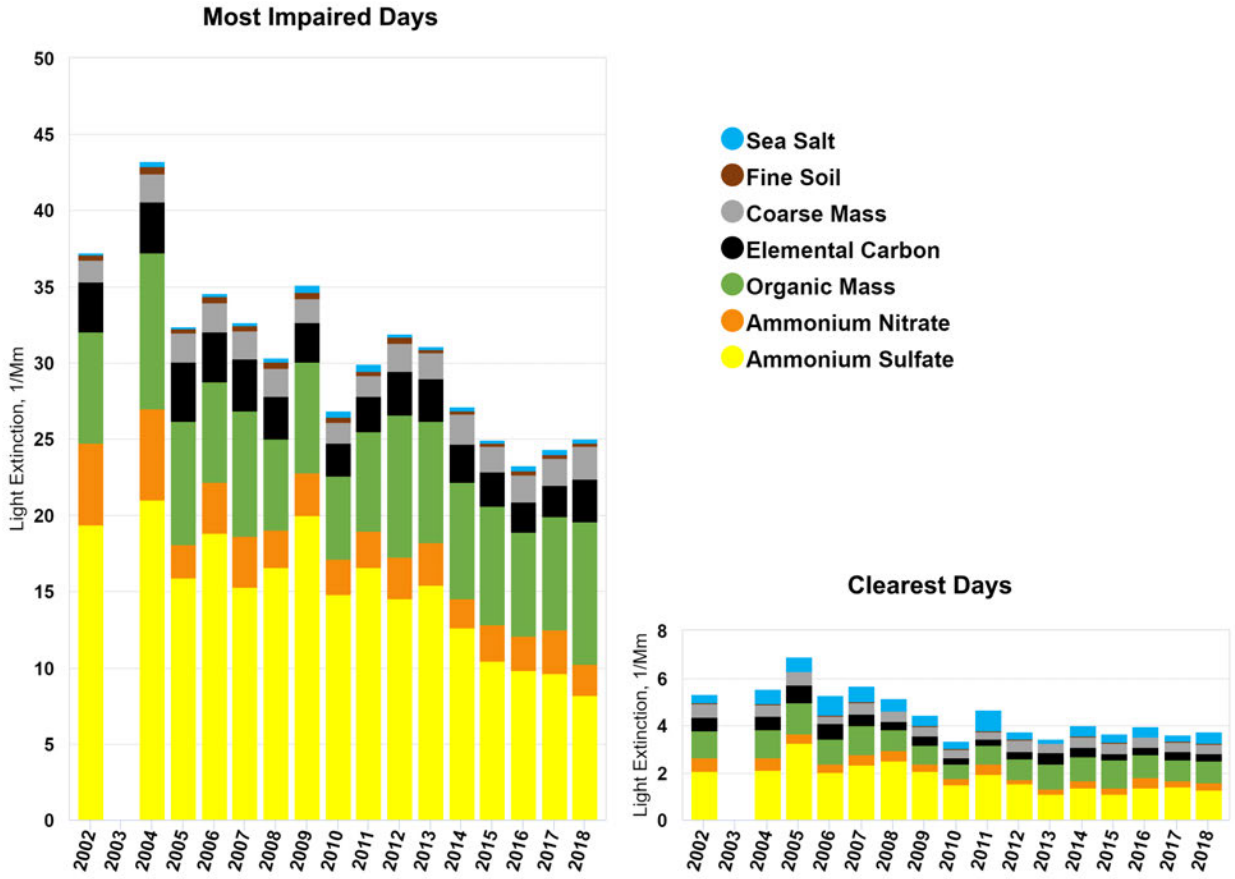


Figure 3–12: Annual species contributions to light extinction for MID and clearest days from 2002 - 2018 at MORA1.

3.6 Goat Rocks Wilderness and Mount Adams Wilderness

The baseline visibility for the Goat Rocks Wilderness and Mount Adams Wilderness is 1.7 dv for the clearest days and 10.5 dv for the MID. The unadjusted URP glidepath goes from 10.5 to 6.1 dv at a rate of 0.07 dv per year (4.4 dv divided by 60 years), which is the rate that would need to be maintained to reach natural visibility conditions in the park by 2064.

The current conditions (2014 - 2018) calculated from WHPA1 monitoring data are 1.0 dv for the clearest days and 8.0 dv for the MID. The clearest days' visibility improved by 0.7 dv from the baseline. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 1.0 dv. The MID visibility improved by 2.5 dv and is under the unadjusted URP glidepath.

Figure 3–13 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at WHPA1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most recent annual average MID are below the glidepath, which indicates a rate of visibility improvement that will accomplish the 2064 natural conditions goal.

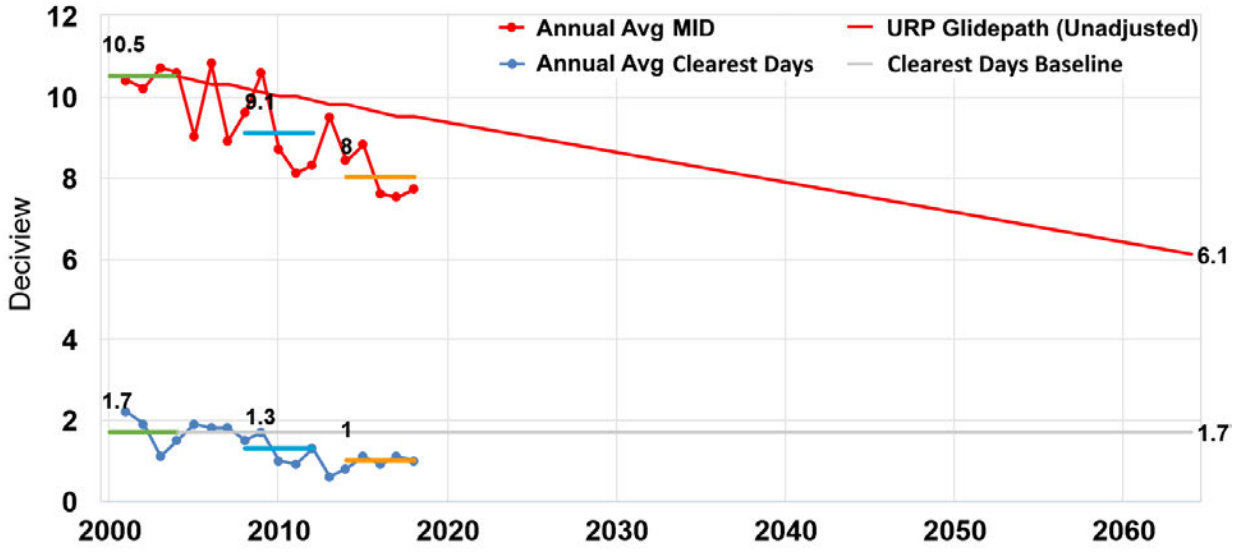


Figure 3–13: Current visibility conditions compared to the unadjusted URP glidepath and baseline (clearest days) at WHPA1.

Figure 3–14 shows the annual species contributions to light extinction from 2014 - 2018 for both MID and clearest days. Sulfates decreased in 2016 for MID, with the decrease sustained through the rest of the five-year period. Organic mass increased in 2015 and 2018 for MID. All species showed very little change for clearest days.

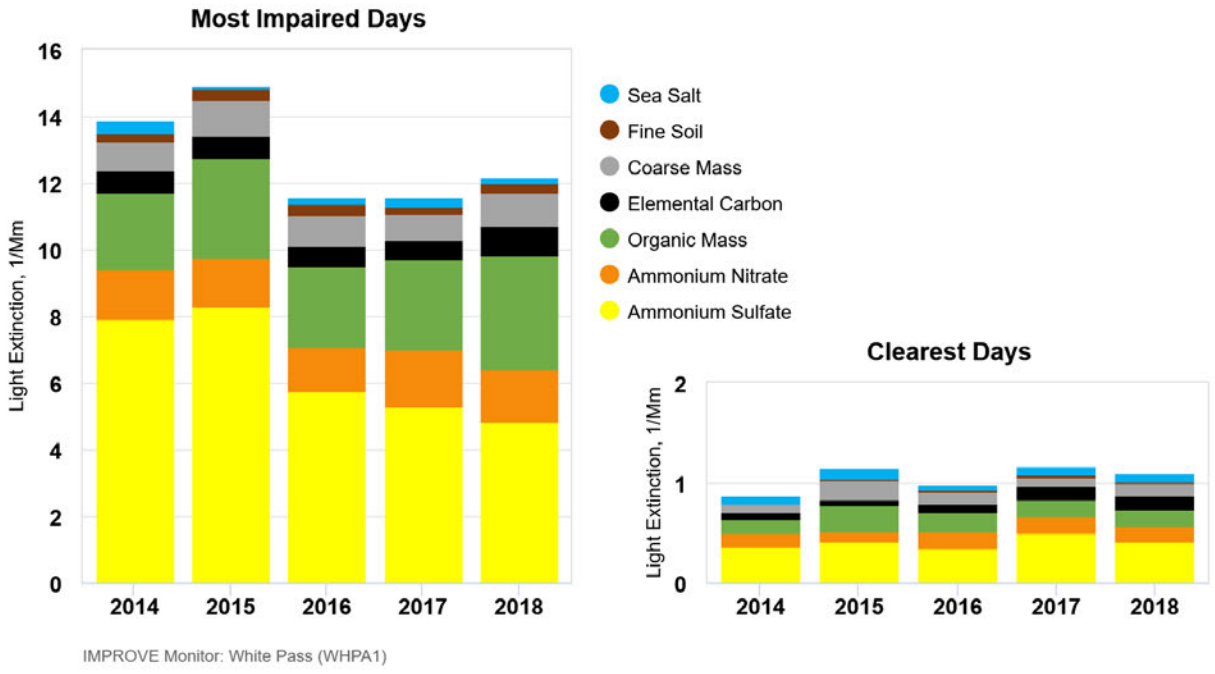


Figure 3–14: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at WHPA1.

Table 3-20 shows the annual species contribution during the five-year period for the MID. Sulfates contributed half of the light extinction to MID from 2014 - 2018. During the five-year period, sulfates (50%) were the largest contributor to light extinction, followed by organic mass (22%) and nitrates (12%). Elemental carbon, coarse mass, fine soil, and sea salt had minimal contributions to light extinction.

Table 3-20: Annual species contributions to light extinction for MID from 2014 - 2018 at WHPA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	3%	1%	2%	2%	2%	2%
Fine Soil	2%	2%	3%	2%	2%	2%
Coarse Mass	6%	7%	8%	7%	8%	7%
Elemental Carbon	5%	4%	5%	5%	7%	5%
Organic Mass	16%	20%	21%	23%	28%	22%
Ammonium Nitrate	11%	10%	11%	15%	13%	12%
Ammonium Sulfate	57%	56%	50%	46%	40%	50%

Table 3-21 shows the annual species contributions during the five-year period for the clearest days. Sulfates (39%) contributed the most to light extinction followed by organic mass (18%), nitrates (14%), and coarse mass (12%).

Table 3-21: Annual species contributions to light extinction for clearest days from 2014 - 2018 at WHPA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	9%	10%	6%	8%	7%	8%
Fine Soil	1%	1%	1%	1%	2%	1%
Coarse Mass	9%	17%	13%	8%	12%	12%
Elemental Carbon	8%	5%	8%	11%	12%	9%
Organic Mass	17%	23%	20%	15%	15%	18%
Ammonium Nitrate	15%	9%	18%	14%	14%	14%
Ammonium Sulfate	42%	36%	35%	43%	38%	39%

Table 3-22 and Table 3-23 show the seasonality of MID from 2014 - 2018. Sulfates contributed most of the visibility impacts in all seasons. Organic mass contributed nearly a third of visibility impacts in the summer, but less for other seasons. The majority of MID occurred during the spring, when nitrate and coarse mass contributions were largest.

Table 3-22: Number of MID at WHPA1, by season, from 2014 - 2018.

Year	Winter	Spring	Summer	Fall
2014	3	11	3	5
2015	3	10	5	3
2016	0	8	8	7
2017	2	8	11	2
2018	3	9	3	8
5-yr Total	11	46	30	25

Table 3-23: Seasonal species contributions to light extinction for MID from 2014 - 2018 at WHPA1.

Species	Winter	Spring	Summer	Fall
Sea Salt	1%	1%	2%	3%
Fine Soil	2%	3%	1%	1%
Coarse Mass	6%	8%	8%	6%
Elemental Carbon	7%	5%	5%	6%
Organic Mass	14%	19%	29%	22%
Ammonium Nitrate	11%	14%	11%	9%
Ammonium Sulfate	60%	49%	45%	54%

Figure 3–15 shows the long-term trends for WHPA1. Sulfates, nitrates, and organic mass decreased since the baseline period for both MID and clearest days.

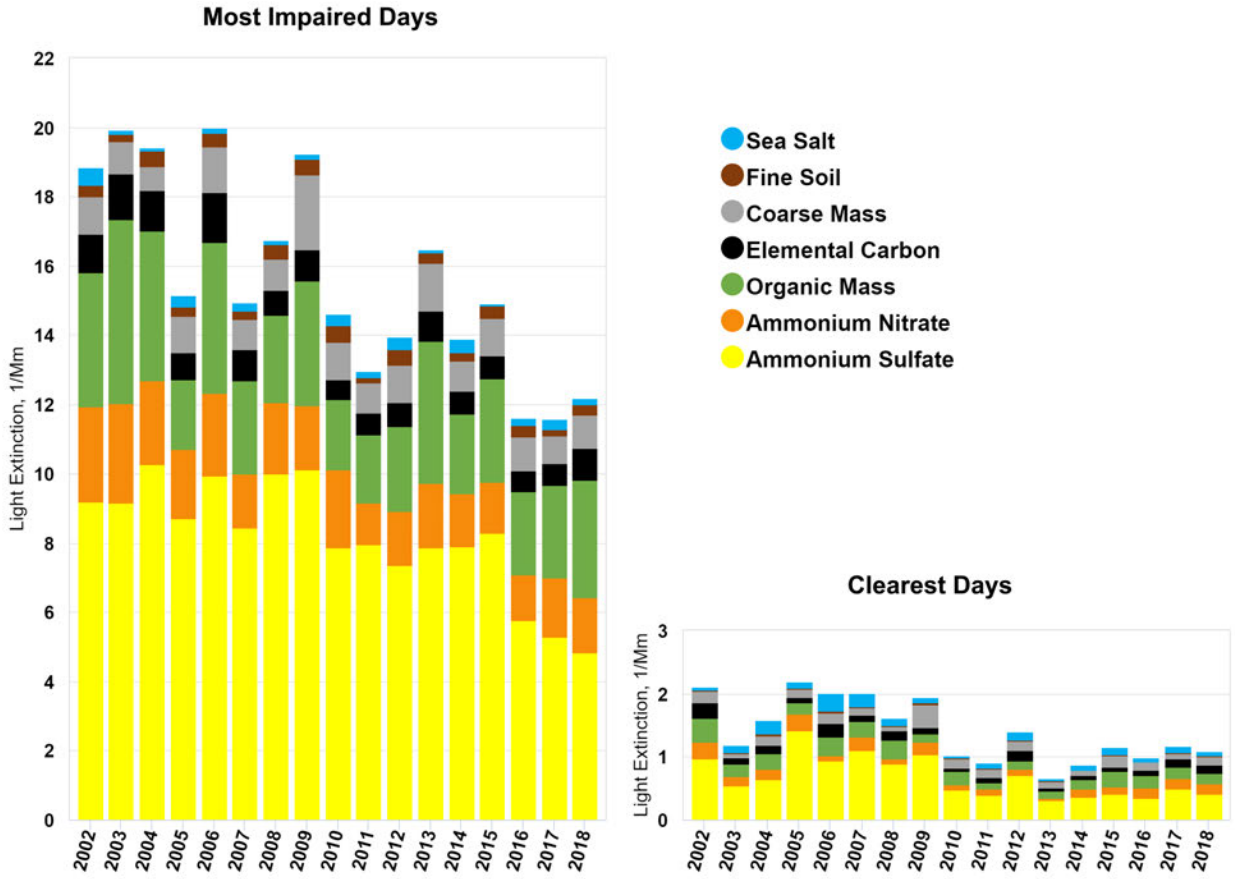


Figure 3–15: Annual species contributions to light extinction for MID and clearest days from 2002 - 2018 at WHPA1.

3.7 Pasayten Wilderness

The baseline visibility for the Pasayten Wilderness is 2.7 dv for the clearest days and 10.4 dv for the MID. Pasayten had the best baseline visibility conditions for the MID of all Washington's Class 1 Areas, and is the second best for the visibility on the clearest days. The unadjusted URP glidepath goes from 10.4 to 6.0 dv at a rate of 0.07 dv per year (4.4 dv divided by 60 years), which is the rate that would need to be maintained to reach natural visibility conditions in the park by 2064.

The current conditions (2014 – 2018) calculated from the PASA1 monitoring data are 1.6 dv for the clearest days and 9.5 dv for the MID. The clearest days' visibility improved by 1.1 dv from the baseline. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 1.0 dv. The MID visibility improved by 0.9 dv so the Pasayten's five-year average for MID is slightly above the unadjusted URP glidepath.

Figure 3–16 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at PASA1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most recent annual average MID are above the glidepath. Note that some days included in the MID were influenced wildfire smoke. Ecology estimated that in Pasayten from 2014-2018, seven percent of the haziest days were influenced by wildfire, with considerable year-to-year variability. Thus, the removal of five percent of the haziest days as allowed by the RHR was insufficient to remove natural events such as wildfire from the MID. After the proposed endpoint adjustment for international emissions in **Chapter 9**, as allowed by the RHR, the most recent MID are below the adjusted glidepath, which indicates a rate of visibility improvement that will accomplish the adjusted 2064 natural conditions goal.

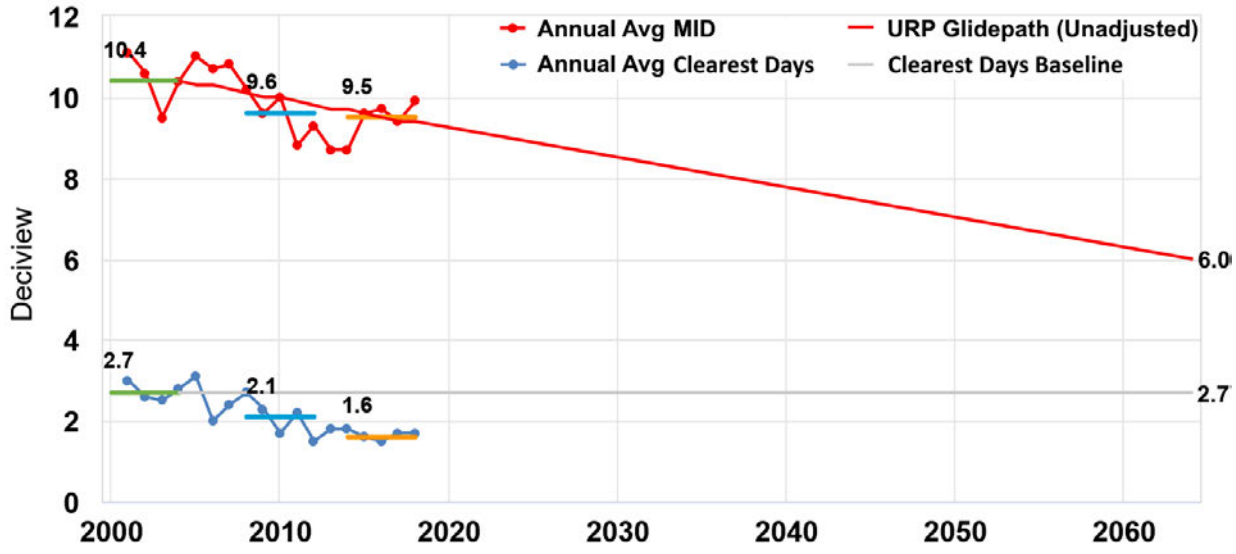


Figure 3–16: Current visibility conditions compared to the unadjusted URP glidepath and baseline (clearest days) at PASA1.

Figure 3–17 shows the annual species contributions to light extinction from 2014 - 2018 for both MID and clearest days. Sulfates decreased over the five-year period for MID and clearest days. Organic mass increased and nitrate showed year-to-year variability for MID. All species showed very little change for clearest days.

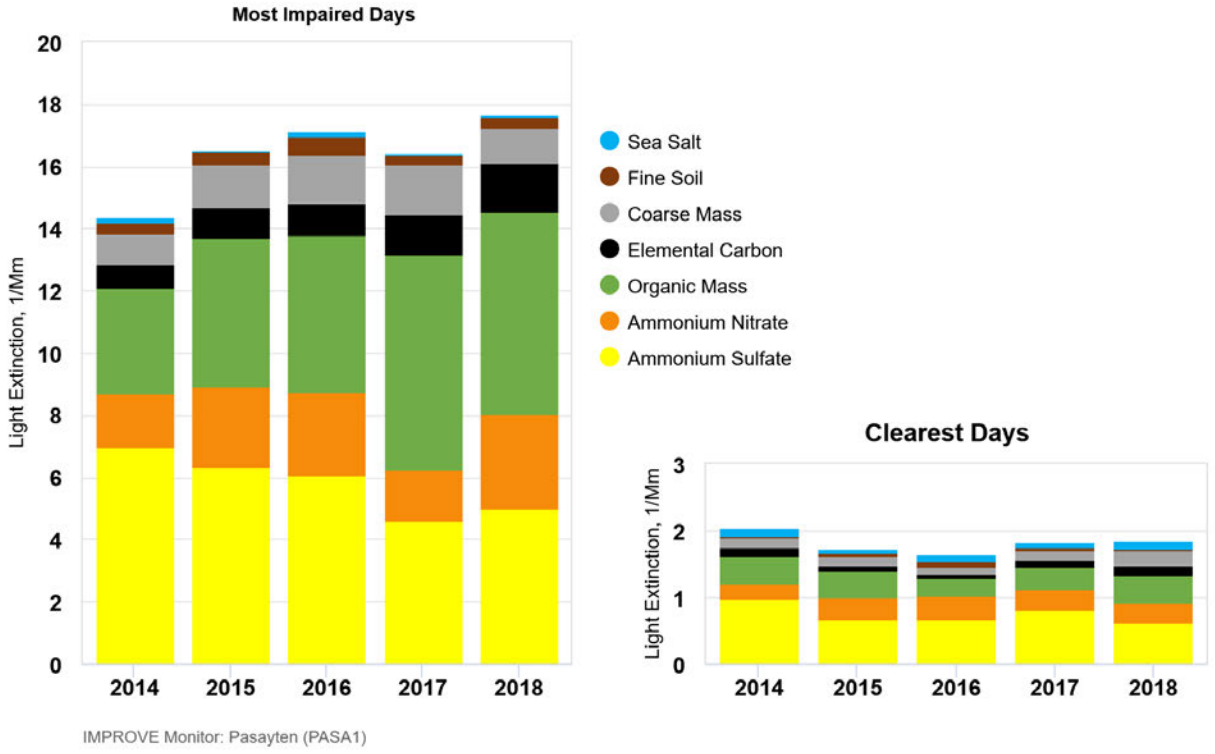


Figure 3–17: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at PASA1.

Table 3-24 shows the annual species contributions during the five-year period for the MID. Sulfates and organic mass each contributed one third of the light extinction to MID from 2014 - 2018. Organic mass increased in 2017 and 2018. During the five-year period, contributions to light extinction were largest from sulfates (35%), organic mass (32%), and nitrates (14%). Elemental carbon, coarse mass, fine soil, and sea salt had minimal contributions to light extinction.

Table 3-24: Annual species contributions to light extinction for MID from 2014 - 2018 at PASA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	1%	1%	1%	0%	0%	1%
Fine Soil	2%	2%	3%	2%	2%	2%
Coarse Mass	7%	8%	9%	10%	6%	8%
Elemental Carbon	5%	6%	6%	8%	9%	7%
Organic Mass	24%	29%	30%	42%	37%	32%
Ammonium Nitrate	12%	16%	16%	10%	17%	14%
Ammonium Sulfate	48%	38%	35%	28%	28%	35%

Table 3-25 shows the annual species contributions during the five-year period for the clearest days. Sulfates (41%) contributed the most to light extinction followed by organic mass (20%) and nitrates (17%).

Table 3-25: Annual species contributions to light extinction for clearest days from 2014 - 2018 at PASA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	5%	4%	4%	4%	6%	5%
Fine Soil	1%	2%	6%	2%	2%	3%
Coarse Mass	7%	9%	7%	8%	12%	9%
Elemental Carbon	6%	5%	4%	6%	8%	6%
Organic Mass	20%	23%	16%	18%	22%	20%
Ammonium Nitrate	12%	18%	22%	17%	15%	17%
Ammonium Sulfate	48%	39%	41%	45%	34%	41%

Table 3-26 and Table 3-27 show the seasonality of MID from 2014 - 2018. Sulfates contributed nearly half the visibility impacts in winter and spring. Organic mass contributed more than a third of visibility impacts in summer and fall. The majority of MID occurred in the fall and spring, but summer MID increased in 2017 due to the large wildfire season in the Pacific Northwest. Six of the seven summer MID in 2017 were during regional wildfire events (Dates: July 12, 2017; July 15, 2017; July 24, 2017; August 14, 2017; August 17, 2017; September 19, 2017). Eleven regional wildfire days were included in the MID for PASA during the five-year period, suggesting that the standard threshold to remove wildfire impacts from MID (top 5% of large organic mass days) was insufficient.

Table 3-26: Number of MID at PASA1, by season, from 2014 to 2018.

Year	Winter	Spring	Summer	Fall
2014	4	11	0	8
2015	1	8	3	9
2016	0	9	4	11
2017	1	7	7	8
2018	2	8	2	12
5-yr Total	8	43	16	48

Table 3-27: Seasonal species contributions to light extinction for MID from 2014 to 2018 at PASA1.

Species	Winter	Spring	Summer	Fall
Sea Salt	0%	0%	1%	1%
Fine Soil	1%	4%	3%	1%
Coarse Mass	3%	11%	13%	5%
Elemental Carbon	6%	5%	6%	8%
Organic Mass	16%	25%	43%	37%
Ammonium Nitrate	24%	10%	5%	19%
Ammonium Sulfate	49%	44%	29%	28%

Figure 3–18 shows the long-term trends for PASA1. Sulfates decreased since the baseline period for both MID and clearest days. Organic mass and nitrates showed some year-to-year variability for MID.

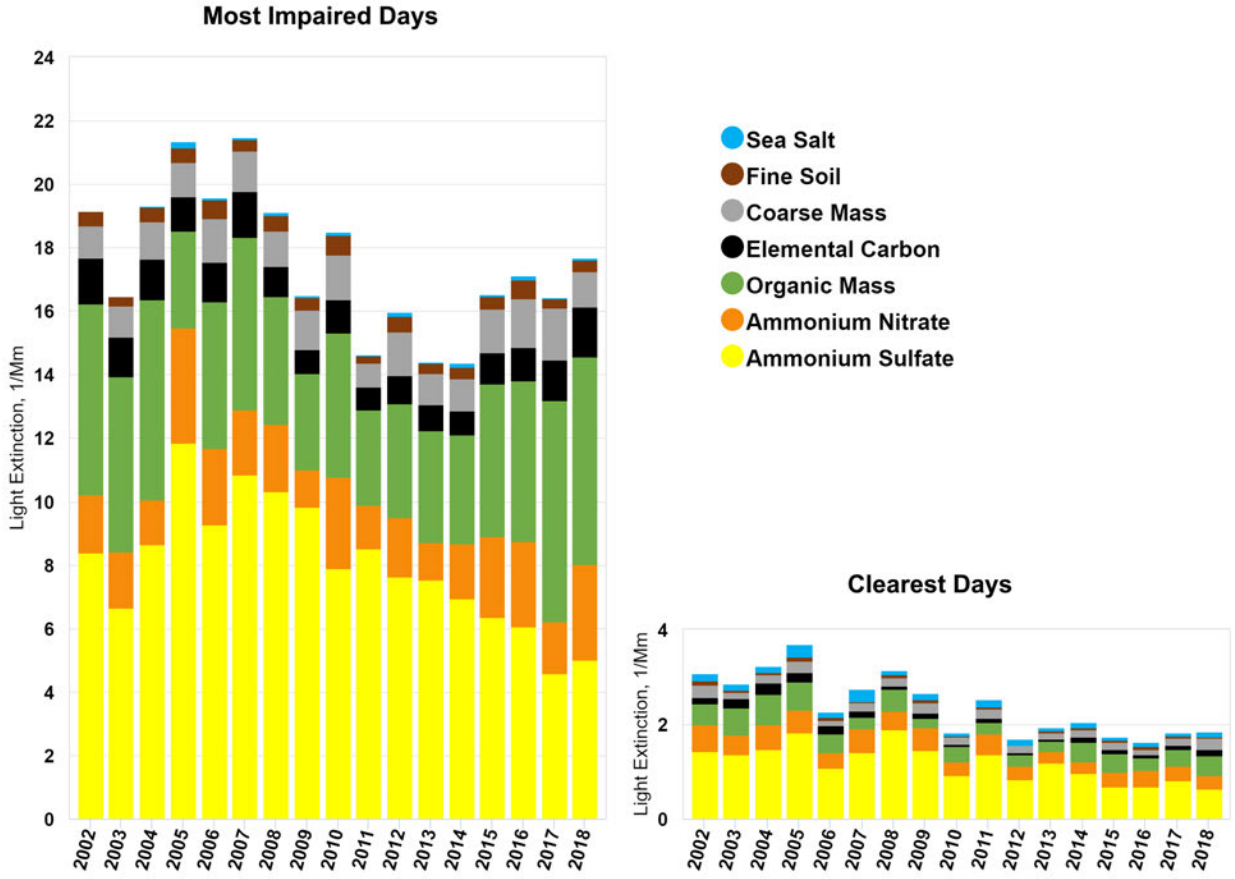


Figure 3–18: Annual species contributions to light extinction for MID and clearest days from 2002 to 2018 at PASA1.

3.8 Summary

All of Washington's Class 1 Areas have shown improvements in visibility on the MID since the baseline and since the first implementation period. The visibility also has not degraded on the clearest days. Sulfates, nitrates and organic mass are the largest contributors to regional haze, with organic mass showing variability from year-to-year. All the Class 1 Areas are also below the unadjusted glidepath for this implementation period except the current five-year MID average for the Pasayten Wilderness, although it has some of the best visibility in the state. The Pasayten's five-year average is slightly above the unadjusted glidepath due to effects of wildfire where the removal of five percent of the haziest days was insufficient to compensate for the effects of fire. The area also borders Canada and receives the most international contributions. In subsequent chapters, we propose adjusting the endpoint of the URP glidepath to account for the impact from international emissions. The Pasayten's 5-year MID average is below the URP glidepath when adjusted for international contributions.

Chapter 4.Emissions Inventory

This chapter summarizes emissions from sources located in Washington that could be affecting visibility in mandatory class 1 Federal areas (Class 1 Areas) in Washington and other states. The Regional Haze Rule (RHR) (40 CFR 51.308 (f)(6)(v)) requires a statewide emissions inventory (EI) of pollutants that we reasonably anticipate to cause or contribute to visibility impairment in any Class 1 Areas. This chapter describes the EI development process, the various EI scenarios developed for regional haze (RH) modeling, a summary of the emissions from each anthropogenic source category, and changes in emissions at facilities selected for a four-factor analysis (FFA).

4.1 Emissions inventory development

The emissions summaries presented in this chapter play an important role in the identification and evaluation of sources that we reasonably expect to influence visibility. An accurate EI helps prioritize emission reduction efforts and helps ensure that model predictions of 2028 visibility impairment are reasonable. The year 2028 represents the second milestone date for demonstrating reasonable progress toward the national visibility goal.

State, local, and tribal air pollution control programs regularly collect and report EI data to EPA. EPA publishes a national emissions inventory (NEI) every three years, which includes all sources of air pollution. Reviewing EI summaries, identifying issues, and correcting errors is an important process that provides a better understanding of emissions sources that could be contributing to visibility impairment.

Western Regional Air Partnership (WRAP) workgroups compiled EI data for use in WRAP modeling and individual state analyses. EI summaries are available from the WRAP Technical Support System (TSS) website[5]. The TSS website also provides references that describe the methods used for RH SIP EI development.

The EPA NEI is the cornerstone of regional haze state implementation plan (RH SIP) EI development. WRAP developed the EI data for RH modeling in collaboration with state, local, and tribal air pollution control programs and EPA, using the 2014 NEI as the starting point. WRAP made several improvements to the 2014 NEI using corrections submitted by the regulatory agencies and updates from the EPA 2016 modeling platform. EPA subsequently released the 2017 NEI in 2020, summarized in this chapter for reference.

4.2 Emissions inventory scenarios

The WRAP focused on EI development for three scenarios: 2014 Actual, Representative Baseline (RepBase), and 2028 On-the-Books (OTB):

- The 2014 Actual EI is a quality-controlled dataset, including state corrections to the 2014 NEI point and nonpoint sources. The purpose of the 2014 Actual EI is to represent the

[5] http://views.cira.colostate.edu/tssv2/

actual emissions of pollutants causing or contributing to visibility impairment during calendar year 2014. The WRAP considers the 2014 Actual EI to be the best available estimates of 2014 emissions for all states in the WRAP. The WRAP used the 2014 Actual EI as the basis to model visibility for the calendar year 2014 and to evaluate model performance.

- The RepBase EI is the modeling baseline used for comparison to future projections. The WRAP designed the Rep Base EI to be the best available data representative of the 2014-2018 five-year period. Ecology used the 2014 Actual EI to develop the RepBase EI with the following updates: states and WRAP workgroups submitted point source emissions, WRAP workgroups developed a representative fire EI, and used the EPA 2016 modeling platform for nonroad emissions. Industrial pulp and paper mill emissions in Washington used the 2017 values for the RepBase EI.
- The 2028 OTB EI is a projected inventory to evaluate reasonable progress toward achieving the national visibility goal. This EI uses the 2016 modeling platform projections for 2028 and emissions submitted by state, local, and tribal air pollution control programs and WRAP workgroups. It includes additional controls or plant closures, which have a planned completion prior to 2028.

The WRAP estimated emissions for the year 2028 by including "On-the-Books" (that is, adopted or soon to be adopted) controls, regulations, and major facility changes. The OTB EI also includes changes to mobile (on-road and non-road) sources as represented in the EPA 2016 modeling platform projections of 2028 emissions. EPA based 2028 mobile source emissions on known fuel standards and projections of population and mobile fleet make-up.

The documentation section of the webpage entitled "Inventory Collaborative 2016v1 Emissions Modeling Platform" [6] (WRAP) cites the methods for projecting mobile source emissions. In summary:

- EPA projected the Commercial Marine Vessel (CMV) (C1 & C2) emissions from 2016 to 2028 using factors derived from the Regulatory Impact Analysis (RIA) *Control of Emissions of Air Pollution from Locomotive Engines and Marine Compression Ignition Engines Less than 30 Liters per Cylinder (73 FR 37095)*.
- EPA developed growth rates for CMV (C3) emissions from 2016 to 2028 using an EPA report on projected bunker fuel demand. The EPA used bunker fuel usage as a surrogate for marine vessel activity.
- EPA estimated locomotive fuel use for 2028 based on the 2018 Annual Energy Outlook (U.S. Energy Information Administration) freight rail energy use growth rate projections for 2016 through 2028.
- EPA used the Motor Vehicle Emissions Simulator (MOVES) model for other non-road sources and for on-road sources, run specifically for 2028.
- EPA reduced medium and heavy-duty truck energy rates for 2014 and later model-year vehicles to account for the Phase 1 of the Greenhouse Gas Emissions Standards and Fuel

[6] http://views.cira.colostate.edu/wiki/wiki/10202

Efficiency Standards for Medium-and Heavy-Duty Engines and Vehicles. (U.S. EPA and NHTSA, 2012).

- Reductions of the Light-duty energy rates for 2017 and later model years vehicles to account for the Light-duty EPA and NHTSA greenhouse gas and fuel economy standards. (U.S. EPA & NHTSA, 2011).

4.3 Emissions inventory comparison

We analyzed anthropogenic EI data for the following visibility-impairing pollutants: sulfur dioxide (SO_2), nitrogen oxides (NOx), volatile organic compounds (VOC), particulate matter ($PM_{2.5}$ and PM_{10}), and ammonia (NH_3). The emissions tables in this section show the primary source categories for each visibility impairing pollutant. The primary emissions source categories vary by the type of pollutant. Using the following groups, we calculated the summaries for anthropogenic sources:

- Point Sources
  - Electric Generating Units (EGU)
  - Non-EGU
- On-road Mobile
- Non-road
  - Commercial Marine Vessel (CMV)
  - Rail
  - Other Non-road (vehicles and equipment)
- Non-point
  - Home heating (wood)
  - Agriculture and fugitive dust (from livestock, tilling, roads, construction)
  - Other non-point
- Fire Events
  - Prescribed fire
  - Agricultural fire

The EI data had two general issues identified:

- Prescribed fire calculations in the modeled scenarios (2014 Actual, RepBase, and 2028 OTB) used EPA methodology. This method is problematic for Washington because most accomplished prescribed burning is as pile burns, which the EPA methodology does not consider. The 2017 NEI prescribed fire emissions are based on our permitted tons burned and appropriate corresponding emission factors, which represents Ecology's best estimate of the category.
- Some non-point emissions in the modeled scenarios (2014 Actual, RepBase, and 2028 OTB) used methodology that Ecology has since revised. Non-point calculations in the 2017 NEI use updated methodology and represent Ecology's best estimate of the category.

Despite the known issues with the EI comparison, the RepBase is comparable to the 2028 OTB in a relative sense for projecting future visibility. However, when attempting to discern the best actual estimate of recent emissions, the 2017 NEI value is the best reference.

SO_2 emissions

Gaseous SO_2 emissions convert to sulfate particles, generally ammonium sulfate, in the atmosphere. Ammonium sulfate particles grow rapidly in size in the presence of water through water absorption and change from solid particles to solution droplets. The size of ammonium sulfate at high relatively humidity (>70%) makes it disproportionally responsible for visibility impairment compared to inorganic salts that do not take up water molecules.

SO_2 emissions in Washington come primarily from point sources, including a coal-fired power plant, oil refineries, primary aluminum plants, pulp and paper mills, and a cement plant. Ecology expects a large reduction in SO_2 emissions by 2028 because TransAlta will cease coal-fired power production by the end of 2025, with one boiler shut down at the end of 2020. CMV was a large source of SO_2 but recent adoption of low-sulfur fuels and port electrification efforts have reduced emissions, as represented in the 2017 NEI.

Table 4-1: Washington state anthropogenic SO_2 emissions (in tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	3,229	1,588	2,134	62
Non-EGU Point	11,577	12,503	8,060	12,528
On-Road Mobile	552	552	410	241
CMV	10,232	374	478	516
Rail	10	10	11	10
Other Non-Road	52	50	47	34
Home Heating (Wood)	229	229	225	229
Agriculture and Dust				
Other Non-Point	2,042	2,042	1,097	2,042
Prescribed Fire	997	1,611	18	1,611
Agricultural Fire	111	111	152	111
Total (tons/year)	**29,031**	**19,070**	**12,632**	**17,384**

NOx emissions

The burning of any material or fuel can generate NOx (NO + NO_2) emissions because atmospheric oxygen and nitrogen chemically react at temperatures found in combustion. NOx reacts in the atmosphere to form nitrate particles such as Ammonium Nitrate (NO_3). Like Ammonium Sulfate ($(NH_4)_2SO_4$), NO_3 particles grow rapidly in the presence of water to reach a size that is disproportionately responsible for visibility impairment.

NOx emissions come predominantly from on-road mobile sources. Ecology expects those vehicular emissions to continue decreasing through 2028 due to new fuel efficiency standards and the transition to cleaner-burning (and electric) vehicles. We also expect total NOx

emissions from non-road mobile sources to decrease. Another sizable reduction in NOx will occur when coal-fired power production ceases at TransAlta. Overall, Ecology expects NO_X emissions in Washington to decline by more than 40 percent by 2028, primarily due to significant improvements in on-road and non-road mobile source emissions.

Table 4-2: Washington state anthropogenic NOx emissions (in tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	10,023	8,482	10,196	2,250
Non-EGU Point	20,687	21,948	20,567	21,439
On-Road Mobile	130,500	130,500	89,319	34,366
CMV	16,767	19,062	23,458	17,652
Rail	15,202	15,202	14,258	11,631
Other Non-Road	28,398	24,509	23,200	13,886
Home Heating (Wood)	1,530	1,530	1,381	1,530
Agriculture and Dust				
Other Non-Point	12,050	12,050	10,455	12,050
Prescribed Fire	1,662	1,614	717	1,614
Agricultural Fire	479	479	1,063	479
Total (tons/year)	**237,298**	**235,376**	**194,614**	**116,897**

VOC emissions

VOCs emitted into the atmosphere can condense and oxidize to form secondary organic aerosols, which can degrade visibility. VOCs also play a role in the photochemical production of ozone in the troposphere. The dominant source of VOCs is biogenic emissions, which comprise more than half of the total Washington VOC emissions. Forests and other vegetation emit these natural emissions. VOCs react with NOx to produce nitrated organic particles that impact visibility in the same series of chemical events that lead to ozone. Thus, strategies to reduce ozone in the atmosphere often lead to visibility improvements. However, since natural biogenic VOCs are a dominant source, it is difficult to get visibility improvements by controlling VOCs from anthropogenic sources.

The largest sources of anthropogenic VOC emissions include on-road mobile sources and solvent use (included in the “other non-point” category). Population growth primarily drives significant VOC increases in the “other non-point” category for 2028. However, Ecology expects VOC reductions from mobile sources in the 2028 inventory to more than offset any increases due to population growth.

Table 4-3: Washington state anthropogenic VOC emissions (in tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	114	65	285	36
Non-EGU Point	11,764	11,291	10,118	11,299
On-Road Mobile	71,971	71,971	59,158	26,295
CMV	596	1,073	1,173	1,252
Rail	744	716	611	494
Other Non-Road	36,508	25,629	24,166	19,189
Home Heating (Wood)	15,448	17,371	13,803	17,370
Agriculture and Dust	2,236	2,236	1,635	2,236
Other Non-Point	86,545	86,545	97,490	86,545
Prescribed Fire	29,998	72,388	3,406	72,388
Agricultural Fire	748	747	2,369	747
Total (tons/year)	**256,672**	**290,032**	**214,214**	**237,851**

$PM_{2.5}$ emissions

$PM_{2.5}$ in the EI includes primary emissions of particulate matter less than 2.5 microns in size, and is synonymous with smoke and fine aerosols. Depending on the year, wildfires generate the majority of $PM_{2.5}$ emissions in Washington. The primary anthropogenic sources are non-point, including fugitive dust (agriculture, construction, and roads) and residential wood combustion. Ecology expects modest $PM_{2.5}$ reductions from the on-road and non-road sectors as they use technology that is more efficient. However, there are large uncertainties when projecting categories like fugitive dust, prescribed burning, and wildfires.

Table 4-4: Washington state anthropogenic $PM_{2.5}$ emissions (in tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	402	537	671	315
Non-EGU Point	4,007	4,040	2,978	4,057
On-Road Mobile	3,808	3,808	2,573	1,484
CMV	651	396	464	443
Rail	389	389	356	298
Other Non-Road	2,824	2,332	2,217	1,316
Home Heating (Wood)	12,371	12,371	10,614	12,371
Agriculture and Dust	18,304	18,304	29,822	18,304
Other Non-Point	12,932	12,932	6,383	12,932
Prescribed Fire	12,337	21,860	2,420	21,860
Agricultural Fire	1,895	1,894	2,703	1,894
Total (tons/year)	**69,920**	**78,863**	**61,200**	**75,274**

PM_{10} emissions

PM_{10} in the EI includes primary emissions of particulate matter less than 10 microns in size, representing the sum of coarse and fine particles. The primary anthropogenic source is fugitive dust (agriculture, construction, and roads), but fire categories do have significant influence on state totals. Small non-point category increases, which are sensitive to population growth, match the small reductions expected from the on-road and non-road sectors.

Table 4-5: Washington state anthropogenic PM_{10} emissions (tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	427	586	914	334
Non-EGU Point	4,576	4,594	3,446	4,613
On-Road Mobile	6,913	6,913	5,219	5,029
CMV	819	418	490	469
Rail	404	404	367	307
Other Non-Road	2,973	2,451	2,331	1,402
Home Heating (Wood)	12,377	12,377	10,622	12,377
Agriculture and Dust[7]	237,282	237,282	183,637	237,282
Other Non-Point	14,854	14,854	7,505	14,854
Prescribed Fire	14,557	24,800	2,778	24,800
Agricultural Fire	2,718	2,717	2,769	2,717
Total (tons/year)	**297,900**	**307,396**	**220,078**	**304,184**

[7] The TSS data from this row showed dust emissions after meteorological adjustment. We replaced those values with the unadjusted numbers so that they are directly comparable to the 2017 NEI values.

Ammonia emissions

Agricultural related activities such as livestock operations and farming fertilizer applications are the primary sources of NH_3. NH_3 emissions can react with SO_2 and NOx to form sulfate and nitrate particles, which are significant contributors to visibility impairment. Washington has a strong agricultural community that will continue operating indefinitely. We expect no changes to agricultural practices that will decrease ammonia emissions.

Table 4-6: Washington state anthropogenic ammonia emissions (tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	69	88	106	86
Non-EGU Point	436	449	388	449
On-Road Mobile	2,356	2,356	2,206	1,744
CMV	8	8	9	9
Rail	9	9	9	9
Other Non-Road	48	40	40	45
Home Heating (Wood)	735	735	656	735
Agriculture and Dust	27,538	27,538	34,570	27,538
Other Non-Point	1,562	1,562	1,252	1,562
Prescribed Fire	2,394	3,602	2,244	3,602
Agricultural Fire	1,952	1,950	6,164	1,950
Total	**37,107**	**38,337**	**47,644**	**37,729**

4.4 Facilities selected for Four-Factor Analysis (FFA)

This section provides emissions from major point sources identified for FFA. Ecology selected seventeen facilities for additional evaluation, spanning six categories:

- Aluminum Production
- Cement Manufacturing
- Glass Manufacturing
- Electric Power Generation
- Paper Manufacturing
- Petroleum Refineries

Table 4-7: Information for facilities selected for FFA

Category	Current Facility Name	FIPS	Site Code
Aluminum Production	Alcoa Primary Metals Intalco Works	53073	0001
Aluminum Production	Alcoa Wenatchee, LLC	53007	0001
Cement Manufacturing	Ash Grove Cement Company	53033	11339
Flat Glass Manufacturing	Cardinal FG Winlock	53041	2175
Electric Power Generation	TransAlta Centralia Generation, LLC	53041	754
Paper Manufacturing	Boise Paper	53071	0003
Paper Manufacturing	COSMO Specialty Fibers, Inc.	53027	0001
Paper Manufacturing	Georgia-Pacific Consumer Operations, LLC	53011	0005
Paper Manufacturing	Longview Fibre Paper and Packaging, Inc.	53015	0002
Paper Manufacturing	Nippon Dynawave Packaging Co.	53015	0003
Paper Manufacturing	Port Townsend Paper	53031	0001
Paper Manufacturing	WestRock Tacoma Mill	53053	0008
Petroleum Refineries	BP Cherry Point Refinery	53073	10007
Petroleum Refineries	Phillips 66 Ferndale Refinery	53073	00005
Petroleum Refineries	Shell Puget Sound Refinery	53057	00003
Petroleum Refineries	Tesoro Northwest Company	53057	00005
Petroleum Refineries	US Oil & Refining Co.	53053	12593

Aluminum production facilities

Alcoa has two aluminum smelters in Washington State under Ecology's Industrial Section jurisdiction: Intalco in Ferndale (Whatcom County) and Wenatchee Works (Chelan County). Alcoa curtailed the Wenatchee facility in 2015 and the Ferndale facility in 2020. Both facilities have a very large potential to emit SO_2, and would contribute to regional haze if Alcoa re-started aluminum production operations. Ecology held facility emissions constant at 2014 Actual levels for the RepBase and 2028 OTB scenarios.

Cement manufacturing

The Ash Grove Cement Company (King County; Puget Sound Clean Air Agency jurisdiction) is one of the largest NOx point sources in the state, emitting over 1,000 tons of NOx per year. Ecology held facility emissions constant at 2014 Actual levels for the RepBase and 2028 OTB scenarios.

Flat glass manufacturing

The Cardinal FG Winlock (Lewis County; SWCAA jurisdiction) glass manufacturing facility is one of the largest NOx point sources in the state, emitting over 800 tons per year. Facility emissions were set to 2014 Actual levels for the RepBase and the 2028 OTB scenario assumed reductions from a selective catalytic reduction control with ammonia injection, which will be installed in 2021.

Electric power generation

The TransAlta Centralia coal-powered EGU (Lewis County; SWCAA jurisdiction) has historically been one of the largest sources of NOx and SO_2 in the state, currently emitting over 5,000 tons of NOx and 1,500 tons of SO_2 per year. The facility will cease coal-fired energy production before 2028; one unit ceased coal-fired operation in 2020 and the other in 2025 with additional NOx reductions until then. Ecology set facility emissions to 2014 Actual levels for the RepBase and to zero for the 2028 OTB scenario.

Paper manufacturing

Seven paper-manufacturing facilities in the state collectively emit over 6,000 tons of NOx, 1,500 tons of SO_2, and 1,300 tons of PM_{10} per year. Facility emissions were set to 2017 NEI levels for the RepBase and 2028 OTB scenarios.

Petroleum refineries

Five petroleum refineries in the state collectively emit over 5,500 tons of NOx and 1,000 tons of SO_2 per year. Ecology held facility emissions constant at 2014 Actual levels for the RepBase and 2028 OTB scenarios.

Table 4-8: Annual NOx emissions for FFA facilities (tons/year)

Current Facility Name	2011	2012	2013	2014	2015	2016	2017	2018	2019	Rep Base	2028 OTB
Alcoa Primary Metals Intalco Works	152	185	220	227	213	188	192	183		227	227
Alcoa Wenatchee, LLC	63	66	67	70	63	1	0	0		70	70
Ash Grove Cement Company	918	665	997	1,144		1,343	1,368	1,159		1,144	1,144
Cardinal FG Winlock	810	657	774	791	807	808	809	809		791	250
TransAlta Centralia Generation, LLC	6,635	4,658	7,793	7,538	5,624	5,019	6,232	5,939		7,538	0
Boise Paper	861	760	629	742	676	681	637	600		637	637
COSMO Specialty Fibers, Inc.	367	364	374	465	644	606	402	384		402	402
Georgia-Pacific Consumer Operations, LLC	528	489	464	463	453	452	486	235		486	486
Longview Fibre Paper and Packaging, Inc.	1,372	1,389	1,498	1,215	952	1,044	1,041	1,092		1,041	1,041
Nippon Dynawave Packaging Co.	2,137	2,221	2,048	2,086	2,024	1,969	1,949	2,276		1,949	1,949
Port Townsend Paper	473	493	482	494	488	489	475	490		475	475
WestRock Tacoma Mill	945	985	890	940	1,032	1,084	1,121	1,035		1,121	1,121
BP Cherry Point Refinery	1,991	1,876	1,959	1,893	1,865	1,905	1,930	1,820		1,893	1,893
Phillips 66 Ferndale Refinery	788	702	784	723	726	769	674	691		723	723
Shell Puget Sound Refinery	1,101	1,319	1,409	1,230	1,076	1,109	1,054	1,146		1,230	1,230
Tesoro Northwest Company	1,882	2,051	1,731	1,918	1,826	2,020	1,971	1,878		1,918	1,918
US Oil & Refining Co.	134	127	135	133		63	115	116		133	133

Table 4-9: Annual SO_2 emissions for FFA facilities (tons/year)

Current Facility Name	2011	2012	2013	2014	2015	2016	2017	2018	2019	Rep Base	2028 OTB
Alcoa Primary Metals Intalco Works	4,538	4,723	4,672	4,794	5,022	4,374	3,987	4,103		4,794	4,794
Alcoa Wenatchee, LLC	2,906	3,127	3,712	2,935	2,741	0				2,935	2,935
Ash Grove Cement Company	51	37	42	57		68	69	67		57	57
Cardinal FG Winlock	56	47	54	57	59	59	56	55		57	71
TransAlta Centralia Generation, LLC	1,136	1,228	2,820	3,037	2,386	1,438	1,707	1,502		3,037	0
Boise Paper	793	604	534	186	68	692	885	393		885	885
COSMO Specialty Fibers, Inc.	214	206	230	237	353	369	242	255		242	242
Georgia-Pacific Consumer Operations, LLC	19	20	19	17	16	30	40	21		40	40
Longview Fibre Paper and Packaging, Inc.	202	302	133	141	220	126	198	258		198	198
Nippon Dynawave Packaging Co.	582	484	378	440	351	376	390	328		390	390
Port Townsend Paper	150	187	198	79	51	44	46	68		46	46
WestRock Tacoma Mill	349	347	263	261	244	190	190	224		190	190
BP Cherry Point Refinery	1,026	930	879	917	907	781	828	726		917	917
Phillips 66 Ferndale Refinery	108	73	46	49	44	45	38	43		49	49
Shell Puget Sound Refinery	369	445	466	349	233	246	225	228		349	349
Tesoro Northwest Company	315	284	237	191	130	125	80	80		191	191
US Oil & Refining Co.	5	4	4	4		7	6	7		4	4

Table 4-10: Annual PM_{10} emissions for FFA facilities (tons/year)

Current Facility Name	2011	2012	2013	2014	2015	2016	2017	2018	2019	Rep Base	2028 OTB
Alcoa Primary Metals Intalco Works	679	736	705	637	708	696	599	563		637	637
Alcoa Wenatchee, LLC	546	395	430	457	467	3	3	3		457	457
Ash Grove Cement Company	31	30	36	43		30	29	16		43	43
Cardinal FG Winlock	10	8	12	12	12	11	16	16		12	15
TransAlta Centralia Generation, LLC	415	209	236	187	140	299	423	347		187	0
Boise Paper	127	124	123	120	113	122	134	106		134	134
COSMO Specialty Fibers, Inc.	272	232	285	272	398	417	280	333		280	280
Georgia-Pacific Consumer Operations, LLC	167	193	178	173	181	151	163	95		163	163
Longview Fibre Paper and Packaging, Inc.	81	257	333	218	202	213	209	220		209	209
Nippon Dynawave Packaging Co.	76	75	121	129	133	129	124	144		124	124
Port Townsend Paper	314	264	291	275	247	220	193	181		193	193
WestRock Tacoma Mill	97	125	155	153	136	201	222	223		222	222
BP Cherry Point Refinery	131	128	98	83	107	118	84	130		83	83
Phillips 66 Ferndale Refinery	59	46	65	64	59	54	60	59		64	64
Shell Puget Sound Refinery	236	228	193	183	207	177	182	191		183	183
Tesoro Northwest Company	154	162	143	157	152	140	144	136		157	157
US Oil & Refining Co.	12	12	12	12		11	12	12		12	12

4.5 Summary

The EI summarizes emissions from sources located in Washington that we reasonably expect to affect visibility in Class 1 Areas in Washington and other states. We used the EI to summarize the anthropogenic emissions from each source category and the changes in emissions at the facilities subjected to a four-factor analysis. We used these emission summaries to prioritize emission reduction efforts and ensure that model predictions of 2028 visibility impairment are reasonable.

Chapter 5.Regional Haze Modeling

Washington relied on the Western Regional Air Partnership (WRAP) modeling for this Regional Haze (RH) State Implementation Plan (SIP). This chapter describes the modeling effort conducted by WRAP for the western contiguous states. Also discussed are model configuration, model performance, and source apportionment options.

WRAP used the Comprehensive Air Quality model and Extensions (CAMx) to perform the representative baseline and 20218 OTB scenarios. CAMx results were used to calculate Relative Response Factors (RRFs), which were applied to the measured baseline period concentrations at the IMPROVE sites. This provided a visibility projection for 2028. Chapter 9 discusses visibility projection results in the context of Reasonable Progress Goals and the Uniform Rate of Progress Glidepath, as determined by the RRFs derived from CAMx simulations.

The WRAP provided source apportionment results using the Weighted Emissions Potential (WEP) technique and the CAMx Particulate Matter Source Apportionment Technology (PSAT) tool. The WEP is a useful method for identifying sources that impair visibility at the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitors, and requires far less computational resources than CAMx PSAT. However, the CAMx PSAT analysis is more appropriate for computing projected visibility because it considers all possible sources of air pollution and atmospheric processes. Chapter 6 discusses the WEP and PSAT results.

5.1 CAMx simulations

The primary tool used by the WRAP for projecting future visibility is the CAMx v 7.0. CAMx is a state-of-the-science photochemical grid model that comprises a "one-atmosphere" treatment of tropospheric air pollution that includes source apportionment techniques[8]. The CAMx model takes into account emissions, advection and dispersion, photochemical transformation, aerosol thermodynamics and phase transfer, aqueous chemistry, and wet and dry deposition of trace species.

CAMx requires meteorological inputs of three-dimensional gridded variables such as wind, temperature, humidity, cloud cover, and precipitation. The CAMx simulations computed for WRAP utilized gridded meteorological data from the Weather Research and Forecasting model. The Weather Research and Forecasting model is the most common source of modeled meteorology in the U.S. used as input to photochemical grid models. Local, state, national, and international modeling efforts use the Weather Research and Forecasting model extensively.

WRAP and the Western Air Quality Study (WAQS) developed the modeling platform with two-way nesting between the continental U.S. (36 km grid-cells) and the western U.S. (12-km grid-cells) modeling domains. Ramboll Group A/S (Ramboll) conducted model simulations for the 2014 base case, the representative baseline, and the 2028 on-the-books (OTB) future U.S. anthropogenic emissions scenarios. Ramboll simulated two 2028 emission scenarios: one with

[8] http://www.camx.com/home.aspx

2014 actual fires and one with a representative fire dataset developed by the WRAP Fire and Smoke Work Group.

Ramboll compiled emissions updates submitted by local, state, and federal agencies and went through several updates as requested by states in the WRAP. Ramboll included a wind-blown dust pre-processor for better soil and coarse mass performance during dust events. They also implemented a bi-directional ammonia deposition scheme for better nitrate performance, especially in agricultural regions. The emission inventories were prepared for CAMx using the Sparse Matrix Operator Kernel Emissions (SMOKE) program. See Chapter 4 for more information about the anthropogenic emissions inventory data used in modeling.

CAMx simulations of the WRAP region required emission inventory data outside the WRAP region. Ramboll compiled emissions for Pacific offshore commercial marine vessels, non-WRAP states, Mexico, and Canada. WRAP posted results on the Technical Support System (TSS) website[9]. The CAMx model also requires input of specific concentrations of visibility-impairing pollutants at the boundaries of the modeling domain. Boundary conditions represent pollutants reaching North America from the rest of the world. Boundary conditions came from the WRAP Revised 2014 GEOS-Chem Base Case.

5.2 CAMx performance

RAMBOLL evaluated the performance of CAMx simulations by comparing CAMx model-simulated concentrations with 2014 ambient monitoring data from a large number of sites. This evaluation determined that the model's performance justified use of the model for simulating future conditions. RAMBOLL used the 2014 Actual emissions inventory for the simulation. They evaluated CAMx for both the most impaired days and the clearest days. See the CAMx 2014v2 Model Performance Evaluation section reported on the WRAP/WAQS 2014v2 Modeling Platform Description and Western Region Performance Evaluation (MPE)[10] site.

The following list summarizes model performance evaluation findings for particulate speciation monitors in the northwest part of the WRAP modeling domain at the locations of IMPROVE and Chemical Speciation Network (CSN) sites:

- Sulfate (SO_4)
  - Year-round overestimation in the northwest.
- Nitrate (NO_3)
  - Initial tests largely underestimated nitrate, but the addition of a bi-directional ammonia deposition scheme to the final 2014 modeling scenario-increased nitrate (NO_3). This may have been too much of an increase for the northwest.
  - Final result was year-round overestimation of nitrate (NO_3) in the northwest at IMPROVE sites but better nitrate (NO_3) performance in the northwest at CSN sites.
  - Better nitrate (NO_3) performance in cold months when monitored concentrations are greater.

[9] https://views.cira.colostate.edu/tssv2/

[10] http://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx

- Organic mass
    - Overestimation in many parts of the domain, including the northwest.
    - Overestimation of primary organic aerosol (POA) on days when fire impacts occur.
    - Dominated by fires and biogenic secondary organic aerosol (SOA), which are both large sources of uncertainty and generally due to uncontrollable emissions.
- Elemental carbon
    - Overestimated in the northwest during fire impacts, but otherwise concentrations are small.
- Soil and coarse mass
    - The model underestimates windblown dust emissions, causing underestimates of soil and coarse mass during windblown dust events.
    - Better soil performance than Round one RH SIPs due to new method to calculate elements from the model, which matches monitoring methods.
    - Coarse mass (CM) is underestimated in all climate regions and seasons.
        - Much of CM monitored is likely local as CM has a higher deposition rate and shorter transport distance.
        - Subgrid-scale impacts are difficult for a regional grid-model to simulate.
    - Given the uncertainties in the CM modeling results, future-year CM projections were held constant, with an RRF = 1.

Model performance was analyzed for IMPROVE monitors that represent mandatory Class 1 Areas in the state of Washington. Light extinction derived from the 2014 IMPROVE monitor data was compared to the 2014, representative baseline, and OTB model scenarios. CAMx over-predicted light extinction at every IMPROVE monitor for the average clearest days and most impaired days (MIDs).

All model species related to anthropogenic emissions consistently over-predicted for 2014 clearest days at Washington State IMPROVE monitors, across all months. Figure 5–1 shows the clearest days model performance for the 2014 model scenario. The representative baseline and 2028 OTB model scenarios were similar to the 2014 model scenario for clearest days at all sites, except for organic mass in October at NOCA1. The representative baseline and 2028 OTB modeling scenarios showed a tripling of the organic mass bias at NOCA1 for clearest days (not shown), due to change-over to the “representative” fire emissions dataset.

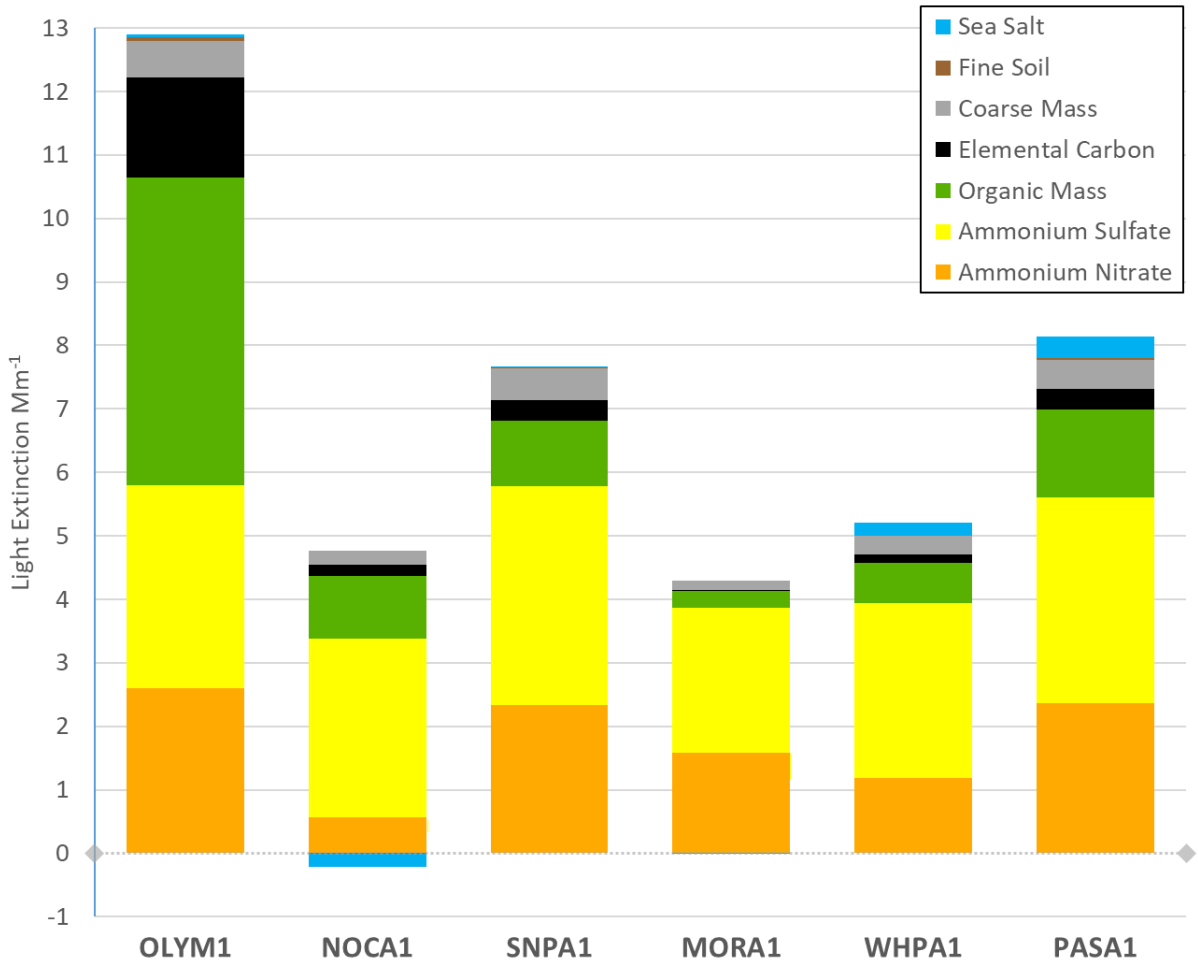


Figure 5–1. Average model bias of light extinction in the 2014 modeling scenario for 2014 clearest days at all sites.

The CAMx performance at Class 1 Area IMPROVE monitors in Washington State for MID is shown in Figures 5-2 thru 5-7. Sulfates, nitrates, and organic mass are over-predicted in the model for Washington State. Upon further analysis of individual model days, it is evident that fire emissions included in the modeling were severely over-estimated on MIDs. The representative baseline and 2028 OTB model simulations used a different fire dataset than the 2014 simulations, shifting the largest model bias from the PASA1 site to SNPA1 and other locations. Overestimation of emissions from prescribed burning in Washington State is not surprising, given that fire emissions calculations from EPA (2014 model scenario) and WRAP (representative baseline and 2028 OTB scenarios) do not accurately represent pile burning, which is the dominant form of prescribed burning in Washington. Wildfire emissions also had negative impacts on model performance, especially for representative baseline and 2028 OTB scenarios, because the wildfire days screened from the 2014 MID are not the same days with highest wildfire impacts in the model. Despite the model performance issues related to fire emissions, they do not negatively influence the RRFs (and therefore the future visibility projection) because the 2028 future scenario holds fire emissions constant relative to the baseline. In fact, over-prediction of model species causes visibility projections (RPGs) to be

more conservative since the proportional change in model scenario predictions due to OTB emissions controls is reduced, thereby constraining the RRF closer to one (no projected change).

Ecology used the CAMx modeling results with the understanding that they were the best tool available to forecast concentrations of visibility-impairing pollutants and projected visibility in 2028, the end of the second implementation period. Despite known model performance issues, we can still use CAMx results in combination with the RRF approach to evaluate the benefits of emission reduction strategies for nitrates and sulfates. The RRF allows us to project visibility changes at Class 1 Areas for regional haze planning purposes.

Model performance for MID at OLYM1

Figure 5–2 shows that elemental carbon, nitrates, and organic mass are over-predicted at OLYM1 for all model scenarios while sea salt is under-predicted. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios increased model bias for MID due to clear over-predictions of organic mass in August and September. The largest model bias occurred in October, December, and January due to over-predictions of nitrates and organic mass, but these were not related to wildland fire emissions and persisted across all model scenarios.

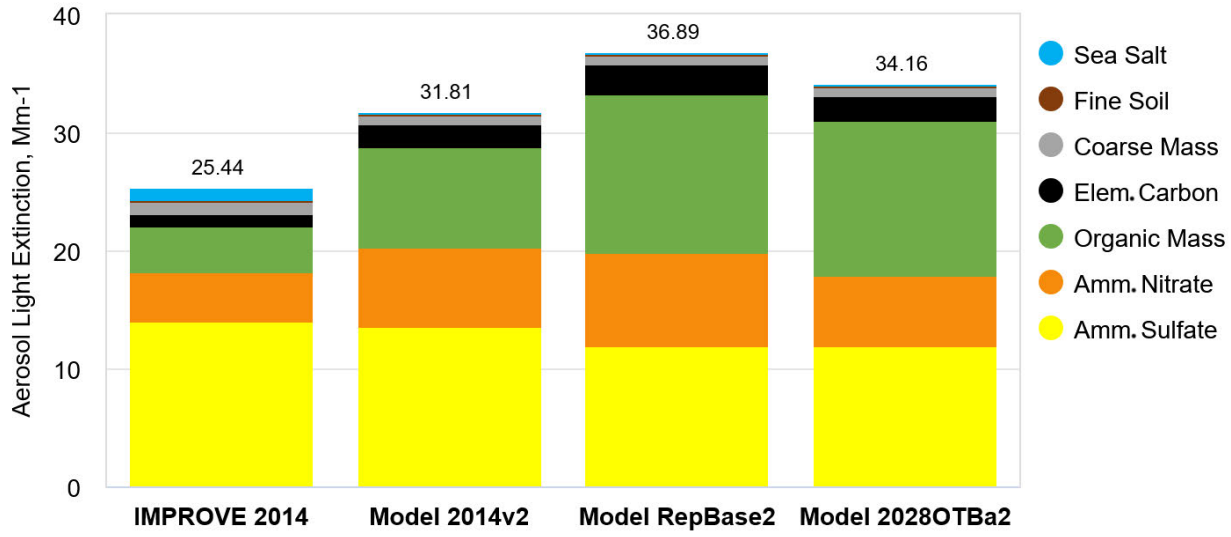


Figure 5–2. Average annual light extinction on MID observed at OLYM1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions.

Model performance for MID at NOCA1

Figure 5–3 shows that nitrates and organic mass are over-predicted at NOCA1 for all model scenarios. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios greatly increased model bias for MID due to clear over-predictions of organic mass in September and October, likely due to over-predictions of prescribed burning emissions in the representative fire dataset. There is also consistent over-prediction of nitrates for 2014 MID across most months.

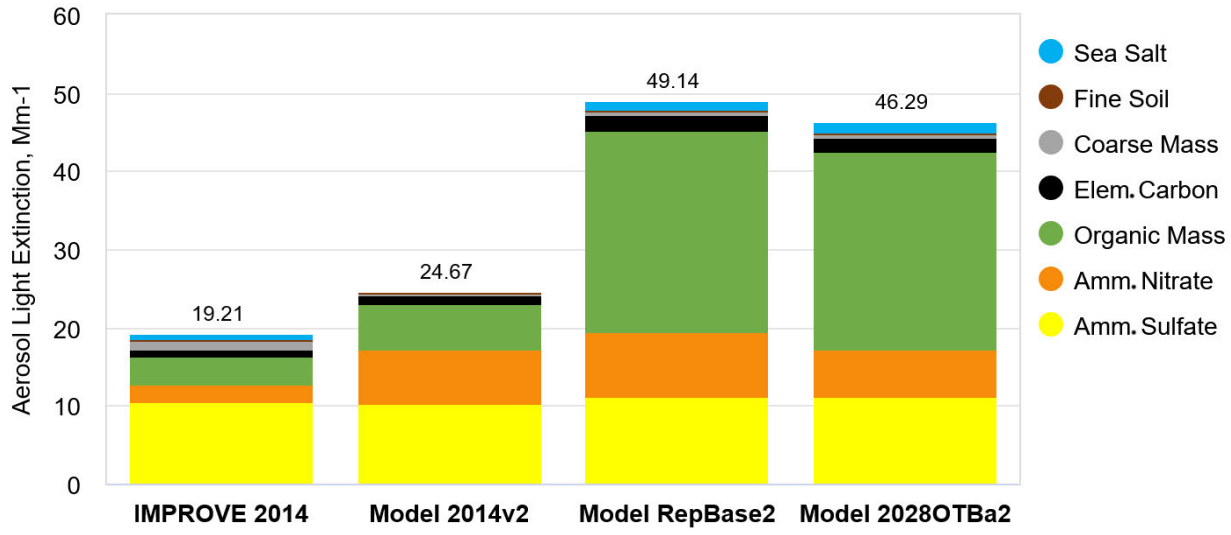


Figure 5–3. Average annual light extinction on MID observed at NOCA1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions.

Model performance for MID at SNPA1

Figure 5–4 shows that all pollutants are extremely over-predicted at SNPA1 for the representative baseline and 2028 OTB scenarios. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios severely increased model bias for MID due to clear over-predictions of organic mass in August, due to over-predictions or incorrect timing of wildfire emissions in the representative fire dataset. There is also clear over-prediction of nitrates from all model scenarios on springtime MIDs.

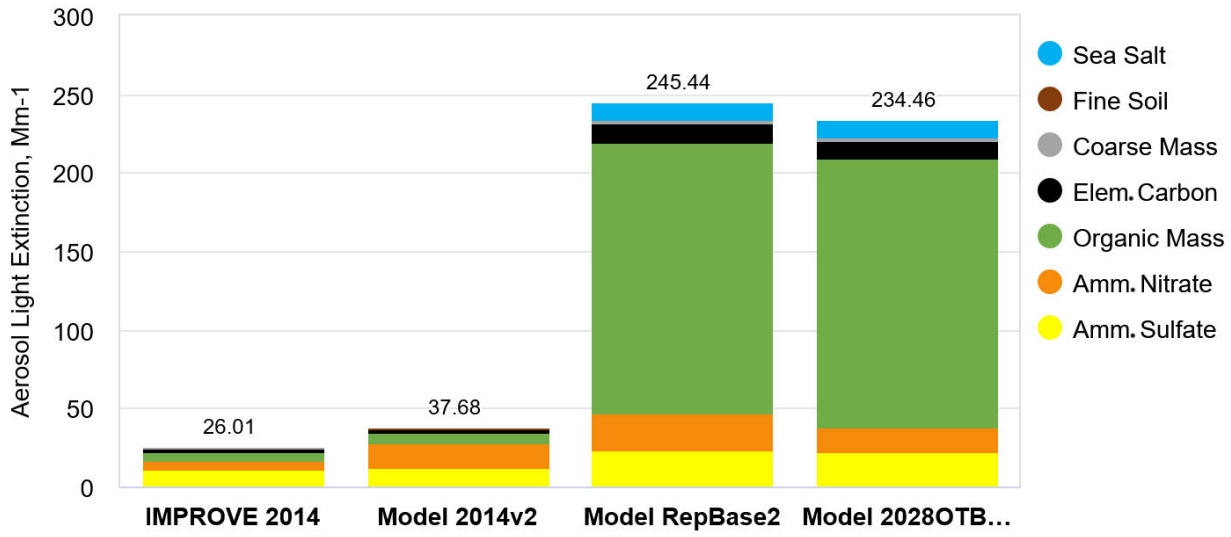


Figure 5–4. Average annual light extinction on MID observed at SNPA1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions.

Model performance for MID at MORA1

Figure 5–5 shows that nitrates and organic mass are over-predicted at MORA1 for all model scenarios. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios greatly increased model bias for MID due to clear over-predictions of organic mass in August, likely due to over-predictions or incorrect timing of wildfire emissions in the representative fire dataset. There is also clear over-prediction of nitrates from all model scenarios on springtime MIDs.

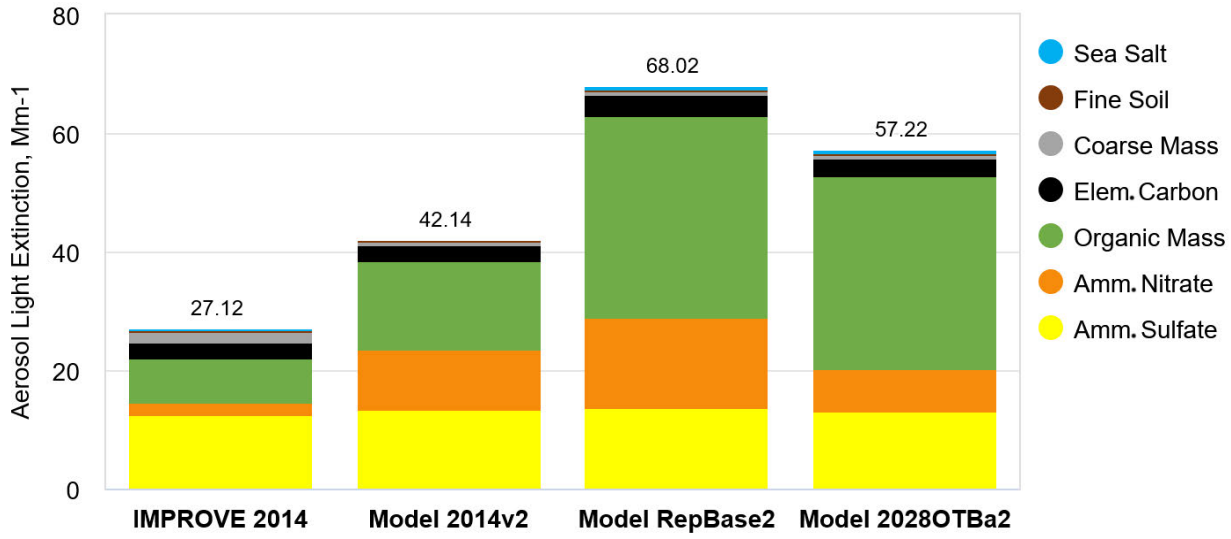


Figure 5–5. Average annual light extinction on MID observed at MORA1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions

Model performance for MID at WHPA1

Figure 5–6 shows that nitrates and organic mass are over-predicted at WHPA1 for all model scenarios. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios had only a small effect on organic mass performance. There is a clear over-prediction of nitrates from all model scenarios on MIDs across all months.

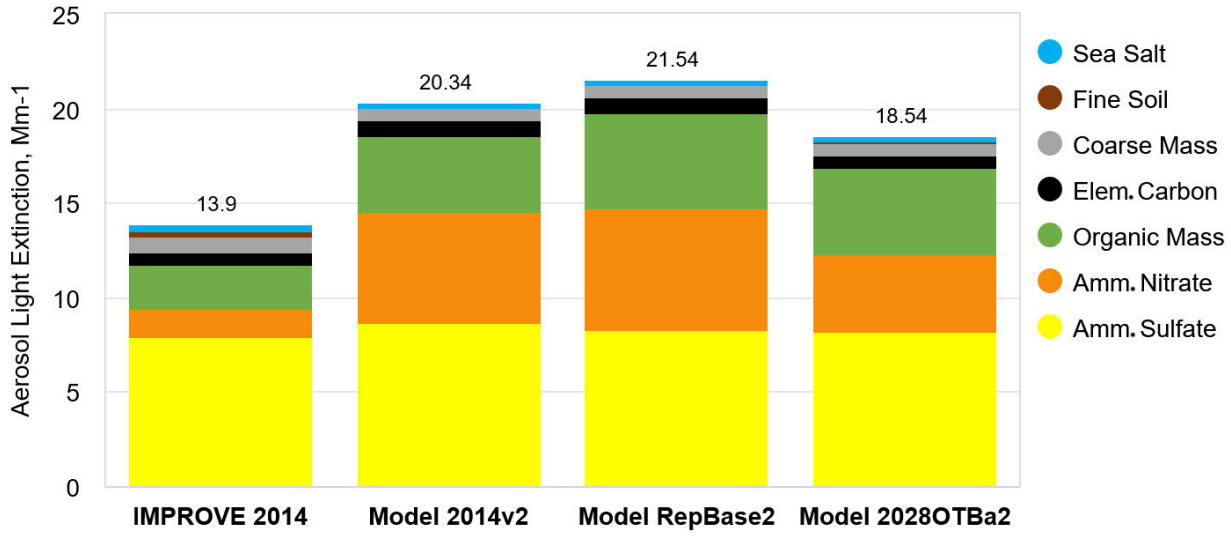


Figure 5–6. Average annual light extinction on MID observed at WHPA1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions.

Model performance for MID at PASA1

Figure 5–7 shows that nitrates and organic mass are over-predicted at PASA1 for all model scenarios. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios greatly improved model performance, due to removal of an incorrectly modeled prescribed fire in October from the 2014 model scenario. There is a clear over-prediction of nitrates from all model scenarios on MIDs across all months.

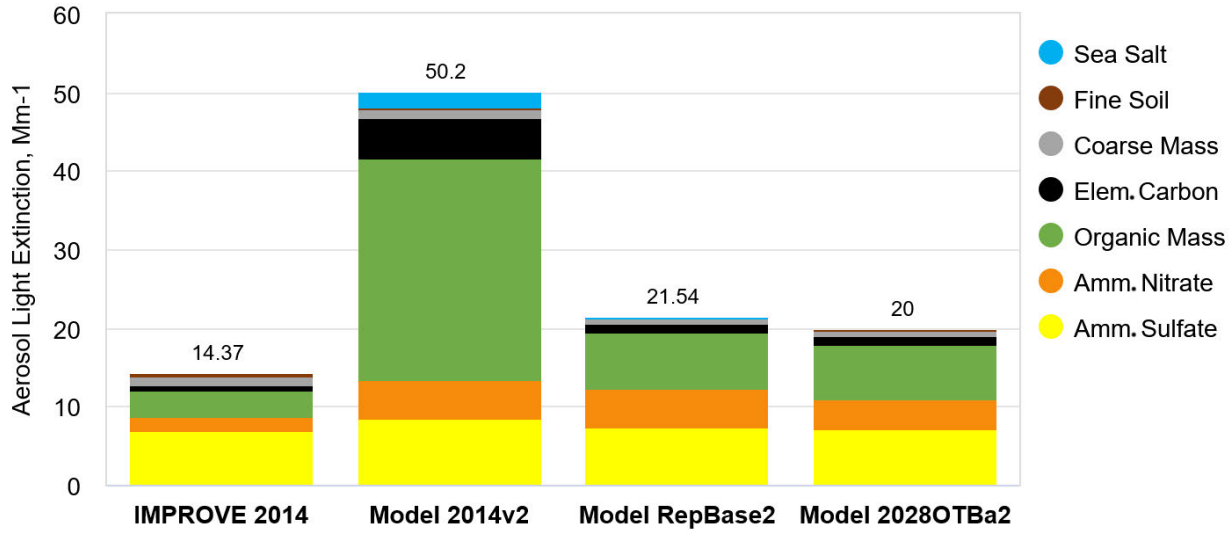


Figure 5–7. Average annual light extinction on MID observed at PASA1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions.

5.3 Source apportionment options

In order to determine the significant sources contributing to haze in Washington's Class 1 Areas, we rely upon source apportionment analysis provided on the WRAP TSS website[11].

WRAP provided two options for analyzing source apportionment of light extinction caused by pollutants at IMPROVE monitors:

1. The WEP tool, which was used to attribute sources of sulfate, nitrate, organic mass, and elemental carbon.
2. The PSAT tool, which was used to attribute sources of sulfate and nitrate. Source apportionment is especially important for anthropogenic sources of sulfate and nitrate because they have major impacts on visibility at Class 1 Areas.

The WEP is a screening tool that helps to identify source regions that have the potential to contribute to haze formation at specific Class 1 Areas. WEP combines emission inventories, meteorological model data, and the calculated residence time of air masses over each model grid-cell, to estimate the potential for a visibility-impairing pollutant to affect a specific Class 1

[11] http://views.cira.colostate.edu/tssv2/.

Area. WEP is obtained by combining the emissions weighted residence time at IMPROVE monitors with 2028 OTB emissions of light extinction precursors. The WEP analysis provided a broad overview of potential contributions from within and near Washington but does not look at emissions from outside the domain or Pacific offshore, nor does it account for chemistry or deposition. Ecology used the WEP tool to estimate anthropogenic source locations for light-extinction precursors: sulfur dioxide for ammonium sulfate extinction, nitrogen oxides for ammonium nitrate, primary organic aerosol for organic mass, and elemental carbon for itself. Chapter 6 discusses the WEP results.

The PSAT tool was used to further analyze sulfate and nitrate source apportionment for the 2028 OTB CAMx scenario that, unlike the WEP, accounts for all known physical and chemical processes in the atmosphere. The PSAT results also provide more information than the WEP, because they estimate contributions from all regions. PSAT allows a comparison of the relative contributions from Washington State, USA, international, natural, and wildland fire sources. PSAT results also estimate contributions from various emissions categories within the source regions. The PSAT analysis can be useful in determining contributing sources that may be controllable within Washington and in identifying potentially controllable sources, or the need for controls, in other jurisdictions (neighboring states, other countries, and Pacific offshore). Chapter 6 discusses the PSAT results.

Overall, while results from both tools provide relative information on sources of visibility-impairing pollutants, the PSAT results are more reliable and the WEP results more qualitative because of the way the results are developed. The PSAT results come from one-atmosphere, photochemical modeling simulations for sulfate and nitrate, and thus are a modeling prediction of how emissions impact a Class 1 Area. WEP only estimates impacts from the residence time of the air mass over an area and the total annual anthropogenic emissions in that area without consideration of natural sources, chemistry, or sources outside the model domain.

Chapter 6.Source Apportionment and Washington's Impacts on Mandatory Class 1 Areas

This chapter discusses the following:

- Expected contributions from regional anthropogenic emissions to light extinction at Washington's mandatory Class 1 Areas in 2028,
- Expected contributions from international, natural, and wildland fire sources to light extinction at Washington's Class 1 Areas in 2028,
- Expected sulfate and nitrate contributions from Washington anthropogenic emissions to light extinction at out-of-state Class 1 Areas in 2028.

The contributions from regions and source categories were determined using Particulate Matter Source Apportionment (PSAT) and Weighted Emissions Potential (WEP), described in Chapter 5. The WEP includes elemental carbon, organic mass, nitrates, and sulfates but is only for nearby anthropogenic emissions. PSAT only includes nitrates and sulfates, but accounts for all global sources.

The WEP and PSAT analyses presented in this chapter are based purely on model data generated by CAMx, the Hybrid Single-Particle Lagrangian Integrated Trajectory (HYSPLIT) model, and related pre-processors. Model simulations used 2014 meteorology and the 2028 on-the-books (OTB) emissions inventory. WEP and PSAT results did not adjust using relative response factors (RRFs), as is done for the reasonable progress goals (RPGs), due to the computational expense and time that would have been required to do source apportionment for all visibility-impairing species.

We discuss baseline monitored haze and the 2028 RPGs in this chapter for reference. This is because it is important to consider actual observations when attempting to extrapolate model results to the real world. W compared modeled light extinction by species to the baseline monitoring to take into account model bias. Model bias is a consideration when attempting to infer relative source contributions from PSAT and WEP analyses (see Chapter 5). In general, the model bias analysis shows an over-prediction of anthropogenic pollutants.

The Western Regional Air Partnership (WRAP) modeling does not include source apportionment analysis for the Representative Baseline (RepBase) model scenario. However, emissions inventory changes between RepBase and 2028 OTB are the only factors responsible for differences between the two model scenarios. We held constant emissions from non-point, international, natural, and wildland fire for both model scenarios. Reductions of projected visibility impairment in the model-generated results (and thereby the RPGs) are likely from a short list of notable changes:

- Shutdown of TransAlta Centralia coal-fired power plant boilers is a significant reduction in Washington State SO_2 emissions.
- Reduction in on-road mobile NOx emissions by 74 percent in Washington, which caused the majority of modeled nitrate reductions. Less significant reductions of NOx from other source categories were also included.

- There were significant reductions in point and mobile emissions outside of Washington. However, anthropogenic emissions from other states likely have a non-significant impact on visibility at Washington State Class 1 Areas. This is a result of the predominant wind-flow in Washington.

The WEP does not consider wildland fire. The PSAT model tracks wildland fire, but the model analyses do not provide the necessary information to make reasonable conclusions about source apportionment of wildland fire. This is because organic mass is not part of the PSAT analysis, the PSAT does not track wildland fire geographically, and a "representative" fire dataset in the CAMx model simulations replaced actual 2014 fire emissions. The WRAP state generally agreed that recent revisions to the Regional Haze Rule (RHR) make it clear that days impacted by wildland fire should not be used to track reasonable progress. Therefore, calculating modeled wildland fire contributions to Interagency Monitoring of Protected Visual Environments (IMPROVE) monitors by state was not needed. However, several conducted "no fire" simulations are viewable on the WRAP Technical Support System (TSS) website (https://views.cira.colostate.edu/tssv2/).

Each Class 1 Area organizes the data. Where two Class 1 Areas share an IMPROVE monitor the areas are discussed together. Presentation of the data is in the following order:

- Olympic National Park – OLYM1
- North Cascades National Park and Glacier Peak Wilderness - NOCA1
- Alpine Lakes Wilderness – SNPA1
- Mount Rainer National Park – MORA1
- Goat Rocks Wilderness and Mount Adams Wilderness – WHPA1
- Pasayten Wilderness – PASA1

The area of influence (AOI), determined by HYSPLIT, and the WEP analyses of sulfate, nitrate, organic mass, and elemental carbon on most impaired days (MID) are presented. The WEP considers 2028 OTB anthropogenic emissions in the Western US modeling domain but does not consider natural, international, or wildland fire (wildfire and prescribed fire) emissions. The WEP analyses summarizes using the following categories:

- EGU: includes emissions from major point sources that are electric generating units.
- Non-EGU: includes emissions from major point sources that are not electric generating units. Note that insignificant upstream and midstream processes from the oil & gas industry are included with non-EGU in Chapter 4 but not shown here.
- On-road: includes emissions from all vehicles that travel on roads.
- Non-road: includes emissions from locomotives, commercial marine vessels, mobile equipment, and other non-road vehicles.
- Non-point: includes emissions from all other anthropogenic sources, not categorized elsewhere such as institutional, commercial, residential, and agricultural.

Discussed in this chapter as well is the rank point analysis, which presents the relative contribution of out-of-state point sources to the total point source WEP.

Also presented are the PSAT analyses of sulfate and nitrate on MID and clearest days, which considers all sources. The following categories summarize the PSAT analyses:

- Washington anthropogenic: includes industrial, institutional, commercial, residential, agricultural, and mobile sources within Washington State. This source category has very little uncertainty because it was specifically developed for the RH modeling.
- USA anthropogenic: includes industrial, institutional, commercial, residential, agricultural, and mobile sources within the USA (but not Washington State). This source category has very little uncertainty because it was specifically developed for the RH modeling.
- International anthropogenic: includes industrial, institutional, commercial, residential, agricultural, and mobile sources outside of the USA. This source category has moderate uncertainty because it is influenced by international sources from many countries both inside and outside the model domain.
- Natural: vegetation, soils, sea salt, and volcanos. Note that this is not the same as the RHR definition of "natural" sources because wildfire is not included. This source category has moderate uncertainty due to the parameterization of natural emissions.
- Wildland fire: wildfire (WF) and prescribed fire (Rx) for USA, Canada, and Mexico. This source category has large uncertainty and is greatly overestimated in the CAMx modeling for MID in the state of Washington.

Within the state-level PSAT results, anthropogenic sources are further separated into similar categories as the WEP, except on-road and non-road sources are lumped together. Remaining anthropogenic sources are effectively the sum of all non-point categories. Most state-level PSAT results show similar expectations for 2028 light extinction impacts from within Washington State:

- Mobile sources will be the largest source of nitrates. For reference, the 2028 OTB mobile emissions inventory of NOx for Washington State is 44% on-road vehicles, 23% commercial marine vessels, 15% locomotives, and 18% other non-road vehicles and equipment.
- Non-EGU will be the largest source of sulfates. For reference, the 2028 OTB non-EGU emissions inventory of SO_2 for Washington State is 62% aluminum production, 16% paper manufacturing, and 12% petroleum refineries.

Note that there are small inconsistencies between the reported model species light extinction values in the various tools on the TSS, due to the processes needed to convert model concentrations to light extinction and the lack of PSAT results for all species. For consistency, the reported model values for each species in this chapter were taken from the model performance analysis on the TSS, which vary slightly compared to the total of all components in the state-level PSAT bar charts.

6.1 Olympic National Park

The OLYM1 IMPROVE monitoring site represents the visibility at Olympic National Park. The 2014 to 2018 average conditions in Chapter 3 show that sulfates (44%), organic mass (21%),

and nitrates (19%) together contribute to 84% of the light extinction on MID. On the clearest days, sulfates (30%), organic mass (22%), and nitrates (20%) contributed to 72% of the light extinction at OLYM1.

WEP and rank point analyses

The WEP analysis for the OLYM1 site on MID for the 2028 OTB scenario is summarized in Figure 6.1, showing an AOI of sources in western Washington and the Puget Sound region. There is also some minimal influence from sources in the Portland, OR and Vancouver, BC metropolitan areas. Nitrates at OLYM1 show considerable influence from non-EGU point, on-road, non-road, and non-point sources. Sulfates at OLYM1 show considerable influence from non-EGU Point, non-road, and non-point sources. Non-point sources mostly influence organic mass at OLYM1. Non-point sources mostly influence elemental carbon, but also shows a large influence from on-road and non-road sources.

The rank point WEP analysis attributed 98.9% of point source nitrates to Washington State, with 1.0% and 0.3% attributed to Oregon and California, respectively. The rank point WEP analysis attributed 99.4% of point source sulfates to Washington State, with 0.5% attributed to Oregon.

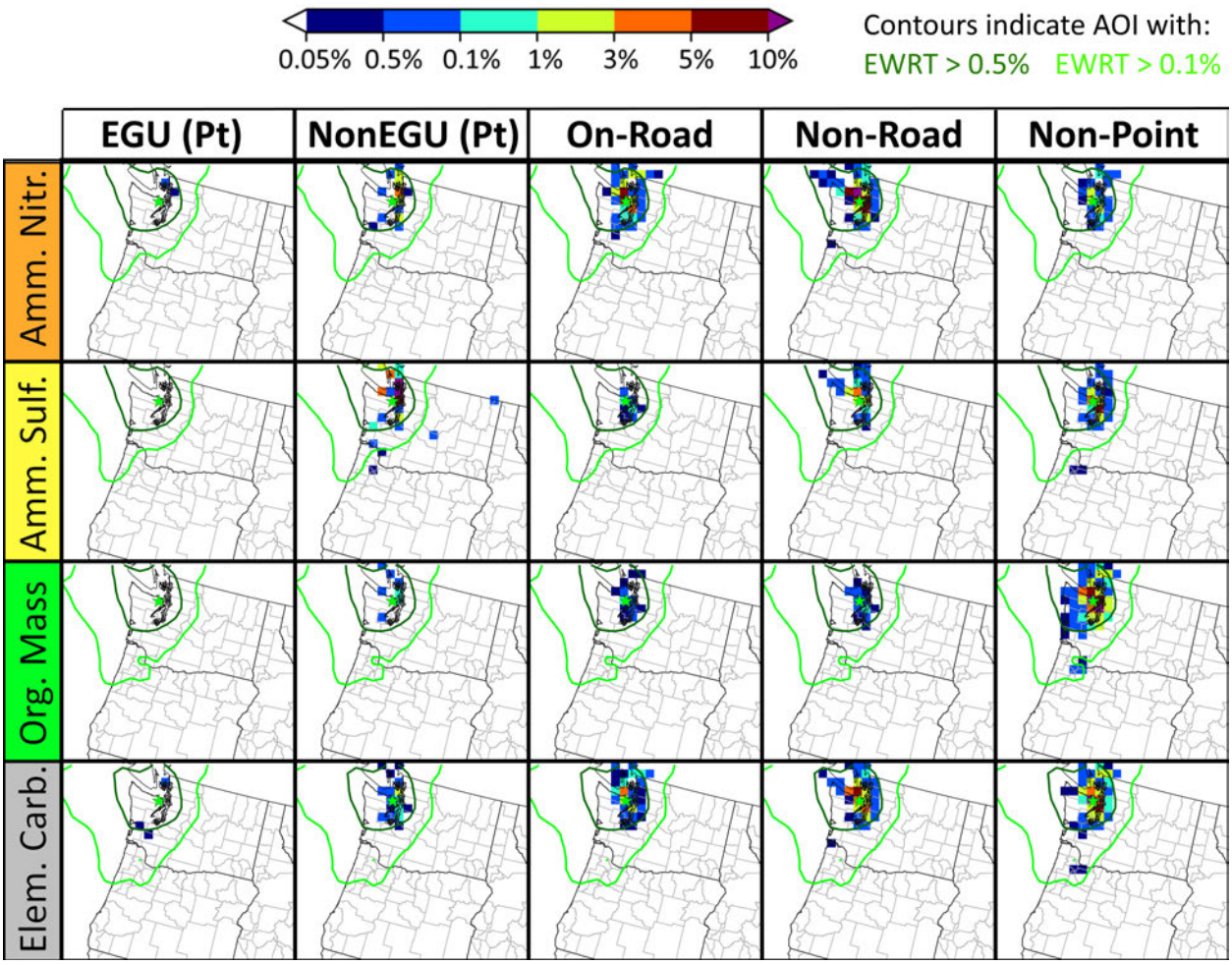


Figure 6-1: WEP for source area potential to contribute to extinction on MID by pollutant at the OLYM1 IMPROVE monitor (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at OLYM1.

Most Impaired Days

The PSAT tracer analysis shows that 2028 MID visibility impacts of sulfates at OLYM1 are expected to come primarily from natural (52%), international anthropogenic (22%) and wildland fire (13%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 9% of the sulfates responsible for light extinction at OLYM1. See Figure 6-2 for more information.

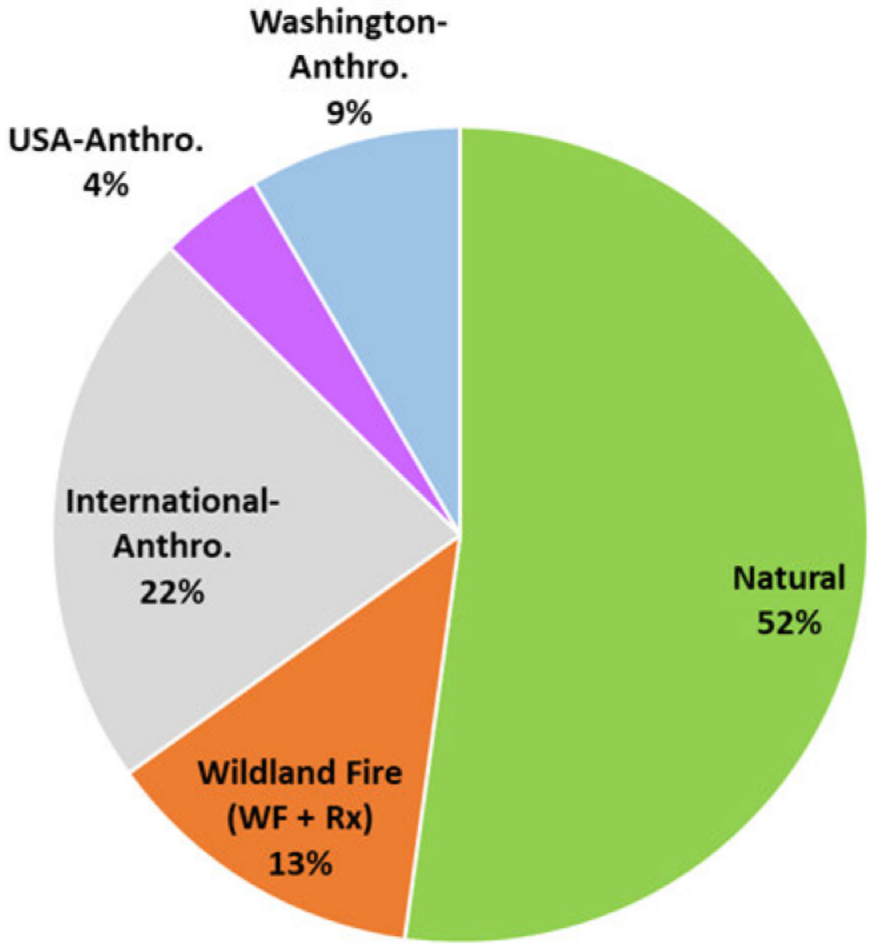


Figure 6-2: Expected source regions of sulfates (SO4) in 2028 at OLYM1 for MID (CAMx total = 11.9 Mm^{-1}).

The modeled sulfates for 2028 MID at OLYM1 was 11.9 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 10.03 Mm^{-1} and 10.00 Mm^{-1}, respectively.

Figure 6-3 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the OLYM1 monitoring site on 2028 MID.

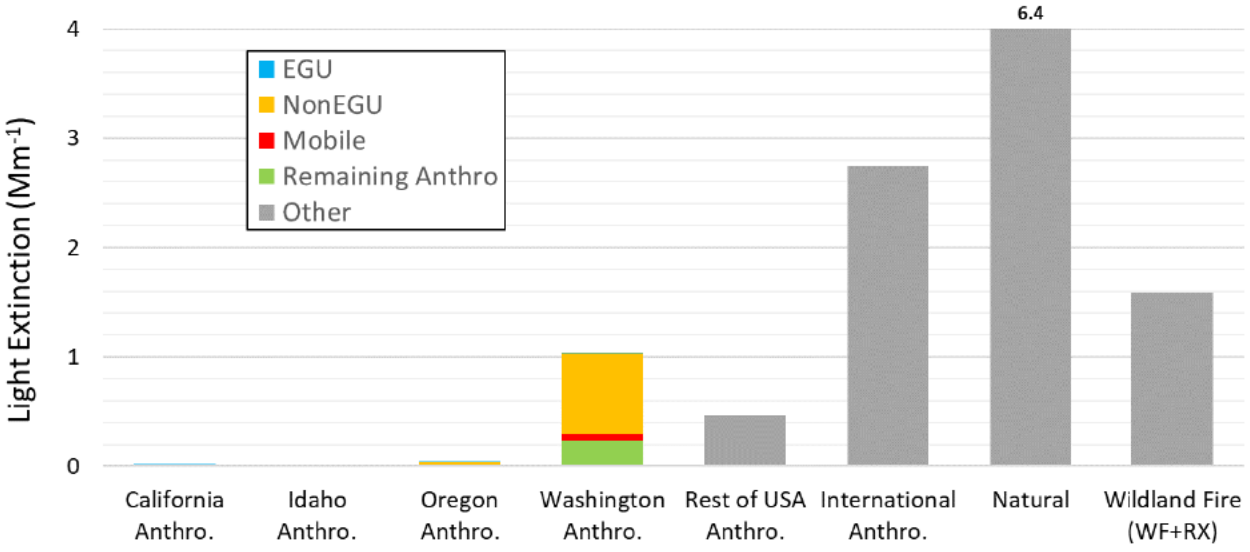


Figure 6-3: Expected source categories and regions of SO_4 in 2028 at OLYM1 for MID (CAMx total = 11.9 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at OLYM1 are expected to come primarily from natural (37%), out-of-state US anthropogenic (24%), and international anthropogenic (19%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 16% of the sulfates responsible for light extinction at OLYM1. See Figure 6-4 for more information.

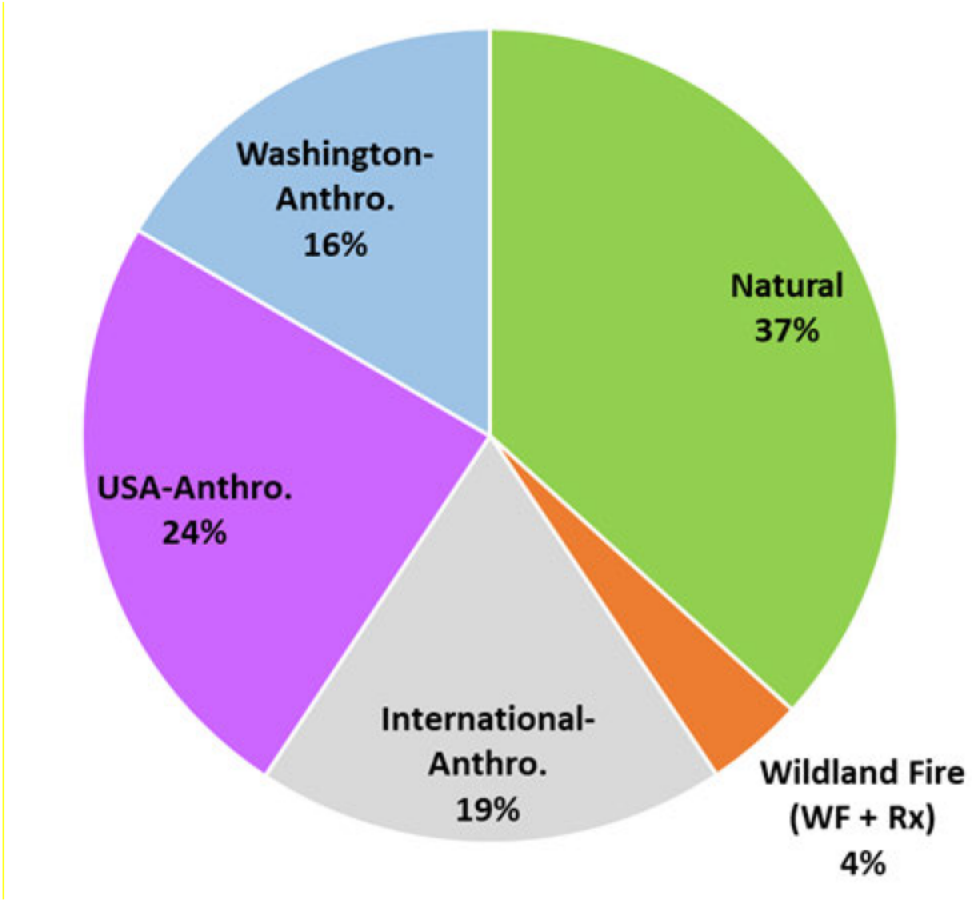


Figure 6-4: Expected source regions of SO_4 in 2028 at OLYM1 for clearest days (CAMx total = 4.2 Mm^{-1}).

The modeled sulfates for 2028 clearest days at OLYM1 was 4.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 1.01 Mm^{-1} and 1.00 Mm^{-1}, respectively. Figure 6-5 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at OLYM1 on 2028 clearest days.

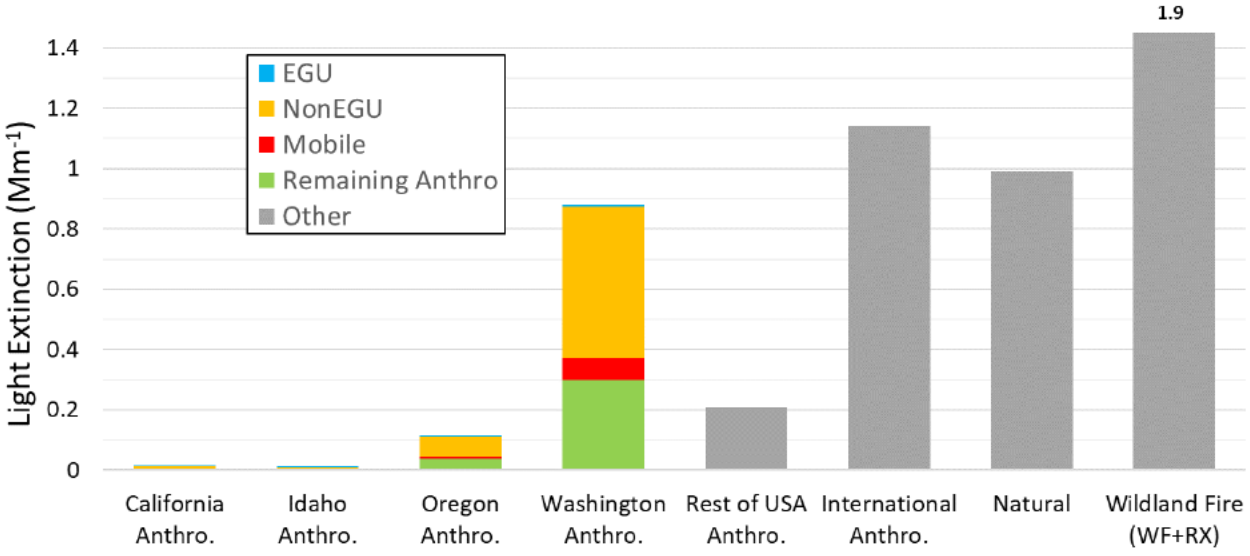


Figure 6-5: Expected source categories and regions of SO_4 in 2028 at OLYM1 for clearest days (CAMx total = 4.2 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the third largest species contribution to light extinction for the MID and second largest species contribution for the clearest days during the 2014-2018 baseline at OLYM1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at OLYM1 are expected to come primarily from international anthropogenic sources (47%) while natural sources (8%), and wildland fires (2%) are expected to have minimal impacts. All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 36% of the nitrates responsible for light extinction at OLYM1 on MID. See Figure 6-6 for more information.

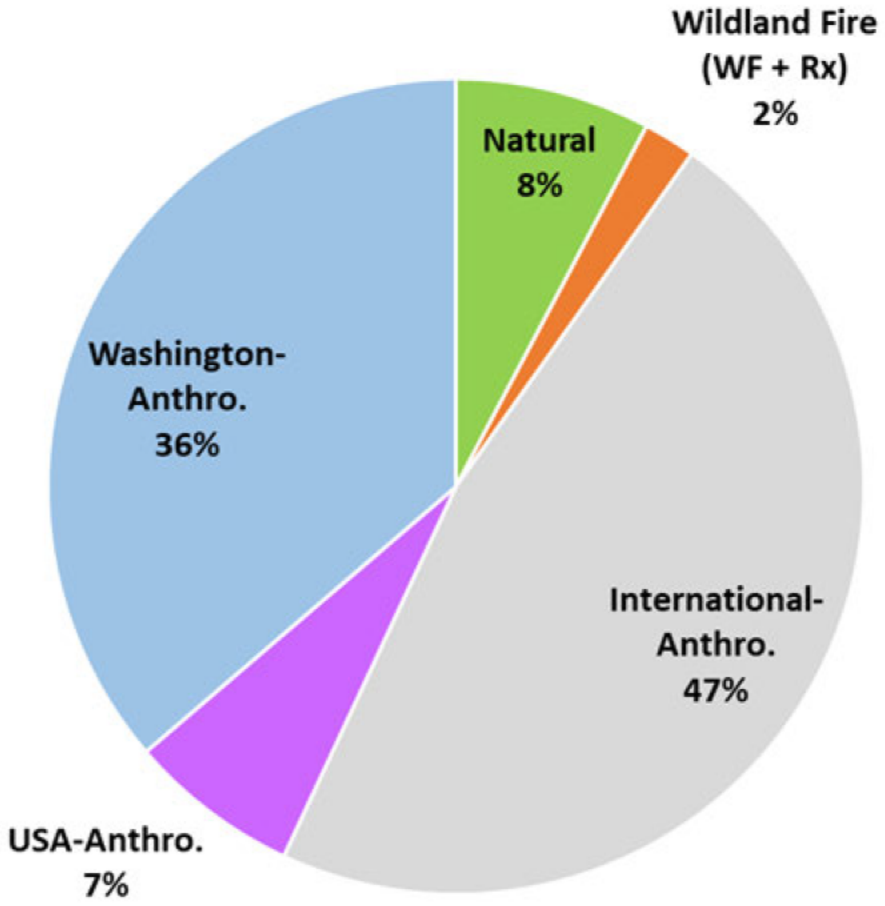


Figure 6-6: Expected source regions of NO_3 in 2028 at OLYM1 for MID (CAMx total = 5.9 Mm^{-1}).

The modeled nitrates for 2028 MID at OLYM1 was 5.9 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 4.28 Mm^{-1} and 3.28 Mm^{-1}, respectively.

Figure 6-7 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at OLYM1 on 2028 MID.

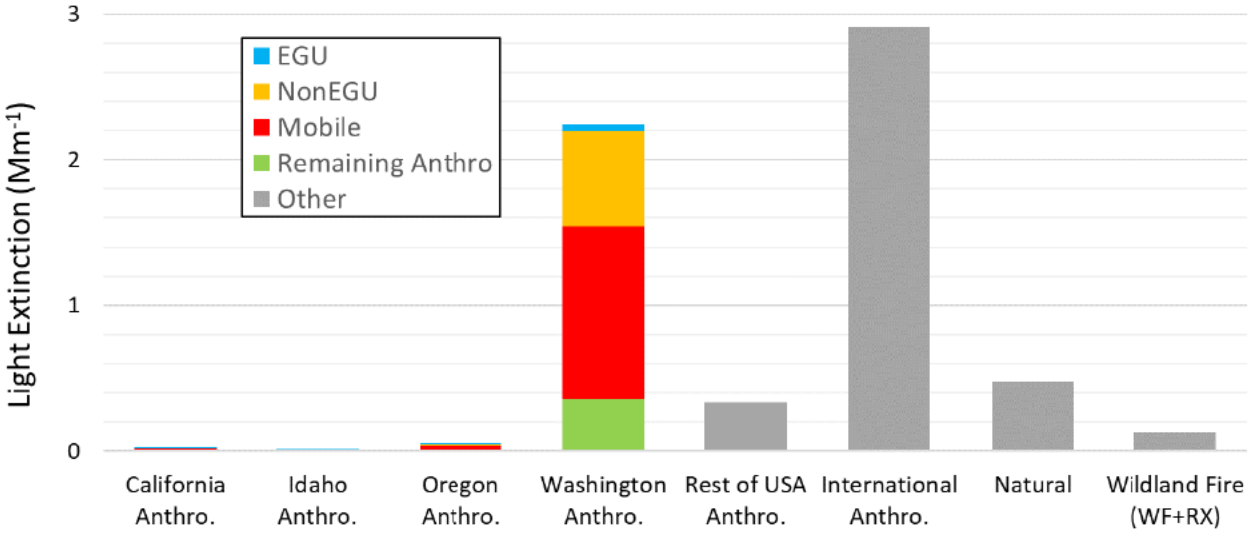


Figure 6-7: Expected source categories and regions of NO_3 in 2028 at OLYM1 for MID (CAM_X total = 5.9 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of nitrates at OLYM1 are expected to come primarily from out-of-state US anthropogenic (44%) sources. Washington anthropogenic sources are expected to contribute 33% of the nitrates responsible for light extinction at OLYM1 on clearest days. See Figure 6-8 for more information.

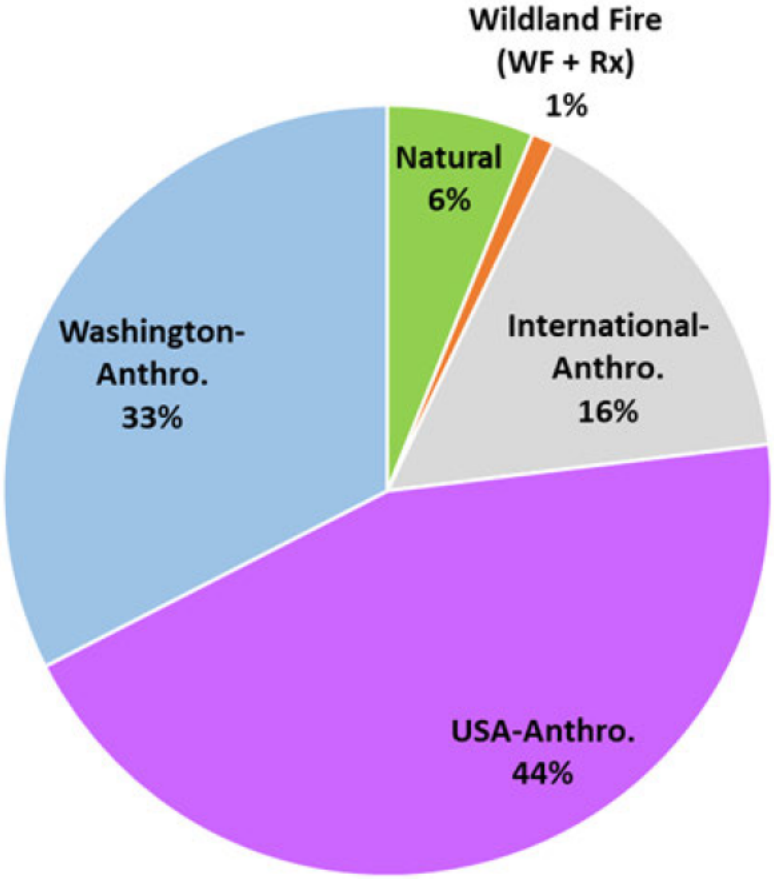


Figure 6-8: Expected source regions of NO_3 in 2028 at OLYM1 for clearest days (CAMx total = 2.5 Mm^{-1}).

The modeled nitrates for 2028 clearest days at OLYM1 was 2.5 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.65 Mm^{-1} and 0.46 Mm^{-1}, respectively. Figure 6-9 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at OLYM1 on 2028 clearest days.

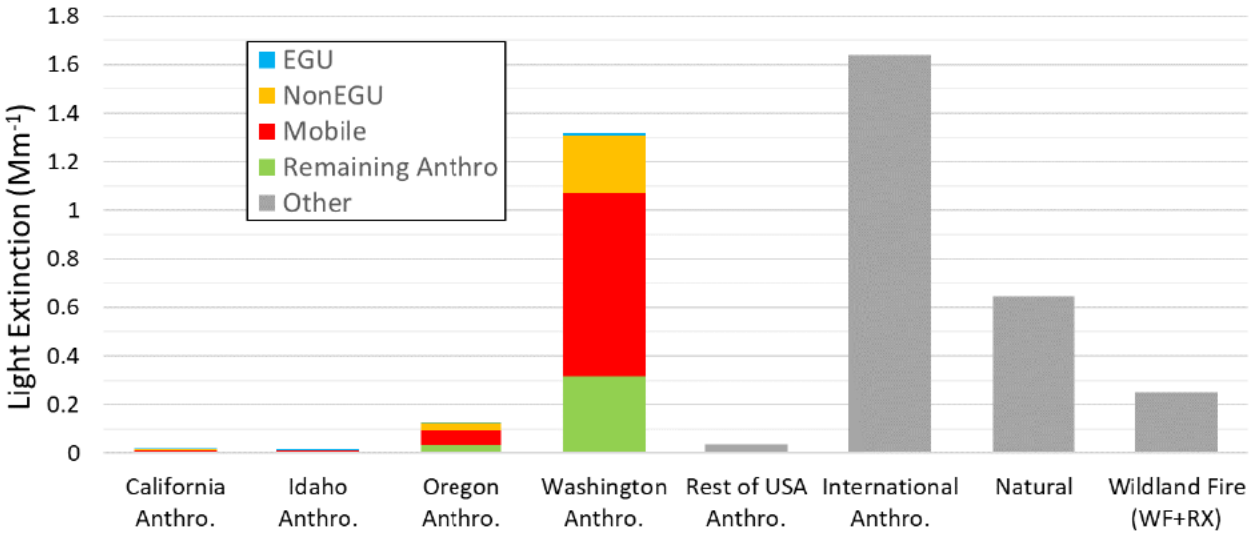


Figure 6-9: Expected source categories and regions of NO_3 in 2028 at OLYM1 for clearest days (CAMx total = 2.5 Mm^{-1}).

6.2 North Cascades National Park and Glacier Peak Wilderness

The North Cascades National Park and Glacier Peak Wilderness areas are represented by the NOCA1 IMPROVE monitoring site. The baseline conditions in Chapter 3 show that together organic mass (24%), sulfates (49%), and nitrates (10%) contributed to 83% of the light extinction on the MID at this monitoring site. On the clearest days, sulfates (36%), organic mass (26%), and nitrates (13%) contributed to 75% of the light extinction at this monitoring site.

WEP and rank point analyses

The WEP analysis for the NOCA1 site on MID for the 2028 OTB scenario is summarized in Figure 6-10, showing an AOI of sources in western Washington and the Puget Sound region, including considerable influence from the Vancouver, BC metropolitan area. Nitrates at NOCA1 show considerable influence from non-EGU Point, on-road, non-road, and non-point sources. Sulfates at NOCA1 show considerable influence from non-EGU point and non-point sources. Organic mass at NOCA1 is mostly influenced by non-point sources. Elemental carbon is mostly influenced by non-point sources but also shows a considerable influence from non-road sources. The rank point WEP analysis attributed 99.6% of point source nitrates to Washington State, with 0.3% attributed to Oregon. The rank point WEP analysis attributed 99.6% of point source sulfates to Washington State, with 0.3% attributed to Oregon.

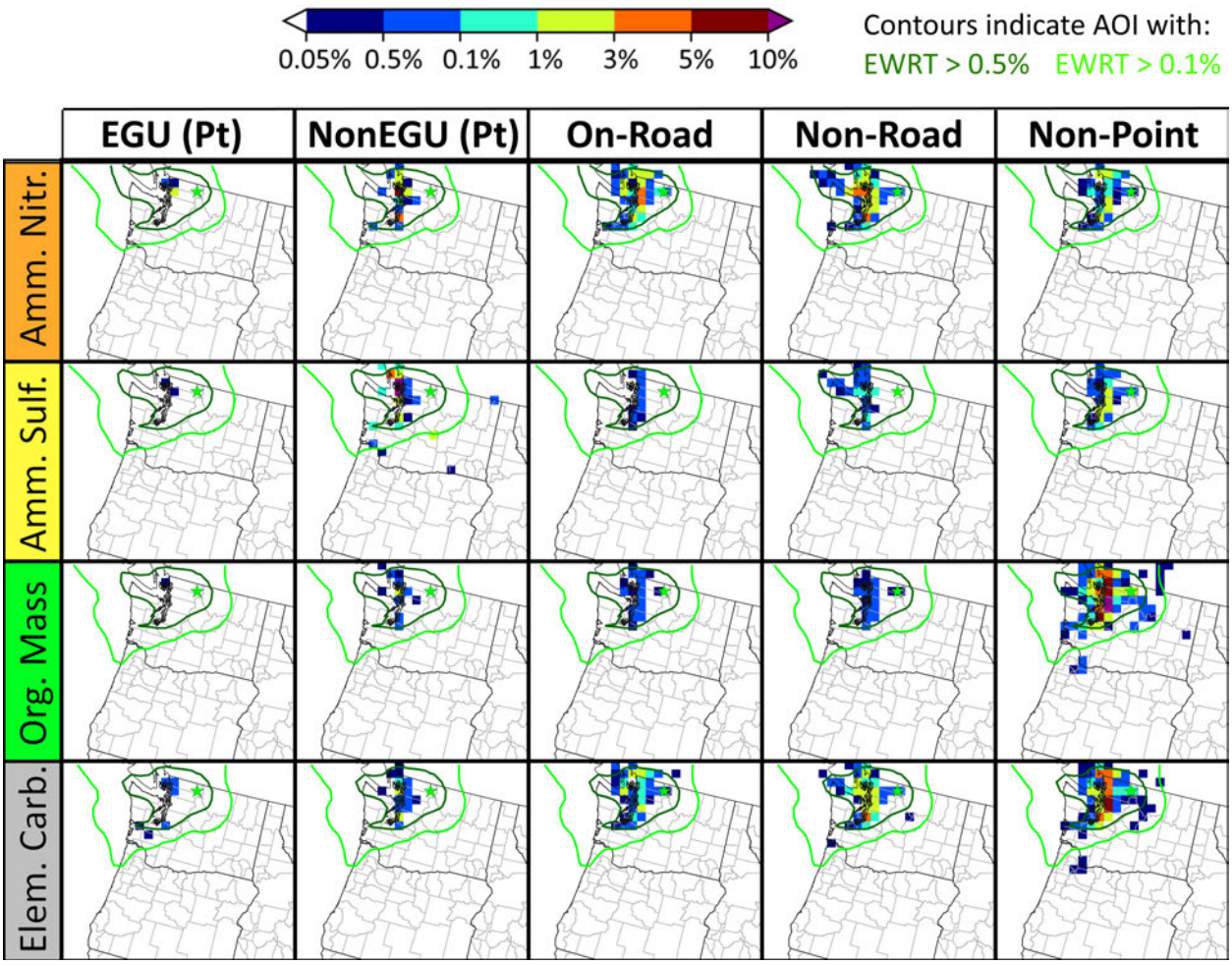


Figure 6-10: WEP for source area potential to contribute to extinction on MID by pollutant at the NOCA1 IMPROVE monitor (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at NOCA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of sulfates at NOCA1 are expected to come primarily from natural (35%), international anthropogenic (26%) and wildland fire (26%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 10% of the sulfates responsible for light extinction at NOCA1. See Figure 6-11 for more information.

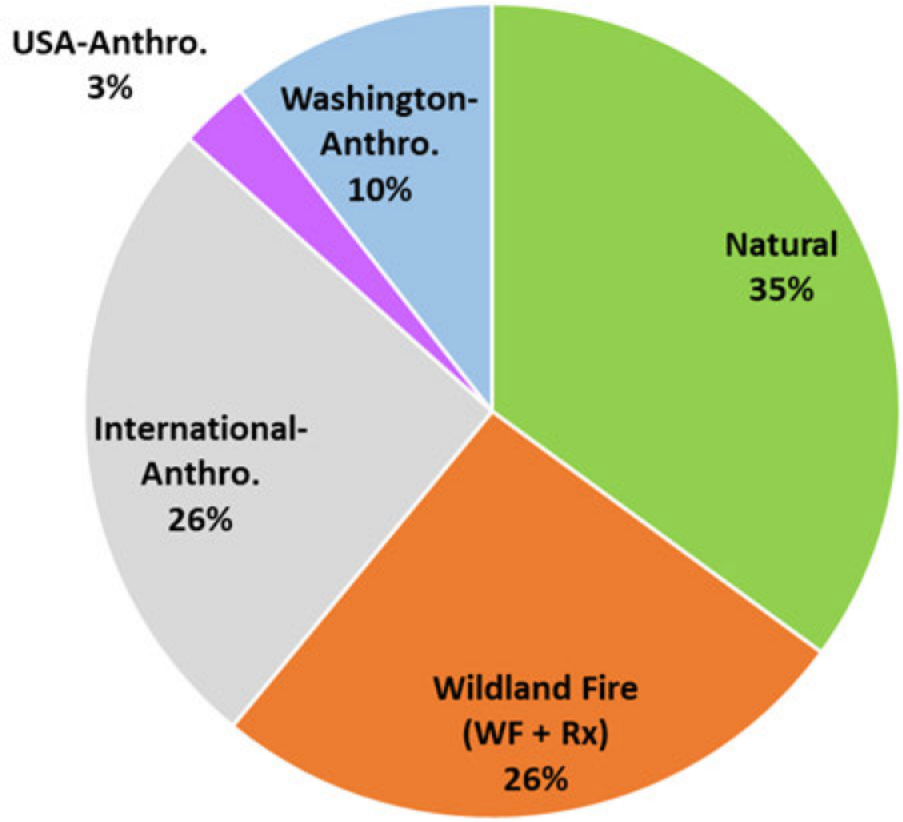


Figure 6-11: Expected source regions of SO_4 in 2028 at NOCA1 for MID (CAMx total = 11.3 Mm^{-1}).

The modeled sulfates for 2028 MID at NOCA1 was 11.3 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 8.14 Mm^{-1} and 8.16 Mm^{-1}, respectively. Figure 6-12 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the NOCA1 monitoring site on 2028 MID.

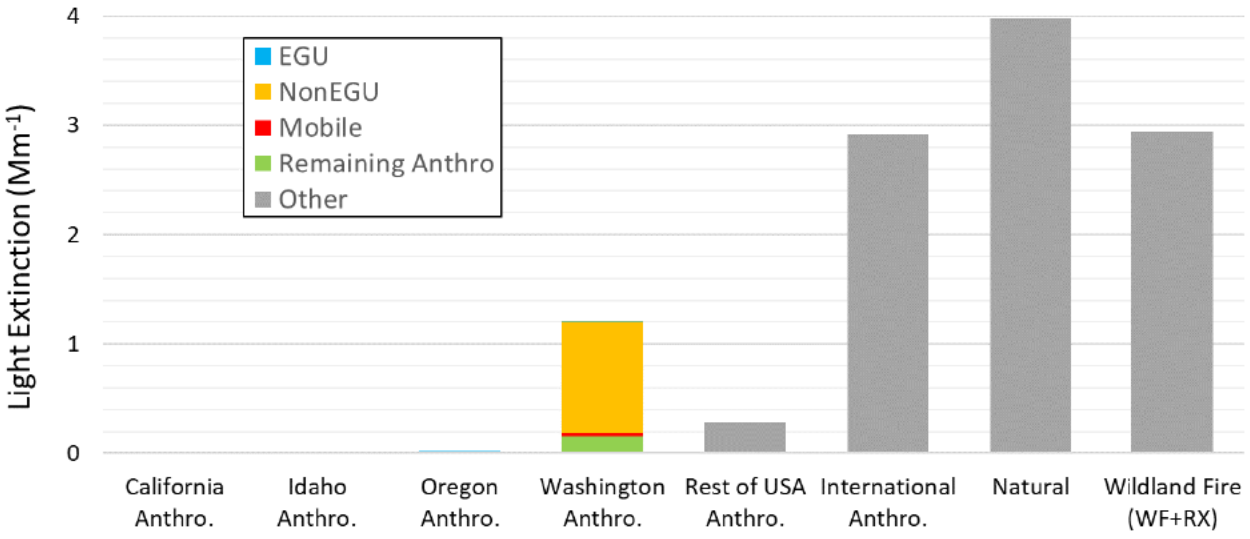


Figure 6-12: Expected source categories and regions of SO_4 in 2028 at NOCA1 for MID (CAMx total = 11.3 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at NOCA1 are expected to come primarily from natural (46%), international anthropogenic (30%), and out-of-state US anthropogenic (12%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 8% of the sulfates responsible for light extinction at OLYM1. See Figure 6-13 for more information.

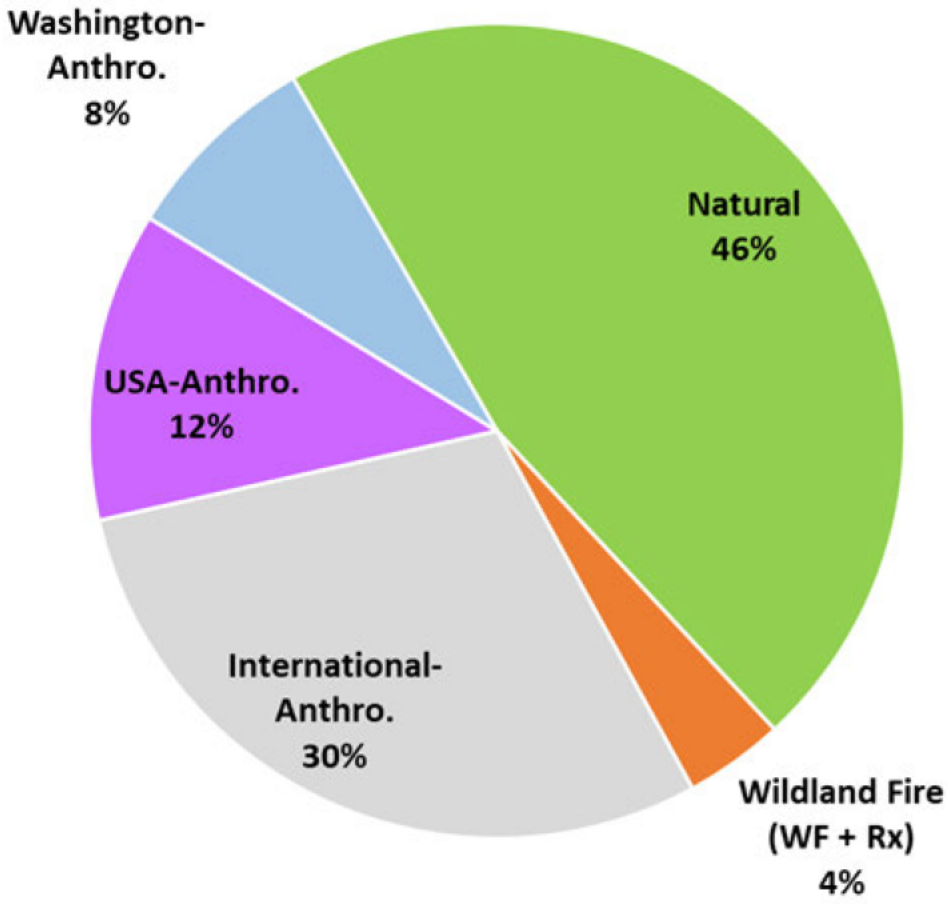


Figure 6-13: Expected source regions of SO_4 in 2028 at NOCA1 for clearest days (CAMx PSAT total = 3.6 Mm^{-1})

The modeled sulfates for 2028 clearest days at NOCA1 was 3.6 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.66 Mm^{-1} and 0.65 Mm^{-1}, respectively. Figure 6-14 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at NOCA1 on 2028 clearest days.

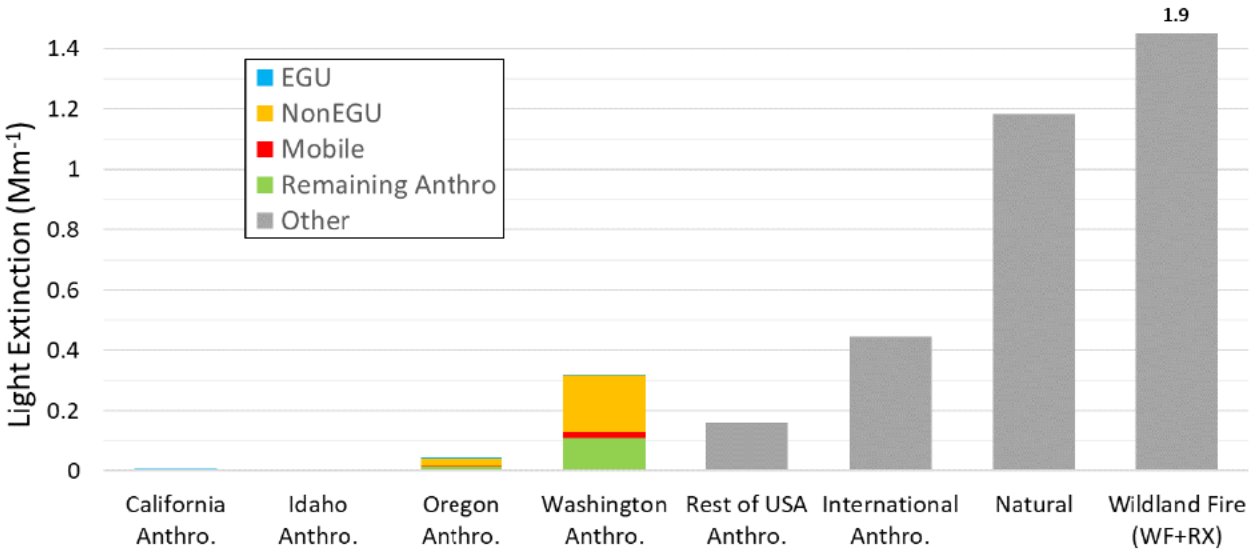


Figure 6-14: Expected source categories and regions of SO_4 in 2028 at NOCA1 for clearest days (CAMx total = 3.6 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the third largest species contribution to light extinction for the MID and clearest days during the 2014-2018 baseline at NOCA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at NOCA1 are expected to come primarily from international anthropogenic sources (45%) while natural sources (18%), and wildland fires (5%) are expected to have minimal impacts. All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 25% of the nitrates responsible for light extinction at NOCA1. See Figure 6-15 for more information.

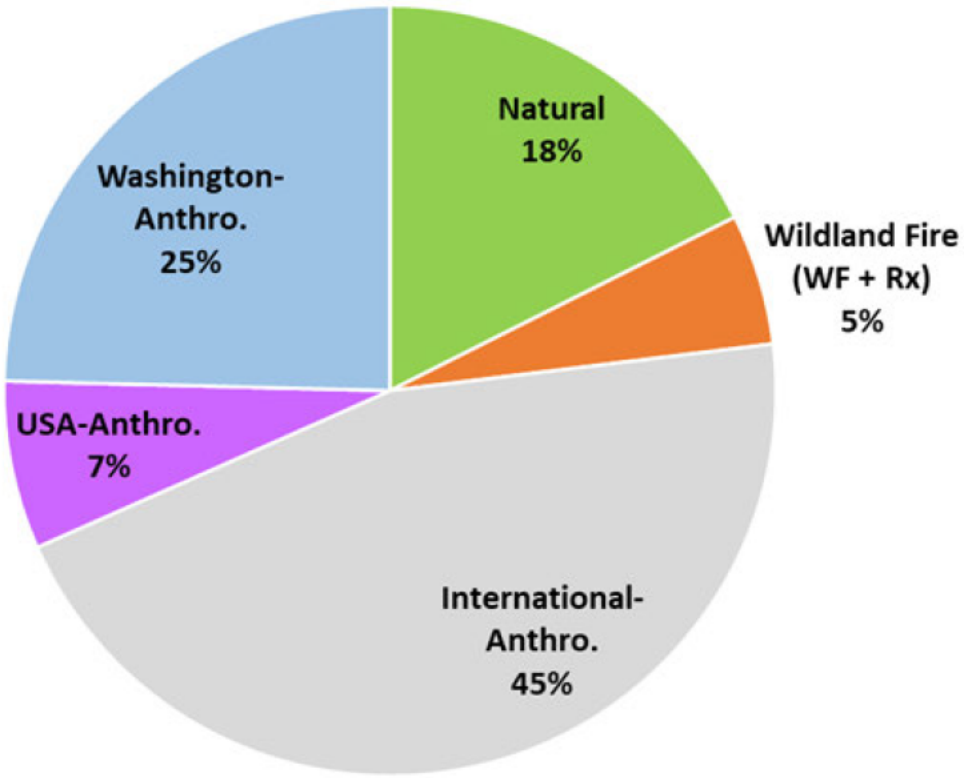


Figure 6-15: Expected source regions of NO_3 in 2028 at NOCA1 for MID (CAMx total = 5.9 Mm-1).

The modeled nitrates for 2028 MID at NOCA1 was 5.9 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 1.73 Mm^{-1} and 1.24 Mm^{-1}, respectively.

Figure 6-16 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at NOCA1 on 2028 MID.

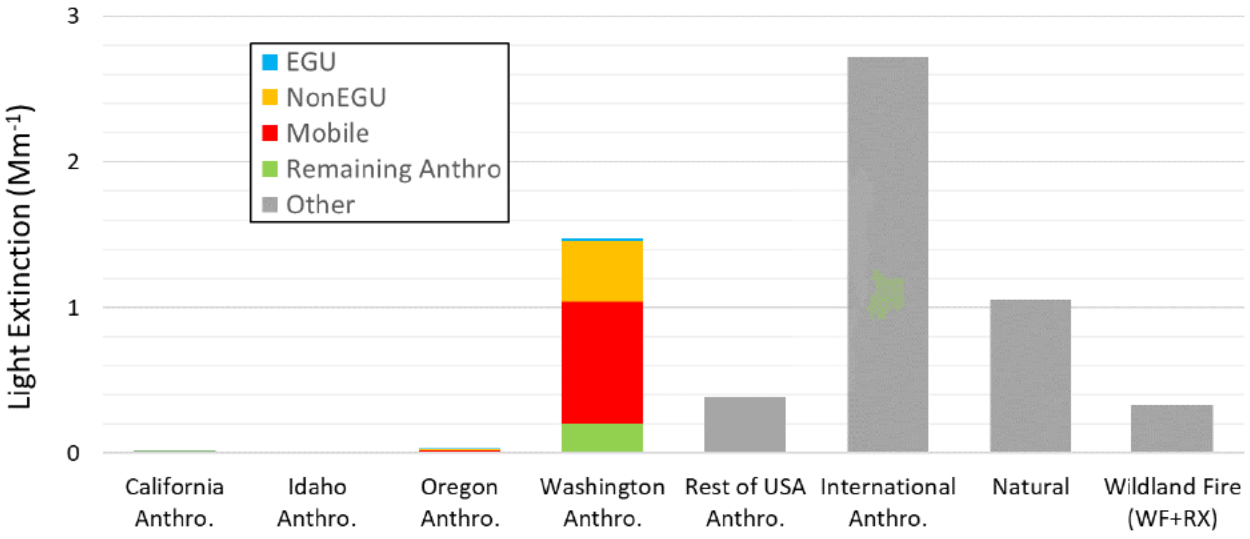


Figure 6-16: Expected source categories and regions of NO3 in 2028 at NOCA1 for MID (CAMx total = 5.9 Mm-1).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of nitrates at NOCA1 are expected to come primarily from out-of-state US anthropogenic (33%), and international anthropogenic (25%) sources. Washington anthropogenic sources are expected to contribute 22% of the nitrates responsible for light extinction at NOCA1 on clearest days. See Figure 6-17 for more information.

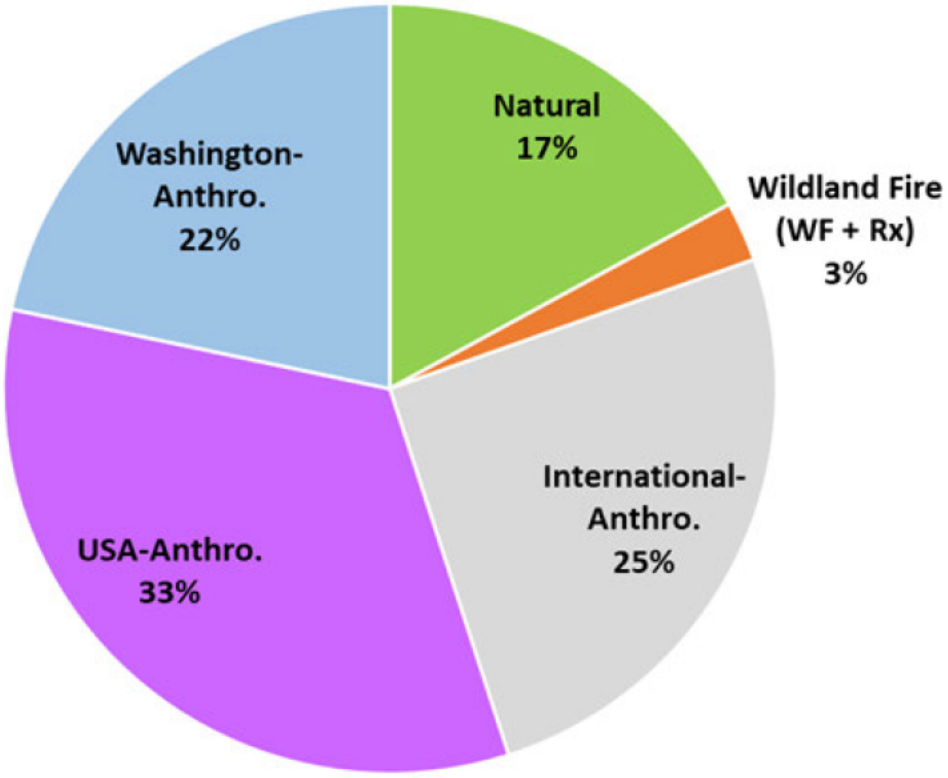


Figure 6-17: Expected source regions of NO_3 in 2028 at NOCA1 for clearest days (CAMx total = 0.8 Mm^{-1}).

The modeled nitrates for 2028 clearest days at NOCA1 was 0.8 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.24 Mm^{-1} and 0.19 Mm^{-1}, respectively. Figure 6-18 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at the NOCA1 monitoring site on 2028 clearest days.

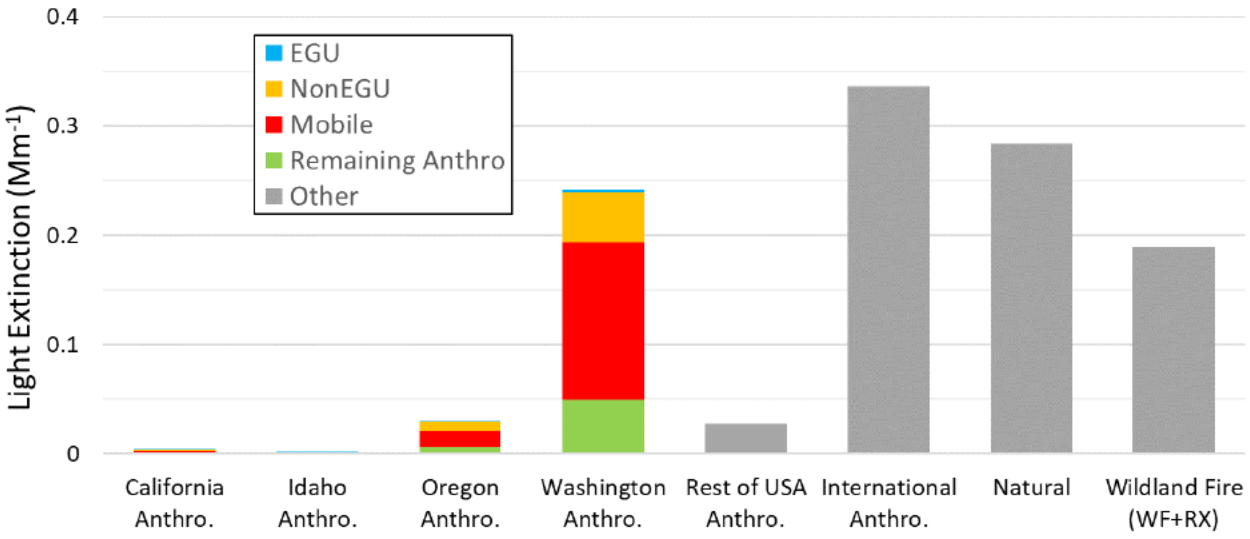


Figure 6-18: Expected source categories and regions of NO_3 in 2028 at NOCA1 for clearest days (CAMx total = 0.8 Mm^{-1}).

6.3 Alpine Lakes Wilderness

Alpine Lakes Wilderness is represented by the SNPA1 IMPROVE monitoring site. The baseline conditions presented in Chapter 3 show that sulfates (35%), organic mass (25%), and nitrates (26%) together contribute to 76% of the light extinction on the MID at this site. On the clearest days sulfates (33%), nitrates (20%), and organic mass (22%) contribute to 75% of the light extinction at this monitoring site.

WEP and rank point analyses

The WEP analysis for the SNPA1 site on MID for the 2028 OTB scenario is summarized in Figure 6-19, showing an AOI of sources that span western and central Washington, the Puget Sound area, and the Vancouver, BC and Portland, OR metropolitan areas. Nitrates at SNPA1 show considerable influence from on-road, Non-road, and non-point sources. Sulfates at NOCA1 show considerable influence from non-EGU Point and non-point sources. Organic mass at SNPA1 is mostly influenced by non-point sources. Elemental carbon is mostly influenced by non-point sources but also shows influence from non-EGU Point, on-road, and non-road sources. The rank point WEP analysis attributed 90.9% of point source nitrates to Washington State, with 8.2%, 0.4%, 0.3%, and 0.2% attributed to Oregon, California, Idaho, and Tribal Lands, respectively. The rank point WEP analysis attributed 98.3% of point source sulfates to Washington State, with 1.4% and 0.2% attributed to Oregon and California, respectively.

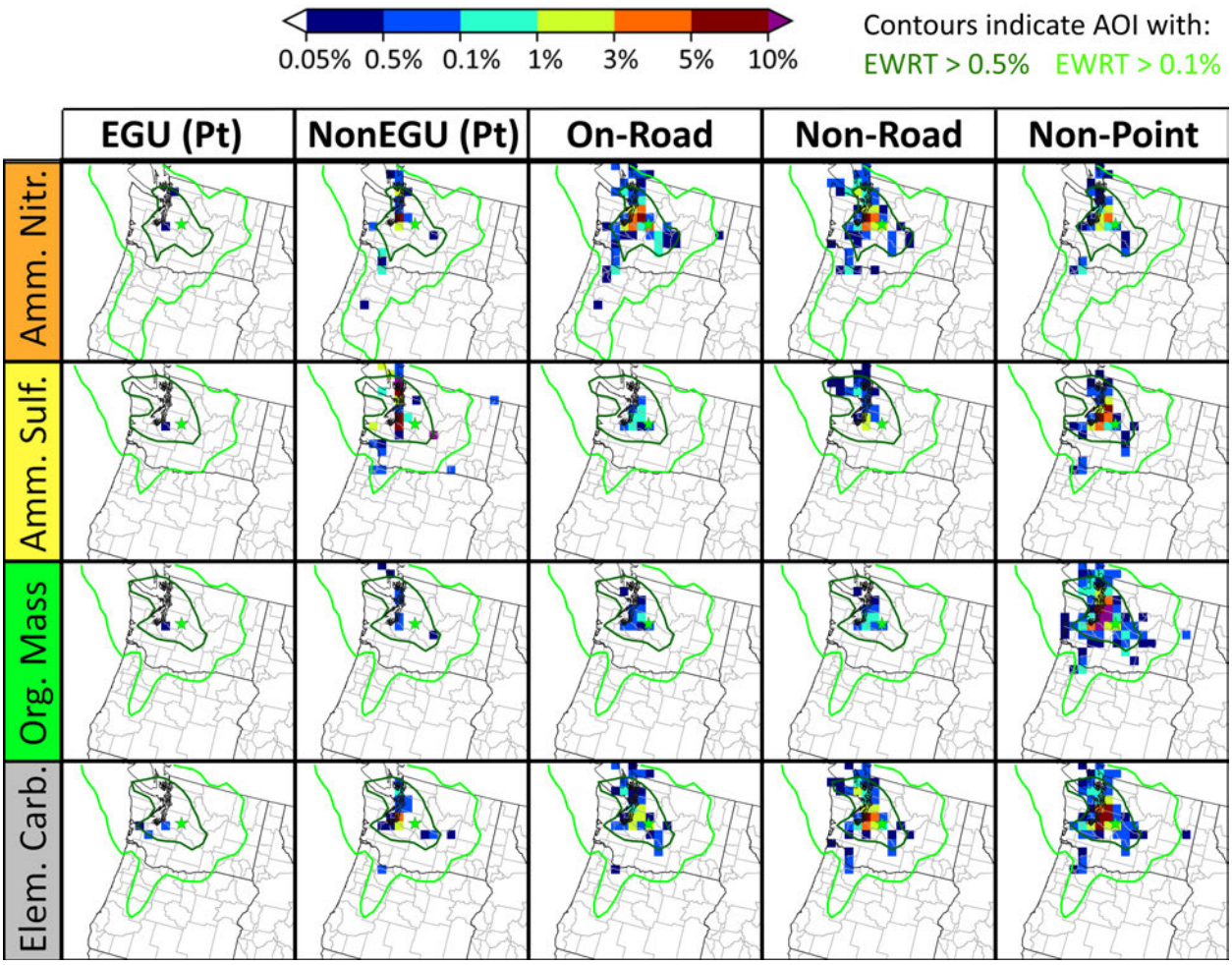


Figure 6-19: WEP for source area potential to contribute to extinction on MID by pollutant at SNPA1 (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at SNPA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of sulfates at SNPA1 are expected to come primarily from wildland fire (55%), natural (21%), and international anthropogenic sources (14%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 8% of the sulfates responsible for light extinction at SNPA1. See Figure 6-20 for more information.

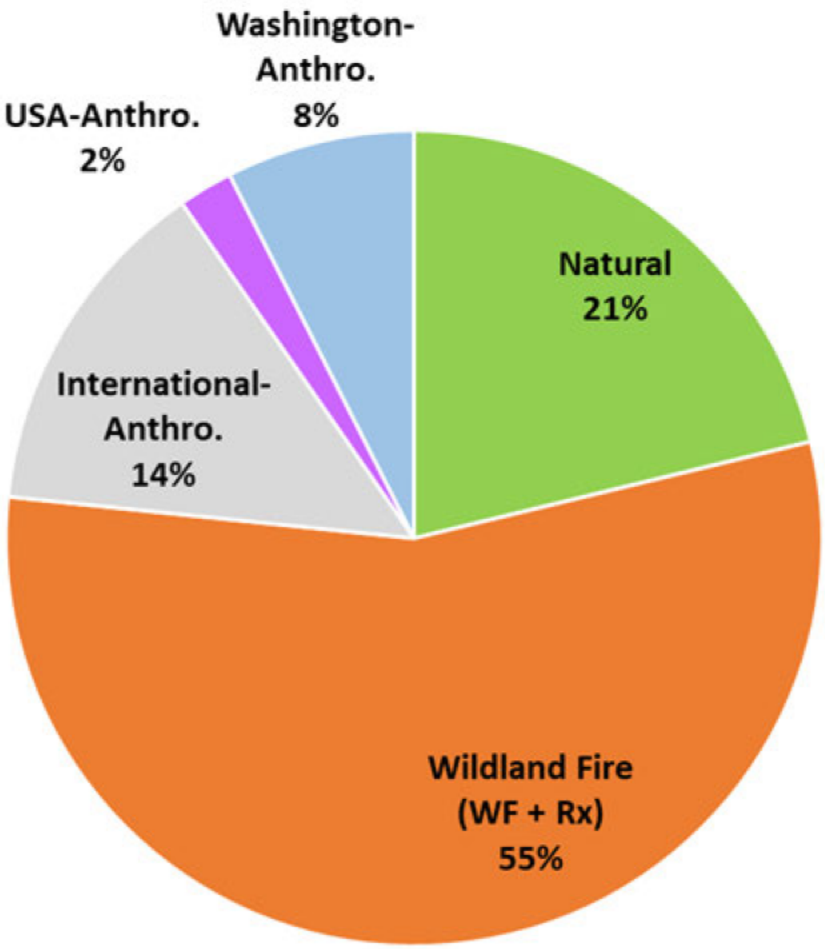


Figure 6-20: Expected source regions of SO_4 in 2028 at SNPA1 for MID (CAMx total = 22.9 Mm^{-1}).

The modeled sulfates for 2028 MID at SNPA1 was 22.9 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 8.84 Mm^{-1} and 8.75 Mm^{-1}, respectively. The impacts of wildland fire on MID are clearly overestimated in the model for SNPA1, which is supported by the immense organic mass modeled at the site (171.3 Mm^{-1}). Figure 6-21 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the OLYM1 monitoring site on 2028 MIDs.

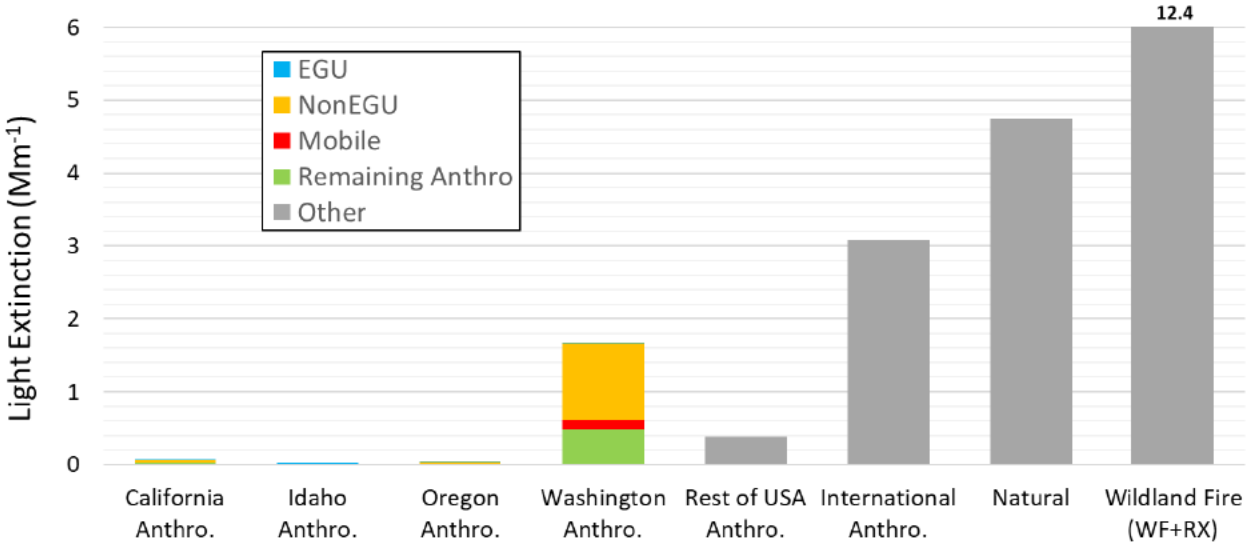


Figure 6-21: Expected source categories and regions of SO_4 in 2028 at SNPA1 for MID (CAMx total = 22.4 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at SNPA1 are expected to come primarily from natural (47%), international anthropogenic (22%), and out-of-state US anthropogenic (18%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 11% of the sulfates responsible for light extinction at SNPA1. See Figure 6-22 for more information.

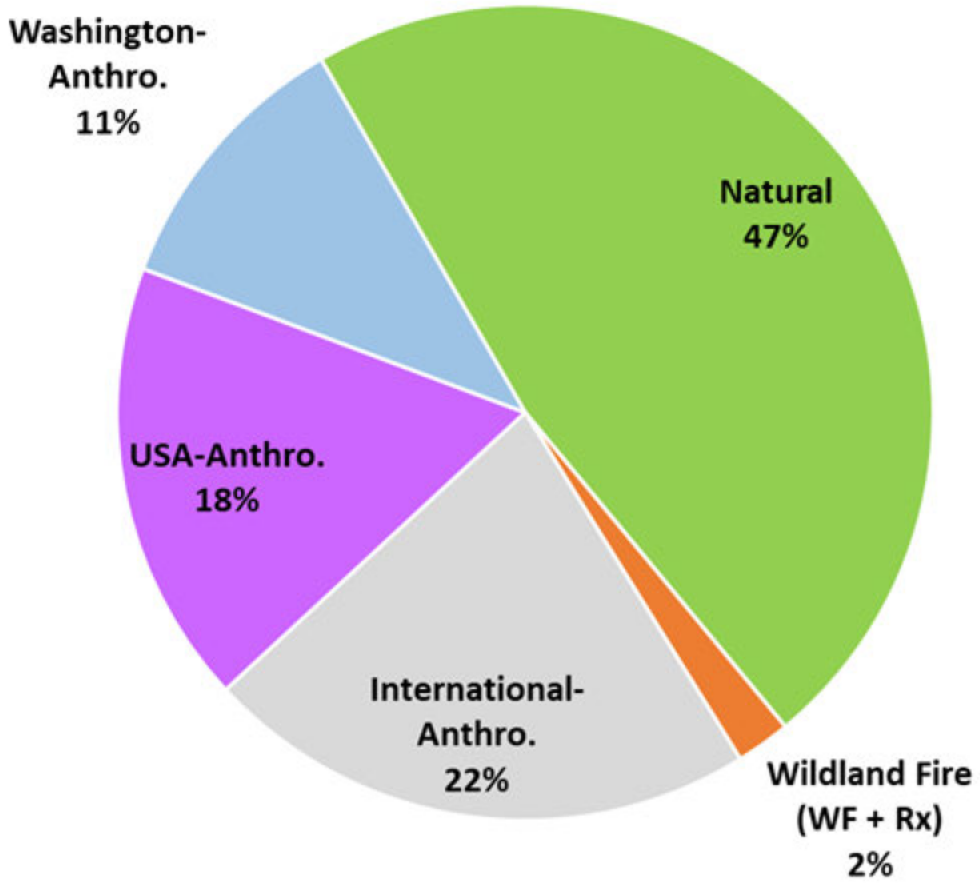


Figure 6-22: Expected source regions of SO_4 in 2028 at SNPA1 for clearest days (CAMx total = 4.4 Mm^{-1}).

The modeled sulfates for 2028 clearest days at SNPA1 was 4.4 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 1.01 Mm^{-1} and 0.98 Mm^{-1}, respectively.

Figure 6-23 shows an expectation within Washington that non-EGU point sources contribute the most sulfate light extinction at SNPA1 on 2028 clearest days.

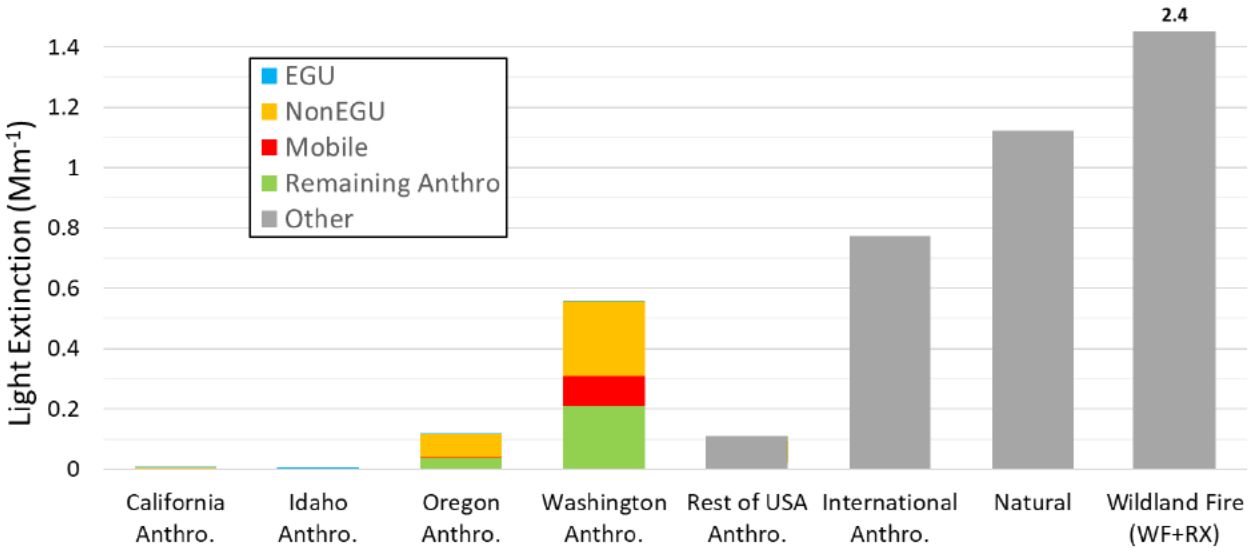


Figure 6-23: Expected source categories and regions of SO_4 in 2028 at SNPA1 for clearest days (CAMx total = 4.4 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the 2nd largest species contribution to light extinction for the MID clearest days during the 2014-2018 baseline at SNPA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at SNPA1 are expected to be most influenced from Washington anthropogenic sources (38%). Wildland fires (26%), international anthropogenic (19%), and natural sources (11%) are expected to have some impacts but are beyond Washington's control. See Figure 6-24 for more information.

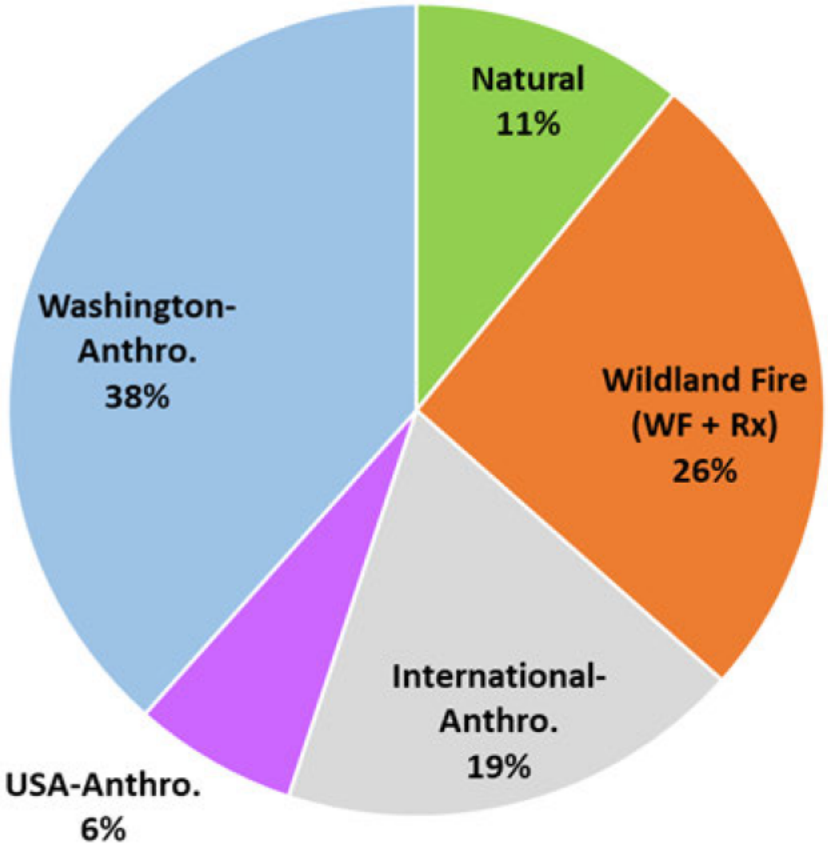


Figure 6-24: Expected source regions of NO_3 in 2028 at SNPA1 for MID (CAMx total = 14.9 Mm^{-1}).

The modeled nitrates for 2028 MID at SNPA1 was 14.9 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 6.75 Mm^{-1} and 4.26 Mm^{-1}, respectively.

Figure 6-25 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at SNPA1 on 2028 MIDs.

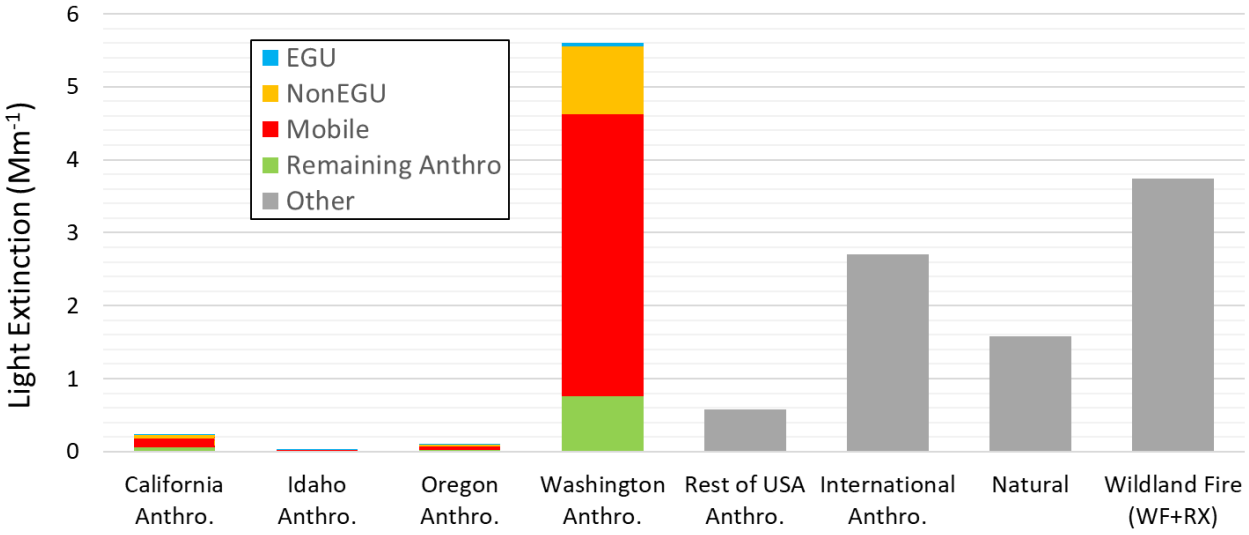


Figure 6-25: Expected source categories and regions of NO_3 in 2028 at SNPA1 for MID (CAMx total = 14.9 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days' visibility impacts of nitrates at SNPA1 are expected to come primarily from out-of-state US anthropogenic (40%) sources. Washington anthropogenic sources are expected to contribute 26% of the nitrates responsible for light extinction at SNPA1 on clearest days. See Figure 6-26 for more information.

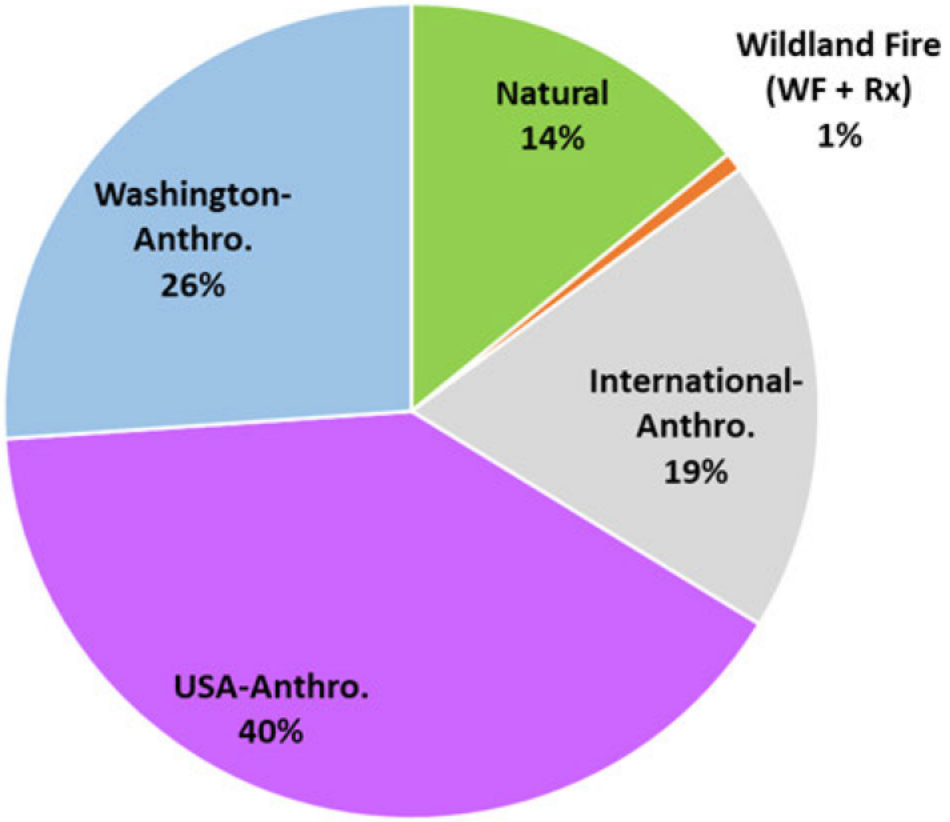


Figure 6-26: Expected source regions of NO_3 in 2028 at SNPA1 for clearest days (CAMx PSAT total = 2.2 Mm^{-1}).

The modeled nitrates for 2028 clearest days at SNPA1 was 2.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.61 Mm^{-1} and 0.45 Mm^{-1}, respectively.

Figure 6-27 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at the SNPA1 monitoring site on 2028 clearest days.

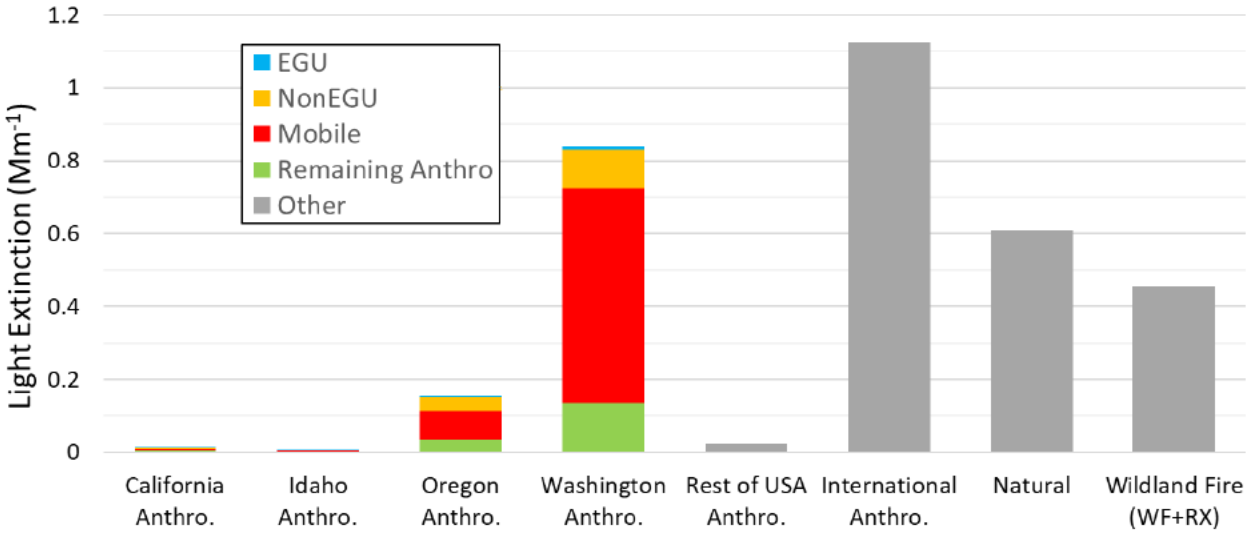


Figure 6-27: Expected source categories and regions of NO_3 in 2028 at SNPA1 for clearest days (CAMx PSAT total = 2.2 Mm^{-1}).

6.4 Mount Rainier National Park

Mount Rainier National Park is represented by the MORA1 IMPROVE monitoring site. The baseline conditions in Chapter 3 show that sulfates (41%) and organic mass (31%) make up 72% of the light extinction on the MID at this monitoring site. Nitrates (7%) and elemental carbon (9%) contribute to another 16% of the light extinction on the MID at this monitoring site. On the clearest days, sulfates (34%) and organic mass (26%) make up 60% of the light extinction at this monitoring site. Nitrates (8%) and elemental carbon (10%) contribute to another 18% of the light extinction on the clearest days at this monitoring site.

WEP and rank point analyses

The WEP analysis for the MORA1 site on MID for the 2028 OTB scenario is summarized in Figure 6-28, showing an AOI of sources in western Washington and the Puget Sound region. There is also some minimal influence from sources in the Portland, OR and Vancouver, BC metropolitan areas. Nitrates at MORA1 show considerable influence from non-EGU Point, on-road, non-road, and non-point sources. Sulfates at MORA1 show considerable influence from non-EGU Point, non-road, and non-point sources. Organic mass at MORA1 is mostly influenced by non-point sources. Elemental carbon is influenced by non-EGU Point, on-road, non-road, and non-point sources. The rank point WEP analysis attributed 97.3% of point source nitrates to Washington State, with 2.6% attributed to Oregon. The rank point WEP analysis attributed 95.6% of point source sulfates to Washington State, with 4.2% and 0.2% attributed to Oregon and California, respectively.

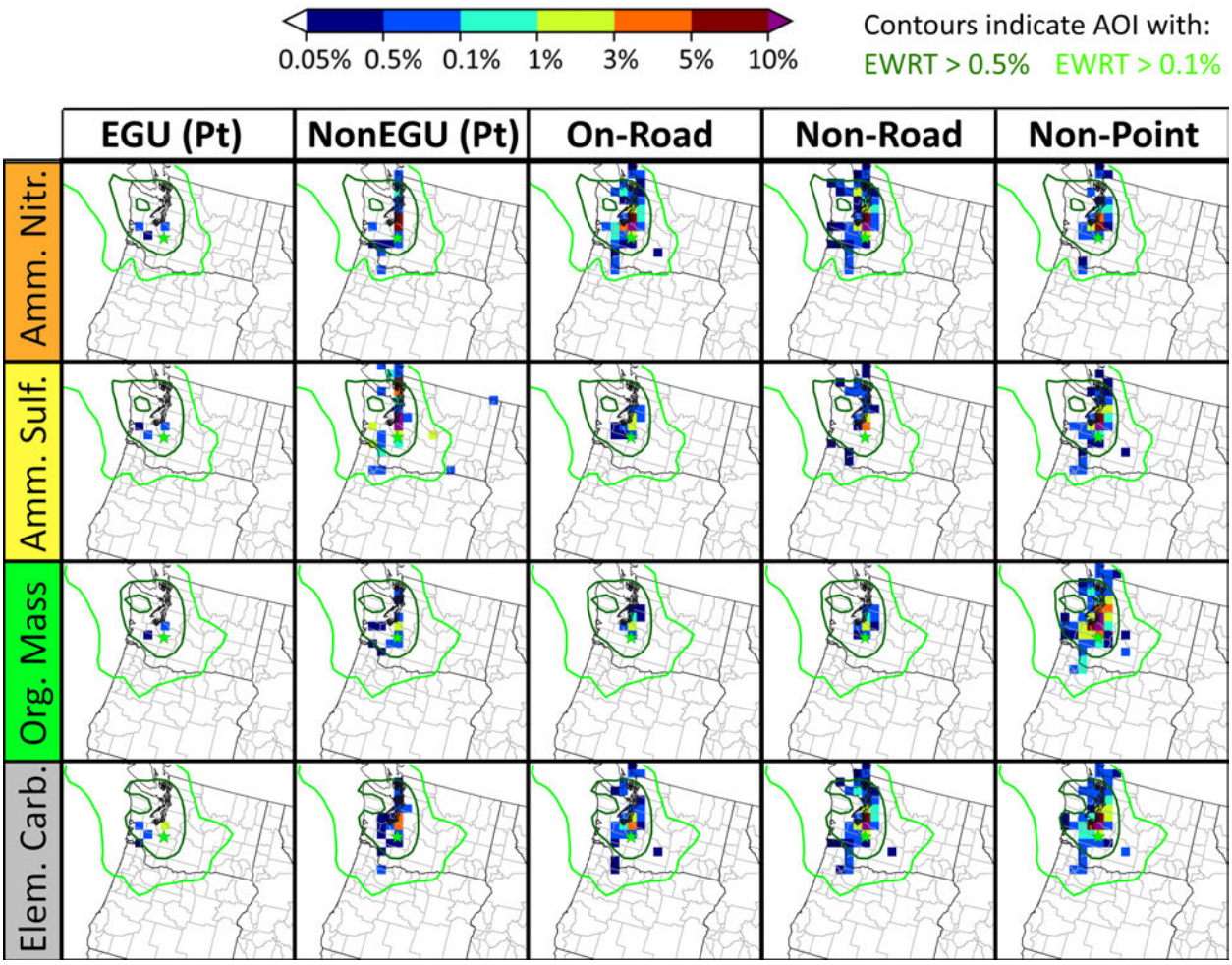


Figure 6-28: WEP for source area potential to contribute to extinction on MID by pollutant at the MORA1 IMPROVE monitor (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at MORA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of sulfates at MORA1 are expected to come primarily from natural (39%), wildland fire (25%), and international anthropogenic sources (23%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 10% of the sulfates responsible for light extinction at MORA1. See Figure 6-29 for more information.

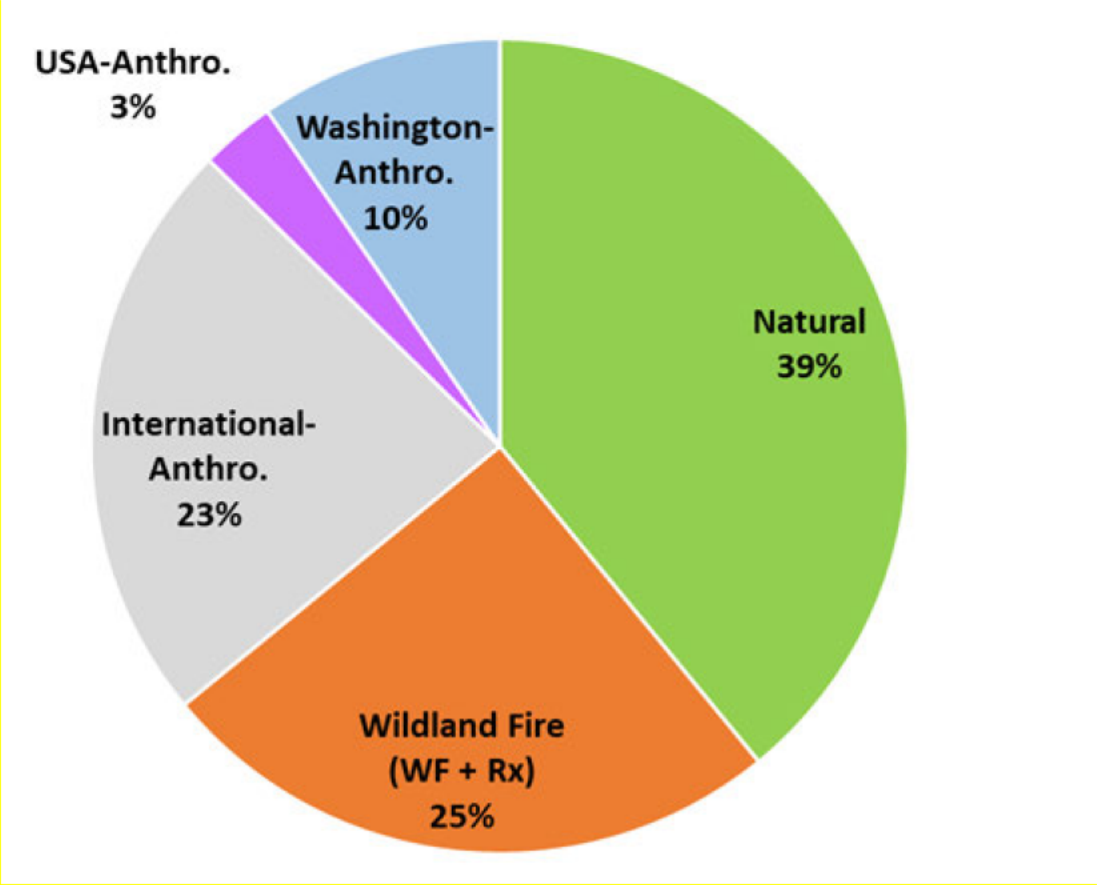


Figure 6-29: Expected source regions of SO_4 in 2028 at MORA1 for MID (CAMx total = 13.2 Mm^{-1}).

The modeled sulfates for 2028 MID at MORA1 was 13.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 10.15 Mm^{-1} and 9.7 Mm^{-1}, respectively.

Figure 6-30 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the OLYM1 monitoring site on 2028 MIDs.

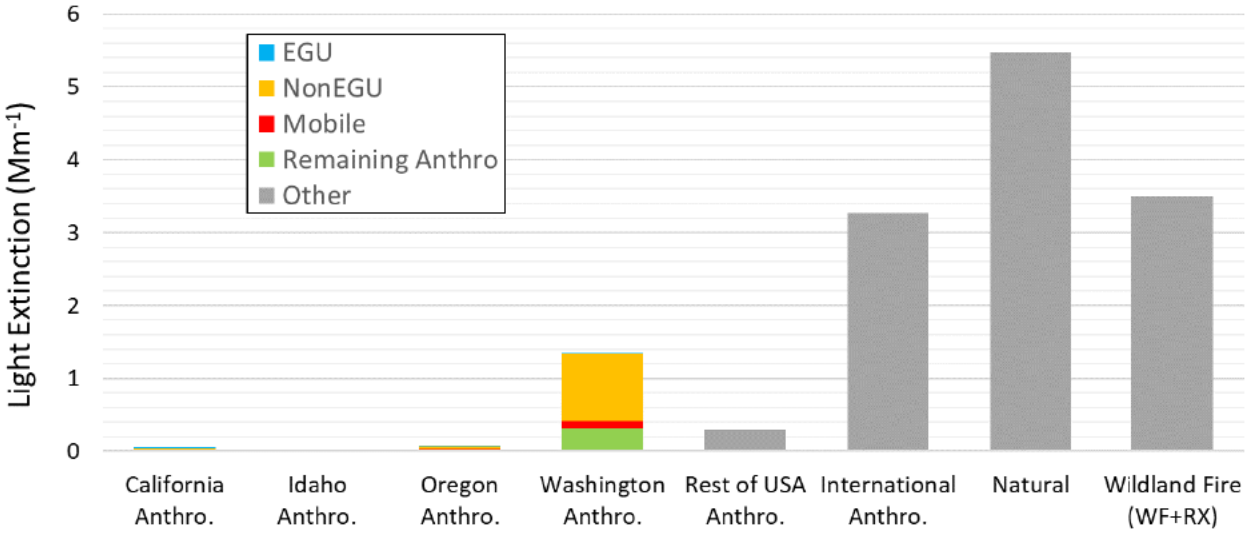


Figure 6-30: Expected source categories and regions of SO_4 in 2028 at MORA1 for MID (CAMx total = 13.2 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at MORA1 are expected to come primarily from natural (36%), out-of-state US anthropogenic (28%), and international anthropogenic (26%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 7% of the sulfates responsible for light extinction at SNPA1. See Figure 6-31 for more information.

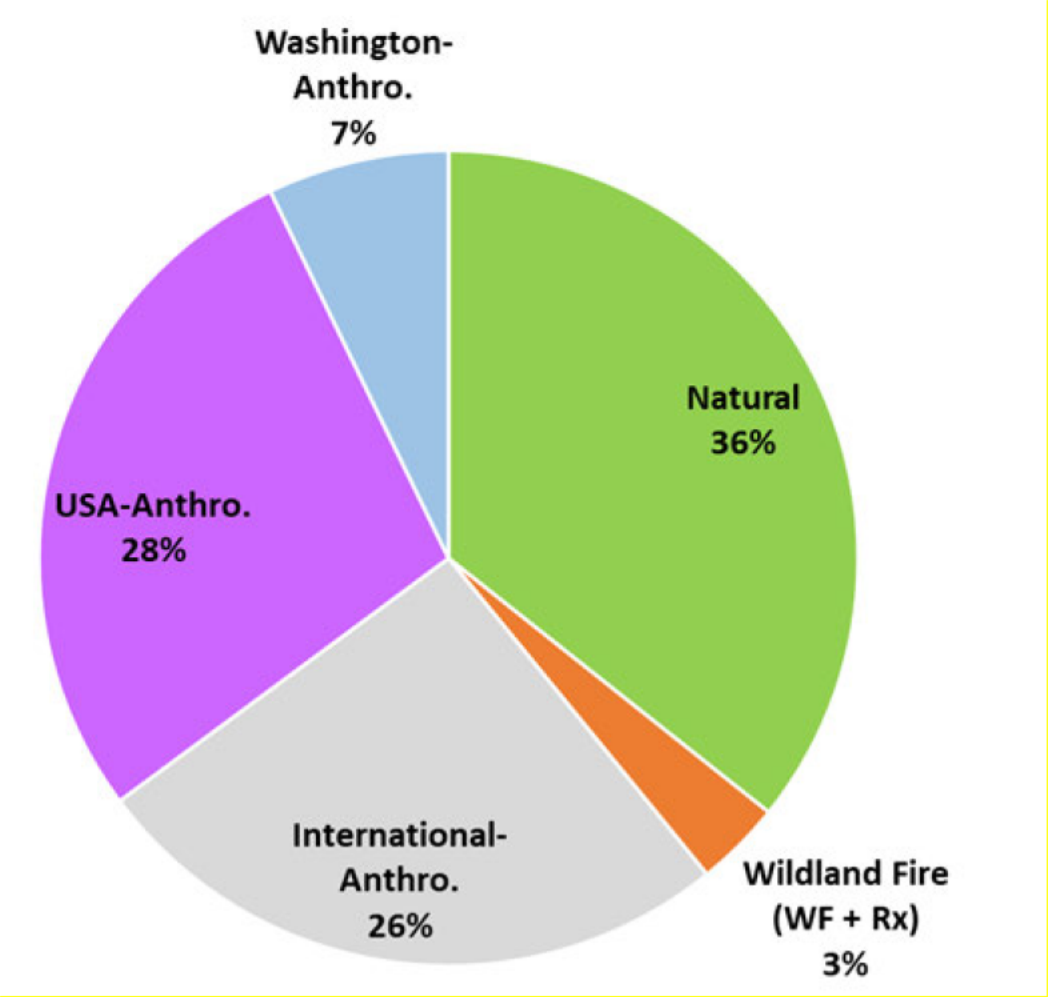


Figure 6-31: Expected source regions of SO_4 in 2028 at MORA1 for clearest days (CAMx total = 3.7 Mm^{-1}).

The modeled sulfates for 2028 clearest days at MORA1 was 3.7 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 1.3 Mm^{-1} and 1.22 Mm^{-1}, respectively.

Figure 6-32 shows an expectation within Washington that, non-EGU point sources contribute the majority of sulfate light extinction at MORA1 on 2028 clearest days.

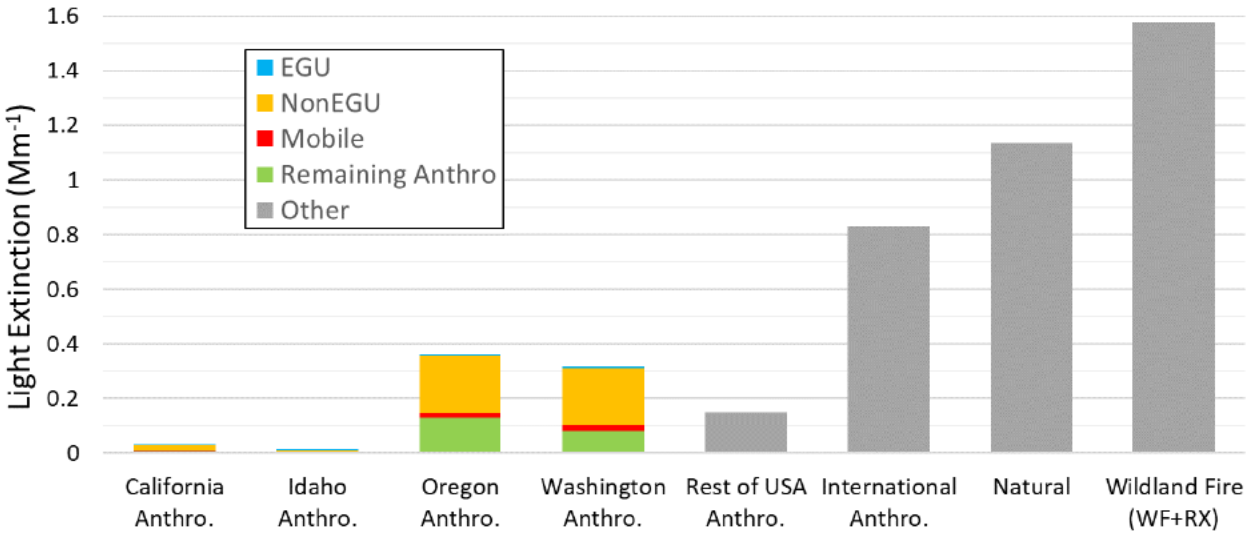


Figure 6-32: Expected source categories and regions of SO_4 in 2028 at MORA1 for clearest days (CAMx total = 3.7 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the 3rd largest species contribution to light extinction for the MID and 6th largest species contribution for the clearest days during the 2014-2018 baseline at MORA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at MORA1 are expected to be most influenced from Washington anthropogenic sources (46%). International anthropogenic (18%), Wildland fires (15%), and natural sources (14%) are expected to have some impacts but are beyond Washington's control. See Figure 6-33 for more information.

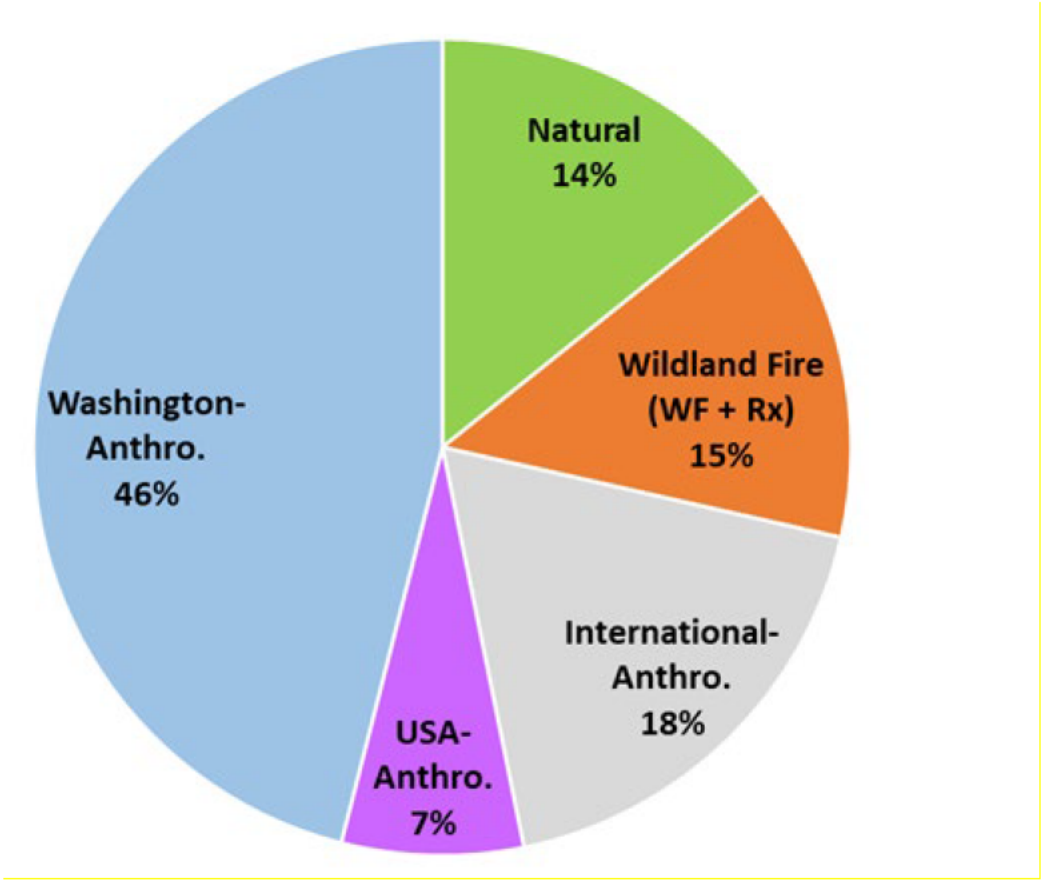


Figure 6-33: Expected source regions of NO_3 in 2028 at MORA1 for MID (CAMx total = 7.2 Mm^{-1}).

The modeled nitrates for 2028 MID at MORA1 was 7.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 2.27 Mm^{-1} and 1.13 Mm^{-1}, respectively.

Figure 6-34 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at MORA1 on 2028 MIDs.

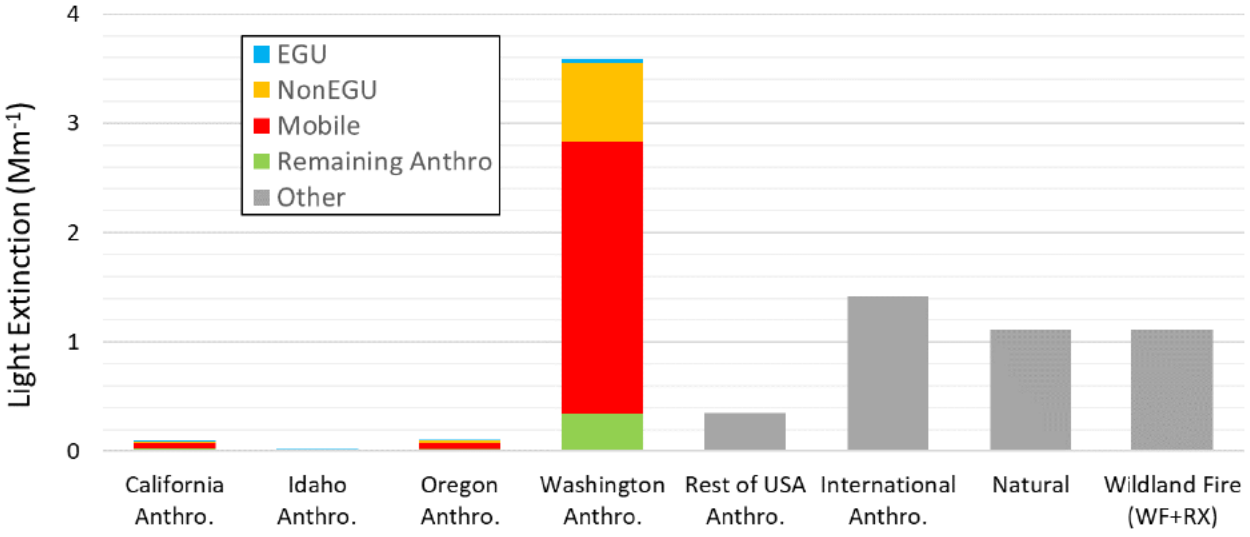


Figure 6-34: Expected source categories and regions of NO_3 in 2028 at MORA1 for MID (CAMx total = 7.2 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of nitrates at MORA1 are expected to come primarily from out-of-state US anthropogenic (54%) and international anthropogenic (20%) sources. Washington anthropogenic sources are expected to contribute 15% of the nitrates responsible for light extinction at MORA1 on clearest days. See Figure 6-35 for more information.

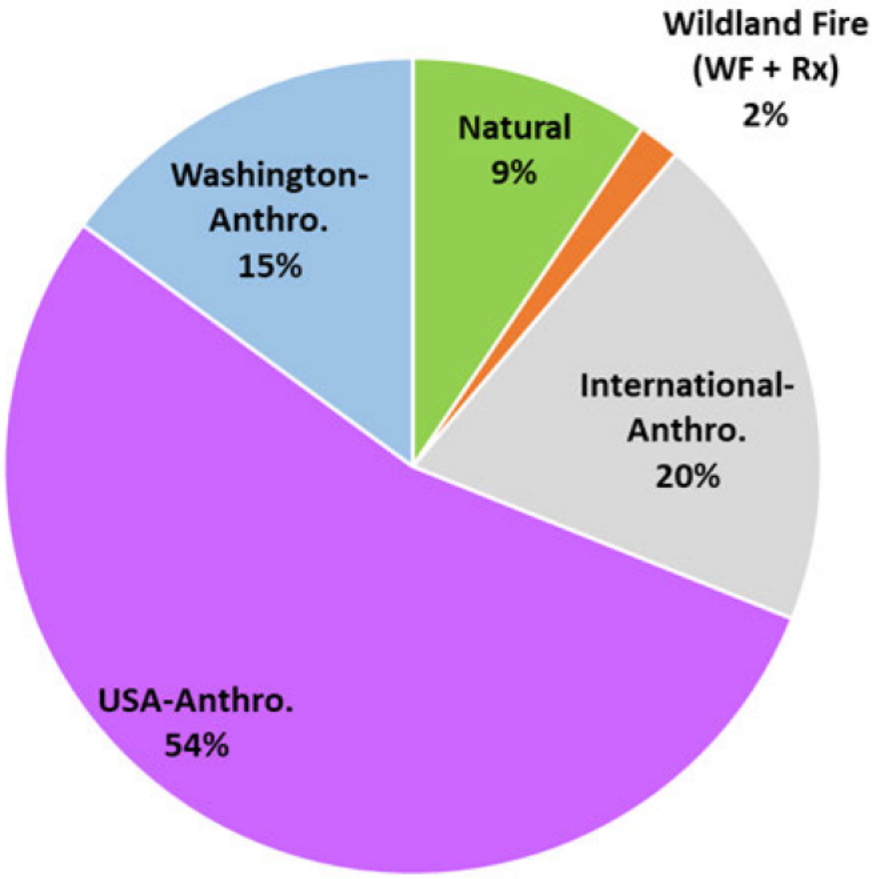


Figure 6-35: Expected source regions of NO_3 in 2028 at MORA1 for clearest days (CAMx total = 1.6 Mm^{-1}).

The modeled nitrates for 2028 clearest days at MORA1 was 1.6 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.32 Mm^{-1} and 0.24 Mm^{-1}, respectively.

Figure 6-36 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at MORA1 on 2028 clearest days.

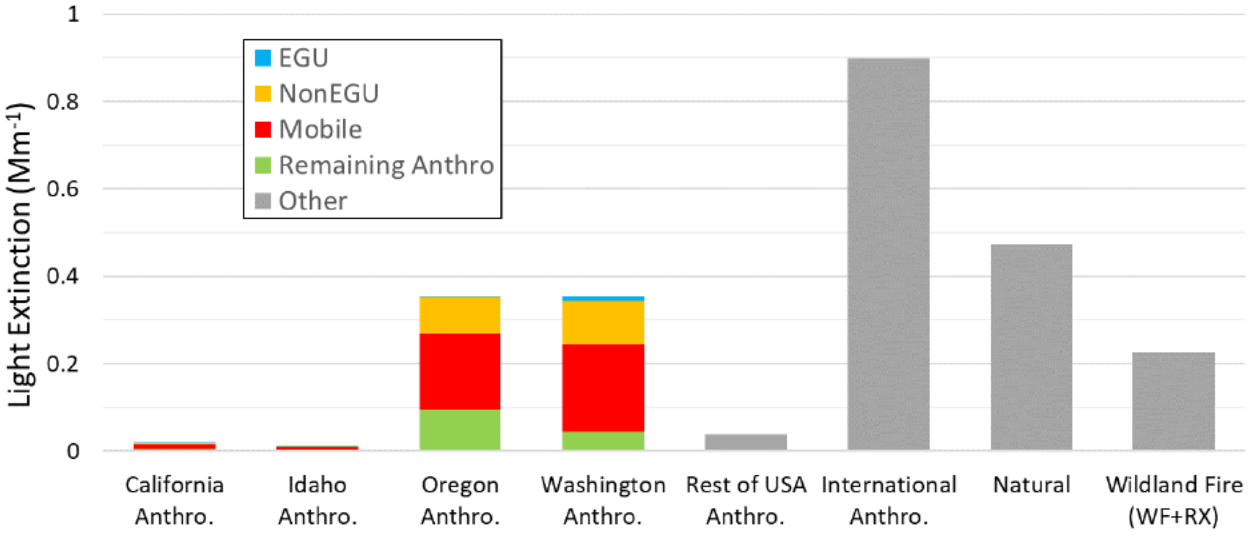


Figure 6-36: Expected source categories and regions of NO_3 in 2028 at MORA1 for clearest days (CAMx total = 1.6 Mm^{-1}).

6.5 Goat Rocks Wilderness and Mount Adams Wilderness

Goat Rocks Wilderness and Mount Adams Wilderness are represented by the WHPA1 IMPROVE monitoring site. The baseline conditions in Chapter 3 show that sulfates (50%), organic mass (22%), and nitrates (12%) together contribute to 84% of the light extinction on the MID at this monitoring site. On the clearest days sulfates (39%), organic mass (14%), and nitrates (14%) contribute to 67% of the light extinction at this monitoring site.

WEP and rank point analyses

The WEP analysis for the WHPA1 site on MID for the 2028 OTB scenario is summarized in Figure 6-37, showing an AOI of sources that span western and central Washington, the Puget Sound area, and the Vancouver, BC and Portland, OR metropolitan areas. Nitrates at WHPA1 show considerable influence from non-EGU Point, on-road, non-road, and non-point sources. Sulfates at WHPA1 show considerable influence from non-EGU Point and non-point sources. Organic mass at WHPA1 is mostly influenced by non-point sources. Elemental carbon is mostly influenced by non-point sources but also shows influence from non-EGU Point, on-road, and non-road sources. The rank point WEP analysis attributed 86.7% of point source nitrates to Washington State, with 11.9%, 0.9%, 0.3%, and 0.1% attributed to Oregon, Tribal Lands, Idaho, and California, respectively. The rank point WEP analysis attributed 89.1% of point source sulfates to Washington State, with 10.4%, 0.2%, and 0.2% attributed to Oregon, Tribal Lands, and California, respectively.

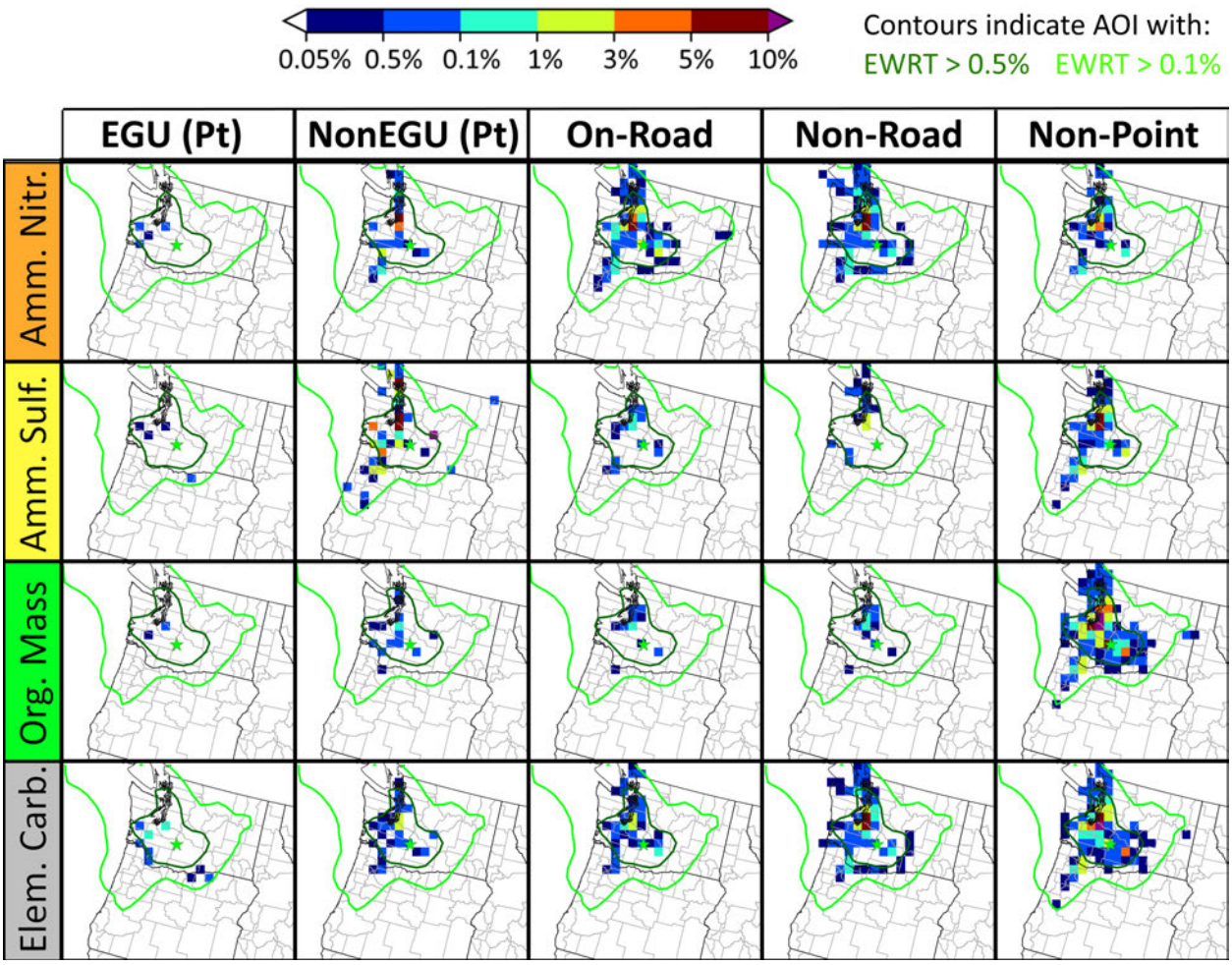


Figure 6-37: WEP for source area potential to contribute to extinction on MID by pollutant at the WHPA1 IMPROVE monitor (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at WHPA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of sulfates at WHPA1 are expected to come primarily from international anthropogenic (52%) and natural sources (35%). These sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 6% of the sulfates responsible for light extinction at WHPA1. See Figure 6-38 for more information.

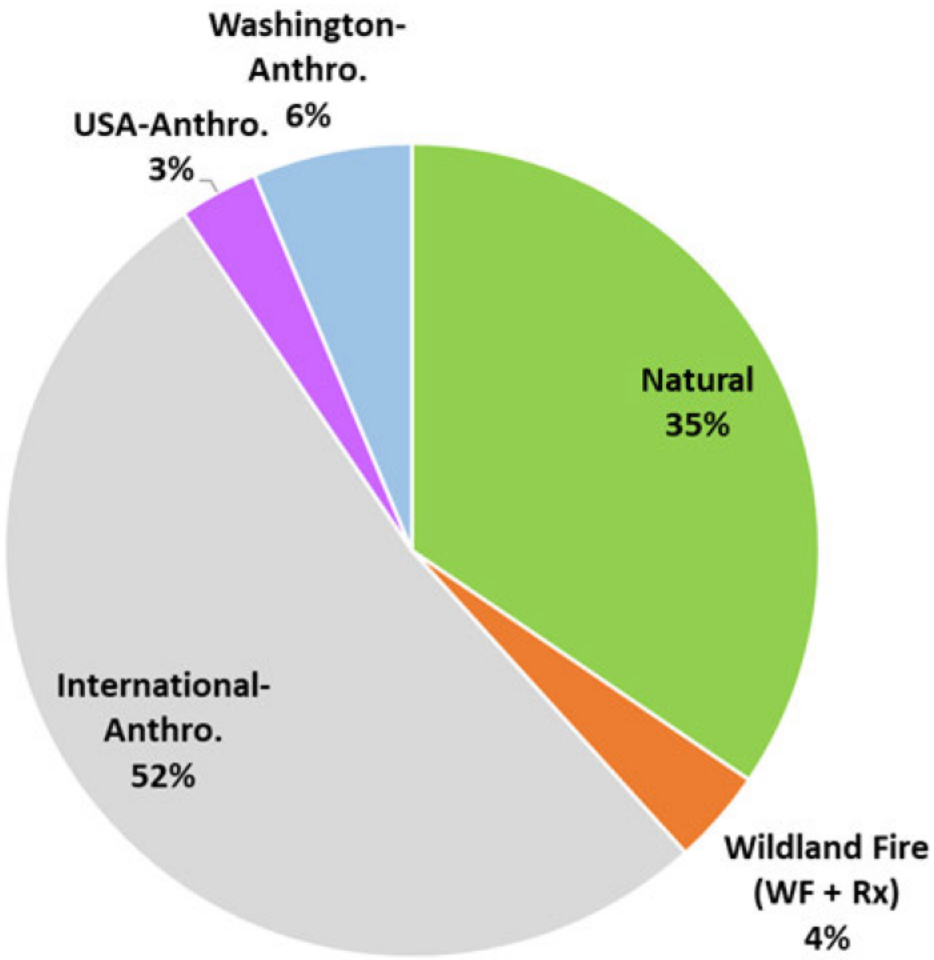


Figure 6-38: Expected source regions of SO_4 in 2028 at WHPA1 for MID (CAMx total = 8.2 Mm^{-1}).

The modeled sulfates for 2028 MID at WHPA1 was 8.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 6.37 Mm^{-1} and 6.32 Mm^{-1}, respectively.

Figure 6-39 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the OLYM1 monitoring site on 2028 MIDs.

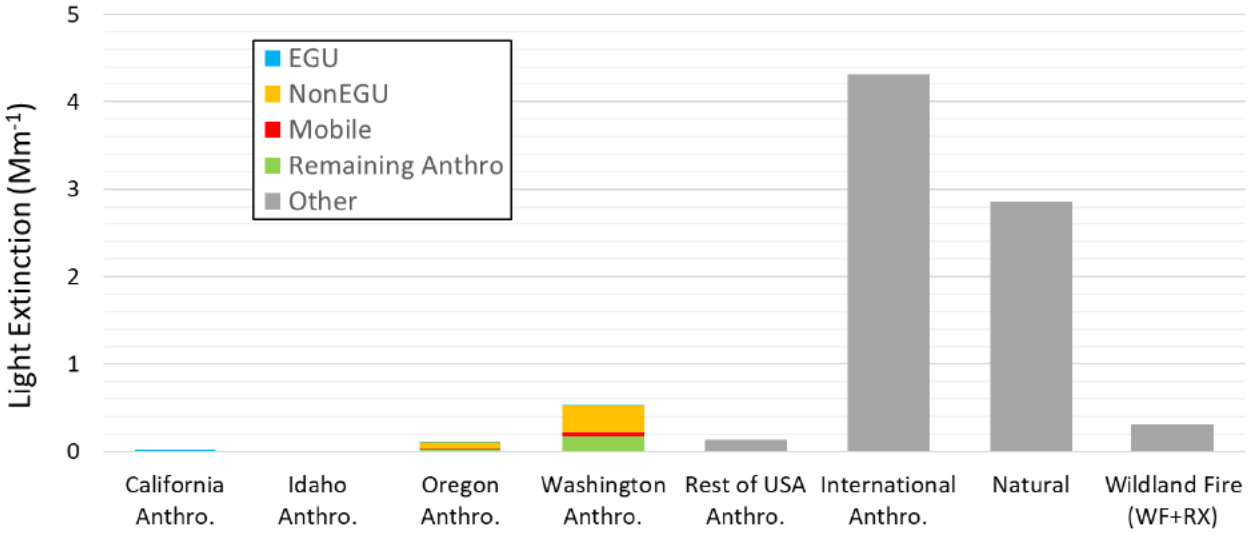


Figure 6-39: Expected source categories and regions of SO_4 in 2028 at WHPA1 for MID (CAMx total = 8.2 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at WHPA1 are expected to come primarily from natural (49%), international anthropogenic (27%), and out-of-state US anthropogenic (18%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 5% of the sulfates responsible for light extinction at WHPA1. See Figure 6-40 for more information.

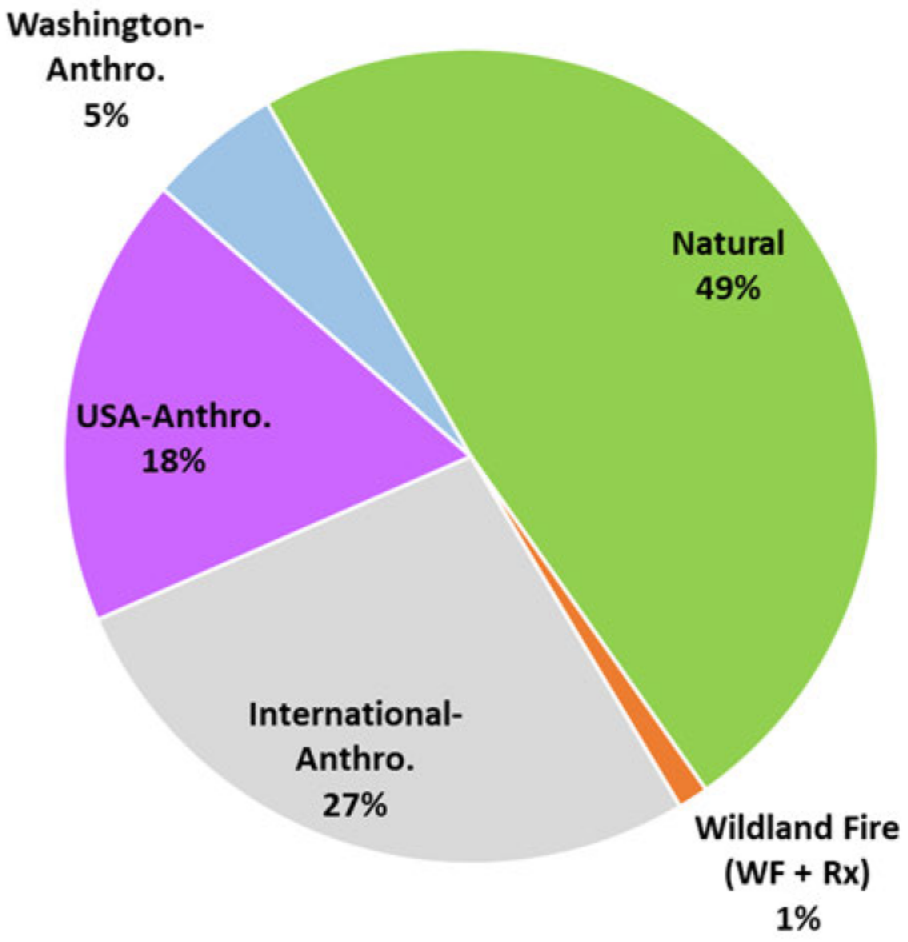


Figure 6-40: Expected source regions of SO_4 in 2028 at WHPA1 for clearest days (CAMx total = 3.0 Mm^{-1}).

The modeled sulfates for 2028 clearest days at WHPA1 was 3.0 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.41 Mm^{-1} and 0.39 Mm^{-1}, respectively.

Figure 6-41 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at WHPA1 on 2028 clearest days.

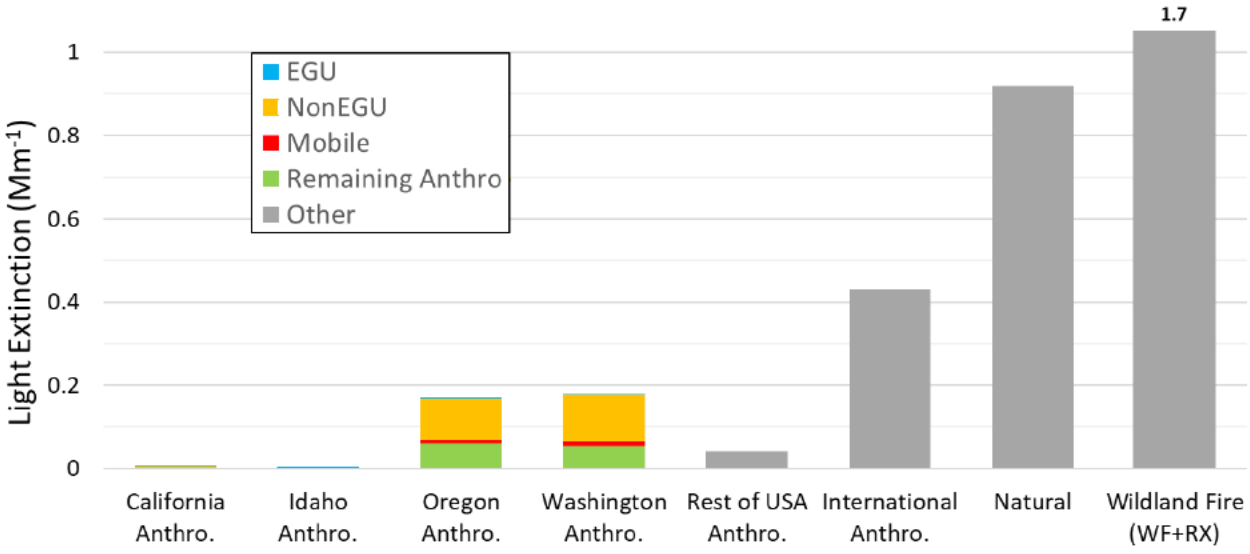


Figure 6-41: Expected source categories and regions of SO_4 in 2028 at WHPA1 for clearest days (CAMx total = 3.0 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the 3rd largest species contribution to light extinction for the MID clearest days during the 2014-2018 baseline at WHPA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at WHPA1 are expected to be considerably influenced by Washington anthropogenic sources (34%). International anthropogenic (35%) and natural sources (19%) are also expected to have considerable impacts but are beyond Washington's control. See Figure 6-42 for more information.

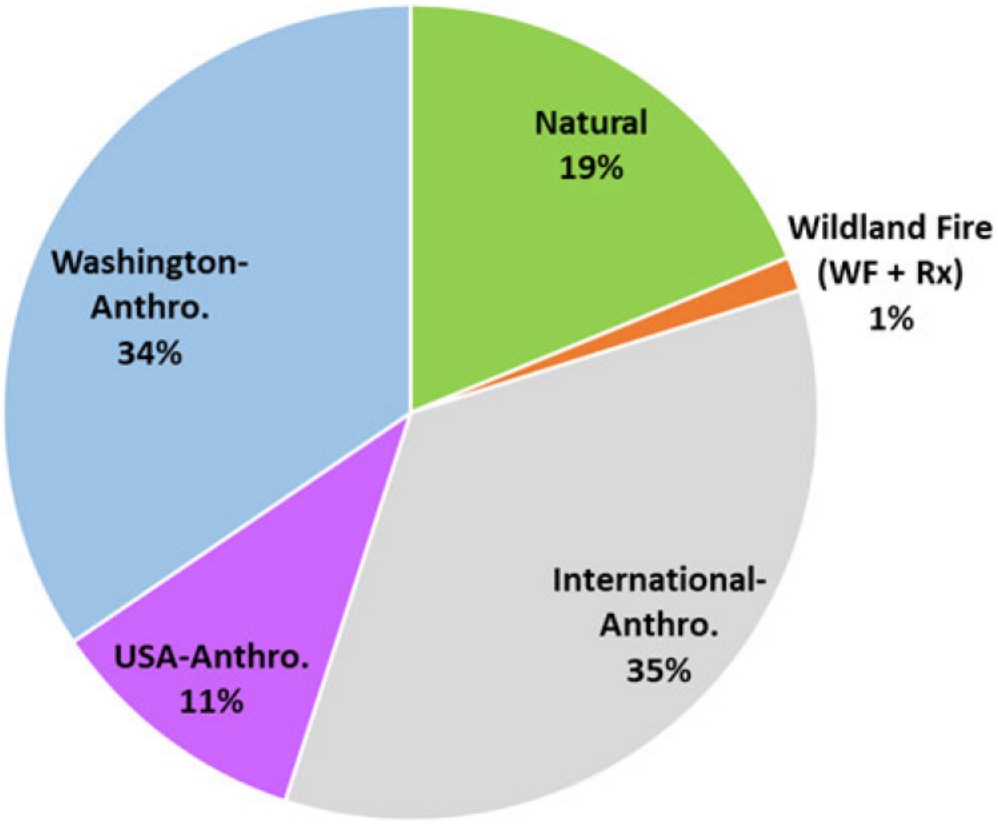


Figure 6-42: Expected source regions of NO_3 in 2028 at WHPA1 for MID (CAMx total = 4.1 Mm^{-1}).

The modeled nitrates for 2028 MID at WHPA1 was 4.1 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 1.53 Mm^{-1} and 0.97 Mm^{-1}, respectively.

Figure 6-43 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at WHPA1 on 2028 MIDs.

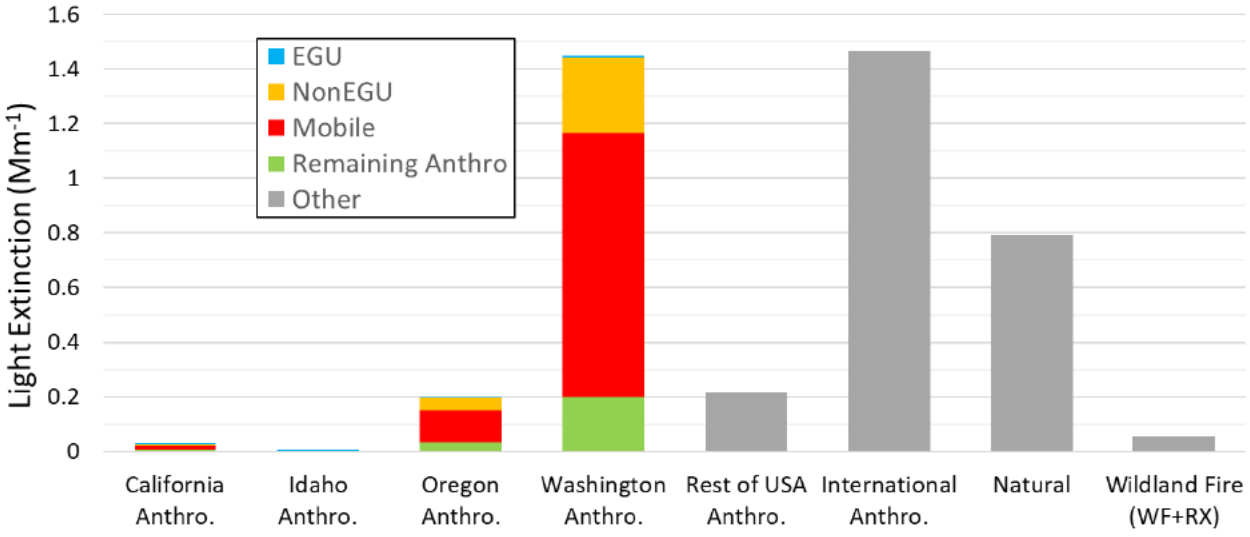


Figure 6-43: Expected source categories and regions of NO_3 in 2028 at WHPA1 for MID (CAMx total = 4.1 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of nitrates at WHPA1 are expected to come primarily from out-of-state US anthropogenic (44%) and international anthropogenic (25%) sources. Washington anthropogenic sources are expected to contribute 11% of the nitrates responsible for light extinction at WHPA1 on clearest days. See Figure 6-44 for more information.

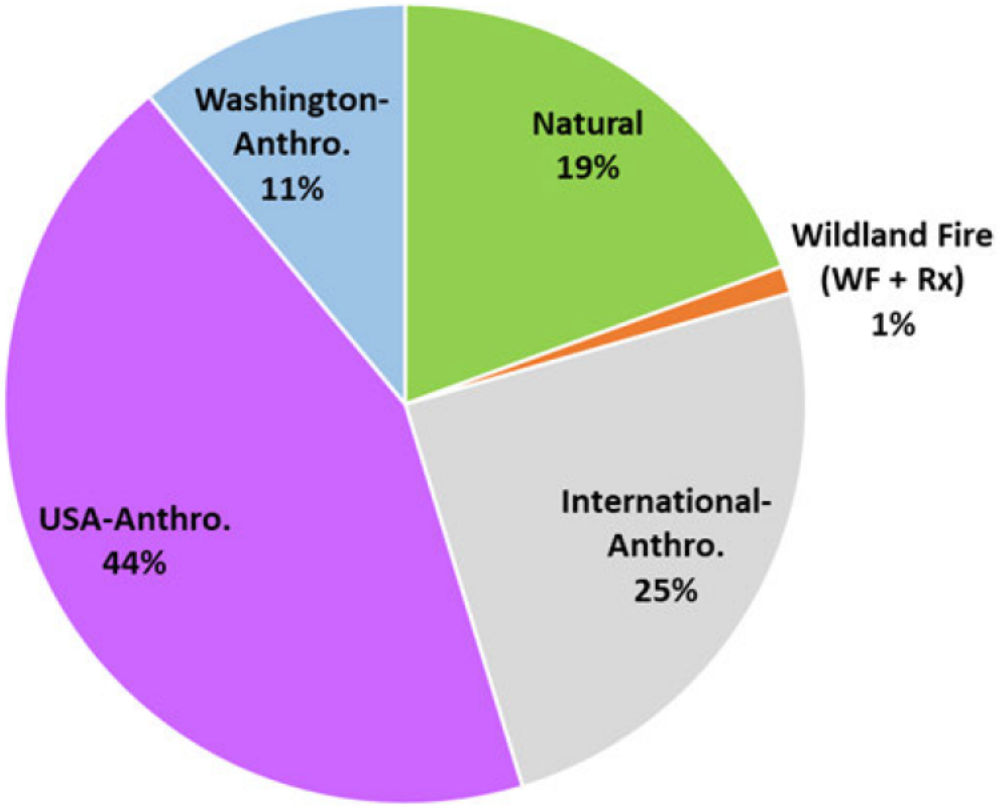


Figure 6-44: Expected source regions of NO_3 in 2028 at WHPA1 for clearest days (CAMx total = 1.1 Mm^{-1}).

The modeled nitrates for 2028 clearest days at WHPA1 was 1.1 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.15 Mm^{-1} and 0.12 Mm^{-1}, respectively.

Figure 6-45 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at WHPA1 on 2028 clearest days.

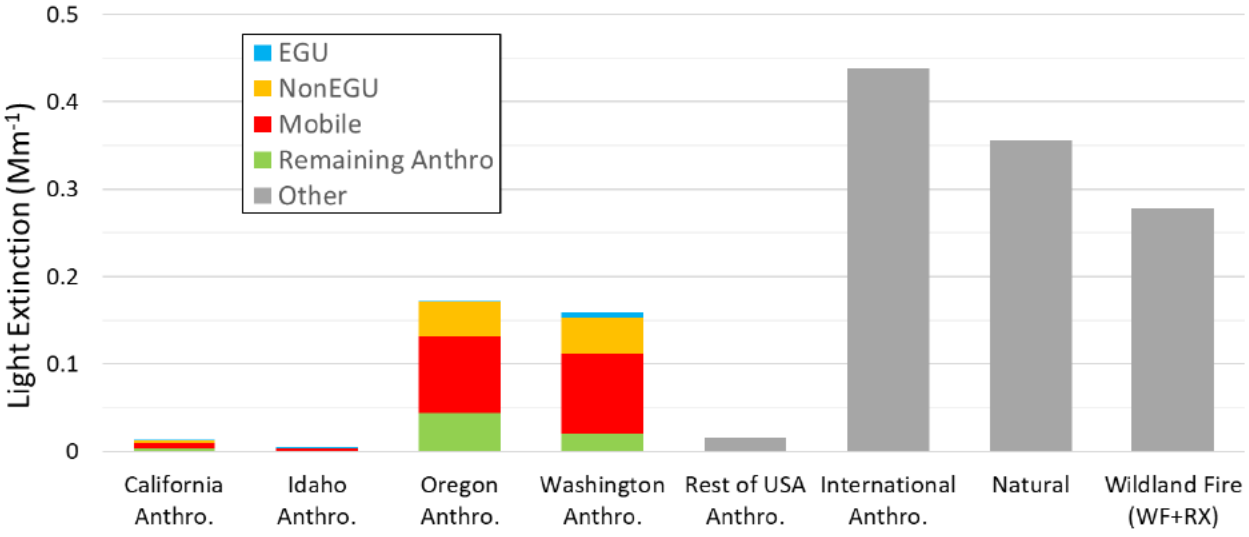


Figure 6-45: Expected source categories and regions of NO_3 in 2028 at WHPA1 for clearest days (CAMx total = 1.1 Mm^{-1}).

6.6 Pasayten Wilderness

Pasayten Wilderness is represented by the PASA1 IMPROVE monitoring site. The baseline conditions in Chapter 3 show that organic mass (32%) and sulfates (35%) make up 67% of the light extinction on the MID at this monitoring site. Elemental carbon (8%) and nitrates (14%) contribute to another 22% of the light extinction on the MID at this monitoring site. On the clearest days, sulfates make up 35% of the light extinction at this monitoring site. Organic mass (32%) and nitrates (14%) make up another 46% of the light extinction on the clearest days at this monitoring site.

WEP and rank point analyses

The WEP analysis for the PASA1 site on MID for the 2028 OTB scenario is summarized in Figure 6-46, showing an AOI of sources that span the entire state of Washington, the Puget Sound area, and the Vancouver, BC metropolitan area. Nitrates at PASA1 show considerable influence from non-EGU Point, on-road, non-road, and non-point sources. Sulfates at PASA1 show considerable influence from Non-Egu Point and non-point sources. Organic mass at PASA1 is mostly influenced by non-point sources. Elemental carbon is mostly influenced by non-point sources but also shows influence from non-EGU Point, on-road, and non-road sources. The rank point WEP analysis attributed 61.7% of point source nitrates to Washington State, with 26.5%, 8.2%, 2.7%, 0.6%, and 0.3% attributed to Tribal Lands, Oregon, Idaho, California, and Montana, respectively. The rank point WEP analysis attributed 89.5% of point source sulfates to Washington State, with 8.7%, 1.3%, 0.3%, 0.1%, and 0.1% attributed to Tribal Lands, Oregon, Idaho, Montana, and California, respectively.

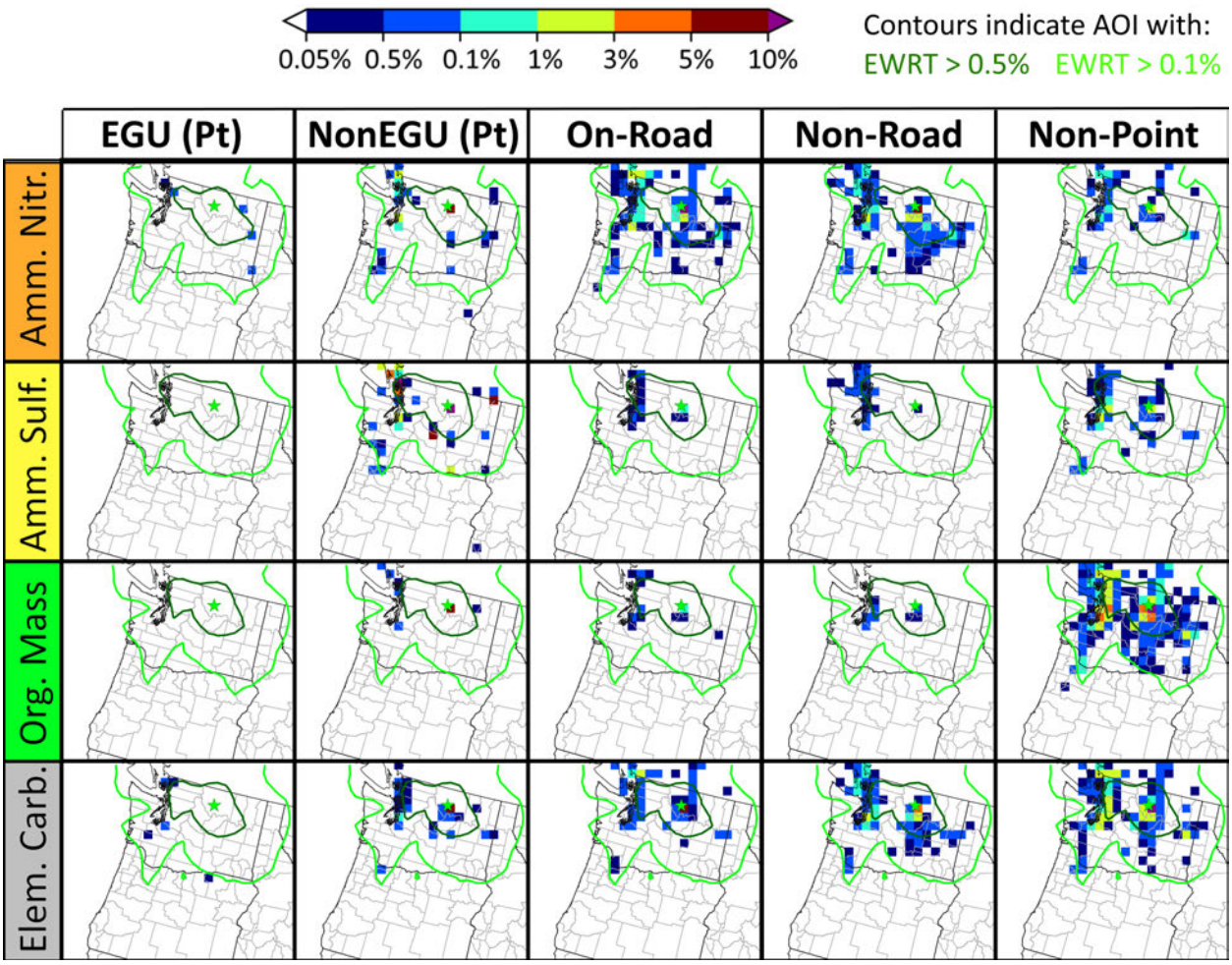


Figure 6-46: WEP for source area potential to contribute to extinction on MID by pollutant at the PASA1 IMPROVE monitor (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at PASA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of sulfates at PASA1 are expected to come primarily from international anthropogenic (49%) and natural sources (34%). These sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 7% of the sulfates responsible for light extinction at PASA1. Figure 6-47 for more information.

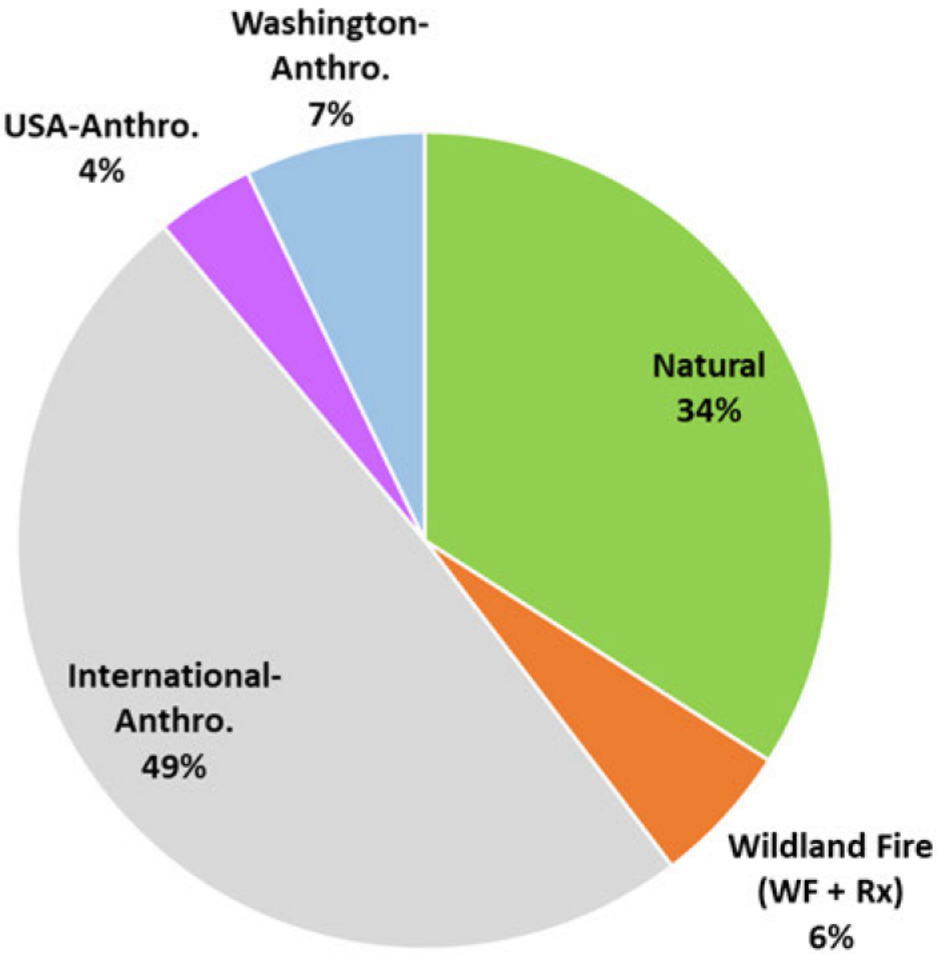


Figure 6-47: Expected source regions of SO_4 in 2028 at PASA1 for MID (CAMx total = 7.2 Mm^{-1}).

The modeled sulfates for 2028 MID at PASA1 was 7.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 5.78 Mm^{-1} and 5.77 Mm^{-1}, respectively.

Figure 6-48 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the OLYM1 monitoring site on 2028 MIDs.

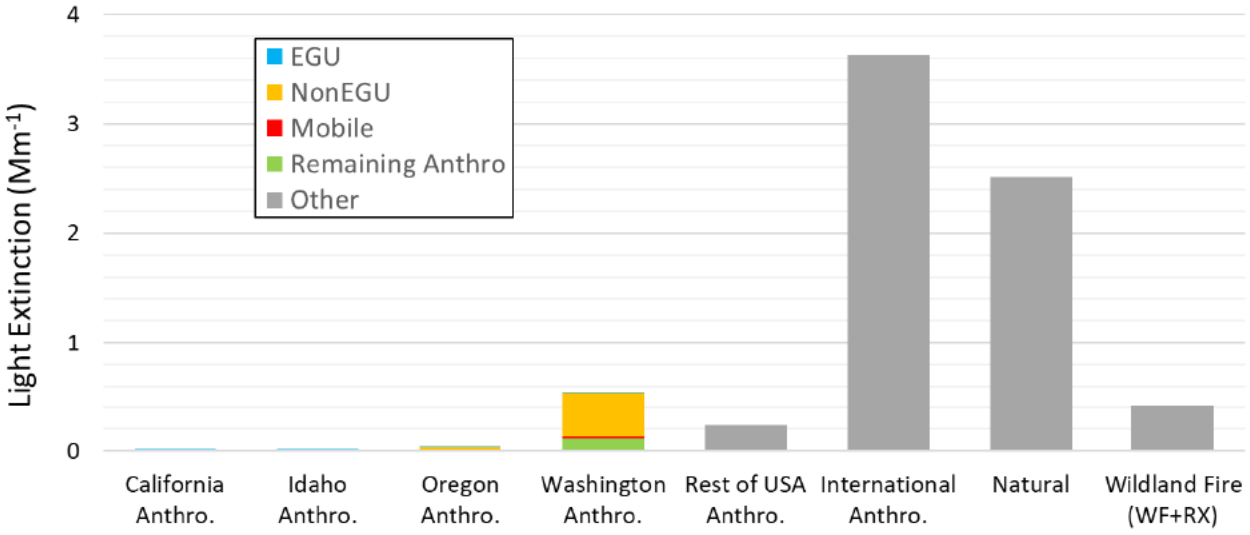


Figure 6-48: Expected source categories and regions of SO_4 in 2028 at PASA1 for MID (CAMx total = 7.2 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at PASA1 are expected to come primarily from natural (42%), international anthropogenic (25%), and out-of-state US anthropogenic (17%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 13% of the sulfates responsible for light extinction at PASA1. See Figure 6-49 for more information.

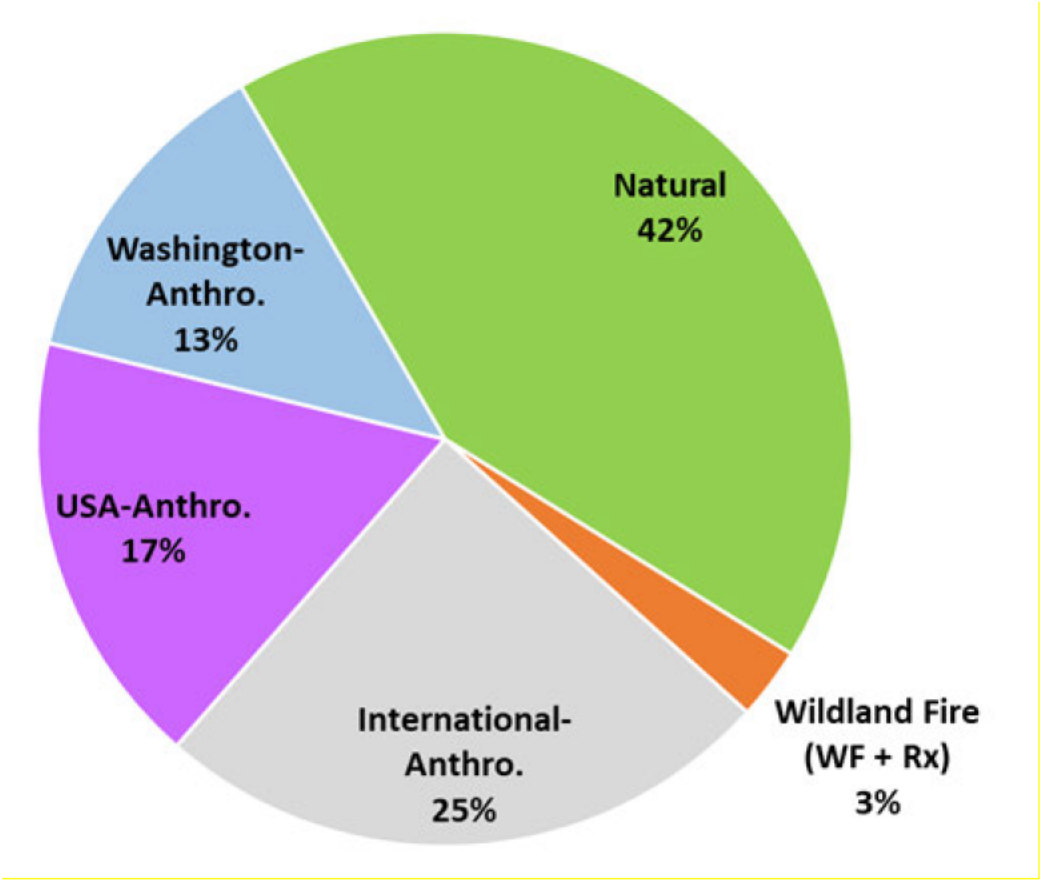


Figure 6-49: Expected source regions of SO_4 in 2028 at PASA1 for clearest days (CAMx total = 4.0 Mm^{-1}).

The modeled sulfates for 2028 clearest days at PASA1 was 4.0 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.75 Mm^{-1} and 0.71 Mm^{-1}, respectively.

Figure 6-50 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at PASA1 on 2028 clearest days.

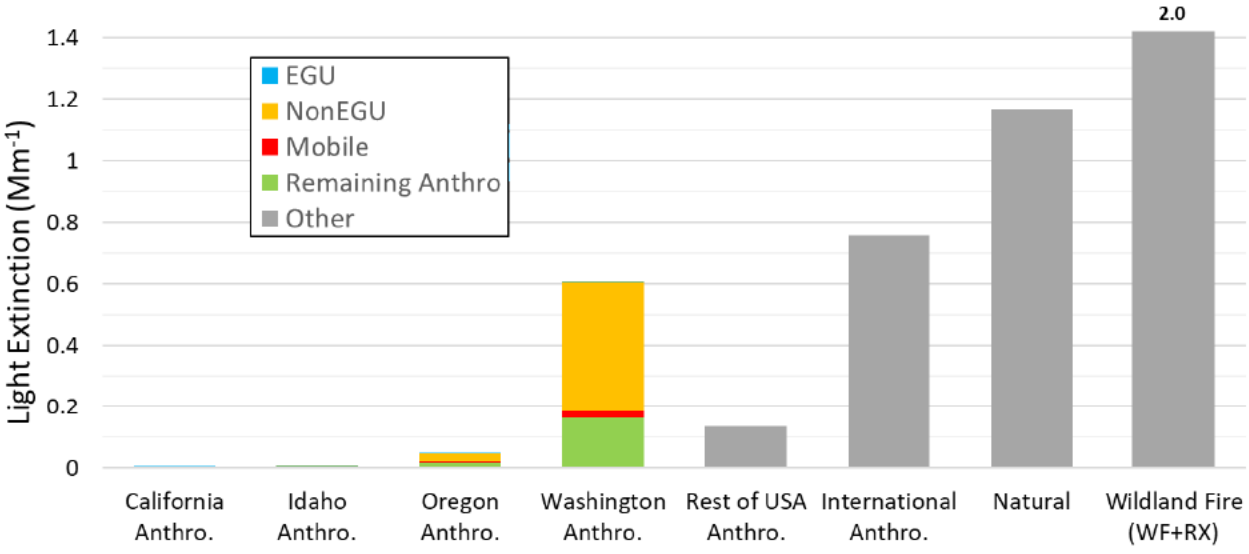


Figure 6-50: Expected source categories and regions of SO_4 in 2028 at PASA1 for clearest days (CAMx total = 4.0 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the 3rd largest species contribution to light extinction for the MID clearest days during the 2014-2018 baseline at PASA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at PASA1 are expected to be most influenced from international anthropogenic sources (46%), while natural sources (16%) and wildland fires (15%) are expected to have some impacts. All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 18% of the nitrates responsible for light extinction at PASA1. See Figure 6-51 for more information.

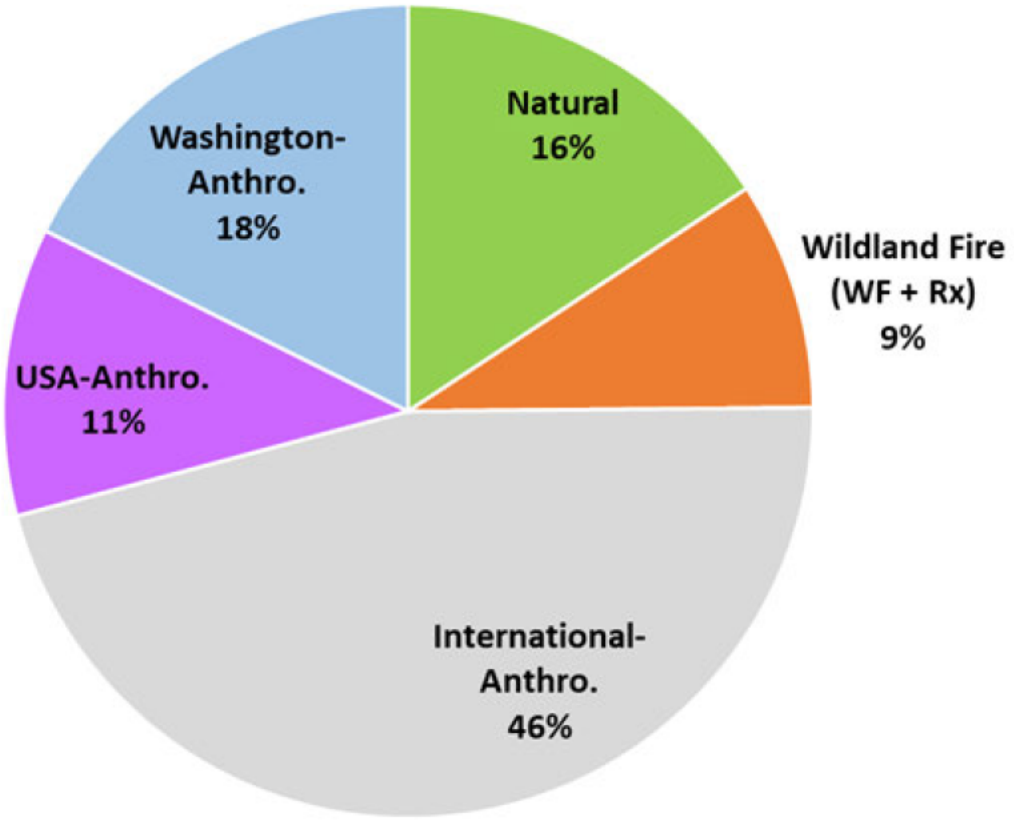


Figure 6-51: Expected source regions of NO_3 in 2028 at PASA1 for MID (CAMx total = 3.8 Mm^{-1}).

The modeled nitrates for 2028 MID at PASA1 was 3.8 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 2.34 Mm^{-1} and 1.79 Mm^{-1}, respectively.

Figure 6-52 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at PASA1 on 2028 MIDs.

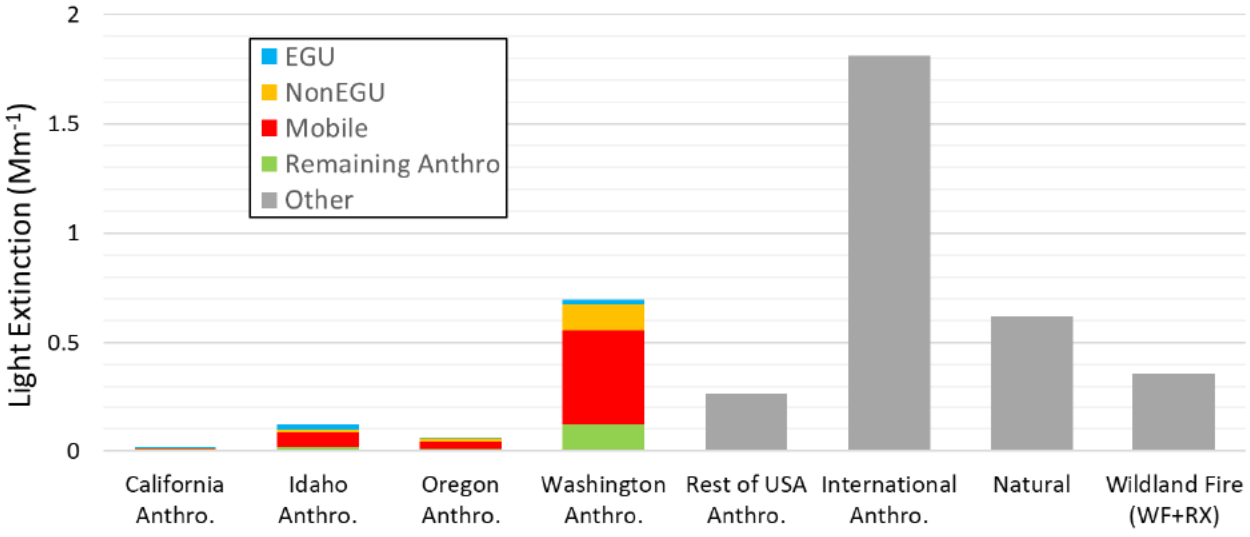


Figure 6-52: Expected source categories and regions of NO_3 in 2028 at PASA1 for MID (CAMx total = 3.8 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of nitrates at PASA1 are expected to come primarily from out-of-state US anthropogenic (39%) sources. Washington anthropogenic sources are expected to contribute 23% of the nitrates responsible for light extinction at PASA1 on clearest days. See Figure 6-53 for more information.

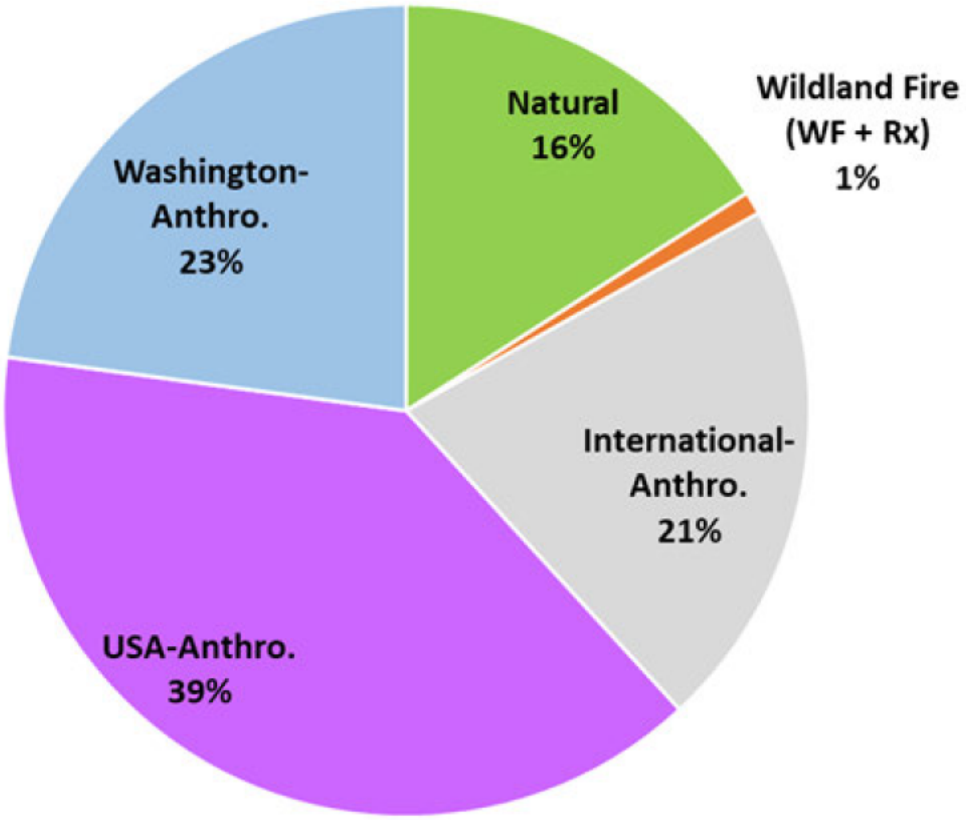


Figure 6-53: Expected source regions of NO_3 in 2028 at PASA1 for clearest days (CAMx total = 2.1 Mm^{-1}).

The modeled nitrates for 2028 clearest days at PASA1 was 2.1 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.30 Mm^{-1} and 0.23 Mm^{-1}, respectively.

Figure 6-54 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at PASA1 on 2028 clearest days.

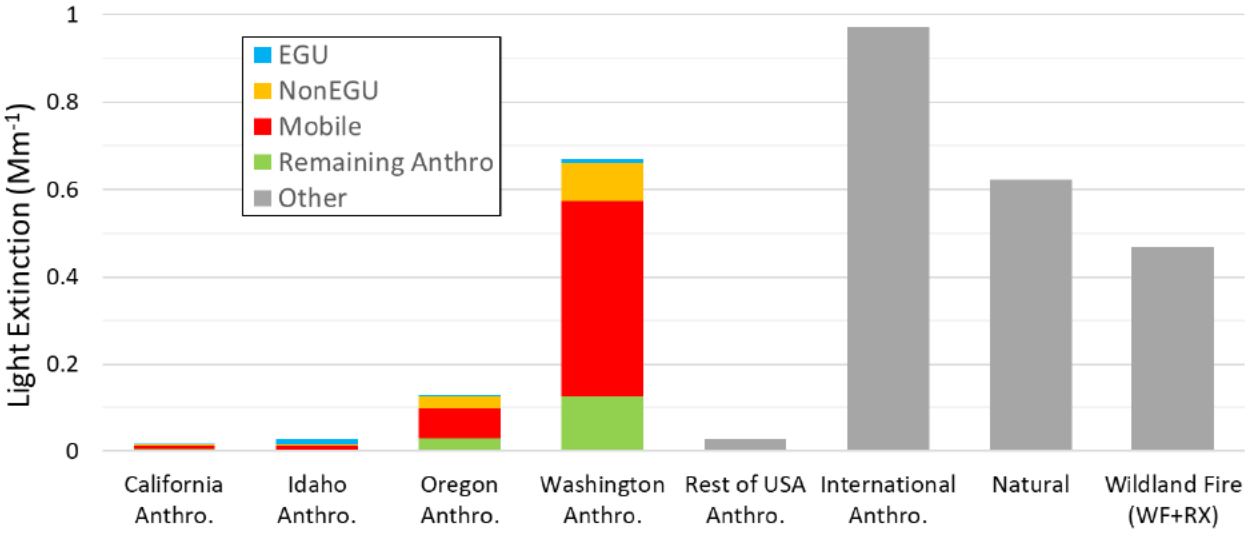


Figure 6-54: Expected source categories and regions of NO_3 in 2028 at PASA1 for clearest days (CAMx PSAT total = 2.1 Mm^{-1}).

6.7 In-State Contribution of Nitrates and Sulfates

Table 6-1 summarizes the in-state sources of sulfates by source category at each in-state mandatory Class 1 Area in 2028, as determined by the PSAT analysis. Table 6-2 summarizes the in-state sources of nitrates by source category at each in-state mandatory Class 1 Area in 2028, as determined by the PSAT analysis.

Table 6-1: Expected in-state anthropogenic sulfate contributions by source category for Washington's Mandatory Class 1 Areas in 2028.

Site	Days	Total WA Anthro.	WA EGU	WA non-EGU	WA Mobile	Remaining WA Anthro.
OLYM1	MID	8%	0%	6%	0%	2%
OLYM1	Clearest	17%	0%	9%	1%	6%
NOCA1	MID	11%	0%	9%	0%	1%
NOCA1	Clearest	8%	0%	5%	0%	3%
SNPA1	MID	7%	0%	5%	1%	2%
SNPA1	Clearest	11%	0%	5%	2%	4%
MORA1	MID	10%	0%	7%	1%	2%
MORA1	Clearest	7%	0%	5%	1%	2%
WHPA1	MID	6%	0%	4%	0%	2%
WHPA1	Clearest	5%	0%	3%	0%	2%
PASA1	MID	7%	0%	5%	0%	2%
PASA1	Clearest	13%	0%	9%	0%	3%

Table 6-2: Expected in-state anthropogenic nitrate contributions by source category for Washington's Mandatory Class 1 Areas in 2028.

Site	Days	Total WA Anthro.	WA EGU	WA non-EGU	WA Mobile	Remaining WA Anthro.
OLYM1	MID	36%	1%	11%	19%	6%
OLYM1	Clearest	33%	0%	6%	19%	8%
NOCA1	MID	25%	0%	7%	14%	3%
NOCA1	Clearest	22%	0%	4%	13%	4%
SNPA1	MID	38%	0%	6%	27%	5%
SNPA1	Clearest	26%	0%	3%	18%	4%
MORA1	MID	46%	0%	9%	32%	4%
MORA1	Clearest	15%	1%	4%	8%	2%
WHPA1	MID	34%	0%	7%	23%	5%
WHPA1	Clearest	11%	0%	3%	6%	1%
PASA1	MID	18%	1%	3%	11%	3%
PASA1	Clearest	23%	0%	3%	15%	4%

6.8 Other Mandatory Class 1 Areas Impacted by Washington Anthropogenic Emissions

The PSAT source apportionment modeling results were evaluated to determine which mandatory Class 1 Areas in nearby states are expected to be affected by emissions from Washington anthropogenic sources for sulfates and nitrates. Washington anthropogenic sources are expected to contribute a small percentage (e.g. less than 5%) of nitrates or sulfates to all IMPROVE monitors in nearby states on MID. However, some larger contributions are expected from Washington anthropogenic sources to several Montana (CABI1, FLAT1, GLAC1, MONT1, SULA1) and Oregon (KALM1, MOHO1, STAR1, THSI1) IMPROVE sites on MID that range from 5% to 22% of nitrates and 2% to 4% of sulfates. Though not shown here, the PSAT details confirm that the majority of anthropogenic emissions originating in Washington that affect out-of-state IMPROVE sites are from non-EGU (sulfates) and mobile sources (nitrates) identifies the percentage of the total modeled light extinction by species due to anthropogenic emissions from sources within Washington at IMPROVE monitors in California, Oregon, Idaho, Nevada, Montana, Utah, and Wyoming. Table 6-3 identifies all IMPROVE monitors where Washington anthropogenic sources are expected to contribute at least 0.1% of the nitrate or sulfate light extinction, based on the PSAT results. The percentage contribution is based on contributions from all modeled source areas relative to the total sulfates or nitrates, separately.

Washington anthropogenic sources are expected to contribute a small percentage (e.g. less than 5%) of nitrates or sulfates to all IMPROVE monitors in nearby states on MID. However, some larger contributions are expected from Washington anthropogenic sources to several Montana (CABI1, FLAT1, GLAC1, MONT1, SULA1) and Oregon (KALM1, MOHO1, STAR1, THSI1) IMPROVE sites on MID that range from 5% to 22% of nitrates and 2% to 4% of sulfates. Though not shown here, the PSAT details confirm that the majority of anthropogenic emissions originating in Washington that affect out-of-state IMPROVE sites are from non-EGU (sulfates) and mobile sources (nitrates).

The PSAT identified sulfate contributions from non-EGU point sources in Washington, originating from the 12,053 tons of non-EGU SO2 emissions included in the model (see Chapter 6). However, 64 percent of those modeled SO2 emissions (7,729 tons) are from the two aluminum facilities in Washington (Alcoa Wenatchee and Alcoa Intalco). WRAP modeled these facilities using historical emissions data and with no assumed emissions reductions. The Alcoa Wenatchee facility curtailed in 2015, going to zero emissions, and announced on December 13, 2021, that it will permanently close. The Alcoa Intalco facility curtailed in 2020 and went to zero emissions. Ecology and Intalco entered into an Agreed Order in January 2021 requiring Intalco to conduct a four-factor analysis before restarting (see Chapter 7 and appendix Q for more details).

As a result of the above analysis, we have determined that sources in Washington do not have significant impacts in other States' mandatory Class 1 Areas beyond the measures already addressed in this SIP submittal. Ecology did not receive any request for additional reductions from neighboring states during our consultations with them.

Table 6-3: Washington's Anthropogenic Emissions Contribution to Sulfate and Nitrate Light Extinction at Mandatory Class 1 Areas outside of Washington.

State	Site	MID Sulfates (% from WA Anthro)	Clearest Days Sulfates (% from WA Anthro)	MID Nitrates (% from WA Anthro)	Clearest Days Nitrates (% from WA Anthro)
CA	AGTI1	0.1%	0.1%	0.0%	0.1%
CA	BLIS1	0.2%	0.3%	0.1%	0.3%
CA	DOME1	0.1%	0.2%	0.1%	0.2%
CA	HOOV1	0.1%	0.1%	0.1%	0.2%
CA	JOSH1	0.1%	0.3%	0.0%	0.2%
CA	KAIS1	0.1%	0.0%	0.1%	0.0%
CA	LABE1	0.1%	0.3%	0.3%	0.1%
CA	LAVO1	0.2%	0.4%	0.5%	0.1%
CA	PINN1	0.3%	0.1%	0.3%	0.0%
CA	PORE1	0.3%	0.2%	1.1%	1.3%
CA	RAFA1	0.2%	0.1%	0.2%	0.1%
CA	REDW1	0.5%	0.5%	4.6%	4.4%
CA	SAGA1	0.1%	0.1%	0.0%	0.0%
CA	SAGO1	0.1%	0.1%	0.0%	0.1%
CA	SEQU1	0.2%	0.1%	0.1%	0.1%
CA	TRIN1	0.2%	0.3%	0.3%	0.1%
CA	YOSE1	0.1%	0.2%	0.1%	0.1%
ID	CRMO1	0.8%	1.8%	1.7%	4.5%
ID	SAWT1	1.4%	3.2%	3.3%	7.2%
MT	CABI1	2.6%	10.1%	8.6%	21.7%
MT	FLAT1	2.7%	7.1%	6.6%	15.3%
MT	FOPE1	0.6%	0.8%	0.8%	0.8%
MT	GAMO1	2.1%	2.1%	4.5%	6.0%
MT	GLAC1	2.4%	3.9%	6.3%	8.1%
MT	MELA1	0.5%	0.4%	0.5%	0.5%
MT	MONT1	2.3%	4.2%	5.1%	10.8%
MT	NOCH1	0.5%	1.3%	0.6%	2.5%
MT	SULA1	2.8%	2.2%	7.4%	7.6%
MT	ULBE1	0.5%	2.8%	0.7%	4.3%
NV	JARB1	1.0%	1.5%	2.9%	4.8%
OR	CRLA1	0.9%	0.1%	3.9%	0.2%
OR	HECA1	2.0%	2.6%	3.6%	10.1%
OR	KALM1	1.5%	0.2%	7.3%	0.9%
OR	MOHO1	4.4%	2.0%	22.1%	13.1%

State	Site	MID Sulfates (% from WA Anthro)	Clearest Days Sulfates (% from WA Anthro)	MID Nitrates (% from WA Anthro)	Clearest Days Nitrates (% from WA Anthro)
OR	STAR1	3.5%	2.0%	15.3%	8.7%
OR	THSI1	1.9%	0.2%	9.4%	0.4%
UT	BRCA1	0.2%	0.2%	0.4%	0.3%
UT	CANY1	0.2%	0.5%	0.4%	1.0%
UT	CAPI1	0.2%	0.5%	0.4%	0.8%
UT	ZICA1	0.1%	0.5%	0.1%	0.7%
WY	BRID1	0.6%	1.0%	1.4%	2.6%
WY	NOAB1	1.4%	0.9%	1.9%	2.5%
WY	YELL2	1.2%	1.1%	2.9%	1.6%

Chapter 7.Source Selection and Four-factor Analysis

7.1 Introduction

The Regional Haze Rule (RHR, 40 CFR 51) requires Washington State to submit a long-term strategy that includes enforceable emissions limitations, compliance schedules, and other measures necessary to make reasonable progress toward 2064 natural visibility conditions in Class 1 Areas. The state must determine what new emission reductions, if any, are necessary to make reasonable progress by considering the four statutory factors:

- Costs of compliance,
- The time necessary for compliance,
- The energy and non-air quality environmental impacts of compliance, and
- The remaining useful life of any potentially affected sources.

This chapter describes Washington's source selection criteria and describes the analyses to determine controls that are reasonable and needed to make reasonable progress. Controls identified are part of the long-term strategy described in Chapter 8.

EPA issued a memorandum[12] on July 8, 2021, to "help support SIP development, submittal, review, and action for the second planning period". The RHR SIP submittal was due to EPA on July 31, 2021, and Ecology has been developing the SIP submittal for the last few years. Ecology has attempted to implement the items addressed in the clarification memorandum to the maximum extent practicable considering the limited time provided between issuance of the memorandum and the due date of the RHR SIP.

7.2 Source screening analysis (Q/d)

Ecology used annual emissions and distance from the nearest Class 1 Area to select sources for the additional analysis. Q/d is a ratio of visibility-impairing emissions (in tons) produced by a source (Q) to its distance from the nearest Class 1 Area (d). We did not screen mobile sources or non-point sources with Q/d; we discuss them in Chapter 8, Long-term Strategy.

Ecology used Washington's 2014 point-source emissions data to calculate Q values. The Western Regional Air Partnership used 2014 as the base year for modeling as it was the most recent year of certified available data when the analysis was initiated. Ecology maintains an annual point-source Emissions Inventory (EI) for all major sources in the state. Many non-major point-source emissions totals were also received from regional offices and local clean air agencies. The reported emissions of compounds that contribute to regional haze (NOx, PM_{10}, SO_2, and NH_3) were summed (Q) for each point-source. We calculated the distance (d) from the source to the nearest Class 1 Area. Sources with larger Q/d values represent larger visibility impacts on Class 1 Areas.

[12] Peter Tsirigotis, Director, "Clarifications Regarding Regional Haze Second Implementation Plans for the Second Implementation Period," memo, addressed to Regional Air Division Directors, Regions 1-10, July 8, 2021

Major and non-major point-source data from 2014 were screened initially, but the analysis was biased by the approximately 1,100 non-major sources in the inventory with a Q/d of less than one. Ecology conducted a second screening of only the major sources. The selected major sources represent approximately 80 percent of the haze-causing emissions for the entire EI.

For the second Q/d screening we removed the non-major sources and only evaluated the 119 major sources in the EI. We focused on major sources because they contribute 90 percent of the total Q/d value even though they represent only 10 percent of the total number of all stationary sources. We screened the major sources using two thresholds: the sources with a Q/d ratio of 10 or greater and the sources that were in the top 80 percent of the sum of Q/d values of all major sources. The results are shown in **Error! Reference source not found.**. The sum of all major Q/d values was 756. Eighty percent of the Q/d sum for major sources is 605 with a Q/d threshold of 15.6. We then considered a Q/d value of 10 or greater. The Q/d threshold of 10 or greater includes more sources than the 80 percent threshold. Therefore, we chose the Q/d value of 10 or greater for the threshold to require a four-factor analysis (FFA) since it includes more sources.

There are 16 major sources with a Q/d ≥ 10. We added two sources with a Q/d ≤ 10 so that all the facilities in a selected source category were included in the FFA. The two facilities added are Packaging Corporation of America (PCA), a paperboard mill, and US Oil, an oil refinery. See Chapter 4 for more information about the annual emissions from these selected facilities.

Ecology conducted reasonableness analyses on major facilities with a Q/d of ≥ 10 along with two additional facilities. These identified stationary sources contribute 90 percent of the haze-causing emissions in the state.

Table 7-1: Q/d of sources selected for FFA

Facility Site Name	Q (tons) of NOX, PM10, SO2, and NH3	d (km) to nearest CIA	Q/d	Nearest CIA	Category 1	Agency
TransAlta Centralia Generation, LLC	10749.4	71.8	149.8	Mount Rainier NP	Coal powered electric	SWCAA
McKinley Paper Company	367.2	4.4	83.1	Olympic NP	Pulp and Paper Plant	ORCAA
Alcoa Primary Metals Wenatchee Works	3461.7	42.8	80.9	Alpine Lakes Wilderness	Alumina Refining and Aluminum Production	Ecology - Industrial
Alcoa Primary Metals Intalco Works	5658.5	78.9	71.7	North Cascades NP	Alumina Refining and Aluminum Production	Ecology - Industrial
BP Cherry Point Refinery	2945.0	80.8	36.4	North Cascades NP	Petroleum Refineries	NWCAA
Tesoro Northwest Company	2312.3	75.4	30.7	Olympic NP	Petroleum Refineries	NWCAA
WestRock Tacoma	1353.7	48.4	27.9	Mount Rainier NP	Pulp, Paper, and Paperboard Mills	Ecology - Industrial
Nippon Dynawave Packaging Company Longview	2656.0	104.8	25.3	Mount Adams Wilderness	Paperboard Mills	Ecology - Industrial
Puget Sound Refining Company (Shell)	1793.1	73.0	24.5	Olympic NP	Petroleum Refineries	NWCAA

Facility Site Name	Q (tons) of NOX, PM10, SO2, and NH3	d (km) to nearest CIA	Q/d	Nearest CIA	Category 1	Agency
Pt Townsend Paper Corporation	848.0	35.0	24.2	Olympic NP	Paper (not Newsprint) Mills	Ecology - Industrial
Ash Grove Cement Co, E Marginal	1243.6	53.8	23.1	Alpine Lakes Wilderness	Cement Manufacturing	PSCAA
Cosmo Specialty Fibers, Inc.	973.8	58.2	16.7	Olympic NP	Paperboard Mills	Ecology - Industrial
WestRock Longview, LLC	1574.2	100.7	15.6	Mount Adams Wilderness	Paperboard Mills	Ecology - Industrial
Georgia-Pacific Consumer Operations LLC	653.0	45.4	14.4	Mount Hood Wilderness	Paper (except Newsprint) Mills	Ecology - Industrial
Phillips 66	840.6	77.2	10.9	North Cascades NP	Petroleum Refineries	NWCAA
Cardinal FG Winlock	859.8	80.1	10.7	Mount Rainier NP	Flat Glass Manufacture	SWCAA
Packaging Corporation of America (PCA) Wallowa	1048.3	111.5	9.4	Eagle Cap Wilderness	Paperboard Mills	Ecology - Industrial
US Oil & Refining Co	149.2	46.4	3.2	Mount Rainier NP	Oil Refinery	PSCAA
Total	39487.5		658.7			

Facility notification of selection for four-factor analysis

Ecology contacted the facilities selected in Spring of 2019, and informed them that we had selected them for additional RH emission analyses (see Appendix G). Some of these facilities had existing legal requirements or pending permit actions to reduce emissions, so Ecology did not request a FFA from them. We requested that facilities in the pulp and paper and the refinery source categories perform a FFA and provide the results to Ecology. Ecology also requested that the Ash Grove Cement Company and Cardinal Glass perform an FFA.

7.3 Reasonableness evaluation

When performing a reasonableness analysis on the selected facilities, the emission controls already in place and enforceable are the baseline controls in the analysis. Facilities with no new controls identified rely on the existing controls for the state to make reasonable progress.

Ecology conducted a reasonableness analysis on emission control technology for the sources selected in the Q/d analysis. This analysis determined if there were new reasonable emission controls needed to make reasonable progress at each Class 1 Area.

Four-factor analysis and reasonably available control technology (RACT) equivalency

The RHR requires States to perform a Four-Factor Analysis (FFA) to determine whether the installation of new emission controls at certain facilities is necessary for the State to make reasonable progress toward the national visibility goal. In Washington State, RCW 70A.15.2230 (the "RACT statute") is the legal mechanism that Ecology can use to require existing sources to install new emission controls that are determined to be reasonable. Because the analysis performed under the State's RACT process is equivalent to the RHR's FFA, Ecology will use the RACT process to require the installation of reasonable emission controls for purposes of compliance with the RHR.

40 CFR 51.308(f) requires the State's long-term strategy to include all measures that are "necessary to make reasonable progress, as determined pursuant to [40 CFR 51.308](f)(2)(i) through (iv)." In turn, 40 CFR 51.308(f)(2)(i) requires the State to consider the following four statutory factors in determining which emission reductions measures are necessary to make reasonable progress:

- the costs of compliance,
- the time necessary for compliance,
- the energy and non-air quality environmental impacts of compliance, and
- the remaining useful life of any potentially affected anthropogenic source of visibility impairment.

Pursuant to RCW 70A.15.1030(20) and 70A.15.2230(5), the RACT evaluation of new emission controls at existing stationary sources requires Ecology to consider the following:

- the impact of the source upon air quality,
- the availability of additional controls,

- the emission reduction to be achieved by additional controls,
- the impact of additional controls on air quality,
- and the capital and operating costs of the additional controls.

The costs of compliance

Under the RACT analysis, Ecology characterizes and considers the cost of compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. The cost of compliance factor in 40 CFR 51.308(f)(2)(i) directly correlates to the RACT analysis consideration of capital and operating costs of the additional controls. The capital and operating costs in RACT are for purchase, installation, and operation of all equipment. These costs include the actual emission control equipment, any non-air quality equipment, and the energy costs to operate the equipment.

The time necessary for compliance

Under the RACT analysis, Ecology characterizes and considers the time necessary for compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Under the RACT analysis requirements, Ecology determines the time necessary for compliance as part of considering the capital and operating costs of the additional controls and impact of the source upon air quality. Specifically, a shorter amount of time for compliance would involve costs distributed over a shorter time and thus have a larger annualized cost. The impact of the source on air quality is also a consideration in the time for compliance. The longer it takes to install and operate the control equipment the greater the negative impact on air quality.

The energy and non-air quality environmental impacts of compliance

Under the RACT analysis, Ecology characterizes and considers the energy and non-air quality environmental impacts of compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Ecology considers the energy and non-air quality environmental impacts of compliance factor as part of analyzing the capital and operating costs of the additional controls in the RACT analysis. The RACT analysis includes costs for equipment directly related to the emissions and all indirectly required equipment needed to install and operate the new controls. The operating cost requirement in the RACT analysis also covers the energy impacts of the controls and supporting equipment.

The remaining useful life of any potentially affected anthropogenic source of visibility impairment

Under the RACT analysis, Ecology characterizes and considers the remaining useful life of any potentially affected anthropogenic source of visibility impairment consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Ecology considers the remaining useful life of an emissions control system as part of calculating the capital and operating costs of the system. Specifically, the annualized costs of the emissions control system are affected by the remaining useful life. The shorter the useful life, the larger the annual costs associated with control equipment.

Additionally, RACT requires consideration of the impact of the source upon air quality.' This is consistent with the CAA, RHR, and EPA guidance. While the four statutory factors must be considered in determining what is necessary to make reasonable progress, they are not the only factors that States may consider in this evaluation. As explained by EPA in its 2019

guidance, States have the flexibility to consider other factors, including visibility benefits, when determining the emission reduction measures that are necessary to make reasonable progress:

> "Section 51.308(f)(2)(i) of the Regional Haze Rule requires consideration of the four factors listed in CAA section 169A(g)(1) and does not mention visibility benefits. However, neither the CAA nor the Rule suggest that only the listed factors may be considered. Because the goal of the regional haze program is to improve visibility, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal. Likewise, it is reasonable that such information on visibility benefits be considered in light of other factors that may weigh for or against the control at issue. Such a balancing of outcomes is consistent with CAA section 169A(b)(2), which states that SIPs must contain elements as may be necessary to make reasonable progress towards meeting the national visibility goal. Thus, EPA interprets the CAA and the Regional Haze Rule to allow a state reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other factors when determining whether a measure is necessary to make reasonable progress."[13]

Therefore, Ecology will use the RACT process to (1) evaluate and determine the emissions reduction measures that are necessary to make reasonable progress and (2) incorporate these measures into its long-term strategy and Regional Haze SIP in a manner that is enforceable as a legal and practical matter.

Reasonable control evaluation

The Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data shows that ammonium sulfate ($(NH_4)_2SO_4$) and ammonium nitrate (NH_4NO_3) are two of the most significant pollutants impairing visibility in Washington's Class 1 Areas. $(NH_4)_2SO_4$ is primarily from point sources and offshore sources (shipping traffic), and NH_4NO_3 is primarily from point and mobile sources, with slight contributions from non-point sources. After the initial screening for source selection, the FFA in this chapter evaluates reasonable controls for point sources of nitrogen oxides (NOx) and sulfur dioxides (SO_2) emissions.

Ecology relies on current Washington state laws and regulations to implement any controls identified as reasonable. Washington has four potential mechanisms for implementing identified emission controls:

- Agreed order (AO) – a legally binding order that requires agreement between the parties
- Permit modification – permittee initiated change to their facility
- Reasonably available control technology – Revised Code of Washington (RCW 70A.15.2230)

Ecology prefers to use permit modifications and AOs to achieve emission reductions as these methods have the source and Ecology working together to achieve reductions. These options

[13] EPA-457/B-10-003, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, Section II.B.5.

are currently not available for use with the refinery or pulp & paper industry categories during this implementation period.

Ecology will use the RACT process to evaluate reasonable emission reductions for facilities without an AO or permit modification. The result of the RACT process is a determination of the minimum emissions controls required at a facility. The determination is made through rule making for a category of sources, or a source specific order. RACT identifies the emission control equipment and the timelines for installation and operation of the equipment. The RACT rule or RACT order is federally enforceable when EPA approves it into the SIP.

Ecology has limited resources and is choosing to prioritize the implementation of reasonable controls. As discussed in EPA's guidance:[14]

"Another potentially reasonable approach might be for a state that identifies cost-effective new controls at a multitude of sources to choose to require controls at only a subset of those sources that constitute the vast majority of the visibility benefit. In this case, the state could rely on visibility benefits to prioritize which sources would receive new controls."

Ecology identified potential reasonable controls at a multitude of sources and is prioritizing a subset of those sources that constitute a vast majority of the visibility benefit during this implementation period. Ecology's first priority is to identify reasonable controls at the refinery facilities.

A number of factors supports the selection of refineries as the first priority. These factors include:

- Four of the five refinery facilities are located in the Puget trough, west of several Class 1 Areas. Their cumulative regional haze causing emissions influence the same Class 1 Areas.
- Predominant winds direct the emissions from the refineries towards several Class 1 Areas.
- The refineries' potential emission reductions of 4,200 tons per year account for the vast amount of potential emission reductions.

Pulp & paper mills are a subset of sources that are lower priority than refineries because:

- The pulp & paper mills are not located as close to each other as the refineries so they do not have as great of a cumulative effect.
- One mill identified with potential reasonable cost controls, Packaging Corporation of America (PCA) Wallula, is located in a direction that is downwind from the nearest Class 1 Areas. This lessens, but does not remove, the influence the mill's emissions have on Class 1 Areas.
- The potential reduction of 450 tons per year in regional haze emissions from the pulp & paper mills reasonable controls is vastly less than potential refinery emission reductions.

[14] Peter Tsirigotis, Director, "Clarifications Regarding Regional Haze Second Implementation Plans for the Second Implementation Period," memo, addressed to Regional Air Division Directors, Regions 1-10, July 8, 2021.

7.4 Facility specific reasonableness analyses

The following sections contain the facility specific FFA information and Ecology's analysis of additional emission controls. TransAlta and Cardinal Glass emission reductions were included in the long-term strategy and the 2028 modeled emission projections (on-the-books) for determining reasonable progress goals. Emission reductions from the remaining facilities were not included in the modeled 2028 projection since implementation will likely occur during the next implementation period. This is due to long planning timelines at these types of facilities combined with coordination of control installation and scheduled facility maintenance shutdowns.

Ash Grove Cement Company

Ash Grove Cement Company (Ash Grove) operates a dry process cement kiln in the Duwamish Industrial area of Seattle. The primary haze causing emissions at the plant comes from the cement kiln and its associated clinker cooler baghouses. Clinker is an intermediate product in cement production.

The existing particulate controls installed at the plant meet the regulatory requirements for dry material handling. The plant also complies with the Portland Cement Manufacturing National Emission Standards for Hazardous Air Pollutants (NESHAP). This standard regulates particulate matter (PM) as a surrogate for metals (40 CFR Part 63 Subpart LLL). This NESHAP was last updated mid 2018 when the EPA determined that there were no developments in practices, processes, and control technologies that warrant revisions to the Maximum Achievable Control Technology (MACT) standards for this source category (83 FR 35122-35136, 2018).

SO_2 emissions at the plant come from burning sulfur containing fuels. The plant is capable of burning coal, natural gas, and tire-derived fuels. The plant has not been using coal for the last couple of years, but still has the ability to use it. As the facility can still use coal, SO2 emissions from the 2014 EI (with coal combustion) were included in the modeling to determine progress. The alkaline cement clinker removes some SO2 from the combustion gases. The facility uses this as a primary method of SO2 control. Nitrogen oxides (NOx) emissions from the plant also come from the combustion of all fuels allowed by permit.

Consent decree

Ash Grove entered into a consent decree with EPA, Ecology, the Puget Sound Clean Air Agency (PSCAA), and other state agencies in 2013 [SEE APPENDIX E]. The consent decree required the Seattle facility to submit an optimization protocol for the Seattle Kiln. The purpose of the protocol was to optimize the operation of the Seattle Kiln to reduce NOx emissions to the maximum extent practicable from that kiln. EPA reviewed the optimization plan in consultation with the PSCAA.

The protocols for the optimization plan included key operating parameters resulting in the minimization of emissions of NOx. The consent decree required minimization of NOx to the greatest extent practicable without:

- Incurring unreasonable cost.
- Causing an exceedance of any other applicable emissions limit.

- Impairing production quality or quantity.

The protocols also required the facility to identify all potential process and/or operational changes that they could implement to reduce emissions of NOx.

On June 30, 2016, the facility submitted the NOx demonstration period report and data related to optimization. On August 25, 2016, EPA, in consultation with Ecology and PSCAA, reviewed the data and approved the limit of 5.1 pounds of NOx per ton of clinker on a 30-day rolling average.

Four Factor Analysis

The following analysis recognizes that EPA approved the consent decree of 2013 and the optimization of the facility to limit NOx emissions in 2016. The goal was to reduce NOx emissions to the greatest extent practicable within reasonable costs. Ecology does not typically perform RACT analysis on single facilities that have had a reasonable analysis performed within the last five years. The following evaluates possible additional controls.

NOx emission controls by selective catalytic reduction

Selective catalytic reduction (SCR) is a potentially viable method to reduce NOx emissions. Efficient operation of an SCR requires consistent exhaust temperatures. Changes in the temperature of the exhaust gas result in reduced NOx removal efficiency. The exit stack temperature at the facility is typically around 350°F. The typical SCR operation temperature is 650°F so the exhaust would require heating When exhaust stream temperatures are too low, there is the potential that injected ammonia (the reducing agent) won't react (ammonia slip). Conversely, when the exhaust stream temperature is too high, ammonia (NH_3) can oxidize to NO, potentially reducing efficiencies. The reducing process needs excess NH_3 to achieve removal efficiencies in excess of 80 percent and can result in ammonia slip.

There is a risk of fouling the catalyst bed when operating an SCR. Installing the catalyst bed downstream of the particulate matter controls, (this facility uses baghouse dust collectors), can reduce fouling. The low exhaust gas temperature exiting the baghouse would require the installation of a heat exchanger system to reheat the exhaust stream to the desired reaction temperature range of between 480 °F to 800 °F. The use of a preheater or heat recovery would be required, however the use of a preheater would require additional fuel consumption and create even more NOx.

Installation of an SCR system would require storage and handling equipment for ammonia. An SCR system requires a catalytic reactor, heat exchanger, and potentially additional NOx control equipment for the emissions associated with the heat exchanger fuel combustion.

Installing the SCR in the high dust exhaust stream (e.g. before the baghouse) would put the SCR in the optimal temperature zone but there is a risk of fouling the catalyst. Faster fouling of the catalyst would result in increased operation cost and increased plant down time. A larger catalyst volume and mechanical mechanism to clean the catalyst could mitigate the fouling impacts but would require a larger physical footprint for installation.

NOx emission controls by selective non-catalytic reduction

The Consent Decree described above required the facility to optimize a selective non-catalytic reduction (SNCR) emission control system. Ash Grove submitted a new source review application with Puget Sound Clean Air Agency (PSCAA) in 2016 for the installation of the SNCR system. A permit has not been issued because of unresolved technical issues.

The main technical issue is that the permit application requested to operate the SNCR process on an "as needed" basis to achieve NOx limits determined during a 2016 demonstration period for the EPA Consent Decree. PSCAA and Ash Grove are working on resolving the technical issues in the application with the goal of issuing a permit for the SNCR system. This permit will form the basis for emission standards that will apply to the SNCR system. Ecology intends to supplement the RHR SIP once the permit is issued. In the interim, Ecology has determined the EPA Consent Decree limit of 5.1 pounds of NOx per ton of clinker on a 30-day rolling average is adequate for reasonable progress at this time until a final permit for the SNCR system is issued by Puget Sound Clean Air Agency.

Particulate matter emission controls

The facility upgraded their emission controls in 2019 with the installation of a Dustex 10-module pulse jet baghouse with rated flow rate of 185,000 actual cubic feet per minute (ACFM). They performed this upgrade under a permit modification with PSCAA. The permit modification requires the facility to meet the requirements of the Best Available Control Technology (BACT) requirements. PSCAA accepted the upgrade as BACT, so additional control analyses are not required.

Under the EPA's July 8, 2021 Clarification Memo (page 9) "if a state can demonstrate that a source will continue to implement its existing measures and will not increase its emission rate, it may not be necessary to require those measures under the regional haze program in order to prevent future emission increases." We note that the existing particulate controls installed at the plant meet the regulatory requirements for dry material handling. The plant also complies with the Portland Cement Manufacturing National Emission Standards for Hazardous Air Pollutants (NESHAP). This standard regulates particulate matter (PM) as a surrogate for metals (40 CFR Part 63 Subpart LLL). This NESHAP was last updated mid 2018 when the EPA determined that there were no developments in practices, processes, and control technologies that warrant revisions to the Maximum Achievable Control Technology (MACT) standards for this source category (83 FR 35122-35136, 2018). Because these emissions are unlikely to increase and are subject to a federally enforceable control, Ecology has determined that incorporation of a PM emission limit in the SIP is not necessary for reasonable progress.

SO_2 emission controls

The primary emission of SO_2 from the facility is from the burning of coal, tires, and various oils. The primary emission control for SO_2 is a wet scrubber. Space is limited at the site and installation of a wet scrubber would require extensive facility rearrangement and a retention pond for the waste water, in addition to the capital cost of the wet scrubber. Based on this, we do not consider the cost of a wet scrubber reasonable at this time.

The existing controls for SO_2 emissions at the facility limiting emissions to 200 ppm at 10% O2 for one hour average and a not to exceed of 176 tons per year were deemed adequate to meet reasonable progress.

Cost of compliance

Installing SCR NOx or SO_2 emission controls would require significant facility reconstruction. The Ash Grove facility brochure in [APPENDIX E] shows how congested the site is. To create room the emission devices would have to be elevated above the existing facility and would run into area height restrictions. The other option of raising existing plant equipment or positioning the emission control device above other equipment would require extensive structural work and would require that the facility shut down operations during construction and reconfigure the site. This would result in significant additional costs above capital expenditure and operational cost for the emission control equipment.

Ash Grove submitted a permit application for an SNCR system, and this indicates that the cost of SNCR installation is reasonable. Ecology is working with PSCAA and Ash Grove to optimize the proposed SNCR system so that the permitted system maximizes NOx emission reductions without excessive ammonia emissions.

Time necessary for compliance

Typical planning periods to design and then install SCR NO_X or SO_2 controls are two to three years. A tuning period after installation is required to understand the physical operation of the equipment. For the Ash Grove facility, the time required to plan and then install any equipment would increase by one to two years to allow for extensive facility modifications to accommodate any equipment.

With the base infrastructure of the SNCR system already in place at the facility, an analysis and subsequent optimization study would take six to twelve months. This time estimate comes from the actual time required to perform an optimization study at a coal-fired power plant in the state. Most of the time involved in the optimization study is in setting the system parameters and then operating the facility under the parameters long enough to collect stabilized data.

Energy and non-air quality environmental impacts of compliance

SCR equipment would require preheating the exhaust stream before it enters the SCR. Preheaters burn fuel to generate heat and this would consume additional energy and create additional emissions.

The installation of a wet scrubber for SO_2 controls would require obtaining a water quality permit for use with the liquid in the wet scrubber. Depending on the permit requirements, the facility could need additional energy to treat the liquid from the wet scrubber before discharge off-site.

The SNCR system is already in place and the facility is working on obtaining a permit.

Remaining useful life of any potentially affected sources

Proper maintenance of this facility should allow it to continue operations well into the future.

Summary and preliminary recommendations

Ecology does not recommend installation of additional emission control equipment. The particulate matter controls at the site were recently upgraded. The cost for SCR NOx and wet scrubbing SO_2 equipment installation is also unreasonable due to the confined space at the site. The existing controls for particulate matter and SO_2 where used in the model to determine reasonable progress. The installation of a new SNCR system will be permitted by PSCAA identifying use requirements.

Cardinal Glass

Cardinal FG Company Winlock (Cardinal) operates a flat glass manufacturing plant in Winlock, near the intersection of Avery Road and Highway 603, in Lewis County, Washington. In 2019, Cardinal submitted a permit modification application to SWCAA to install an SCR emission control device and increase production of plate glass. The application also proposed removing the current emission control of limiting excess oxygen. SWCAA is working with the facility to issue a permit to add SCR to the existing plant.

Ecology identified Cardinal in the Q/d analysis as a facility to review under the RH program. On January 17, 2020, Cardinal FG Company submitted a four-factor analysis.

Four-factor analysis

Cardinal FG Company Winlock submitted an application to SWCAA to modify the facility's permit by:

- Installing an SCR system to control NO_X emissions from the glass furnace;
- Increasing rated furnace production from 650 tpd to 750 tpd;
- Removing an SCR from Emergency Generator #1;
- Installing a new emergency generator; and
- Establishing voluntary emission limits at levels below major source thresholds.

The use of the current emission control system will cease once the SCR system commences operation. The facility will also install a new supplemental heater between the Electrostatic Precipitator (ESP) and the SCR system. This heater will raise the exhaust stream temperatures to the range required for proper SCR operation.

Table 7-2 shows the emissions, by pollutant in tons, after the requested modification is complete. The table also shows the change in emissions from the current permit values to the requested modified permit values.

Table 7-2: Emissions summary

Pollutant	Facility-wide potential to emit after permit modification in tons per year (tpy)	Pollutant emissions change between current limits and permit modification limits in tons per year (tpy)
NOx	249.62	-583.05

CO	249.00	-522.48
VOC	57.79	1.92
SO_2	114.21	41.75
PM	141.96	16.84
PM_{10}	141.96	6.84
$PM_{2.5}$	141.96	16.84

Cost of compliance

Oxides of Nitrogen (NOx) – cost and cost/ton

Cardinal's permit modification application estimated a reduction of glass furnace annual NOx emissions from 828.05 to 245.0 tons per year (tpy). This is an annual reduction of 583.05 tpy. The estimated cost of the new SCR control system is $10 million. Based on 3.5 percent interest and 20-year life, the annual cost is $944,000 per year. Using the annualized cost and emissions reduction, the estimated cost effectiveness is $1,469 per ton of NOx. The actual cost will be higher since this does not include operating costs.

Ecology requested additional data needed to use the EPA Control Cost Manual from Cardinal to compare the EPA Control Cost Manual results to actual data for quality purposes. Ecology received the following unit specific information from Cardinal on June 15, 2020:

- Exhaust rate of 181,157 acfm @ 600 F
- SCR inlet NOx = 437.5 lbs/hr (above current emission limit)
- SCR outlet NOx = 49.1 lbs/hr
- Capital cost updated to $11 million (annualized cost not updated)

SO_2, PM – Temperature change – higher scrubber temperature and reheat - cost and cost/ton

The operating temperature of the new SCR system will require the existing spray dryer and electrostatic precipitator (ESP) to operate at higher temperatures, reducing their collection efficiency and requiring a reheat burner. This increased temperature results in a greater fuel consumption and SO_2 emissions. The SO_2 emissions limit will increase from 0.6 to 0.8 lbs of SO_2/ton of glass. The natural gas-fired reheat burner will have a capacity of 17 - Million British Thermal Units (MMBtu)/hr.

The permit modification application includes a production increase at the facility from 650 to 750 tons per day (TPD). This results in an increase of total annual PM emissions even though the total PM emission limits of 0.94 lbs/ton will not change.

Time necessary for compliance

Cardinal expects to have the proposed SCR installed and operational in 2021. The permit was issued by SWCAA to the facility on February 11, 2021, and the SCR should be operating by the end of 2021.

Energy and non-air quality environmental impacts of compliance

SCR - Ammonia and PM increases

The design of the SCR system at the facility assumes a 19 percent ammonia reagent usage of 816 lbs/hr. Appendix D of the permit modification application calculates ammonia emissions. SWCAA permit 20-3409 contains the permit modification application. Based on an ammonia slip limit of 10 parts per million (ppm), estimated ammonia emissions based on continuous operation will be 9.58 tpy.

The total particulate matter (PM) emission limits of 0.94 lbs PM/ton of glass will not change. Total PM emissions will increase, however, due to the facility increasing throughput capacity from 650 to 750 tpd of glass.

Appendix C of the permit modification application (in Appendix S) calculates PM emissions. The PM emissions from the glass furnace will increase from 111.0 to 127.84 tpy, for an increase of 16.84 tpy.

The SO_2 emissions limit will increase from 0.6 to 0.8 lbs/ton. SO_2 emission increases will occur due to the increase in capacity from 650 to 750 tpd of glass. Appendix C of the permit modification application calculates SO_2 emissions. The SO_2 emissions from the glass furnace will increase from 75.6 to 117.35 tpy, for an increase of 41.75 tpy.

SO_2/PM controls - additional fuel if needed – added emissions

The existing SO_2 and PM controls for the glass furnace do not use fuel.

Remaining useful life of any potentially affected sources

The Cardinal facility has operated since 2006. The new SCR system's design life will last at least 30 years if the facility performs proper maintenance.

Ecology's review

The RH program does not prohibit or limit construction of new stationary sources of emissions or modification of existing stationary sources of emissions. Cardinal submitted a permit modification application for increased glass production and a change in emission control devices. The NOx emission reductions resulting from the installation of the SCR are part of Ecology's long-term strategy for achieving reasonable progress goals in Class 1 Areas for this implementation period. Based on the above information and SWCAA's technical support document for the permit action, Ecology concludes:

- The new SCR will reduce NOx emissions. The permitted emissions will be reduced to 250 tpy. Ecology's independent review of the cost for installation of the SCR determined approximately $1,600/ton of NOx reduced. The facility's estimate was slightly higher as the company included the additional equipment (temporary stack and larger crane) to install the new system while the facility stays in operation. This could explain the higher actual cost when compared to the EPA Control Cost Manual when using a base reconstruction factor of 1.0.
- This cost is reasonable for NOx reductions. If the facility were not taking action on their own initiative to install a SCR system, Ecology would have pursued Cardinal Glass to install one. The permit modification with SWCAA is the only action needed for RH reductions.

Table 7-3: Cardinal cost vs Ecology using the EPA Control Cost Manual with June 15, 2020, updated exhaust flow and capital cost

Company	Actual cubic feet per minute	Capital costs ($)	Annualized costs ($)
Cardinal FG Winlock	181,157	11,000,000	944,000
EPA Model - R =1.0	181,157	10,899,998	750,225

Summary and preliminary recommendations

- The operating temperature of the new SCR system will require the existing spray dryer and ESP to operate at higher temperatures, reducing the collection efficiency and requiring a reheat burner. Ecology concluded that the resulting minor increase in PM and SO_2 is offset by the larger decrease in NOx.
- The facility is working to obtain local permits needed for the installation of the SCR.
- The new permit limit for ammonia of 10 ppm and 9.5 tpy is reasonable. New SCR systems will typically have actual ammonia emissions less than 2 ppm after tuning.

Coal-fired electrical generation unit

TransAlta Centralia Generation (TransAlta) is a coal-fired power plant located east of Centralia, WA. This is the largest source of NOx in the state. TransAlta's large quantity of emissions and tall stacks create NOx impacts to all of the Class 1 areas within 300 km of the facility. TransAlta operates a two unit, pulverized coal-fired power plant. Each unit of the plant rates at 702.5-megawatt (MW) net output. Operation of a coal-fired power plant results in visibility impairing emissions of PM, SO_2, and NOx.

The Coal-Fired Electric Generation Facility Bill was signed in 2011, with an effective date of July 22, 2011. The state's greenhouse gas emission performance standard for power plants codified at RCW 80.80.040determined the main environmental impacts of the bill. The requirements in RCW 80.80.040 have compliance dates for one boiler to cease coal-fired generation by December 31, 2020, and the other boiler to cease coal-fired generation by December 31, 2025. TransAlta has ceased coal-fired power generation on one boiler and plans to cease coal-fired power generation in the other boiler by December 31, 2025.

Ecology identified TransAlta as a best available retrofit technology (BART) eligible facility in the first implementation period of RH. Ecology issued a BART Order to TransAlta on June 18, 2010 (2010BARTtransalta). This BART Order required the installation of a SNCR emission control device. Ecology issued a revision to the BART Order on December 13, 2011. The revision incorporated an optimization study on urea volume injections for the SNCR. Ecology issued a second revision to the BART order on July 29, 2020. The second revision required the installation of automated controls on the combustion system, a lower NOx emission limit, and removal of specific urea injection volumes.

In the summer of 2019, TransAlta experienced emission opacity readings that would have exceeded the opacity limits if TransAlta had not reduced plant capacity to compensate. During a maintenance shutdown, the facility examined their ESPs. The ESPs had a visual fouling of all

interior components, which dramatically reduced their efficiency. The facility analyzed the material in the ESPs and identified it as ammonia sulfate. The source of ammonia in the system was from the reactions of urea in the SNCR system.

In coordination with SWCAA and Ecology, TransAlta installed a computerized emission control system called a Combustion Optimization System with Neural Network program (Neural Net) to decrease the ammonia slip in the SNCR. SWCAA agreed to use enforcement discretion in 2019 on the urea injection rate mandated in the 2011 BART Order revision while TransAlta was tuning the Neural Net. TransAlta collected enough process data during tuning of the neural net to agree to a more stringent NOx emission standard of 0.18 lb/MMBtu, a decrease from the 0.21 lb/MMBtu allowed under the 2011 BART Order revision.

Because the Neural Net is able to maintain a more stringent emission standard, Ecology eliminated unnecessary requirements when issuing the second BART order revision. Specifically, the 2020 order:

- Removed the requirement of a specific urea injection rate to allow TransAlta to inject urea as required to meet the new emission standard.
- Removed the requirement to analyze and report nitrogen and sulfur coal content as the facility would have to meet NOx, SO_2, and PM emission standards regardless of the coal used.
- Changed the requirement for ammonia emission monitoring to require monitoring only when using a urea injection rate of greater than 1.5 gallons per minute.

The BART Order was submitted to EPA and approved into the Washington SIP on May 11, 2021.

Four factor analysis

The FFA of TransAlta reflects the RCW 80.80 and the Memorandum of Agreement (MOA) between TransAlta and the Governor of Washington that TransAlta will completely cease coal-fired power generation by December 31, 2025. It also discusses the second BART Order revision that reduces NOx emissions at the facility.

Cost of compliance

The agreement to cease coal-fired power generation greatly influences the compliance cost for installing any emission controls at TransAlta. The first unit ceased operation on December 31, 2020. This decreased by approximately half the plant emissions from coal-fired power generation. This emission reduction requires no capital cost. Operational costs to ensure that the unit will no longer be able to generate power from coal will occur, but all parties already considered this as part of the MOA.

The second BART Order revision includes the installation of the Neural Net to control combustion variables in one of the boilers. TransAlta proposed this installation and during optimization testing, the data confirmed that the controls could reduce NOx emissions. Ecology did not request the costs associated with installing, testing, and optimizing of the neural net as TransAlta proposed it and resulted in decreased NOx emissions for the remaining coal-fired power generation life of the facility.

Time necessary for compliance

TransAlta ceased coal-fired power generation on one of their units in December 2020. TransAlta will cease coal-fired power generation on their last unit by December 31, 2025. The Neural Net installation has already occurred and the more stringent emission limit applies to the facility until it ceases coal-fired power generation.

Energy and non-air quality environmental impacts of compliance

The energy required to meet compliance for ceasing coal-fired power operation is zero. We did not take non-air quality environmental impacts for the future of the facility into account for this analysis.

For the Neural Net, TransAlta is anticipating payback within a couple of years. This is because more efficient combustion controls reduce the amount of coal required to produce the same amount of heat.

Remaining useful life of any potentially affected sources

The facility useful life for coal-fired power generation is until December 31, 2025.

Summary and preliminary recommendations

TransAlta already has an agreement to cease coal-fired power generation by December 31, 2025. This will result in coal-related emissions from the facility going to zero. Ecology used the zero emission level in determining 2028 projected emissions and reasonable progress goals in Washington's Class 1 Areas, as well as potential effects in Class 1 Areas of neighboring states. With the installation of the neural net, the facility will also have a reduced NOx emission standard for the remaining life of the facility. For these reasons, Ecology does not anticipate further emission reductions or emission control devices for Regional Haze purposes.

Primary aluminum production

The state of Washington currently has two primary aluminum reduction facilities:

- Alcoa Primary Metals Wenatchee Works located in Wenatchee, Washington.
- Alcoa Primary Metals Intalco Works located in Ferndale, Washington

Alcoa curtailed the Wenatchee facility in 2015 and the Ferndale facility in 2020, while keeping both air permits active. Ecology did not include emission reductions from either facility when modeling on-the-books visibility projections for 2028 or determining reasonable progress goals in the state's Class 1 Areas although future emissions inventories may show emission reductions resulting from curtailment.

In 2014, the emissions from the sites were as follows:

Table 7-4: Primary aluminum facility 2014 emissions

Facility	Tons $PM_{2.5}$	Tons SO_2	Tons NOx
Alcoa Intalco	637	4,794	227
Alcoa Wenatchee	457	2,935	70

Alcoa Wenatchee Works

The Wenatchee Works facility, curtailed since 2015, has very low emissions. The facility is performing all the requirements of their air permits and could restart at any time. Wenatchee Works would need time to expand their work force from the current curtailment level and additional physical activities would need to occur prior to returning to production.

The four-factor analysis of Wenatchee Works is complicated by the curtailment status. Annual emissions are very low while in curtailment and not typical of emissions during operation. In 2016-2018, annual emissions were less than 10 tpy for all pollutants. A facility in curtailment is also not generating revenue because the facility is not selling any aluminum.

Four-factor analysis

The primary haze-causing pollutant from the facility when it is operating is SO_2. A wet scrubber and associated liquid handling structures is often used for SO_2 emission control. The following FFA details how installation of a wet scrubber system is not reasonable when the facility is in curtailment.

Cost of compliance

The cost of compliance will always be unreasonable for a facility in curtailment since the analysis is based on cost/ton of actual emissions. The facility reported 10 tons of total annual emissions in 2016. Assuming the facility could install control equipment for the entire 10 tons, the cost per ton of emissions reduced will exceed $10,000 per ton of pollutants removed with only a $100,000 expenditure. A cost of $10,000 per ton is not a reasonable cost for primary aluminum facilities at this time.

Facilities with large emissions of SO_2, in tons per year, typically use wet scrubbers for emission control. Direct capital equipment costs for wet scrubbers are typically in the millions of dollars range and installing a wet scrubber would require spending at least $100,000 per ton of SO_2 removed based on current emissions, which is not reasonable.

Because the facility has the potential to restart at any time, emissions could potentially return to pre-curtailment levels. In this situation, an analysis of the facility could potentially result in reasonable emission control costs. Calculations of the cost of compliance would depend on numerous variables, from the number of pot lines brought back on line, amount of aluminum produced, regaining experienced operators for efficient operations, and other operational determinations.

We would need to determine numerous variables associated with a restart of the facility before performing a cost analysis. At the time of facility restart, we would need to do an analysis to determine the reasonableness of the cost of potential controls.

Time necessary for compliance

With the facility in curtailment and no emission control equipment deemed reasonable, the facility is already complying with reasonable emission control. If the facility comes out of curtailment, we would need a new FFA to determine time for compliance if we identify control equipment.

Energy and non-air environmental impacts

With the facility in curtailment and no emission control equipment deemed reasonable, the facility would not have any new non-air environmental impacts. If the facility comes out of curtailment, we would need a new four-factor analysis to determine non-air environmental impacts if we identify control equipment.

Remaining useful life

The facility is currently in curtailment and not operating. The facility is performing maintenance on equipment to keep the facility in position to restart in the future. The facility has permanently closed a pot line within the last five years.

Summary and preliminary recommendations

Wenatchee Works is currently in curtailment and installation of additional emission control devices is not reasonable at this time. With the potential of the facility to restart at any time, Ecology entered into an Agreed Order (AO #18100) (WenatcheeAORH) with the facility that requires the facility perform a FFA before restarting and provide the analysis to Ecology.

The AO conditions stipulate that Alcoa shall:

1. Prepare and submit a four-factor analysis to Ecology for review and approval at least 180 days prior to restarting any of the facility's potlines. Alcoa will base the analysis on the facility's permitted emission limits and will assess potential emission control measures against the following four statutory factors:
    - The cost of compliance,
    - Time necessary for compliance,
    - Energy and non-air quality impacts of compliance, and
    - Remaining useful life of the source.
2. Within 60 days of receipt of Ecology's comments on the four-factor analysis provide all additional information and/or documentation requested by Ecology, if any, and submit an updated four-factor analysis that adequately addresses Ecology's comments.
3. Install or otherwise implement and begin operating all emission control measures identified in the final four-factor analysis submitted within three years of Ecology's approval.

Alcoa Intalco

The Intalco facility near Ferndale is capable of making approximately 307,000 tons of aluminum metal each year. The facility is located in an area that had air monitor readings that were exceeding the one-hour sulfur dioxide (SO_2) National Ambient Air Quality Standards (NAAQS). Ecology and Intalco entered into Agreed Order 16449 on July 25, 2019 (IntalcoAO16449). Intalco agreed in the AO to submit a complete Notice of Construction (NOC) application for the installation of a wet scrubber design and engineering report by October 31, 2020.

We anticipated using the information required under the terms of the AO to perform the FFA for our RH SIP. Ecology did not request the facility to perform a FFA as the AO obviated the need to perform one. On April 22, 2020, the Intalco facility announced that it was curtailing production. The AO contains a clause that "[n]ot withstanding anything else in this Order, in the event that Intalco announces the closure or curtailment of one of its three potlines (A, B, or C line, or any combination or equivalent measure thereof), then upon thirty days' prior written notice to Ecology, this Order and Intalco's obligations hereunder will become null and void."

With the curtailment and subsequent voiding of the wet scrubber AO Ecology cannot count potential emissions reductions from that control.

The Intalco facility is planning to perform all requirement of their permits and could restart at any time. Intalco would need time to expand their work force from the current curtailment level and additional physical activities would need to occur prior to returning to production.

The FFA of Intalco during curtailment is more complicated than on an operating facility. Annual emissions are very low while in curtailment and not typical of emissions during operation. Emissions should be comparable to the Wenatchee Work primary aluminum facility that is already in curtailment. The Wenatchee Works facility had annual emissions in 2016-2018 that were less than 10 tpy total for all pollutants. The Intalco facility in curtailment is also not generating revenue because the facility is not selling any aluminum.

Four-factor analysis

The primary haze-causing pollutant from the facility when it is operating is SO_2. A wet scrubber and associated liquid handling structures is often used for SO_2emission control. The following FFA details how installation of a wet scrubber system is not reasonable when the facility is in curtailment.

Cost of compliance

The cost of compliance will always be unreasonable for a facility in curtailment since the analysis is based on cost/ton of actual emissions. If Intalco curtailed emissions are similar to the Wenatchee Works facility's reported 10 tons of total annual emissions in the 2016 EI, then Intalco will also have around 10 tons of annual emissions. Assuming the facility could install control equipment for the entire 10 tons, the cost per ton of emissions reduced will exceed $10,000 per ton of pollutants removed with only a $100,000 expenditure. A cost of $10,000 per ton is not a reasonable cost for primary aluminum facilities at this time.

Facilities with large emissions of SO_2, in tons per year, typically use wet scrubbers as emission control. Direct capital equipment costs for wet scrubbers are typically in the millions of dollars

range and installing a wet scrubber would require spending at least $100,000 per ton of SO_2 removed based on current emissions, which is not reasonable.

Because the facility has the potential to restart at any time, emissions could potentially return to 2014 EI (2014EI) levels. In this situation, an analysis of the facility could potentially result in reasonable emission control costs. Calculations of the cost of compliance would depend on numerous variables from the number of pot lines brought back on line, amount of aluminum produced, regaining experienced operators for efficient operations, and other operational determinations.

Numerous variables associated with a restart of the facility need to be determined before performing a cost analysis. At the time of facility restart, we would need to do an analysis to determine the reasonableness of the cost of compliance.

Time necessary for compliance

With the facility in curtailment and no emission control equipment deemed reasonable, the facility is already complying with reasonable emission control. If the facility comes out of curtailment, we would need a new FFA to determine time for compliance if we identify control equipment.

Energy and non-air environmental impacts

With the facility in curtailment and no emission control equipment deemed reasonable, the facility would not have any new non-air environmental impacts. If the facility comes out of curtailment, we would need a new FFA to determine non-air environmental impacts if we identify control equipment.

Remaining useful life

The facility is currently in curtailment and not operating. The facility is performing maintenance on equipment to keep the facility in position to restart in the future. Because of the uncertainties, we cannot determine the remaining useful life of the facility at this time.

Summary and preliminary recommendations

Intalco is currently in curtailment and installation of additional emission control devices is not reasonable at this time. With the potential of the facility to restart at any time, Ecology entered into an Agreed Order (AO) with the facility that requires the facility perform a FFA before restarting and provide the analysis to Ecology.

The AO conditions stipulate that Intalco shall:

1. Prepare and submit a four-factor analysis to Ecology for review and approval at least 180 days prior to restarting any of the facility's potlines. Intalco will base the analysis on the facility's permitted emission limits and will assess potential emission control measures against the following four statutory factors:
    - The cost of compliance,
    - Time necessary for compliance,
    - Energy and non-air quality impacts of compliance, and

- Remaining useful life of the source.

2. Within 60 days of receipt of Ecology's comments on the four-factor analysis provide all additional information and/or documentation requested by Ecology, if any, and submit an updated four-factor analysis that adequately addresses Ecology's comments.
3. Install or otherwise implement and begin operating all emission control measures identified in the final four-factor analysis submitted within three years of Ecology's approval.

7.5 Chemical pulp & paper mill four-factor analysis

The pulp & paper facilities include six sulfate (Kraft) and one sulfite chemical processing facilities. Cosmo Specialty Fiber is currently the only sulfite mill in Washington. The modeled 2028 reasonable progress goals did not include any emission reductions from any of the pulp & paper mills. Ecology has limited resources and is choosing to prioritize the sequence of implementation of reasonable controls. Ecology has identified potential cost-effective controls at a multitude of sources and is choosing to require reasonable controls at only a subset of those sources.

As discussed in EPA's guidance:

> "Another potentially reasonable approach might be for a state that identifies cost-effective new controls at a multitude of sources to choose to require controls at only a subset of those sources that constitute the vast majority of the visibility benefit. In this case, the state could rely on visibility benefits to prioritize which sources would receive new controls." [15]

Ecology is prioritizing implementation of potential new controls starting with refinery facilities because:

- The pulp & paper mills are not located as close to each other as the refineries so they do not have as great of a cumulative effect.
- One mill identified with potential reasonable cost controls, Packaging Corporation of America (PCA) Wallula, is located in a direction that is downwind from the nearest Class 1 Areas. This lessens, but does not remove, the influence the mill's emissions have on Class 1 Areas.
- A potential reduction of 470 tons per year in regional haze emissions from the pulp & paper mills reasonable controls is vastly less than potential refinery emission reductions.

After we complete the reasonability analysis and determination for the refinery facilities, we plan to identify and implement any reasonable controls at pulp and paper facilities. Ecology will update the SIP if new emission controls are installed at pulp and paper facilities during this

[15] Peter Tsirigotis, Director, "Clarifications Regarding Regional Haze Second Implementation Plans for the Second Implementation Period," memo, addressed to Regional Air Division Directors, Regions 1-10, July 8, 2021, Section 5.1, at page 12-13.

implementation period. In the interim, Ecology has determined that no additional controls are necessary for RP at this time or included in the LTS.

Four-factor request and initial review

On September 10, 2019, Ecology requested an FFA from the seven chemical pulp mills in Washington State. Ecology received a combined FFA report from the six Kraft mills and a separate FFA from the sulfite mill (Cosmo) on December 5, 2019. After review, on January 13 2020, Ecology requested that six of the seven mills provide additional information to Ecology by February 28, 2020 [APPENDIX I].

Ecology did not request additional information from GP Camas because they are no longer a Kraft mill and facility emissions were reduced below the Q/d screening threshold. The 2019 Emission Inventory indicates regional haze causing emissions for the GP Camas facility reduced from 653 tons to 83.1 tons. The reduced emission mass changes the Q/d value from 23.1 to 1.8. With the new Q/d value being less than the threshold value of 10 for consideration, Ecology removed the facility from further analysis. If GP Camas pursues operation as a chemical pulp mill in the future, they will need to go through new source review.

On February 20, 2020, Cosmo requested a time extension for submitting additional information due to impacts of the coronavirus in China, where delivery of their product was delayed. Ecology agreed to a time extension to April 30, 2020.

Ecology received follow-up information from each of the mills in a timely manner. The FFAs and follow-up information from the pulp mills are in Appendix O. The FFA supplied from the mills all indicate that additional emission controls are unreasonable. Ecology evaluated and adjusted this information for NOx, SO_2, and PM control. Appendix J is a summary of Ecology's revised costs/ton for controls for NOx, SO_2, and PM, costs/ton, and estimated useful life at a 3.25 percent interest rate for the facilities.

Potentially reasonable controls at current chemical pulp mills

Ecology identified some potential reasonable controls at three Kraft mills and a sulfite mill. The Kraft mills are Nippon Dynawave Packaging Company Longview (Nippon), Packaging Corporation of America (PCA) Wallula, and WestRock PC, LLC Tacoma. The sulfite mill is Cosmo Specialty Fibers, Inc. (Cosmo) mill. Because Ecology has identified potential cost-effective controls at a multitude of sources, we are choosing to require any potential reasonable controls at only a subset of those sources. Ecology has chosen to perform a more extensive and in-depth engineering evaluation at refinery facilities first. This decision is based on the refineries having a greater potential amount of reductions to regional haze causing emissions than pulp & paper mills. The refineries are also geographically located such that they influence the same Class 1 Areas concurrently. The pulp & paper mills are more dispersed and have less of a combined influence on the Class 1 Areas.

For NOx control using a low-NOx burner, the following units have estimated cost/ton value less than the potential reasonableness threshold of $6,300/ton. Adding these controls could potentially reduce NO_X emissions by approximately 150 tpy.

- Nippon Boiler #9 ($2,754/ton) with approximately 97 tons potential reduction

- PCA boiler #1 ($5,893/ton); with approximately 26 tons potential reduction
- PCA boiler #2 ($4,834/ton) with approximately 30 tons potential reduction

For NOx control using an SCR or SNCR, the following units have a cost/ton value less than the potential reasonableness threshold of $6,250/ton. Adding one of these controls could potentially reduce NOx emissions by approximately 500 tpy to 1025 tpy.

- Nippon hog fuel (HF) boiler #11 ($5,413 for SNCR); ($5,466/ton for SCR); with approximately 329 tons or 848 tons potential reduction respectively.
- Nippon Boiler #9 ($6,041 for SCR) with approximately 175 tons potential reduction.
    - This unit was discussed above in the low-NOx burner section. Please note that only one of these options would be used.

For PM_{10} control, the following units have a cost/ton value less than the potential reasonableness threshold of $7,800/ton. Adding these controls could potentially reduce PM_{10}emissions by approximately 30 to 225 tpy depending whether Cosmo is included (see footnotes for Cosmo).

- WestRock Tacoma Lime Kiln #1 ($6,964/ton) with approximately 33 tons potential reduction.

For SO_2 control, Ecology did not receive recent cost incurred information from the pulp mills (the scrubber at WestRock Tacoma was for HCl control). The SO_2 control cost estimates that the pulp mills submitted to Ecology are greater than the potential cost threshold range of the other RH pollutant costs of $6,250 - $7,800.

Additional considerations

Ecology considered the following information as part of the reasonability analysis:

- GP Camas is no longer operating as a chemical pulp mill and the emissions will change. The facility would have to apply as a new source if it ever wanted to become a chemical pulp mill in the future. This would result in evaluation of emission controls requirements at that time.
- The Cosmo mill was in curtailment from May 10, 2020 until January 27, 2021. This shows the mills sensitivity to market conditions and impacts what the reasonable cost threshold for new emission equipment is.
- Currently, no one has practically demonstrated using SCRs for recovery furnaces (boilers), but they could potentially progress to a level of technical feasibility during a future implementation period. Since this is not shown to be technically feasible at this time, those controls will not be considered for analysis during this implementation period.

Conclusion

The pulp & paper mills identified no reasonable controls in their FFAs. Ecology will need to perform a more extensive and in-depth engineering evaluation on potential control to generate more accurate and defensible cost estimates. Ecology has limited resources and is choosing to prioritize the sequence of implementation of reasonable controls. Ecology has identified

potential cost-effective controls at a multitude of sources and is choosing to require reasonable controls at only a subset of those sources at this time.

Pulp & paper mill sources are not the first priority for new control implementation. This decision is based on:

- The pulp & paper mills are not located as close to each other as the refineries so they do not have as great of a cumulative effect.
- One mill identified with potential reasonable cost controls, Packaging Corporation of America (PCA) Wallula, is located in a direction that is generally downwind from the nearest Class 1 Areas. This lessens, but does not remove, the influence the mill's emissions have on Class 1 Areas.
- The potential reduction of 450 tons per year in regional haze emissions from the pulp & paper mills reasonable controls is vastly less than potential refinery emission reductions (approximately 4,000 tons).

After we complete the reasonability analysis and determination for the refinery facilities, we plan to conduct a reasonability analysis at pulp and paper facilities. This will be included in a SIP revision or the next implementation period, depending on the timing.

7.6 Refineries

Five petroleum refineries are located in the state of Washington. The refineries are Cherry Point refinery (BP Cherry Point), Shell Anacortes refinery (Shell), Marathon Anacortes refinery (Tesoro), Ferndale refinery (Phillips 66), and U.S. Oil refinery (U.S. Oil).

Refineries have extended timeframes for design, acquisition, and installation of equipment. Work at refineries must be scheduled during narrow time windows to coincide with other work during facility shutdowns. Performing work outside of these periods significantly increases cost if the facilities would shut down solely for the equipment installation. The next facility shutdowns may occur outside of this implementation period so no emission reductions were included in the modeled 2028 visibility projections.

The refineries in Washington are over 40 years old and the facilities have maintained the majority of the equipment in a manner that has not required updating emission controls to current standards. EPA national enforcement actions and the installation of new equipment have led to the updating of some equipment. All the refineries have made changes to accommodate the new fuel standards, lower sulfur requirements, and benzene content.

Table 7-5. General refinery information.

Refinery	Process Capacity (barrels/day)	Footprint (acres)	Year Built
BP	234,000	3,300	1971
Phillips 66	107,500	900	1954
Shell	149,000	800	1958
MPC	125,000	900	1955
US Oil	42,000	136	1957

Each refinery has the same NAICS code, but are uniquely configured with different considerations for each. The major difference is in how they handle the heavy crude bottom fraction:

- BP Cherry Point uses hydrocracker and coker units.
- Phillips 66 uses a Fluidized Catalytic Cracking Unit (FCCU).
- Shell uses a FCCU and coker.
- Tesoro uses a FCCU.
- U.S. Oil produces asphalt or exports it to other refineries for further processing.

All the refineries have flexibility to send intermediate products to other refineries for final processing.

Table 7-6 shows how Washington refineries compare nationally based on NOx emissions per barrel of production capacity. The data is from the 2014 EPA emission data (2014 NEI Data, 2014) of 88 refineries located in nine states: AK, CA CO, IL, LA, MT, TX, WA, and WY. Table 7-6 only shows a subset of the 88 refineries and all Washington refineries are shown. The table is sorted from highest to lowest NOx emissions divided by production capacity. Washington refineries represent four of the top five facilities in the nine states in NOx emissions per 1,000 barrels produced per day. Three Washington refineries emit more oxides of nitrogen per barrel of production capacity than per year of any other refinery in the U.S.

Table 7-6: Washington refineries annual emissions and production capacity

State	Company	NOX tpy 2014	Ranking NOx tpy	1,000 BPD	NOx tpy/1,000 BPD
WA	Tesoro Northwest Company	1,918	3	119	16.12
WA	Shell Puget Sound Refinery	1,230	16	145	8.48
WA	BP Cherry Point Refinery	1,882	4	242	7.78
LA	Equilon Enterprises LLC - Shell Oil Products US Norco Refinery	1,626	11	225	7.23
WA	Phillips 66 Ferndale Refinery	723	31	105	6.89
IL	Exxon Mobil Oil Corp	1,386	13	238	5.83
LA	Phillips 66 Co - Alliance Refinery	1,432	12	253	5.66
IL	ConocoPhillips Co	1,863	6	334	5.58
LA	Citgo Petroleum Corp - Lake Charles Manufacturing Complex	2,197	1	418	5.25
TX	Beaumont Refinery	1,868	5	365	5.12
LA	ExxonMobil Refinery & Supply Co - Baton Rouge Refinery	1,944	2	540	3.60
TX	Deer Park Plant	1,702	9	500	3.40
TX	Baytown Refinery	1,828	8	560	3.26
WA	US Oil & Refining Co	133	68	41	3.24
TX	Port Arthur Refinery	1,858	7	603	3.08
TX	Galveston Bay Refinery	1,692	10	571	2.96
LA	Marathon Petroleum Co LP - LA Refining Division - Garyville Refinery	1,379	14	564	2.45

Refinery planning process

Ecology offered to enter into a cooperative AO with each refinery to achieve enforceable NOx emission reductions. We proposed to calculate the total amount of NOx reductions each refinery would achieve if they implemented Subpart Ja of the New Source Performance Standards (40 CFR 60 Subpart Ja). The Ja NOx total emission values would be used to calculate NOx emissions reductions that would need to occur over the remaining implementation periods prior to 2064. The refinery could meet the calculated NOx emission reductions through any NOx reduction work and not specifically tied to Ja requirements.

Ecology met with the refineries and the Western States Petroleum Association (WSPA) on September 17, 2019, to discuss this approach. At that meeting, Ecology also discussed not using the Subpart Ja option but doing a reasonability analysis at each facility. This would require a RACT determination for each facility based on their unique configurations. Ultimately, the refineries selected the reasonability analysis option over the AO approach.

On November 27, 2019, Ecology requested that the refineries perform a FFA review of equipment at the refineries. Ecology limited the scope of the FFA to equipment with large emissions of NOx. Ecology limited the scope to facilitate timely returns of the FFA to fit the timeline for RH SIP submittal. We requested the FFA for NOx emission reductions on specific pieces of equipment.

The refineries requested time extensions to the FFA request date and Ecology extended the final deadline to May 1, 2020. All of the refineries delivered their FFA's to Ecology prior to May 1, 2020.

Two refineries did not submit information on FCCU controls following criteria in Ecology's FFA request. Ecology agrees that the facilities did not need to submit a FFA on the units. Ecology subsequently decided to evaluate NOx controls using the EPA Control Cost Manual on the FCCUs since they are a large source of NOx emissions.

The refineries' FFAs indicated selective catalytic reduction (SCR) controls were not a cost-effective emissions control for any units analyzed. The refineries also indicated that low-NOx burners were either not a cost-effective emissions control or that more extensive and in-depth engineering evaluation would be required to establish costs on a unit-by-unit basis.

Ecology did a preliminary analysis using the EPA Control Cost Manual for SCR systems and worksheet model. Preliminary results indicate that SCR controls are cost-effective for the FCC units and various heaters and boilers. Ecology will perform a more extensive and in-depth engineering evaluation on each refinery to generate more accurate and defensible cost estimates. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable.

During formal consultation with the Federal Land Managers, Ecology received a request to include analysis of the calciner units at the Cherry Point Refinery. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable in regards to SO_2 emissions.

All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

Cherry Point Refinery (BP)

BP operations

BP has a total crude oil capacity of 250,000 barrels per calendar day. The refinery processes Canadian crude, domestic crude from North Dakota and Alaska North Slope and international crudes to manufacture gasoline, distillates, heavy fuel oil and propane. The refinery distributes products through pipeline-connected terminals, marine terminal via ships and barges. BP is the only refinery in the Pacific Northwest capable of manufacturing diesel made from biomass-based feed stocks. The refinery processes bio-mass feed stocks alongside conventional feed stocks in an existing ultra-low-sulfur diesel unit. Over the past decade, BP invested more than $1.5 billion in capital improvements at the refinery (BP, 2021).

PSD permit

Ecology issued a PSD permit to BP Cherry Point (BP) on May 23, 2017. During the PSD permit's public comment period, the National Park Service submitted comments regarding impacts to the Olympic National Park (NP).

Below is a summary of the Federal Land Manager's comments that directly pertain to RH and visibility:

- According to modeling performed by the NPS, the NPS believes that "emissions from the refinery are currently causing visibility impairment at Olympic NP and North Cascades NP and significantly contributing to excess nitrogen deposition at both parks." In addition, the NPS also believes that the Coker Replacement project itself "will significantly increase the impacts of visibility-impairing pollutants at Olympic NP and significantly increase nitrogen deposition at North Cascades NP."
- On October 14, 2016, the NPS provided helpful clarifications of their concerns in a document submitted to Ecology. The letter from NPS documented no dispute that the facility followed PSD regulations, or that the BP application was complete, but rather emphasized the different approaches used to address PSD regulatory applicability from approaches used to address project impacts on the Class 1 Areas Air Quality Related Values (AQRV).
- On December 25, 2016, the NPS sent a letter to Ecology stating that emissions from the Cherry Point refinery were adversely impacting air quality related values at North Cascades and Olympic National Parks.

Regional Haze, Four Factor Analysis 2020

BP submitted a FFA to Ecology in April 2020 and determined that it was not reasonable to install new emissions control equipment. Ecology used the EPA Control Cost Manual with a retrofit factor of one to generate baseline costs for installation of SCR controls. These costs indicate that it might be reasonable to install new SCR controls. The refineries and the Western

States Petroleum Association (WSPA) contend that Ecology did not use the EPA Control Cost Manual for SCR systems appropriately.

Ecology's preliminary analysis using the EPA Control Cost Manual for SCR systems and worksheet model indicates that SCR controls are cost-effective for the FCC units and various heaters and boilers. Ecology will perform a more extensive and in-depth engineering evaluation on each refinery to generate more accurate and defensible cost estimates. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable.

All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

The following is Ecology's review of the FFA supplied by BP Cherry Point on selected equipment compared to the Cost Reports and Guidance for Air Pollution Regulations- Section 4 - NOx Controls spreadsheet[16]:

Table 7-7: BP Cherry Point equipment identified for RACT analysis

Company	Equipment	EPA Control Cost Manual $/Ton	Refinery $/Ton	TPY Reduced	Comment
BP	#1 Reformer heaters	3,101	24,378	304	
BP	Crude heater	2,051	24,378	393	
BP	Reforming furnace #1 (N H2 Plant)	6,161	78,065	262	Combined North & South stacks
BP	Reforming furnace #2 (S H2 Plant)				

Ecology reviewed the following equipment using the EPA Control Cost Manual:

Reformer Heaters

BP supplied a table with limited supporting data.

[16] Cost Reports and Guidance for Air Pollution Regulations- Section 4 - NOx Controls spreadsheet: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

Table 7-8 shows the costs for the retrofit that BP supplied compared to the costs from the EPA Control Cost Manual (EPA, 2021). Ecology determined that a more detailed RACT analysis is justified to refine costs.

Table 7-8: Reformer heaters cost comparison

Costs	BP FFA costs	Ecology – EPA Control Cost Manual
Capital cost $	94,809,582	9,929,730
Maintenance $/yr	420,048	49,649
Reagent $/yr	284,001	57,895
Catalyst $/yr	180,467	33,548
Annualized cost $/yr	7,827,719	943,315
NOX tpy reduced	321	304
$/ton NOX reduced	24,378	3,101

Ecology used the EPA Control Cost Manual cost with 90 percent control efficiency. BP did not supply the data they used to scale their costs.

Crude Heater

BP supplied a table with limited supporting data. Table 7-9 shows the costs for the retrofit that BP supplied compared to the costs from the EPA Control Cost Manual (EPA, 2021). Ecology determined that a more detailed RACT analysis is justified to refine costs.

Table 7-9: Crude heater cost comparison

Costs	BP FFA costs	Ecology – EPA Control Cost Manual
Capital cost $	94,809,582	9,325,358
Maintenance $/yr	420,048	46,627
Reagent $/yr	284,001	51,515
Catalyst $/yr	180,467	29,852
Annualized cost $/yr	7,827,719	871,136
NOX tpy reduced	321	425
$/ton NOX reduced	24,378	2,051

The EPA Control Cost Manual (EPA, 2021) uses current cost with 90 percent controls. BP did not supply the cost data they used to scale their cost data.

Two Reforming Furnace #1 (H2 PLANT)

BP supplied a table with limited supporting data. Table 7-10 shows the costs for the retrofit that BP supplied compared to the costs from the EPA Control Cost Manual (EPA, 2021). Ecology determined that a more detailed RACT analysis is justified to refine costs.

Table 7-10: Two reforming furnace #1 (H2 Plant) cost comparison

Costs	BP FFA costs	Ecology – EPA Control Cost Manual
Capital cost $	143,325,183	9,325,358
Maintenance $/yr	479,126	46,627
Reagent $/yr	125,031	51,515
Catalyst $/yr	65,513	29,852
Annualized cost $/yr	11,038,382	871,136
NOx tpy reduced	141	141
$/ton NOx reduced	78,065	6,161

The EPA Control Cost Manual uses current cost with 90 percent controls. BP did not supply the data they used to scale their cost data.

Summary

Ecology's preliminary review of the industry supplied FFA data was inconclusive for determining reasonable controls. Therefore, Ecology is performing a detailed cost-analysis to ensure the most effective reasonable controls are identified. All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

Ecology's baseline and initial four-factor review using the EPA Control Cost Manual and a retrofit factor of one determined the following:

- Factor #1 – The costs of compliance
  - $2,100/ton to $6,200/ton
- Factor #2 – The time necessary for compliance.
  - Accommodation for the time necessary for design, and installation of the equipment during a planned shutdown is required to ensure reasonable costs.
- Factor #3 – The energy and non-air quality environmental impacts of compliance
  - The power needed to drive the exhaust fans is included in the analysis.
- Factor #4 – The remaining useful life on existing source subject to such requirement

BP Cherry Point did not indicate that any of the equipment had a limited lifetime.

Conclusion

Ecology will do a reasonability analysis to develop detailed cost-analysis to ensure the most effective reasonable controls are identified. Emission control equipment that is determined to be reasonable will then be required for installation at the facility. The RHR SIP will be amended to reflect any new control requirements. To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls will likely occur in the next implementation period.

Phillips 66

Operations

The Phillips 66 refinery has an average annual processing rate of approximately 108,000 barrels of crude oil per day. Located outside of Ferndale in Whatcom County, this petroleum refinery uses crude oil as a feedstock that is processed into a variety of petroleum products including gasoline, diesel, fuel oil, liquefied petroleum gas (LPG), and butane. The refinery receives crude oil via marine vessels, railcars, and by pipeline (Phillips 66 Refinery, 2021).[17]

Regional Haze, Four Factor Analysis 2020

Phillips 66 submitted a FFA to Ecology in April 2020 and determined that it was not reasonable to install new emissions control equipment. Ecology used the EPA Control Cost Manual with a retrofit factor of one to generate baseline costs for installation of a SCR controls. These costs indicate that it might be reasonable to install new SCR controls. The refineries and the Western States Petroleum Association (WSPA) contend Ecology's application of the EPA Control Cost Manual for SCR systems at refineries is not appropriate.

Ecology's preliminary analysis using the EPA Control Cost Manual for SCR systems and worksheet model indicates that SCR controls are cost-effective for the FCC units and various heaters and boilers. Ecology will perform a more extensive and in-depth engineering evaluation on each refinery to generate more accurate and defensible cost estimates. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable.

All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

As part of our analysis, Ecology compared cost data provided by Phillips 66 with corresponding costs from the EPA Control Cost Manual's SCR tools with the results shown in Table 7-11 below.

Table 7-11: Phillips 66 Equipment identified for RACT

Company	Equipment	EPA Control Cost Manual $/Ton	Refinery $/Ton	TPY Reduced	Comment
Phillips 66	Crude heater 1F-1	2,640	12,225	166	
Phillips 66	FCCU/CO Boiler/Wet Gas Scrubber 4F-100, 4F-101	3,954		247	NSCR is installed.

Ecology reviewed the following equipment using the EPA SCR Cost Model:

[17] https://www.phillips66.com/refining/ferndale-refinery

Crude heater 1F-1

Phillips 66 supplied a table with limited supporting data. Table 7-12 shows the costs for the retrofit that Phillips 66 supplied compared to the costs from the EPA Control Cost Manual. Ecology determined that a more detailed reasonableness is justified to refine costs.

Table 7-12: Crude heater 1F-1 cost comparison

Costs	Facility FFA costs	Ecology – EPA Control Cost Manual
Capital cost $	16,615,487	5,084,927
Maintenance $/yr	83,077	25,425
Reagent $/yr	17,691	20,677
Catalyst $/yr	18,680	11,982
Annualized cost $/yr	1,944,651	437,150
NOX tpy reduced	159	166
$/ton NOX reduced	12,225	2,640

Ecology used the EPA Control Cost Manual cost with 90 percent controls. Phillip 66 did not supply the data they used to scale their cost data.

FCCU/CO Boiler

In 2006, Phillips 66 modified the FCCU to include ESNCR for NOx controls and so was not required to submit a FFA for this unit. As FCC units are a large source of NOx emission at refineries that have them, Ecology decided to use the EPA Control Cost Manual anyway to review reasonableness of installing SCR systems on the FCCUs.

Table 7-13: FCCU/CO boiler cost

Costs	Ecology – EPA Control Cost Manual
Capital cost $	8,983,013
Maintenance $/yr	44,915
Reagent $/yr	49,624
Catalyst $/yr	27,183
Annualized cost $/yr	976,820
NOX tpy reduced	247
$/ton NOX reduced	3,954

Ecology used the EPA Control Cost Manual cost with 90 percent controls.

Summary

Ecology's preliminary review of the industry supplied FFA data was inconclusive for determining reasonable controls. Therefore, Ecology is performing a detailed cost-analysis to ensure the most effective reasonable controls are identified. All controls identified as reasonable in the reasonability analysis have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

Ecology's baseline and initial four-factor review using the EPA Cost Control Manual and a retrofit factor of one determined the following:

- Factor #1 – The costs of compliance
  - $2,600/ton to $4,000/ton
- Factor #2 – The time necessary for compliance
  - Accommodation for the time necessary for design, and install the equipment during a planned shutdown is required to result in reasonable costs.
- Factor #3 – The energy and non-air quality environmental impacts of compliance
  - The power needed to drive the exhaust fans is included in the analysis.
- Factor #4 – The remaining useful life on existing source subject to such requirements.
  - Phillips 66 did not indicate that any of the equipment had a limited lifetime.

Conclusion

Ecology will do a reasonability analysis to develop detailed cost-analysis to ensure the most effective reasonable controls are identified. Emission control equipment that is determined to be reasonable will then be required for installation at the facility. The RHR SIP will be amended to reflect any new control requirements. To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls will likely occur in the next implementation period.

Shell

Operations

The Shell refinery has an average annual processing rate of approximately 145,000 barrels (5.7 million gallons) of crude oil per day. When the refinery first began operating, most of its crude oil came from Canada via pipeline. Although it continues to receive crude from central and western Canada, feedstock also arrives by tanker from oilfields on Alaska's North Slope.

On an annual basis, the refinery produces multiple types of gasoline in addition to fuel oil, diesel fuel, propane, jet fuel, butane, and petroleum coke. It also produces two chemicals---nonene and tetramer---that industry uses in a variety of plastic products. Shell also owns and operates a cogeneration facility on the refinery site.[18]

The cogeneration facility was originally the March Point Cogeneration Company (MPCC), which Puget Sound Refinery (PSR) took possession of in February 2010. Air Liquide and Linde operate

[18] https://www.shell.us/about-us/projects-and-locations/puget-sound-refinery/about-shell-puget-sound-refinery.html

hydrogen plants on property owned by PSR and adjacent to the refinery. However, both Air Liquide and Linde are independent companies and permitted separately from Shell. This report does not address emission sources from Air Liquide and Linde in this report.

Regional Haze, Four-Factor Analysis 2020

Shell submitted a FFA to Ecology in April 2020 and determined that it was not reasonable to install new emissions control equipment. Ecology used the EPA Control Cost Manual with a retrofit factor at one to generate baseline costs for installation of a SCR controls. These costs indicate that it might be reasonable to install new SCR controls. The refineries and the Western States Petroleum Association (WSPA) contend the use of the EPA Control Cost Manual for SCR systems at refineries is not appropriate in how Ecology applied it.

Ecology's preliminary analysis using the EPA Control Cost Manual for SCR systems and worksheet model indicates that SCR controls are cost-effective for the FCC units and various heaters and boilers. Ecology will perform a more extensive and in-depth engineering evaluation on each refinery to generate more accurate and defensible cost estimates. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable.

All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

Table 7-14: Shell equipment identified for RACT rule development

Company	Equipment	EPA Model $/Ton	Refinery $/Ton	TPY Reduced	Comment
Shell	Boiler #1 Erie City--31G-F1	2,441	12,511	179	8-yr life
Shell	Cogen turbine 1 MW	---	---	---	Current SCR controls – Study
Shell	Cogen turbine 2 MW	---	---	---	Current SCR controls – Study
Shell	Cogen turbine 3 MW	---	---	---	Current SCR controls – Study
Shell	FCCU Regenerator Unit	1,948	---	521	
Shell	CRU #2 HTR, INTERHTR--10H-101,102,103	6,346	10,813	69	

Ecology reviewed the following equipment using the EPA Control Cost Manual:

BOILER #1 ERIE CITY--31G-F1

Shell's FFA supplied a table with limited supporting data. Table 7-15 shows the costs for the retrofit that Shell supplied compared to the costs from the EPA Control Cost Manual. Ecology determined that a more detailed reasonableness analysis is justified to provide more credible and defensible costs.

Table 7-15: Boiler #1 Erie City--31G-F1 cost comparison

Costs	Shell	Ecology – EPA Control Cost Manual
Capital cost $	11,420,745	5,084,927
Maintenance $/yr	57,104	25,425
Reagent $/yr	17,221	20,677
Catalyst $/yr	39,340	11,982
Annualized cost $/yr	2,053,888	437,150
NOX tpy reduced	164	179
$/ton NOX reduced	12,511.00	2,441

Ecology used the EPA Control Cost Manual cost with 90 percent controls. Shell did not supply the cost data they used to scale their cost data and had only an eight-year life for the boiler. The limited eight-year lifetime of the boiler caused the cost/ton value to be significantly higher than a 25-year lifetime. With an eight-year lifetime, a requirement for the boiler to be retired after this period would be justified and the boiler should be required to decommission. Any new boiler brought in to replace it would need to go through the permitting process as a new source.

FCCU/CO Boiler

It was Shell's understanding that the addition of particulate matter and SO_2 controls on the FCCU in 2014 meant that they were not required to submit a NOx FFA. Current emissions limit on the FCCU is 1,380 tpy and 142.2 ppm NOx on a yearly average. As FCC units are a large source of NOx emission at refineries that have them, Ecology decided to use the EPA Control Cost Manual anyway to review reasonableness of installing SCR systems on the FCCUs.

Table 7-16: FCCU/CO boiler cost

Costs	Ecology – EPA Control Cost Manual
Capital cost $	10,680,913
Maintenance $/yr	53,405
Reagent $/yr	62,274
Catalyst $/yr	36,086
Annualized cost $/yr	1,014,677
NOX tpy reduced	521
$/ton NOX reduced	1,948

Ecology used the EPA Control Cost Manual cost with 90 percent controls.

CRU #2

Shell supplied a table with limited supporting data. Table 7-17 shows the costs for the retrofit that Shell supplied compared to the costs from the EPA Control Cost Manual. Ecology determined that a more detailed reasonableness analysis is justified to provide more credible and defensible costs.

Table 7-17: CRU #2 cost comparison

Costs	Facility FFA costs	Ecology – EPA Control Cost Manual
Capital cost $	5,939,772	5,084,927
Maintenance $/yr	29,699	25,425
Reagent $/yr	6,165	20,677
Catalyst $/yr	13,454	11,982
Annualized cost $/yr	635,480	437,150
NOX tpy reduced	59	77
$/ton NOX reduced	10,813	6,346

Ecology used the EPA Control Cost Manual cost with 90 percent controls. Shell's cost was similar but they used a lower emission reduction.

Three turbines have SCR installed on the units. The current emission limit is 74 tpy at 9 ppm NO_X. Actual emissions vary from 46-64 tpy (5.6-7.8 ppm) with less than 2 tpy (less than 0.5 ppm) ammonia. As part of the reasonableness analysis an engineering optimization study to minimize NOx emissions is needed to see if emissions can match similar new units permitted below 2 ppm NOx.

Summary

Ecology's preliminary review of the industry supplied FFA data was inconclusive for determining reasonable controls. Therefore, Ecology is performing a detailed cost-analysis to ensure the most effective reasonable controls are identified. All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

Ecology's four-factor review has determined the following:

- Factor #1 – The costs of compliance
  - $1,900/ton to $ 6,300/ton
- Factor #2 – The time necessary for compliance
  - Accommodation for the time necessary for design, and installation of the equipment during a planned shutdown is required to validate reasonable costs.
- Factor #3 – The energy and non-air quality environmental impacts of compliance
  - The power needed to drive the exhaust fans is included in the analysis.
- Factor #4 – The remaining useful life on existing source subject to such requirements
  - Shell indicates that the BOILER #1 ERIE CITY--31G-F1 had a limited lifetime of 8 years. Ecology will work with NWCAA to have a regulatory order on the boiler to shut the unit down by January of 2028.

Conclusion

Ecology will do a reasonability analysis to develop detailed cost-analysis to ensure the most effective reasonable controls are identified. Emission control equipment that is determined to be reasonable will then be required for installation at the facility. The RHR SIP will be amended to reflect any new control requirements. To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls will likely occur in the next implementation period.

Marathon Petroleum Company

Process

Marathon Petroleum Company (MPC) is the current owner of the Anacortes refinery. Located in Anacortes, the refinery has a total crude oil capacity of 119,000 barrels per calendar day.

The refinery processes Canadian crude, domestic crude from North Dakota and Alaska North Slope, and international crudes to manufacture gasoline, distillates, heavy fuel oil, and propane.

The refinery distributes products through pipeline-connected terminals and MPC's marine terminal via ships and barges.[19]

Table 7-18: MPC emission rates pre - and post - best available retrofit technology (BART)

Pollutant	Pre-BART, tpy	Post-BART, tpy	Basis of comparison	Sources included in comparison
NOX	1360	1303	2005 vs. post-BART projects (F-103 ULNB)	BART sources only
SO2	5540	474	2005 vs. 2008 (FGS; RFG treatment*)	All refinery sources
PM/PM10	588	140	2005 vs. post BART projects (FGS); no oil burning at F-103)	BART sources plus F-302

* Refinery Fuel Gas (RFG) treatment improvements affected all combustion sources

2010 regional haze best available retrofit technology

During the first regional haze implementation period the MPC facility was operated by Tesoro. Tesoro had a BART determination and Federal Implementation Plan for Tesoro (MPC) found that four of the BART-eligible sources contribute approximately 93 percent of the NOx emissions from the 14 combustion sources: F-103, F-304, F-6650, and F-6651. Tesoro (MPC) identified that it was cost effective to add NOx controls on these four units. The cost was found unreasonable if the facility needed to have a special outage just for the NOx controls. These outages usually occur every five to six years.

PSD permit

On July 18, 2017, Ecology issued a PSD permit to Tesoro (MPC). During the public comment period, the Federal Land Managers made comments regarding the impacts to the Olympic Class 1 area. These comments are contained in the PSD technical support document, https://fortress.wa.gov/ecy/ezshare/AQ/PSD/PSD_PDFS/Tesoro_Anacortes_TSD.pdf

Federal Land Manager's comments 4-6, pages 45-51 indicated the major issues with the issued PSD permit were:

- Tesoro (MPC) should be reviewed in the next RH period
- Supported the installation of SCR on the new boiler and control of vapors from loading marine vessels

Regional Haze

Ecology's preliminary analysis using the EPA Control Cost Manual for SCR systems and worksheet model indicates that SCR controls are cost-effective for the FCC units and various heaters and boilers. Ecology will perform a more extensive and in-depth engineering evaluation on each refinery to generate more accurate and defensible cost estimates. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable.

[19] https://www.marathonpetroleum.com/Operations/Refining/Anacortes-Refinery/

All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

The following is Ecology's review of the four-factor analysis supplied by MPC on selected equipment compared to BART and the EPA Control Cost Manual:

Table 7-19: Tesoro equipment identified for RACT rule development

Company	Equipment	EPA Model 2020 $/Ton	MPC 2020 $/Ton	BART 2008 $/Ton	TPY reduced
Tesoro	FCCU [20]	1,159	14,381	4,592	843.3
Tesoro	F 102 Crude Heater	2,962	16,086	---	147.6
Tesoro	F 201 Vacuum Flasher Heater	7,589	35,279	---	57.6
Tesoro	F 6650 CAT Reformer Heater	3,736	21,196	3,349	117
Tesoro	F 6651 CAT Reformer Heater	3,520	21,196	3,349	124.2
Tesoro	F 751 Main Boiler	2,159	10,060	---	202.5
Tesoro	F 752 Main Boiler	2,570	10,513	---	170.1

Ecology reviewed the following equipment using the EPA SCR Cost Model:

[20] FCCU is SNCR, others LNB.

FCCU

MPC supplied a table with limited supporting data. Table 7-20 shows the costs for the retrofit that MPC supplied compared to the costs from the EPA Control Cost Manual. Ecology determined that a more detailed reasonableness analysis is justified to provide more credible and defensible costs.

Table 7-20: FCCU cost comparison

Cost	MPC	Ecology EPA Control Cost Manual
Capital cost $	114,030,975	10,286,436
Maintenance $/yr	570,155	51,432
Reagent $/yr	1,340,590	59,974
Catalyst $/yr	116,845	34,754
Annualized cost $/yr	10,747,992	977,202
$/ton NOX reduced	14,381	1,159

Ecology used the EPA Control Cost Manual cost with 90 percent controls. MPC did not supply the cost data they used to scale their cost data. The MPC data is based on SNCR controls at about 60 percent controls, which account for the higher $/ton cost.

F 102 CRUDE HEATER

Both MPC and Ecology used the EPA Control Cost Manual with different results. To reconcile the difference a more detailed reasonableness analysis is justified to provide more credible and defensible costs:

Table 7-21: Crude heater cost comparison

Costs	MPC EPA Control Cost Manual	Ecology EPA Control Cost Manual
Ft3/min-MMBtu/hr	55,577	484
Ammonia $/gal	3.513	0.293
acfm	6,381,721	115,784
Vspace	19,760.72	112
Catalyst Ft2	6,648	121
Capital cost $	20,876,000	5,084,927
Maintenance $/yr	104,380	25,425
Reagent $/yr	315,021	20,677
Catalyst $/yr	3,548	11,982
Annualized cost $/yr	2,021,692	437,150
$/ton NOX reduced	16,086	2,962

MPC incorrectly changed the default value in the model for the ft^3/min-MMBtu/hr input. Ecology used the default value and determined the minimum cost of $439,065/yr.

Other equipment

We used the default cost of $437,150/yr for the other equipment. MPC incorrectly changed the default value for the Ft^3/min-MMBtu/hr input to the EPA Control Cost Manual for all their determinations other than the FCCU.

Summary

Ecology's preliminary review of the industry supplied FFA data was inconclusive for determining reasonable controls. Therefore, Ecology is performing a detailed cost-analysis to ensure the most effective reasonable controls are identified. All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

- Factor #1 – The costs of compliance
  - $1,200/ton to $7,600/ton
- Factor #2 – The time necessary for compliance
  - Accommodation for the time necessary for design, and installation of the equipment during a planned shutdown is required to validate reasonable costs.
- Factor #3 – The energy and non-air quality environmental impacts of compliance
  - The power needed to drive the exhaust fans is included in the analysis.
- Factor #4 – The remaining useful life on existing source subject to such requirements
  - MPC did not indicate that any of the equipment had a limited lifetime.

Conclusion

Ecology will do a reasonability analysis to develop detailed cost-analysis to ensure the most effective reasonable controls are identified. Emission control equipment that is determined to be reasonable will then be required for installation at the facility. The RHR SIP will be amended to reflect any new control requirements. To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls may occur in the next implementation period.

US Oil

Operations

The US Oil Refinery has an average daily processing rate of approximately 41,000 barrels of crude oil per day. It uses crude oil as a feedstock processed into a variety of petroleum products including gasoline, diesel, fuel oil, and asphalt.[21]

Regional Haze, State Implementation Plan, Final December 2010

During the first implementation period, BART was not triggered for US Oil based on their emissions.

Regional Haze four-factor analysis 2020

US Oil submitted a FFA to Ecology in April 2020 and concluded that additional emission control devices were not reasonable. Ecology analyzed the data and concluded that US Oil based the analysis on the EPA Control Cost Manual and the results were similar to Ecology's analysis using the EPA Control Cost Manual. The emissions were only 28 tpy for the largest unit and the cost effectiveness was over $15,000/ton of NO_X reductions.

The following is Ecology's review of the four-factor analysis supplied by US Oil on selected equipment compared to the EPA Control Cost Manual:

[21] http://usor.com/about/about

HEATER H11

The facility supplied a table with the limited supporting data.

Table 7-22: Heater H11 cost comparison

Cost	Facility	Ecology EPA Control Cost Manual
Capital cost $	4,894,235	5,084,927
Maintenance $/yr	24,471	25,425
Reagent $/yr	2,979	20,677
Catalyst $/yr	9,862	11,982
Annualized cost $/yr	522,175	437,150
NOx tpy reduced	28	28
$/ton NOx reduced	18,649	15,612

Ecology and US Oil used the EPA Control Cost Manual with minor differences.

Summary and preliminary recommendations

Ecology's review indicates that additional controls are likely not cost reasonable, but recommends a more detailed and defensible cost reasonableness analysis to verify this initial review. Any reasonable emission control equipment from the analysis will result in a determination of equipment to install with federally enforceable conditions.

- Factor #1 – The costs of compliance
  - Over $15,000/ton for SCR controls
- Factor #2 – The time necessary for compliance
  - Accommodation for the time necessary for design, and installation of the equipment during a planned shutdown is required to validate reasonable costs.
- Factor #3 – The energy and non-air quality environmental impacts of compliance
  - The power needed to drive the exhaust fans is included in the analysis.
- Factor #4 – The remaining useful life on existing source subject to such requirements
  - US Oil did not indicate that any of the equipment had a limited lifetime

Conclusion

Ecology will do a reasonability analysis to develop more robust and defensible cost data. Emission control equipment that is determined to be reasonable will then be required for installation at the facility. The RHR SIP will be amended. Installation of any reasonable emission controls for implementation may occur in the next implementation period to be reasonable.

7.7 Summary

Ecology performed a four-factor analysis on sources selected using the EPA approved Q/d screening process. Ecology focused on major point sources that had a Q/d of 10 or greater. We selected sources emitting approximately 80 percent of all haze-causing emissions in the entire emission inventory for a four-factor analysis.

The selected sources included:

- a flat glass facility,
- five petroleum refineries,
- six pulp &paper facilities,
- a coal-fired power plant,
- a cement plant
- two aluminum smelters

Two facilities have enforceable emission reductions that were used in on-the-books emission projections. The power plant is ceasing coal-fired power production by the end of 2025 and the flat glass facility is changing their emission controls to a SCR system.

The aluminum facilities are currently in curtailment and their actual emissions are essentially zero. An Agreed Order with the two facilities was issued to have the facilities perform a FFA if

and when they restart. This will provide an accurate evaluation of the facilities' impacts on regional haze using actual restart operating conditions.

Ecology has preliminarily identified potential cost-effective controls at a multitude of sources and is choosing to require reasonable controls at only a subset of those sources.[22] Ecology is prioritizing the sequence of implementation of reasonable controls. The first priority is to identify reasonable controls at the refinery facilities. A number of factors supports the selection of refineries as the first priority:

- Four of the five refinery facilities are located in the Puget trough, west of several Class 1 Areas. Their cumulative regional haze causing emissions influence the same Class 1 Areas.
- Predominant winds direct the emissions from the refineries towards several Class 1 Areas.
- The refineries' potential emission reductions of 4,200 tons per year account for the vast amount of potential emission reductions.

Our second priority is to identify and implement reasonable controls at pulp and paper facilities after the refinery facilities. Pulp & paper mills are a subset of sources that are lower priority than refineries because:

- The pulp & paper mills are not located as close to each other as the refineries so they do not have as great of a cumulative effect.
- One mill identified with potential reasonable cost controls, Packaging Corporation of America (PCA) Wallula, is located in a direction that is downwind from the nearest Class 1 Areas. This lessens, but does not remove, the influence the mill's emissions have on Class 1 Areas.
- The potential reduction of 450 tons per year in regional haze emissions from the pulp & paper mills reasonable controls is vastly less than potential refinery emission reductions.

Ecology will supplement the SIP when new controls are determined to be reasonable and scheduled for implementation.

[22] Peter Tsirigotis, Director, "Clarifications Regarding Regional Haze Second Implementation Plans for the Second Implementation Period," memo, addressed to Regional Air Division Directors, Regions 1-10, July 8, 2021.

Chapter 8.Long-term Strategy for Visibility Improvement

8.1 Introduction

Section 169A(b)(2) of the federal Clean Air Act requires each state to submit a Regional Haze (RH) State Implementation Plan (SIP) revision approximately every 10 years. The SIP revision includes a long-term strategy (LTS) for making reasonable progress toward the national visibility goal, which is to remedy any existing visibility impairment in Class 1 Areas resulting from human-caused air pollution and to prevent future visibility impairment.

Washington's LTS for visibility improvement is a set of "enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress, as determined pursuant to [40 CFR 51.308](f)(2)(i) through (iv)" (40 CFR 51.308(f)(2)). Specifically:

(i) The State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment.

(ii) The State must consult with those States that have emissions that are reasonably anticipated to contribute to visibility impairment in the mandatory Class I Federal area to develop coordinated emission management strategies containing the emission reductions necessary to make reasonable progress.

(iii) The State must document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I Federal area it affects.

(iv) The State must consider the following additional factors in developing its long-term strategy:

- (A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
- (B) Measures to mitigate the impacts of construction activities;
- (C) Source retirement and replacement schedules;
- (D) Basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs; and
- (E) The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

Washington's LTS protects Class 1 Areas within and outside the state. It includes controls Ecology determined to be reasonable when we considered the four statutory factors, as well as federal, state, and local controls on haze-causing emissions.

Ecology relied on the Western Regional Air Partnership (WRAP) for air quality modeling and other analytical tools to identify pollutants, the sources of those pollutants, and to predict future levels of visibility impairment. WRAP fostered a regionally consistent approach to haze planning in the western states and provided a sound mechanism for consultation. Consultation among the 15 western states within WRAP has occurred through meetings of WRAP committees, workgroups, and forums with participation by conference calls, face-to-face meetings, and workshops (Appendix K).

The LTS covers a 10-year period from 2018 - 2028 and focuses both on existing regulatory mechanisms and those needed in the future to control and reduce visibility-impairing emissions. The administrative rules the EPA promulgated to implement the federal Clean Air Act's LTS requirements are in 40 CFR 51.308(f)(2)(i). In establishing its LTS for the 2018–2028 implementation period, Ecology evaluated the feasibility of implementing new controls at major and minor stationary sources, mobile sources, and non-point sources (40 CFR 51.308(f)(2)(i)). A detailed summary of that evaluation and the methods used for source selection are in Chapter 7.

Ecology designed the LTS to include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress, as determined pursuant to (f)(2)(i) through (iv). The reasonable progress goals (RPGs) reflect the emissions reductions achieved through implementation of the LTS in each of the state's Class 1 Areas during this implementation period (2018 - 2028). The reasonable progress goals (RPGs) serve as benchmarks for progress toward meeting the national visibility goal by 2064. The description of RPGs for Washington's Class 1 Areas are in Chapter 9 in detail. We measure the success of our LTS by evaluating the resulting RPGs to improvements in visibility on the most impaired days (MID). Chapter 3 has more information about the MID metric.

8.2 Washington's approach to long-term strategy

We identified three categories of pollutants that contribute significantly to the MIDs, which we need to reduce during this second implementation period. Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data shows that sulfates (primarily), nitrates (secondarily), and organic mass are the dominant pollution species affecting visibility in the Class 1 Areas during the MIDs. We identified sources of these pollutants from within and outside Washington State. Chapter 7 describes the source selection and evaluation process that we used to identify potential pollution controls on selected point sources within Washington.

In order to calculate anticipated progress and set toward the RPGs, Ecology incorporated the results of federally mandated controls applicable to out-of-state sources of emissions that contribute to visibility impairment in Washington's Class 1 areas. However, Ecology's emissions control authority only applies to sources and pollutants within the state's regulatory jurisdiction. Emission sources that contribute to visibility impairment in Washington but are outside of Ecology's regulatory jurisdiction include wildfires, prescribed burns, marine vessels,

and both stationary and mobile sources that are located offshore, in other states, or in other countries.

We also identified federal, state and local rules, permits, and standards that limit haze-causing emissions that are already in place, or put in place during this implementation period. We rely in part on these existing emission controls to decrease emissions during and beyond this implementation period of 2018 - 2028.

Federal fuel and engine rules are of special importance to our progress towards RPGs because they have resulted in large reductions in mobile source air pollution during the last 30 years. Improvements in vehicle and engine design, and cleaner, higher-quality fuels have substantially reduced mobile source emissions and we expect the progress to continue, even with more miles driven and more power equipment used every year. We also expect on-going efforts to increase electrification of cars and trucks to reduce mobile source pollution in this second implementation period.

For example, President Biden signed an executive order in August of 2021 that establishes a goal for new cars and trucks sold in the U.S. in 2030 – specifically, that 50 percent be electric vehicles, including battery electric, plug-in hybrid electric or fuel-cell electric vehicles. Although this goal is non-binding, its inclusion in an executive order is likely to drive technological innovation. President Biden also called on EPA and the U.S. Department of Transportation to begin working on rules for:

- new fuel economy standards for passenger cars and light trucks for model year (MY) 2027 through at least MY 2030,
- new fuel economy standards for HD pickup trucks and vans for MY 2028 through at least MY 2030, and
- new fuel economy standards for medium- and HD-engines and vehicles to begin as soon as MY 2030.

In addition to these developments on federal fuel and engines standards, Washington State is currently engaged in rulemaking to reduce mobile source emissions by adopting California's more protective vehicle emission standards for new vehicles sold in Washington, starting with model year 2025 (Chapter 173-423 WAC, Low Emission Vehicles). Ecology expects to finalize this rule by December 30, 2021. In addition, in May 2021, Governor Inslee signed into law the Transportation Fuels-Clean Fuels Program (E3SHB 1091[23], codified at RCW Chapter 70A.535), which requires Ecology to adopt a rule establishing a clean fuels standard to reduce the carbon intensity of transportation fuels used in Washington. The intent of the clean fuels standard is to reduce emissions of not only greenhouse gases but also "conventional air pollutants from diesel and gasoline." (RCW 70A.535.005(3)(a)). Ecology is currently preparing to begin this rulemaking and expects to finalize the rule by December 30, 2022.

[23] https://lawfilesext.leg.wa.gov/biennium/2021-22/Pdf/Bills/Session Laws/House/1091-S3.SL.pdf?q=20210929134724

8.3 Development of Washington's long-term strategy

The Regional Haze Rule (RHR) requires consultation between states on the development of coordinated emission management strategies. Appendix R is a record of our inter-state consultation. (40 CFR 51.308(f)(2)(ii)). This requirement applies both to Class 1 Areas within Washington and to Class 1 Areas outside of Washington where we reasonably anticipate emissions from sources in Washington to contribute to visibility impairment. The RHR also requires that states consider five additional factors in developing their LTS (40 CFR 51.308(f)(2)(iv)). We discuss those five factors later in this chapter.

Through WRAP technical collaborations, the western states agreed upon the RPGs for 2028 (the end of the second implementation period) and a regionally consistent approach to addressing visibility impairment in the west.

8.4 Major visibility-impairing pollutants

Ecology's evaluation of potential controls focused primarily on reduction of sulfates and nitrates during the 2018 - 2028 implementation period. The first (or foundational) RH SIP that covered 2005 - 2018 dealt with both regional haze and reasonably attributable visibility impairment (RAVI). RAVI is visibility impairment clearly attributed to individual sources instead of collective effects from multiple sources over a large area.

IMPROVE monitoring data shows that sulfates (primarily), nitrates (secondarily), and organic mass are the dominant pollution species affecting visibility in the Class 1 Areas during the MIDs. See Chapter 3 for more information on monitoring.

Sulfates

Sulfates are the primary pollutant contributing to total light extinction (including Rayleigh scattering) for the MIDs in 2014 - 2018. Sulfates range from 35 to 50 percent of the total light extinction. In the 2028 projections, sulfates range from 37 to 53 percent of total light extinction and remain the primary pollutant contributing to total light extinction at all of the IMPROVE sites. The 2028 projections show a reduction in sulfate emissions largely due to cessation of coal-fired operation at TransAlta by 2025 and large reductions in marine fuel sulfate levels.

Nitrates

The 2014 – 2018 five-year average of MIDs in Class 1 Areas shows that nitrates contribute 9 to 26 percent of species contribution to light extinction. In the 2028 projections, nitrate contribution to the total light extinction ranges from 5 to 19 percent. The 2028 projections show a reduction in nitrate emissions primarily due to decreases in on-road and non-road mobile source emissions.

Organic mass

Organic mass contributes approximately 21 to 32 percent of total light extinction at IMPROVE sites in Washington in the 2014 – 2018 period. In the 2028 projections, organic mass contributes a similar amount of 21 to 33 percent of total light extinction. Organic mass from fire is an important contributor to light extinction. Several Class 1 Areas see large contributions to

visibility impairment due to smoke from fire; it is the highest in the Pasayten Wilderness. Organic mass is composed of either primary organic aerosols or secondary organic compounds. Primary organic aerosols are particulates directly emitted from combustion processes due to natural and anthropogenic causes. Secondary organic aerosols form particulates from condensation or photo-oxidization of volatile organic compounds from biogenic or anthropogenic sources.

Volatile organic compounds

Non-point sources are the largest human-generated source category of volatile organic compounds in 2018. Emissions from solvent use and residential wood combustion dominate these contributions. Both of these reflect the impact population growth has on the total amount of emissions.

8.5 State, federal, and local rules and controls that limit emissions of visibility-impairing pollutants

Washington's LTS to achieve reasonable progress goals relies on federal, state, and local controls on sources of visibility-impairing pollutants. WRAP identified all existing (adopted) rules and upcoming rules and limits, and incorporated the data into the calculations of expected reductions and improvements in visibility in 2028 (WRAP 2028 modeling). The modeling used the following regulations that limit emissions.

Adopted rules, programs, and permits

Federal fuel and engine rules for on-road and nonroad engines are of special importance. These result in large projected percent decreases in visibility-impairing emissions in Washington by 2028.

- Mobile source controls:
  - Heavy Duty Diesel (2007 and later model year) Engine Standard (40 CFR 86.007-11).
  - Tier 3 Tailpipe Standards (79 Fed. Reg. 23414 (Apr. 28, 2014)). Starting in 2017, these reduced both tailpipe and evaporative emissions from passenger cars, light-duty trucks, medium duty passenger vehicles, and some heavy-duty vehicles. The gasoline sulfur standard will enable more stringent vehicle emissions standards and make emissions control systems more effective.
  - Large Spark Ignition and Recreational Engines and Vehicle Rule (67 Fed. Reg. 68242 (Nov. 8, 2002)).
  - Tier 4 Nonroad Diesel Engines and Fuel Rule (40 CFR Part 1039).
  - Low sulfur fuel requirements for gasoline engines, on-road diesel engines, nonroad diesel engines, and locomotives (40 CFR 80 Subpart I).
  - Ultra-low sulfur diesel fuel for highway, nonroad, locomotive, and marine diesel necessary for new advanced emission control technologies. This contributes to particulate matter reductions in the existing fleet of nonroad engines and equipment (40 CFR 80.500).

- Maximum Achievable Control Technology (MACT) emission standards (40 CFR Part 63): Combustion Turbines (Subpart YYYY), Industrial Boilers and Process Heaters (Subpart DDDDD), and Reciprocating Internal Combustion Engines (RICE) (Subpart ZZZZ).
- Permits and state/EPA consent agreements.
- Ozone and Coarse Particulate Matter (PM_{10}) SIPs in place in the WRAP region.
- State oil and gas emissions control programs.

Additional federal and international rules leading to emission reductions and visibility improvement:

- MACT emission standards (40 CFR Part 63):
  - Petroleum Refineries (Subparts CC and UUU).
  - Boilers (area sources) (Subpart 6J).
  - Revised Utility Boilers (Subpart UUUUU).
  - Various area source MACTs.
- Stationary Spark Ignition Internal Combustion Engine Rules (40 CFR 60 Subpart JJJJ).
- Locomotive and Marine Diesel Emission Standards for engines with a cylinder displacement of less than 30 liters (73 Fed. Reg. 37096 (June 30, 2008)).
- Corresponding EPA rules for Category 3 Marine Diesel Engines with a cylinder displacement equal to or greater than 30 liters (75 Fed. Reg. 22896 (Apr. 30, 2010)).
- International Maritime Organization (IMO) rules reducing NO_2 and SO_2 emissions from commercial marine vessels.

8.6 Controls on visibility-impairing pollutants not in previous RH SIP

Since approval of Washington's 2010 RH SIP, Ecology, EPA, and other federal agencies, have adopted or implemented the following programs to reduce emissions from stationary and mobile sources.

Table 8-1. Control Strategies not in previous RH SIP.

Regulatory Program	Affected Sources	Affected Visibility Impairing Air Pollutants
North American Maritime Emission Control Area (ECA) and Maritime Pollution (MARPOL) Annex VI	Marine vessels operating within 200 nautical miles of United States and Canada's Pacific and Atlantic Ocean coast lines	SOx, NOx, $PM_{2.5}$
40 CFR Part 94 Marine Engine Requirements	Marine vessels operating in US Waters.	NOx, SOx, $PM_{2.5}$
Motor Vehicle CAFE/GHG standards	Light and medium duty on-road vehicles	NOx, $PM_{2.5}$
On-road Tier 3 diesel standards	Diesel fueled engines, especially on road vehicles	SOx, $PM_{2.5}$
Utility Boiler MACT	Coal fired boilers at electric generating stations	$PM_{2.5}$, SOx
Large and Area Source Boiler MACTs	All commercial/industrial boilers	NOx, $PM_{2.5}$, SOx
Commercial and Industrial Solid Waste Incineration Units (CISWI) New Source Performance Standards (NSPS)	Industrial/commercial boilers burning designated solid wastes	NOx, $PM_{2.5}$, SOx
SSI NSPS	Sewage sludge incinerators	NOx, $PM_{2.5}$
Revised Petroleum Refinery NSPS and MACT requirements	Petroleum refineries, very large petroleum storage tanks	VOC, $PM_{2.5}$

The most current emission inventory reflects the effects of many of these rules. Specific marine programs not included in the previous inventory that have significant impacts on Washington air quality include the North American Maritime Emission Control Area (ECA) regulations, the MARPOL VI annex, and the Marine Engine Requirements (40 CFR Part 94).

Starting in August 2012, the ECA required marine vessels within 200 nautical miles of the North American coast to use fuels with no more than 1 percent sulfur content, which decreased to 0.1 percent in 2015. EPA and the U.S. Coast Guard share implementation responsibilities for these requirements and have allowed some shipping companies delayed compliance dates for these requirements. Together, these programs require marine vessels to reduce SO_2 emissions by the equivalent of changing from 3.5–5 percent sulfur by weight fuel to 0.1 percent sulfur by weight

fuel. We expect a 70–90 percent reduction in SOx emissions from marine vessels in the ECA area. According to the EPA, ships complying with the ECA will reduce annual emissions of NOx, SOx and $PM_{2.5}$ by 23 percent, 74 percent and 86 percent, respectively, below the predicted levels without the ECA by 2020 (EPA Fact sheet 420-F-10-105, March 2010).

MARPOL (the International Convention for the Prevention of Pollution from Ships) Annex VI addresses air pollution from ocean-going ships. The MARPOL VI set limits on NOx emissions and has required the use of fuel with lower sulfur content since June of 2011.

40 CFR Part 94 marine engine requirements phase in NOx reductions as manufacturers build new vessels or install new replacement engines. Part 94 requires that new engines meet Tier 2 requirements in 2011 (equal to the MARPOL requirement) and Tier 3 requirements starting in 2016. EPA estimates that these NOx requirements will reduce national marine vessel NOx by 80 percent from 2009 levels.

The effects of the marine vessel fuel sulfur requirements are reflected in the IMPROVE data, though the effects of the ECA are not fully reflected in the data due to the long lead time for the phase-in of the MARPOL requirements and the relatively recent date (2013) for vessels to meet the first stage requirements.

Washington State emission limits and shutdowns

The following emission limits and shutdown schedules have gone into effect since the last implementation period or will occur prior to the end of the second implementation period and are part of Washington's LTS.

- TransAlta Centralia Generation, LLC Power Plant: best available retrofit technology (BART) Order revision and shutdown of coal-fired boilers. TransAlta is the only coal-fired power generation facility in Washington State. The facility ceased coal-fired operation in one boiler in December 2020 and will completely cease coal-fired operation by the end of 2025. Ecology updated the TransAlta BART Order in 2020, and EPA approved its incorporation into the SIP in June 2021 (86 Fed. Reg. 24502). This revised BART Order established lower NOx emissions limits from the remaining coal-fired boiler until the facility ceases coal-fired operation by the end of 2025.
- Cardinal Glass, a flat glass facility, submitted a permit modification application to Southwest Clean Air Agency (SWCAA) to install a selective catalytic reduction (SCR) emission control device and increase production of plate glass. The application also proposed removing the permit's emission controls of limiting excess oxygen. SWCAA issued the permit to the facility on February 11, 2021, and the SCR should be installed and operating in 2022. Ecology is submitting this permit as part of the LTS in our SIP.
- Ash Grove consent decree: The Ash Grove Cement Company entered into a consent decree with EPA, Ecology, the Puget Sound Clean Air Agency (PSCAA), and other state agencies in 2013 (Appendix E). The consent decree required the Seattle facility to submit an optimization protocol for the Seattle Kiln to optimize the operation of this unit to reduce NOx emissions to the maximum extent practicable. On August 25, 2016, EPA, in consultation with affected state agencies, approved the new limit of 5.1 pounds of NOx

per ton of clinker on a 30-day rolling average. Ecology is submitting this consent decree as part of the LTS in our SIP.

Non-regulatory factors can also result in decreased emissions. Economic and market conditions can drive business decisions that may result in decreased or curtailed production. In Washington, two aluminum smelters are currently in curtailment due to market conditions, one since 2014 and the second one since 2020. Ecology worked with these facilities to develop Agreed Orders (AOs 18100 and 18216 in Appendix Q) that require them to complete a four-factor analysis to evaluate emission controls prior to start-up, should they decide to resume operations. The four-factor analysis developed by the smelters will be subject to Ecology's approval, and any controls identified as necessary to make reasonable process must be installed and operational within three years of start-up. In addition, one of the smelters is in an area that EPA designated as being in nonattainment for the 2010 1-hour SO_2 NAAQS, effective April 31, 2021. Nonattainment is a separate and distinct regulatory program of the Clean Air Act, but the emission controls required for purposes of attainment will have visibility benefits. The SO_2 attainment plan will describe any emission controls required to bring the area back into attainment, such as installation of new control equipment and/or new emission limits. Future RH SIP analyses will incorporate the effects of the RH Agreed Orders and the attainment plan on visibility for new controls installed at the smelters as a result. Chapter 7 discusses these facilities in more detail. Ecology is submitting Agreed Orders AO 18100 and AO 18216 in Appendix Q as part of the LTS in our SIP.

Non-point and mobile sources

The RHR requires that states identify all anthropogenic sources of visibility impairment considered by the state when developing its LTS, including stationary, mobile, and non-point sources (40 CFR 51.308(f)(2)(i)). We discuss stationary sources in the previous section and in Chapter 6 (Source Apportionment) and Chapter 7 (four-factor Analysis).

Woodstoves

Woodstove smoke in Washington contributes to visibility impairment in the state. However, since 2007, Washington has decreased emissions from woodstoves by supporting a woodstove buy-back and exchange program (Chapter 173-433 WAC). This program provides grant funding to local clean air agencies and Ecology's regional offices to use in programs that replace older woodstoves with new, cleaner burning woodstoves or cleaner heat sources such as heat pumps, gas stoves, or furnaces. Some of these grant recipients have also run woodstove recycling programs where they buy back and destroy older stoves to remove them from use. Ecology estimates that in the past 13 years, state and local government agencies have bought back or exchanged more than 8,000 stoves for an estimated total reduction of 194 tons of $PM_{2.5}$. Since 2007, Ecology and the local clean air agencies have provided grants to replace 6,068 old woodstoves with cleaner sources of heat and incentives to recycle 2,472 woodstoves that did not meet current emission standards. This has reduced $PM_{2.5}$ emissions by over 200 tons.

Recent federal actions also contribute to the reduction of woodstove emissions. EPA's 2015 NSPS for new woodstoves established "Step 2" emission standards that went into effect in May

2020, limiting $PM_{2.5}$ emissions to 2.0 grams per hour if using crib wood (has standard characteristics) or 2.5 grams per hour if the manufacturer choses to use cord wood for performance testing (40 CFR 60 Subpart AAA). Prior to May 2020, Washington state law was more stringent than the applicable NSPS, limiting $PM_{2.5}$ emissions to 2.5 grams per hour for catalytic devices and 4.5 grams per hour for all other devices (RCW 70A.15.3530). Because the federal standards are now more stringent, Ecology is using its delegated CAA authority to enforce the NSPS Step 2 standards.

Mobile sources

Although Ecology does not directly regulate emissions from mobile sources, we actively participate in programs that reduce mobile source emissions and manage grants that result in reduced emissions and higher fuel economy.

Mobile sources are the largest contributors to NOx emissions in Washington. Population growth has contributed to increased mobile source emissions. Factors that have decreased mobile source emissions include fleet turnover to more fuel efficient or electric vehicles, low sulfur fuel requirements, and adoption of California's low emission vehicle standards.

Motor Vehicle Emission Inspection program retirement

Another program that has contributed to emission reductions from mobile sources was Washington's vehicle emission testing program. The program required vehicles registered in Washington to meet state emission limits as a condition of vehicle registration. The combination of the vehicle emission testing program and advances in vehicle technology led to reduced mobile source emissions. The legislature phased the emission testing program out starting in 2005 based on Ecology's prediction that more fuel efficient and electric vehicles would replace the need for it by 2020 (RCW 70A.25.030). The program ended on January 1, 2020.

New state laws and regulations

Washington has also pursued mobile source emission reductions through the technology of zero emission vehicles (ZEV) and low-emission vehicles (LEV). Special provisions in the federal Clean Air Act (Section 177) allow states to adopt California's standards instead of the federal motor vehicle emission standards. California's standards contain both LEV and ZEV requirements.

In 2005, the Washington Legislature adopted the California vehicle emission standards for passenger cars, light duty trucks, and medium duty passenger vehicles (ESHB 1397). However, the law did not adopt the ZEV standards or the LEV standards for medium duty trucks (trucks generally weighing between 8,500 and 14,000 pounds). The 2020 Legislature expanded Washington's program to include the entire California program and directed Ecology to adopt rules to implement the ZEV program (SB 5811). We are currently in the process of adopting rules to reflect our expanded statutory authority

In addition, Ecology submitted a SIP revision to EPA in 2019 to adopt by reference California's LEV program. The purpose of the SIP revision was to implement programs to reduce vehicle emissions that contribute to formation of ground level ozone and fine particulate matter

($PM_{2.5}$). The precursors to ground level ozone and $PM_{2.5}$ also contribute to regional haze. EPA is currently proposing to approve this revision to the Washington SIP (86 FR 46169).

State grant programs

Ecology has also pursued grant opportunities that result in decreased emissions from mobile sources. Volkswagen (VW) violated federal and state clean air laws by installing illegal emissions software on some diesel vehicles. In January 2016, the U.S. Department of Justice filed a lawsuit on behalf of EPA against VW. After admitting fault, VW reached multiple settlements with EPA and Ecology. Ecology is managing $140 million in settlement funds used to reduce air pollution from transportation. As of February 2020 we have committed $91 million statewide to projects that decrease diesel emissions such as electrification of school buses, transit buses, ferries, state fleet vehicles, port drayage trucks, shore power, and installing light duty electric vehicle charging stations.

Factors required for the long-term strategy

In addition to the FFA, the RHR requires states to consider the following five factors in developing a LTS (40 CFR 51.308(f)(2)(iv)).

Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment (40 CFR 51.308(f)(2)(iv)(A)).

In addition to the ongoing air pollution control programs described above, current state and federal rules and state and local air agency permits limit visibility-impairing emissions from point, non-point, and mobile sources. The projected 2028 emissions inventory reflects the emission reductions from most rules and permits in existence in 2018.

To obtain a permit, future major and minor new sources, or modifications to existing sources, will need to meet state permitting requirements; including meeting Best Available Control Technology (BACT) emission limits. Major New Source Review (NSR) permits include requirements to meet Air Quality Related Values (AQRV) protection criteria established by EPA for Class 1 Areas.

Ecology and local air pollution control authorities work to reduce emissions from existing emission producing units and to minimize new emissions through the state NSR program. This program requires BACT emission reductions for all new sources and modifications that result in an increase of emissions.

State law (RCW 70A.15.2220) requires that when a source decides to modify or replace an existing emission control system, Ecology or the local air pollution control authority must assure that the modified or replacement control system meets a reasonably available control technology (RACT) level of emissions control at a minimum.

Measures to mitigate the impacts of construction activities (40 CFR 51.308(f)(2)(iv)(B)).

Ecology or a local air quality agency regulates construction activities as a source of air pollution. The following State air quality rules (WAC 173-400-040(3) and (9)) address air emissions associated with construction activities.

- WAC 173-400-040(3) (Fallout)
- WAC 173-400-040(4) (Fugitive emissions)
- WAC 173-303-040(9) (Fugitive dust)

Local clean air agencies and local governments have additional rules and policies governing mitigation of air pollution from construction activities. We describe types of construction permits in Washington below. These are all part of a federally enforceable permitting program.

A prevention of significant deterioration (PSD) permit applies to new large facilities or major changes at existing large facilities that could increase air pollution in an area that meets air quality standards. The intent is to prevent that area's air quality from getting worse.

A notice of construction (NOC) approval order is required before installing a new source of air pollution or modifying an existing source of air pollution.

Regulators issue a general order for similar sources of air pollution, instead of a series of individual NOC permits.

An air operating permit (AOP) combines all applicable rules and requirements for operation and procedures, emission standards, monitoring, recordkeeping, and reporting. An AOP is required for major sources that emit or have the potential to emit more than 100 tons per year of any air pollutant, 10 tons per year or more of any hazardous air pollutant, or more than 25 tons per year of a combination of hazardous air pollutants.

Source retirement and replacement schedules (40 CFR 51.308(f)(2)(iv)(C)).

TransAlta's Centralia Power Plant boiler number one ceased coal-fired energy production in December of 2020. The remaining boiler (boiler number two), and thus the entire facility, is required to cease coal-fired operation by the end of 2025. A 2020 revised BART Order requires reduced NOx levels until coal-fired production ceases in 2025.

Basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs (40 CFR 51.308(f)(2)(iv)(D)).

As part of the regional haze LTS, states are required to consider basic smoke management practices for prescribed fire used for agricultural and wildland vegetation (silvicultural) management purposes and smoke management programs (40 CFR Section 51.308(f)(2)(iv)(D)). Under Washington State law, Ecology and the local air agencies regulate agricultural burning (WAC 173-430). The state has established controls required for agricultural burning to minimize adverse health and environmental impacts. The state works with a variety of stakeholders including agricultural burners, agricultural interest groups, and air quality interest groups to encourage development, research, and use of alternatives to burning.

The Washington State Department of Natural Resources (DNR) issues silvicultural burning permits in Washington according to the regulatory direction provided in the SIP-approved 1998 Washington Department of Natural Resources Smoke Management Plan.[24][25] The goal of the plan is to coordinate and facilitate statewide regulation of silvicultural burning on lands under DNR jurisdiction, and on unimproved federally managed forestlands and participating tribal lands. The strategy of DNR's Smoke Management Plan is to balance the protection of public health and visibility with the need for silvicultural burning to improve ecosystem health and reduce the damaging effects of catastrophic wildfires. Prescribed silvicultural burning is a non-point source and prescribed burn plumes can have significant impacts on visibility. Washington proactively addressed this source in its RAVI SIP. Washington incorporated the state's Smoke Management Plan into the September 1999 revisions to the RAVI SIP and EPA approved the Smoke Management Plan's incorporation into the SIP in 2003. DNR is currently revising and preparing to update the Smoke Management Plan in the SIP. Ecology will provide status of the RAVI SIP in the 2025 RH Progress Report.

The anticipated net effect on visibility due to projected changes in point, non-point, and mobile source emissions over the period addressed by the long-term strategy (40 CFR 51.308(f)(2)(iv)(E)).

Ecology used the WRAP modeled inventory for this RH SIP to determine the expected net effect of projected changes to visibility due to emission changes over the control period for the second RH SIP ending in 2028. The modeled effects reflect the implementation of controls on the books.

[24] https://www.epa.gov/sips-wa/epa-approved-nonregulatory-provisions-and-quasi-regulatory-measures-washington-sip

[25] http://file.dnr.wa.gov/publications/rp_burn_smptoc.pdf

Table 8-2 below presents the net effects of emission changes on visibility. The net effect for the MID was considered in establishing RPGs for Washington's mandatory Class 1 Areas. The modeling results show that we meet the goal of no degradation of visibility for the clearest days.

Table 8-2: Anticipated net effect on visibility of emission reductions over the second control period for MID, in deciviews (dv)

Class 1 Area	2014 to 2018 (dv)	2028 projected visibility (dv)	Improvement (dv)
Olympic National Park	11.9	11.5	0.4
North Cascades National Park and Glacier Peak Wilderness	10	9.8	0.2
Alpine Lakes Wilderness	12.7	12.0	0.7
Mount Rainier National Park	12.7	12.0	0.7
Goat Rocks Wilderness and Mount Adams Wilderness	8	7.6	0.4
Pasayten Wilderness	9.5	9.2	0.3

Table 8-3: Anticipated net effect on visibility of emission reductions over the second control period for clearest days, (dv)

Class 1 Area	2014 to 2018 (dv)	2028 projected visibility (dv)	Improvement (dv)
Olympic National Park	3.6	3.4	0.2
North Cascades National Park and Glacier Peak Wilderness	2.5	2.4	0.1
Alpine Lakes Wilderness	3.3	3.1	0.2
Mount Rainier National Park	3.9	3.7	0.2
Goat Rocks Wilderness and Mount Adams Wilderness	1.0	0.9	0.1
Pasayten Wilderness	1.6	1.5	0.1

8.7 Summary

Washington State's LTS for visibility improvement reduces haze-causing emissions that contribute to visibility impairment in Washington's Class 1 Areas and in Class 1 Areas outside of Washington, where we reasonably anticipate Washington emissions contribute to visibility impairment.

The LTS for this second RH SIP includes the following key elements:

- Existing federal and state laws and regulations, including federal fuel and engine rules for on-road and non-road vehicles, are important for making reasonable progress by 2028.
- Additional reductions from mobile sources due to state legislation, rulemaking, and grants will continue to decrease vehicle emissions.
- New emission controls to reduce NOx emissions, including the cessation of all coal-fired energy generation in the state by 2025 (and reductions in NOx at the coal-fired facility until 2025), and SCR operation at Cardinal Glass.
- Organic mass emissions resulting primarily from fire are an important contributor to total light extinction in Washington's Class 1 Areas.
- Regional contributions beyond the direct control of Ecology, from Canada and Pacific offshore sources and wildfires, play a significant role in visibility impairment in Washington's Class 1 Areas.
- Washington's LTS prioritizes improvement to visibility on the MID.

Chapter 9. Reasonable Progress Goals

9.1 Introduction

The Regional Haze Rule requires states to establish reasonable progress goals (RPGs) for mandatory Class 1 Areas within the state. The RPGs, expressed in deciviews (dv), reflect projected visibility improvements achieved by the end of the current implementation period (2018 to 2028) for the most impaired days (MID) and ensure no degradation in visibility on the clearest days. The RPGs are based on the long-term strategy that addresses visibility impairment for each Class 1 Area (see Chapter 8). The long-term strategy includes the measures that are necessary to make reasonable progress during this implementation period.

In the establishment of RPGs, the Regional Haze Rule requires states to consider both:

- The uniform rate of progress (URP) needed to attain natural conditions by 2064 (shown as a glidepath), and
- The four statutory factors required by the federal Clean Air Act to use in determining what measures are necessary to make reasonable progress.

Ecology's calculation of RPGs relies on technical data and analysis developed by the Western Regional Air Partnership (WRAP). Data are available on WRAP's Technical Support System (TSS2) website[26].

WRAP determined the RPGs for each Class 1 Area using the guidance "Procedures for Making Visibility Projections and Adjusting Glidepaths using the WRAP-WAQS 2014 Modeling Platform" (Appendix D). Projected 2028 emissions for mobile sources and major facilities were obtained by WRAP from EPA and states, representing existing and expected controls. The modeled baseline and projections were used to calculate relative response factors (RRFs), which were applied to the measured baseline period concentrations at the IMPROVE sites, thus providing 2028 RPG visibility projections (see Chapter 5 for more information on modeling). The RPGs for Washington's Class 1 Areas are shown in Table 9-1.

[26] http://views.cira.colostate.edu/tssv2/

Table 9-1: Washington's Class 1 Areas and their 2028 reasonable progress goals in deciviews (dv)

Class 1 Area	Reasonable progress goal
Olympic National Park	11.5 dv
North Cascades National Park	9.8 dv
Glacier Peak Wilderness Area	9.8 dv
Alpine Lakes Wilderness Area	12.0 dv
Mount Rainier National Park	12.0 dv
Goat Rocks Wilderness Area	7.6 dv
Mount Adams Wilderness Area	7.6 dv
Pasayten Wilderness Area	9.2 dv

Uniform rate of progress glidepath adjustment

The charts in this chapter illustrate the regional haze glidepath as defined by EPA guidance and an alternative glidepath with a 2064 endpoint adjustment. The adjusted endpoint of the glidepath and thus the associated slope is consistent with methods described in the EPA's September 2019 regional haze modeling Technical Support Document. Per the Regional Haze Rule, a state can select the default glidepath slope or propose to use endpoint adjustment options for international sources and prescribed fire contributions to visibility at each Class 1 Area (40 CFR 51.308(f)(1)(vi)).

Washington's Class 1 Areas are all affected by international anthropogenic contributions that Washington cannot control. Source apportionment results (Chapter 6) show that sulfates from international anthropogenic sources are expected to impact visibility more than in-state sources at all Washington Class 1 Areas. Source apportionment results also show that nitrates from international anthropogenic sources are expected to impact visibility more than in-state sources at most Washington Class 1 Areas, with the exception of Alpine Lakes Wilderness Area and Mount Rainier National Park. We propose to use the international adjustment added to the EPA estimated natural conditions endpoint, calculated using the 2028 modeling results normalized to the monitored visibility.

Four-factor analysis

The RHR requires states to perform a four factor analysis (FFA) to determine whether the installation of new emission controls at certain facilities is necessary for the state to make reasonable progress toward the national visibility goal. 40 CFR 51.308(f)(2)(i) requires the state to consider the following four statutory factors in determining which emission reductions measures are necessary to make reasonable progress:

- Costs of compliance,
- The time necessary for compliance,
- The energy and non-air quality environmental impacts of compliance, and
- The remaining useful life of any potentially affected sources.

Ecology selected point sources with the largest "Q/d" to undergo a FFA, where the annual emissions (Q) is divided by the distance to the nearest Class 1 Area (d). The Q/d point-source screening is discussed in Chapter 7, while the long-term strategies for non-point and mobile sources are discussed in Chapter 8. Ecology requested a FFA from facilities chosen in the source-selection process. Ecology reviewed the FFA information submitted by the sources. The conclusions from this review are described in Chapter 7 and summarized here.

The Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data show that sulfate (SO_4) and nitrate (NO_3) are two of the most significant pollutants impairing visibility in Washington's Class 1 Areas. SO_2 and NOx emissions are precursors of SO_4 and NO_3, respectively. The WRAP visibility projections show that SO_4 and NO_3, which are mostly anthropogenic in origin, are expected to continue impairing visibility in 2028 more than the other monitored pollutant species. The majority of SO_4 impairment at Class 1 Areas from in-state sources is attributed to non-EGU (electric generating units) point sources, as discussed in Chapter 6. The majority of NO_3 impairment at Class 1 Areas from in-state sources is attributed to mobile vehicles.

Ecology is focusing on SO_2 and NOx emission reductions from major point sources for this implementation period (2018 – 2028) because major point sources contribute the majority of the haze-causing emissions that the state can potentially control. SO_2 and NOx make up the majority of the haze-causing emissions from the major sources. NOx emissions from mobile sources decreased significantly prior to 2018 due to the vehicle and engine provisions of Title II of the Clean Air Act and other regulations (40 C. F. R. Parts 85, 86, 88 through 94, 600, and 1033 through 1068), and are expected to continue decreasing each year due to fleet turnover and recent legislation requiring Ecology to adopt California's low emission vehicle standards (SB 5811, 2020)[27] and to establish a clean transportation fuels standard (E3SHB 1091, 2021)[28].

Ecology evaluated projected 2028 emissions of SO_2 and NOx from specific emission processes as defined by Source Classification Codes (SCCs). We identified the SCCs projected to have the largest SO_2 and NOx emissions from in-state point sources. The resulting three groups were industrial processes, external combustion boilers, and internal combustion engines. Emissions of SO_2 and NOx from specific industries and emission source categories vary greatly across these three groups.

Ecology calculated the total emissions of SO_2, NOx, PM_{10}, and NH_3 from each major facility to inform source-selection. The majority of sources selected for FFA are located in the Puget Sound lowlands in western Washington, and may contribute to visibility impairment at multiple Class 1 Areas. Seven of Washington's eight Class 1 Areas are directly to the east of the Puget Sound lowlands, in the Cascade Mountains. The eighth Class 1 Area is located directly to the

[27] https://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/Session Laws/Senate/5811.SL.pdf?cite=2020%20c%20143%20%C2%A7%201

[28] https://lawfilesext.leg.wa.gov/biennium/2021-22/Pdf/Bills/Session Laws/House/1091-S3.SL.pdf?q=20210929134724

west of the Puget Sound lowlands on the Olympic Peninsula. See Chapter 7 for details about the process used and the final list of sources selected for FFA.

Based on the FFAs, we concluded that there is potential for SO_2 and NOx emission reductions from a number of emission points, principally boilers, process heaters, and fluidized catalytic cracking unit/carbon monoxide boiler systems.

Reasonably available control technology

As discussed in Chapter 7, in Washington State, RCW 70A.15.2230 (the "RACT statute") is the legal mechanism that Ecology can use to require existing sources to install new emission controls that are determined to be reasonable. Because the analysis performed under the State's RACT process is equivalent to the RHR's FFA, Ecology will use the RACT process to require the installation of reasonable emission controls for purposes of compliance with the RHR.

After the RACT analysis is complete, Ecology will make a determination of what constitutes reasonable emission control(s) for each selected source. The determination will result in an enforceable requirement to install and operate the controls identified in the analysis. The results of the analysis and the subsequent determinations will be included in a supplement to our Regional Haze SIP revision. Development of controls is discussed more as part of Washington's long-term strategy in Chapter 6 (Source Apportionment) and Chapter 7 (FFA).

Progress in reducing visibility impairing pollutants

As discussed in Chapter 4, projected 2028 emissions and the resulting RPGs reflect controls "on-the-books" (OTB) throughout the WRAP region. OTB controls are existing, legally adopted controls that will reduce visibility impairing pollutants during the second implementation period of 2018 to 2028. Large statewide reductions in NOx (50 percent) are expected by 2028 as a result of engine and fuel rules that reduce vehicle emissions. Significant reductions in NOx and SO_2 are also expected after the full cessation of coal-burning at TransAlta Centralia Generation facility in 2025. Additionally, recent emission reductions measures for TransAlta and Cardinal Glass were included in the long-term strategy and the 2028 modeled emission projections for determining reasonable progress goals. For the purpose of the WRAP modeling and this document these recent emission reduction measures were included in the "2028 OTB projection" because the TransAlta reduction measures were approved by the EPA in the SIP on May 7, 2021 (86 FR 24502) and the revised Cardinal Glass permit was issued by SWCAA to the facility on February 11, 2021 for inclusion in the LTS. These and other controls are discussed in Chapter 8 (long-term strategy).

9.2 Olympic National Park

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at Olympic National Park are monitored at the IMPROVE site OLYM1. The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 14.9 dv. The calculated natural conditions for the adjusted glidepath are 8.9 dv, a difference of 6 dv and

a rate of 0.1 dv per year (6 dv divided by 60 years). This is the rate that needs to be maintained to reach natural visibility conditions in the park by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 1.4 dv. The 2028 RPG is projected to be 11.5 dv, which is a visibility improvement of 3.4 dv from the baseline.

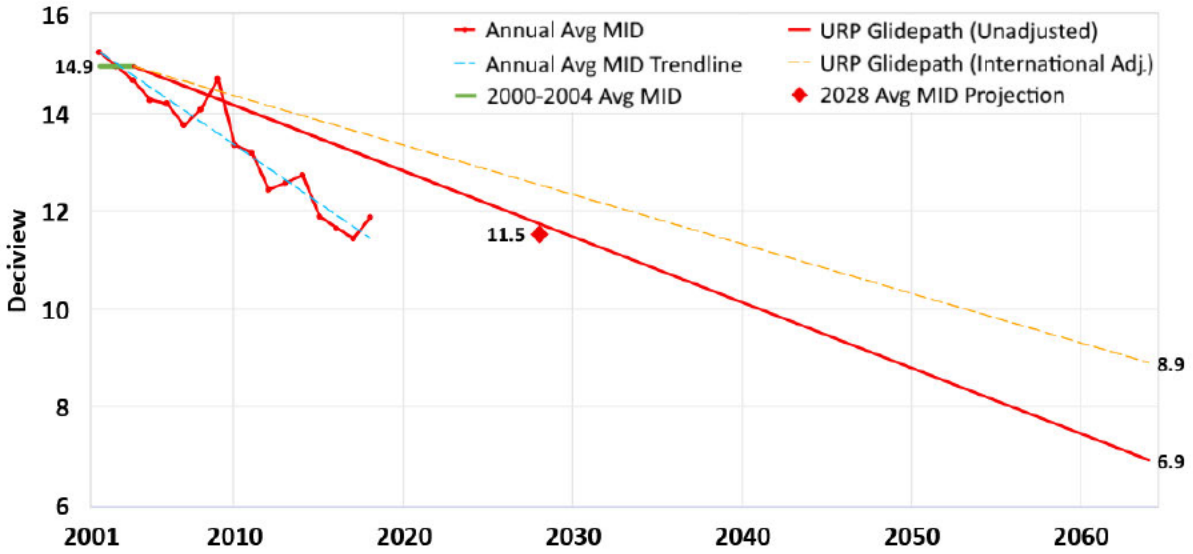


Figure 9-1: Projected 2028 visibility conditions on the MID in Olympic National Park.

Progress in reducing visibility impairing pollutants

Table 9-2: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in Olympic National Park.

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	10.0	4.3	4.6	1.2	1.3	0.2	0.8
2028 OTB projection	10.0	3.3	4.5	1.0	1.3	0.2	0.8
Percent change	0%	-23%	-3%	-14%	0%	-1%	0%

Summary: Ecology concludes from this analysis that progress is being made in reducing visibility impairing pollutants impacting Olympic National Park. The 2028 RPG for Olympic National Park is 11.5 dv assuming emission controls that are on the books.

Clearest days

The monitored 2000-2004 baseline conditions at OLYM1 on the Clearest Days are 6 dv. This second SIP covers the 2018 - 2028 period. WRAP modeling projects no degradation on the

clearest days because the 2028 visibility of 3.37 dv for the clearest days is below the baseline for the clearest days.

9.3 North Cascades National Park and Glacier Peak Wilderness

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at North Cascades National Park and Glacier Peak Wilderness are monitored at the IMPROVE site NOCA1. The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 12.6 dv. The calculated natural conditions for the adjusted glidepath are 8.2 dv, a difference of 4.4 dv and a rate of 0.07 dv per year (4.4 dv divided by 60 years). This is the average rate that needs to be maintained to reach natural visibility conditions in these Class 1 Areas by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 1.8 dv. The 2028 RPG is projected to be 9.8 dv, which is a visibility improvement of 2.8 dv from the baseline and 0.2 dv below the 2014 to 2018 average.

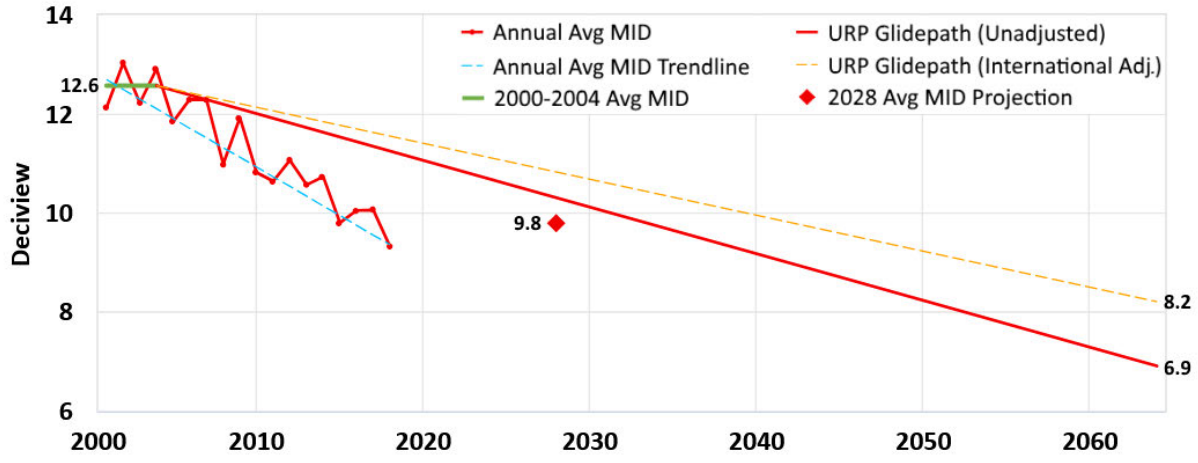


Figure 9-2: Projected 2028 visibility conditions on the MID in North Cascades National Park and Glacier Peak Wilderness

Progress in reducing visibility impairing pollutants

Table 9-3: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in North Cascades National Park and Glacier Peak Wilderness.

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	8.1	1.7	4.0	0.9	1.3	0.2	0.3
2028 OTB projection	8.2	1.2	4.0	0.9	1.3	0.2	0.3
Percent change	0%	-28%	-1%	-4%	0%	-1%	0%

Summary: Ecology concludes from this analysis that progress is being made in reducing visibility impairing pollutants that impact the North Cascades National Park and Glacier Peak Wilderness. The 2028 RPG is 9.8 dv assuming emission controls that are on the books.

Clearest days

The monitored 2000-2004 baseline conditions at NOCA1 on the clearest days are 3.4 dv. WRAP modeling projects no degradation on the clearest days because the 2028 visibility of 2.38 dv for the clearest days is below the clearest days baseline.

9.4 Alpine Lakes Wilderness

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at Alpine Lakes Wilderness are monitored at the IMPROVE site SNPA1. The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 15.4 dv. The calculated natural conditions for the adjusted glidepath are 8.2 dv, a difference of 7.2 dv and a rate of 0.1 dv per year (7.2 dv divided by 60 years). This is the average rate that needs to be maintained to reach natural visibility conditions in the park by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 2.9 dv. The 2028 RPG is projected to be 12.0 dv, which is a visibility improvement of 3.4 dv from the baseline and 0.7 dv below the 2014 to 2018 average.

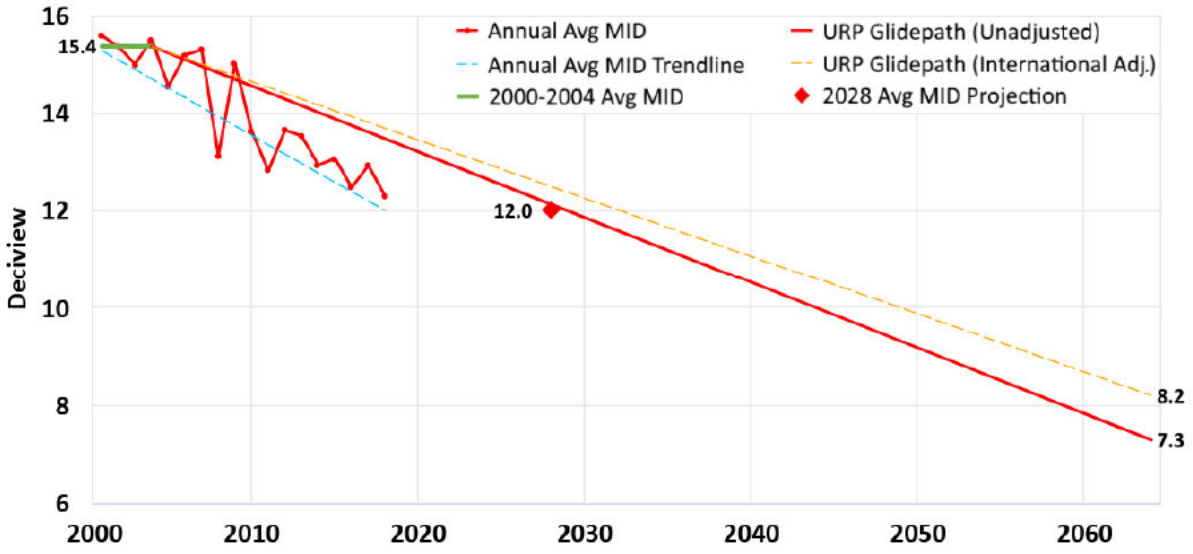


Figure 9-3: Projected 2028 visibility conditions on the MID in Alpine Lakes Wilderness

Progress in reducing visibility impairing pollutants

Table 9-4: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in the Alpine Lake Wilderness.

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	8.8	6.7	6.4	1.8	1.1	0.2	0.3
2028 OTB projection	8.8	4.3	6.3	1.8	1.1	0.2	0.3
Percent change	-1%	-37%	-1%	-4%	0%	-1%	-1%

Summary: Ecology concludes from this analysis that Washington is making progress in reducing visibility impairing pollutants impacting Alpine Lakes Wilderness. The 2028 RPG is 12.0 dv assuming emission controls that are on the books.

Clearest days

The monitored 2000-2004 baseline conditions at SNPA1 on the clearest days are 5.5 dv. WRAP modeling projects no degradation on the clearest days because the 2028 visibility of 3.0 dv is below the clearest days baseline.

9.5 Mount Rainier National Park

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at Mount Rainier National Park are monitored at the IMPROVE site MORA1. The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 16.5 dv. The calculated natural conditions for the adjusted glidepath are 8.9 dv, a difference of 7.6 dv and a rate of 0.1 dv per year (7.6 dv divided by 60 years). This is the average rate that needs to be maintained to reach natural visibility conditions in the park by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 3.0 dv. The 2028 RPG is projected to be 12.0 dv, which is a visibility improvement of 4.5 dv from the baseline and 0.7 below the 2014 to 2018 average.

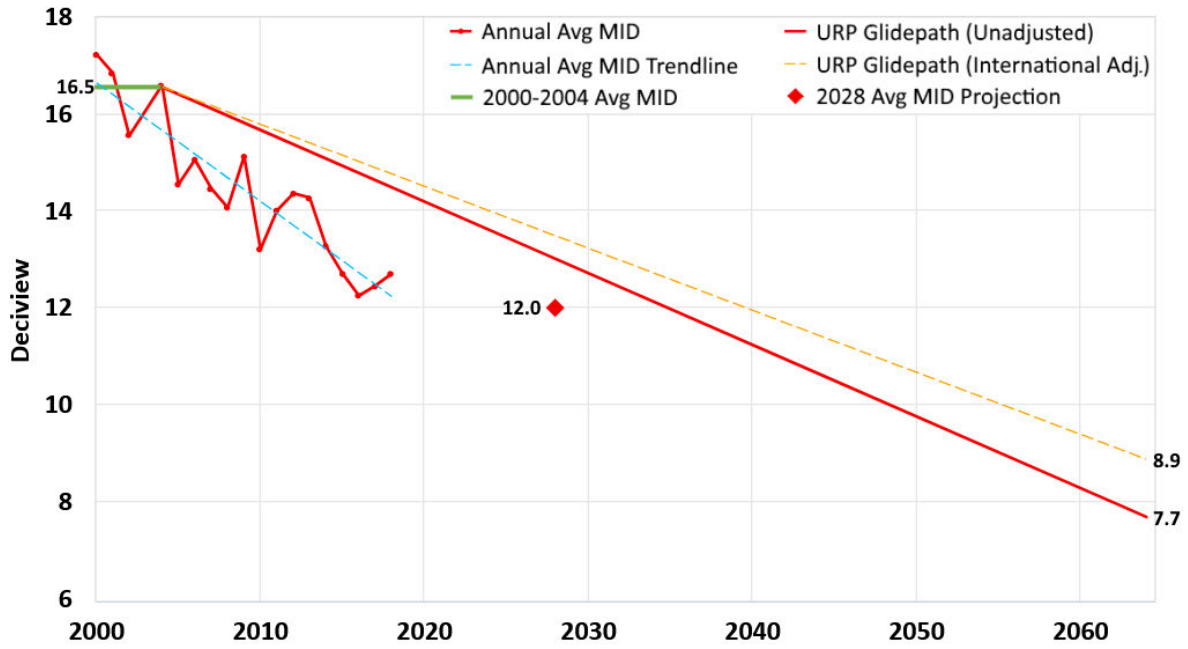


Figure 9-4: Projected 2028 visibility conditions on the MID in Mount Rainier National Park

Progress in reducing visibility impairing pollutants

Table 9-5: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in Mount Rainier National Park.

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	10.1	2.3	7.8	2.3	1.9	0.2	0.3
2028 OTB projection	9.7	1.1	7.4	1.9	1.9	0.2	0.3
Percent change	-4%	-50%	-5%	-16%	+1%	-3%	0%

Sulfate:

Statewide emissions of SO_2 are projected to decline almost 40% between the 2000-2004 baseline period and 2028. This decline results from a 29% reduction in point source emissions and a 95% reduction in on-road and off-road mobile source emissions. The mobile source reduction reflects the removal of sulfur from on-road and off-road fuels.

Summary: Ecology concludes from this analysis that overall Washington is making progress in reducing visibility impairing pollutants impacting Mount Rainier National Park. The 2028 RPG is 12.0 dv assuming emission controls that are on the books.

Clearest days

The monitored 2000-2004 baseline conditions at MORA on the clearest days are 5.5 dv. WRAP modeling projects no degradation on the clearest days because the 2028 visibility of 3.68 dv is below the clearest days baseline.

9.6 Goat Rocks Wilderness and Mount Adams Wilderness

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at Goat Rocks Wilderness and Mount Adams Wilderness are monitored at the IMPROVE site WHPA1. The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 10.5 dv. The calculated natural conditions for the adjusted glidepath are 8.1 dv, a difference of 2.4 dv and a rate of 0.04 dv per year (2.4 dv divided by 60 years). This is the average rate that needs to be maintained to reach natural visibility conditions in the park by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 0.96 dv. The 2028 RPG is projected to be 7.6 dv, which is a visibility improvement of 2.9 dv from the baseline and 0.4 dv below the 2014 to 2018 average. Natural conditions have been reached at these Class 1 Areas and air quality is projected to continue to be better than natural conditions by 2028. However, we anticipate that there may be additional visibility improvements with improved air quality in the state over the remaining implementation periods.

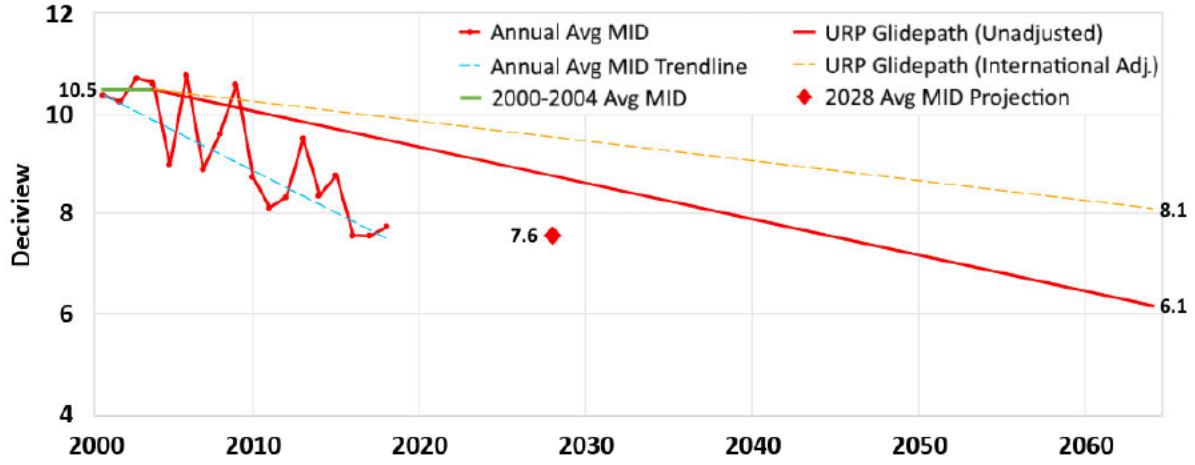


Figure 9-5: Projected 2028 Visibility Conditions on the MID in Goat Rocks Wilderness and Mount Adams Wilderness

Progress in reducing visibility impairing pollutants

Table 9-6: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in Mount Adams Wilderness and Goat Rocks Wilderness

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	6.4	1.5	2.8	0.7	0.9	0.3	0.2
2028 OTB Projection	6.3	1.0	2.6	0.5	0.9	0.3	0.2
Percent Change	-1%	-36%	-7%	-21%	0%	-3%	-1%

Summary: Ecology concludes from this analysis that overall Washington is making progress in reducing visibility impairing pollutants impacting Goat Rocks Wilderness and Mount Adams Wilderness. The 2028 RPG is 7.5 dv assuming emission controls that are on the books. This is less than projected natural conditions of 8.1 with the glidepath adjusted endpoint.

Clearest days

The monitored 2000-2004 baseline conditions at WHPA1 on the clearest days are 1.7 dv. WRAP modeling projects no degradation on the clearest days because the 2028 visibility of 0.91 dv is below the clearest days baseline.

9.7 Pasayten Wilderness

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at Pasayten Wilderness are monitored at the IMPROVE site PASA1 The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 10.4 dv. The calculated natural conditions for the adjusted glidepath are 8.0 dv, a difference of 2.4 dv and a rate of 0.04 dv per year (2.4 dv divided by 60 years). This is the average rate that needs to be maintained to reach natural visibility conditions in the park by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 0.96 dv. The 2028 RPG is projected to be 9.2 dv, which is a visibility improvement of 1.2 dv from the baseline and 0.3 dv below the 2014 to 2018 average.

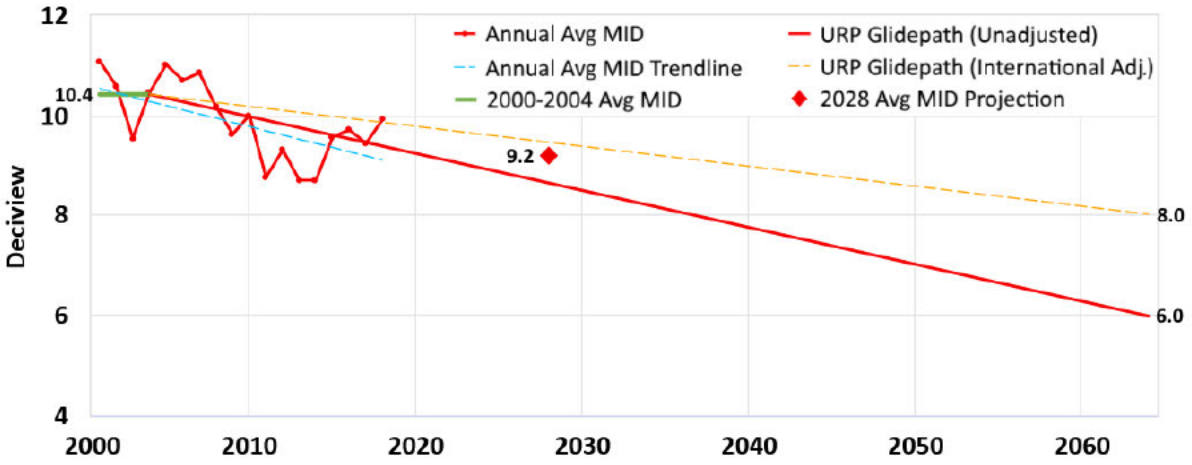


Figure 9-6: Projected 2028 visibility conditions on the MID in Pasayten Wilderness

Progress in reducing visibility impairing pollutants

Table 9-7: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in Pasayten Wilderness

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	5.8	2.3	5.4	1.1	1.3	0.4	0.1
2028 OTB projection	5.8	1.8	5.2	1.0	1.3	0.4	0.1
Percent change	0%	-23%	-2%	-9%	0%	-1%	-1%

Summary: Ecology concludes from the analysis provided above that Washington is making progress in reducing visibility impairing pollutants impacting Pasayten Wilderness. The 2028 RPG is 9.2 dv assuming emission controls that are on the books.

Clearest days

The monitored 2000-2004 baseline conditions at PASA1 on the clearest days are 2.7 dv. WRAP modeling projects no degradation on the clearest days because the 2028 visibility of 1.46 dv is below the clearest days baseline.

9.8 Summary

Ecology established RPGs, in deciviews, for the MID and the clearest days as required by the Regional Haze Rule. These are summarized in Table 9-8 and Table 9.9. It is projected that Washington will continue to make progress during this implementation period and the 2028 MID RPGs are below the URP adjusted glidepath. The 2028 RPGs for the clearest days are projected to stay below the baseline and therefore show no degradation in visibility.

Table 9-8: 2028 reasonable progress goals in deciviews (dv) for the MID

Mandatory Class 1 Areas	Baseline conditions 2000-2004	Five-year average 2014 to 2018	MID reasonable progress goal 2028	Unadjusted glidepath 2028	Adjusted glidepath 2028
Olympic National Park	14.9	11.9	11.5	11.7	12.5
North Cascades National Park & Glacier Peak Wilderness	12.6	10	9.8	10.3	10.8
Alpine Lakes Wilderness	15.4	12.7	12.0	12.1	12.5
Mount Rainier National Park	16.5	12.7	12.0	13	13.9
Goat Rocks Wilderness & Mount Adams Wilderness	10.5	8.0	7.6	8.7	9.5
Pasayten Wilderness	10.4	9.5	9.2	8.6	9.4

Table 9-9: 2028 projections in deciviews (dv) for the clearest days

Mandatory Class 1 Areas	2000-2004 Baseline Conditions	2028 projection
Olympic National Park	6	3.37
North Cascades National Park & Glacier Peak Wilderness	3.4	2.38
Alpine Lakes Wilderness	5.5	3.03
Mount Rainier National Park	5.5	3.68
Goat Rocks Wilderness & Mount Adams Wilderness	1.7	0.91
Pasayten Wilderness	2.7	1.46

International anthropogenic emissions contribute to visibility impairment in all of Washington's Class 1 Areas. International emissions include emissions from Canada, Asia, international commercial marine vessels from outside and inside the Emissions Control Areas, and all other non-US anthropogenic emission sources from outside and inside the modeling domain. Thus Washington is adding the international contributions to the endpoint (natural conditions) of the glidepaths for all the State's Class 1 Areas since those emissions are significant and are not controllable by the state. If prescribed fire has a significant influence on regional haze in the future, natural conditions may need to be adjusted further, as allowed by the Regional Haze Rule.

Under the Regional Haze Rule, RPGs for the clearest days are required to ensure no degradation of visibility from baseline visibility conditions. WRAP's modeling analysis indicates these goals will be met. Washington's average decrease in dv (visibility improvement) is summarized in Table 9-10. The required average decrease in dv per year from 2004–2064 to achieve natural conditions is listed in the second column. For both 2004–2018 and 2004–2028, Washington's visibility improvement per year exceeds the average per year rate needed to achieve natural conditions by 2064.

Table 9-10: Average visibility improvement in deciviews (dv) on MIDs at Washington's Class 1 Areas

Monitor	2004 to 2064 dv average needed per year to stay on track to meet 2064 natural conditions	Actual dv decrease per year 2004 to 2018	Projected 2004 to 2028 RPG dv decrease per year
MORA1	0.13	0.27	0.19
WHPA1	0.04	0.18	0.12
SNPA1	0.12	0.19	0.14
NOCA1	0.07	0.19	0.12
PASA1	0.04	0.06	0.05
OLYM1	0.10	0.21	0.14

Chapter 10.Future Planning Process and Summary

10.1 Future planning process

The Regional Haze Rule requires each state to prepare a long-term monitoring strategy and commit to the periodic collection, reporting, and analysis of monitoring and emissions inventory data. The Regional Haze Rule also includes other requirements regarding periodic progress reports, State Implementation Plan (SIP) revisions, and continuing consultation. These future planning requirements are:

- Submitting a monitoring strategy with the SIP
- Including a commitment to update the statewide emissions inventory of visibility impairing pollutants
- Submitting periodic reports describing progress towards the reasonable progress goals
- Determining the adequacy of the existing SIP
- Revising the SIP every ten years
- Continuing interstate coordination and consultation
- Continuing consultation with the Federal Land Managers (FLMs)

Monitoring strategy

Ecology will continue to work in collaboration with the Western Regional Air Partnership (WRAP) and rely upon their adequate technical support to meet its commitment to conduct the analyses necessary to meet the requirements of the Regional Haze Rule.

Ecology will depend on the Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) monitoring program to collect and report aerosol monitoring data for long-term reasonable progress tracking as specified in the Regional Haze Rule. The Regional Haze Rule is a long-term tracking program with an implementation period set for 60 years and states expect the IMPROVE program will provide data based on the following goals:

- Maintain a stable configuration of the individual monitors and sampling sites, and stability in network
- Continue operations for the purpose of continuity in tracking reasonable progress trends
- Assure sufficient data capture at each site of all visibility-impairing species
- Comply with EPA's quality control and assurance requirements
- Prepare and disseminate periodic reports on IMPROVE program operations

Ecology is relying on the IMPROVE program with the fundamental assumption that network data collection operations will not change, or if changed, will remain directly comparable to those operated by the IMPROVE program during the 2000-04 Regional Haze Rule baseline period. Ecology based the technical analyses and reasonable progress goals in this implementation plan on data from these sites.

Federal agencies provide the human resources to operate these monitors. Ecology will collaborate with the EPA, FLMs, other states, tribes, and the IMPROVE committee to ensure adequate and representative data collection and reporting by the IMPROVE program.

Ecology will use data reported by the IMPROVE program as part of the regional technical support analysis tools found at the Technical Support System (TSS2), as well as other analysis tools and efforts sponsored by WRAP. Ecology will participate in the ongoing regional analysis activities of WRAP to collectively assess and verify the progress toward reasonable progress goals and natural conditions. We will also support interstate consultation as the Regional Haze Rule is implemented, and collaborate with WRAP members to ensure the continued operation of these technical support analysis tools and systems. Ecology may conduct additional analyses as needed.

Statewide emissions inventory updates

Ecology has prepared a statewide inventory of emissions that we reasonably expect to cause or contribute to visibility impairment in Class 1 Areas. Chapter 4 of this plan summarizes the emissions by pollutant and source category.

Ecology will update statewide emissions and will use the data for tracking emission changes and trends. We will update the inventories every three years on the same schedule as the three-year reporting required by EPA's Consolidated Emissions Reporting Rule.

Ecology is a member of WRAP and will continue to use WRAP to store and access emission inventory data for the region. Ecology will also depend on and participate in additional periodic emissions inventory efforts by the WRAP. Further, Ecology will continue to depend on and use the capabilities of the WRAP's regional modeling to simulate the air quality impacts of emissions for haze and other related air quality planning purposes.

Periodic progress reports

The Regional Haze Rule requires states to submit a progress report to EPA every five years evaluating progress towards the reasonable progress goals. The requirements for the progress report are in the Regional Haze Rule (40 CFR 51.308(g)) and are discussed in Chapter 1 of this document.

Washington commits to submitting a report on reasonable progress to EPA every five years. The reasonable progress report will evaluate progress made towards the reasonable progress goals for each mandatory class 1 area. Ecology's review will address each of the required elements listed above. The state will also evaluate the monitoring strategy adequacy in assessing reasonable progress goals.

Determination of State Implementation Plan Adequacy

The Regional Haze Rule requires states to make a determination of the adequacy of the implementation plan as part of its five-year progress report. Based on the findings of the five-year progress report, Ecology finds that no further substantive SIP revisions of the existing plan are required in order to meet established visibility goals at this time.

Future State Implementation Plan Revisions

In addition to a SIP revision made for plan inadequacy, the Regional Haze Rule requires the states to revise and submit a comprehensive regional haze implementation plan revision to EPA every ten years. Future SIP revisions must evaluate and reassess all of the elements required

under40 CFR 51.308(f) and specifically address the items listed in 40 CFR 51.308(f)(1-3). The plan revision must take into account improvements in monitoring data collection and analysis, control technologies and other relevant factors. Washington's commitments to comply with Regional Haze Rule requirements for future plans follows:

Approximately every 10 years, Washington commits to completing and submitting a comprehensive regional haze SIP revision to EPA, evaluating and reassessing all of the elements required under 40 CFR 51.308(f). In evaluating and reassessing these elements, Washington commits to:

- Determine current visibility (most recent five-year period preceding the required date of the SIP submittal for which data is available) conditions for the most impaired and least impaired days and determine the actual progress made towards natural conditions.
- Determine the effectiveness of the long-term strategy for achieving the reasonable progress goals for the prior SIP period as well as include enforceable emission limitations and compliance schedules.
- Affirm or revise the current reasonable progress goals based on assessment of new or updated information, improved technologies and on-going legislation. If the reasonable progress goals are insufficient to attain natural conditions by 2064, Washington will analyze whether there are additional or new control measures to adopt to achieve the degree of visibility improvement projected by the analysis contained in the SIP.

Continuing Interstate Coordination and Consultation

In accordance with 40 CFR 51.308(f)(2)(ii), Washington commits to continue consultation with other states which may reasonably be anticipated to cause or contribute to visibility impairment in Washington's mandatory Class 1 Areas. Washington will also continue consultation with any state for reasonably anticipated Washington's emissions that cause or contribute to visibility impairment in those states' mandatory Class 1 Areas.

Should disagreement arise between another state, or group of states and Washington, Washington will describe the actions taken to resolve the disagreement in its regional haze SIP submittal for EPA's consideration. Washington commits to coordinate its emission management strategies with affected states and will continue to include in its future regional haze SIP revisions all measures necessary to obtain its share of emissions reductions for meeting other states' reasonable progress goals.

Washington commits to continued participation in the WRAP, to the extent possible, and to coordinating future plan revisions with other WRAP member states in addressing regional haze.

Continuing Consultation with the Federal Land Managers

Section 51.308(i)(2) of the Regional Haze Rule requires that the state provide FLMs the opportunity for consultation in person and at least 60 days prior to holding any public hearing on plan revisions.

Washington commits to continuing to provide FLMs the opportunity for consultation in accordance with 40 CFR 51.308(i)(2).

The designated visibility protection program coordinators for the National Park Service and the U.S. Forest Service will coordinate the consultation.

Tribal Communication

Ecology will continue outreach and communication with WA Tribes and tribes in neighboring states to provide the opportunity for engagement with the tribes regarding the regional haze program.

10.2 Amendments to the 2021 regional haze SIP revision

The RHR requires States to perform a Four-Factor Analysis (FFA) to determine whether the installation of new emission controls at certain facilities is necessary for the State to make reasonable progress toward the national visibility goal. In Washington State, RCW 70A.15.2230 (the "RACT statute") is the legal mechanism that Ecology can use to require existing sources to install new emission controls that are determined to be reasonable. Because the analysis performed under the State's RACT process is equivalent to the RHR's FFA, Ecology will use the RACT process to require the installation of reasonable emission controls for purposes of compliance with the RHR.

40 CFR 51.308(f) requires the State's long-term strategy to include all measures that are "necessary to make reasonable progress, as determined pursuant to [40 CFR 51.308](f)(2)(i) through (iv)." In turn, 40 CFR 51.308(f)(2)(i) requires the State to consider the following four statutory factors in determining which emission reductions measures are necessary to make reasonable progress:

- the costs of compliance,
- the time necessary for compliance,
- the energy and non-air quality environmental impacts of compliance, and
- the remaining useful life of any potentially affected anthropogenic source of visibility impairment.

Pursuant to RCW 70A.15.1030(20) and 70A.15.2230(5), the RACT evaluation of new emission controls at existing stationary sources requires Ecology to consider the following:

- the impact of the source upon air quality,
- the availability of additional controls,
- the emission reduction to be achieved by additional controls,
- the impact of additional controls on air quality,
- and the capital and operating costs of the additional controls.

The costs of compliance

Under the RACT analysis, Ecology characterizes and considers the cost of compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. The cost of compliance factor in 40 CFR 51.308(f)(2)(i) directly correlates to the RACT analysis consideration of capital and operating costs of the additional controls. The capital and operating costs in RACT are for purchase, installation, and operation of all equipment. These costs include the actual emission

control equipment, any non-air quality equipment, and the energy costs to operate the equipment.

The time necessary for compliance

Under the RACT analysis, Ecology characterizes and considers the time necessary for compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Under the RACT analysis requirements, Ecology determines the time necessary for compliance as part of considering the capital and operating costs of the additional controls and impact of the source upon air quality. Specifically, a shorter amount of time for compliance would involve costs distributed over a shorter time and thus have a larger annualized cost. The impact of the source on air quality is also a consideration in the time for compliance. The longer it takes to install and operate the control equipment the greater the negative impact on air quality.

The energy and non-air quality environmental impacts of compliance

Under the RACT analysis, Ecology characterizes and considers the energy and non-air quality environmental impacts of compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Ecology considers the energy and non-air quality environmental impacts of compliance factor as part of analyzing the capital and operating costs of the additional controls in the RACT analysis. The RACT analysis includes costs for equipment directly related to the emissions and all indirectly required equipment needed to install and operate the new controls. The operating cost requirement in the RACT analysis also covers the energy impacts of the controls and supporting equipment.

The remaining useful life of any potentially affected anthropogenic source of visibility impairment

Under the RACT analysis, Ecology characterizes and considers the remaining useful life of any potentially affected anthropogenic source of visibility impairment consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Ecology considers the remaining useful life of an emissions control system as part of calculating the capital and operating costs of the system. Specifically, the annualized costs of the emissions control system are affected by the remaining useful life. The shorter the useful life, the larger the annual costs associated with control equipment.

Additionally, RACT requires consideration of the impact of the source upon air quality.' This is consistent with the CAA, RHR, and EPA guidance. While the four statutory factors must be considered in determining what is necessary to make reasonable progress, they are not the only factors that States may consider in this evaluation. As explained by EPA in its 2019 guidance, States have the flexibility to consider other factors, including visibility benefits, when determining the emission reduction measures that are necessary to make reasonable progress:

> "Section 51.308(f)(2)(i) of the Regional Haze Rule requires consideration of the four factors listed in CAA section 169A(g)(1) and does not mention visibility benefits. However, neither the CAA nor the Rule suggest that only the listed factors may be considered. Because the goal of the regional haze program is to improve visibility, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal. Likewise, it is reasonable that such information

on visibility benefits be considered in light of other factors that may weigh for or against the control at issue. Such a balancing of outcomes is consistent with CAA section 169A(b)(2), which states that SIPs must contain elements as may be necessary to make reasonable progress towards meeting the national visibility goal. Thus, EPA interprets the CAA and the Regional Haze Rule to allow a state reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other factors when determining whether a measure is necessary to make reasonable progress."[29]

Washington received four-factor analyses from the refineries that indicated there were no reasonable controls at the refineries. Ecology then conducted preliminary analyses using emission inventory data and the EPA Control Cost Manual. The results from the four-factor analyses and the preliminary control cost model were vastly different. This indicated the need for a more robust analysis to determine reasonableness of controls. Therefore, Ecology will use the RACT process to (1) evaluate and determine the emissions reduction measures that are necessary to make reasonable progress and (2) incorporate these measures into its long-term strategy and Regional Haze SIP in a manner that is enforceable as a legal and practical matter.

Ecology will supplement this plan with the results of the reasonableness analysis. The analysis will include an implementation schedule that will be coordinated with scheduled maintenance shutdowns at the refineries when necessary to maintain costs at a reasonable level. These shutdowns occur approximately every two to six years. Emission reductions from refineries were not included in the 2028 projected emissions for the second implementation period, so this does not affect the modeled 2028 reasonable progress goals.

10.3 Summary

National Visibility Goal

In 1977, Congress amended the Clean Air Act and declared a national visibility goal:

> *"The prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." (CAA § 169A).*

The objectives of the Regional Haze Rule are to improve existing visibility in all 156 mandatory Class 1 Areas, prevent future impairment of visibility by human-caused sources, and meet the national goal of natural visibility conditions by 2064. Emissions from numerous sources that are often mixed and transported long distances cause visibility impairment related to regional haze

Washington's State Implementation Plan

There are planning phases from 2005 to 2064; each planning phase covers approximately 10 years. The first regional haze state implementation plan (regional haze SIP) revision covered the

[29] EPA-457/B-10-003, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, Section II.B.5.

initial planning period from 2005 to 2018. It provided the basis for future SIPs to continue reducing visibility-impairing emissions and meet the national visibility goal by 2064.

This second regional haze SIP sets reasonable progress goals for each of the eight mandatory Class 1 Areas in Washington. The reasonable progress goals reflect already adopted controls for sources that cause or contribute to visibility impairment. Ecology will supplement this second SIP revision with reasonable controls that we determine during the next phase of this implementation period.

Washington developed a long-term strategy that addresses reasonably attributable visibility impairment and regional haze. The long-term strategy applies to mandatory Class 1 Areas both within the state and outside the state where emissions from the state are reasonably anticipated to contribute to visibility impairment. We designed the coordinated strategy to achieve the reasonable progress goals for mandatory Class 1 Areas inside Washington and the reasonable progress goals established by other states for mandatory Class 1 Areas outside of Washington where emissions from Washington are reasonably anticipated to contribute to visibility impairment.

Long-Term Challenges and Issues

Under the Regional Haze Rule, the state of Washington is responsible for doing its share of visibility improvement to achieve the national goal for mandatory Class 1 Areas within Washington and Class 1 Areas outside of Washington that it may affect. The Western Regional Air Partnership (WRAP) has provided a technical framework for understanding and dealing with the source regions and sources of visibility impairment. The WRAP analysis has also revealed significant challenges to long-term reasonable progress and raised technical and regulatory issues.

Significant challenges to meeting the national visibility goal in Washington's mandatory Class 1 Areas:

- Emissions from outside the modeling domain, Pacific offshore, and Canada significantly impact visibility. These are all beyond the state's control. In this regional haze SIP, we have proposed an adjustment to the glidepath endpoint to compensate for these international contributions.
- It will be difficult to achieve natural conditions, at some Class 1 Areas, unless we can either reduce the contribution of organic mass from fire to visibility impairment or not include it in the most impaired days metric. The most impaired days (MID) metric as it is currently calculated is insufficient to remove the effect of all wildfire smoke in Washington. With an increase in catastrophic fire in the Pacific Northwest, this will continue to be a challenge and requires an acceptable method to adjust the MID metric within each state as needed.

Meeting the national goal also requires addressing technical and regulatory issues including:

- Better understanding of the role of biogenic organic aerosols in visibility impairment and analytical technical tools

- Reconsideration of natural conditions especially in light of the expectation that prescribed fire will be more widespread in the future
- Continued development of federal rules reducing visibility-impairing pollutants
- Continued development of controls for on-road and off-road mobile sources

Meeting these challenges and dealing with the issues presented by our changing environment will ultimately enable Washington to achieve natural conditions within the state and contribute to meeting natural conditions in Class 1 Areas outside the state.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-10:
Landfill Inspection Report (Jan. 2025)

INSPECTION REQUIREMENTS FOR CCR LANDFILLS

40 CFR 257.84(b) *Annual Inspections by a Qualified Professional Engineer*

(1) Existing and new CCR landfills and any lateral expansion of a CCR landfill must be inspected on a periodic basis by a qualified professional engineer to ensure that the design, construction, operation, and maintenance of the CCR unit is consistent with recognized and generally accepted good engineering standards. The inspection must, at a minimum, include:

(i) A review of available information regarding the status and condition of the CCR unit, including, but not limited to, files available in the operating record; and

(ii) A visual inspection of the CCR unit to identify signs of distress or malfunction of the CCR unit.

(2) The qualified professional engineer must prepare a report following each inspection that addresses the following:

(i) Any changes in geometry of the structure since the previous annual inspection.

(ii) The approximate volume of CCR contained in the unit at the time of the inspection.

(iii) Any appearances of an actual or potential structural weakness of the CCR unit, in addition to any existing conditions that are disrupting or have the potential to disrupt the operation and safety of the CCR unit; and

(iv) Any other change(s) which may have affected the stability or operation of the CCR Unit since the previous annual inspection.

TransAlta Centralia Mining LLC

Limited Purpose Landfill, Annual Inspection Report

Date, Time, and Weather Conditions of the Inspection:

The annual inspection of the Coal Combustion Residual (CCR) unit, the TransAlta Centralia Mining LLC (TCM) Limited Purpose Landfill (LPLF) was conducted on **January 15, 2025**, beginning at around 10:30AM. The inspection was conducted by Steven J. Mahr, a qualified professional engineer, and accompanied by Marc Read, the manager of landfill operation.

Weather conditions at the time of inspection were cloudy and cool.

In accordance with the requirement the following observations were made during the inspection:

Review of available information

The CCR Operation records were reviewed for the CCR unit, otherwise known as the TCM LPLF. This included the weekly landfill inspection reports on file for the calendar year of 2024. Also reviewed were the weekly fugitive dust control inspection reports. No issues or items of concern developed from the records review.

Visual Inspection of the CCR unit

As noted above, a visual inspection of the TCM LPLF was conducted on January 15, 2025. The inspection began by driving around the perimeter access roads as an initial assessment of the landfill. This was followed by physically walking around the toe of the TCM LPLF and examining the slopes for structural integrity.

(1) Changes in Geometry

There were no changes to geometry in 2024.

(2) Approximate Volume of CCR Contained in the Unit

Records indicate the TCM LPLF contains approximately **851,722 cubic yards** of approved waste materials. Approximately 5,427 cubic yards of waste material was added to the landfill in 2024.

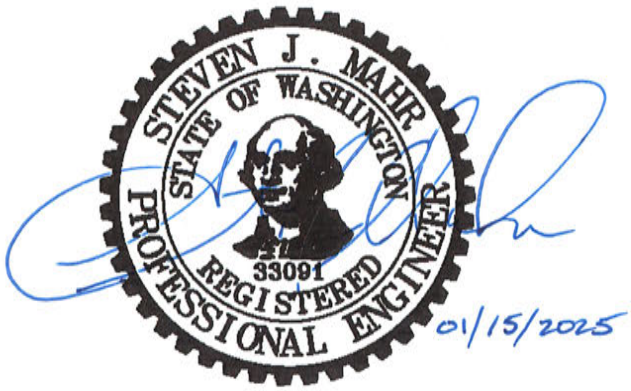
(3) Structural Integrity of the CCR unit

Based on the observations made during the perimeter inspection and the physical walk around the toe of the TCM LPLF there were no appearances of actual or potential structural weakness of

the landfill. **No conditions were observed** at the time of inspection to indicate a disruption of or have the potential to disrupt the operation and safety of the landfill.

CERTIFICATION OF ENGINEER:

By means of this certification, I attest that I am familiar with the requirements and provisions of Title 40 CFR Section 257.84(b), that I, Steven J. Mahr, a registered professional engineer in the State of Washington have visited and examined the CCR unit identified in this report, and that the design, construction, operation, and maintenance of the CCR unit is consistent with recognized and generally accepted good engineering standards.



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-11:
EPA COBRA Health Effects Estimate

An official website of the United States government.

COBRA Web Edition



CO-Benefits Risk Assessment (COBRA) is a screening tool that enables state, local, and tribal government staff and others interested in the effects of air pollution to estimate the air quality and health benefits of different emissions scenarios.

You are using the web-based version of COBRA. For the COBRA desktop application, visit the COBRA download page.

Step 1: Build Scenario

Complete the sections below and click "Add to Scenario."

A. Select Location REQUIRED

Select the states or counties where the emissions changes will occur.

- Tennessee
- Texas
- Utah
- Vermont
- Virginia
- Washington
- West Virginia
- Wisconsin
- Wyoming

Select All | Deselect All

B. Select Sector REQUIRED

Select the industry or sector where the emissions changes will occur.

Sector

Fuel Combustion: Industrial

Subsector (optional)

All subsectors

Subsector (optional)

All subsectors

C. Modify Emissions REQUIRED

Enter emissions changes for **at least one** of the four pollutants below.

$PM_{2.5}$ (Baseline = 1,593.25 tons)

reduce by | increase by

120 (•) tons ( ) percent

SO_2 (Baseline = 2,118.86 tons)

reduce by | increase by

934.72 (•) tons ( ) percent

NO_x (Baseline = 10,318.95 tons)

reduce by | increase by

2804.53 (•) tons ( ) percent

VOC (Baseline = 643.66 tons)

reduce by | increase by

enter # (•) tons ( ) percent

NH_3 (Baseline = 83.95 tons)

reduce by | increase by

enter # tons percent

ADD TO SCENARIO

Step 2: Review Scenario

Review the scenario below. To add changes to more locations or sectors, repeat Step 1 to continue building your scenario.

Location(s)	Sector	Emissions Modification(s)	
Washington - All Counties	Fuel Combustion: Industrial	$PM_{2.5}$ reduce by 120 tons SO_2 reduce by 934.72 tons NO_x reduce by 2,804.53 tons	✕

Discount rate:
2%
Custom: enter %

RUN SCENARIO

Step 3: View Results

BUILD NEW SCENARIO

A. Summary of Health Effects Results

Below is a table with the health effects results based on your scenario.

You are viewing results for all contiguous U.S. states. This is because changes in air quality can impact health endpoints in multiple locations due to the transportation of emissions across state and county lines.

Use the filters below to see health effects for a specific state or county.

1. Filter by state:

All contiguous U.S. states

2. Filter by county: (optional)

All counties

Results for: All Contiguous U.S. States

Export: All results | Current filter

Health Endpoint	Pollutant	Change in Incidence (cases, annual)		Monetary Value (dollars, annual)	
		Low	High	Low	High
Mortality *	$PM_{2.5}$ | O_3	7.5	11	$110,000,000	$170,000,000
Nonfatal Heart Attacks	$PM_{2.5}$	2.3	2.3	$190,000	$190,000
Infant Mortality	$PM_{2.5}$	0.025	0.025	$400,000	$400,000
Hospital Admits, All Respiratory	$PM_{2.5}$ | O_3	0.61	0.61	$14,000	$14,000
Emergency Room Visits, Respiratory	$PM_{2.5}$ | O_3	13	13	$21,000	$21,000
Asthma Onset	$PM_{2.5}$ | O_3	44	44	$3,300,000	$3,300,000
Asthma Symptoms	$PM_{2.5}$ | O_3	6,900	6,900	$2,000,000	$2,000,000
Emergency Room Visits, Asthma	O_3	0.059	0.059	$49	$49
Lung Cancer Incidence	$PM_{2.5}$	0.26	0.26	$12,000	$12,000
Hospital Admits, Cardio-Cerebro/Peripheral Vascular Disease	$PM_{2.5}$	0.4	0.4	$12,000	$12,000
Hospital Admits, Alzheimers Disease	$PM_{2.5}$	1.1	1.1	$24,000	$24,000

Hospital Admits, Parkinsons Disease	$PM_{2.5}$	0.19	0.19	$4,600	$4,600
Stroke Incidence	$PM_{2.5}$	0.23	0.23	$14,000	$14,000
Hay Fever/Rhinitis Incidence	$PM_{2.5}$ | O_3	280	280	$310,000	$310,000
Cardiac Arrest, Out of Hospital	$PM_{2.5}$	0.055	0.055	$3,400	$3,400
Emergency Room Visits, All Cardiac	$PM_{2.5}$	0.97	0.97	$2,100	$2,100
Minor Restricted Activity Days	$PM_{2.5}$	3,000	3,000	$370,000	$370,000
School Loss Days	O_3	3,100	3,100	$5,300,000	$5,300,000
Work Loss Days	$PM_{2.5}$	510	510	$160,000	$160,000
Total Health Effects from $PM_{2.5}$				**$49,000,000**	**$110,000,000**
Total Health Effects from O_3				**$72,000,000**	**$72,000,000**
Total Health Effects				**$120,000,000**	**$180,000,000**

Note: Dollar amounts shown are based on 2023 currency values. Additionally, all values have been rounded to 2 significant figures. Please export the results in order to see values prior to rounding.

* The Low and High values represent differences in the methods used to estimate some of the health impacts in COBRA. For example, high and low results for avoided premature mortality are based on two different epidemiological studies of the impacts of $PM_{2.5}$ on mortality in the United States.

B. Map of Health Effects and Air Quality Results

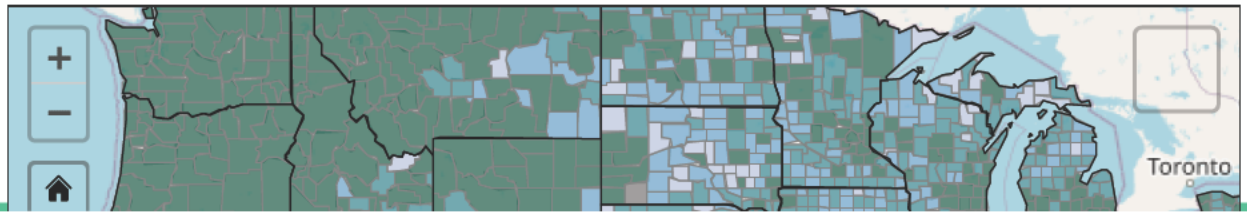
Below is a map showing health effects and air quality data based on your scenario.

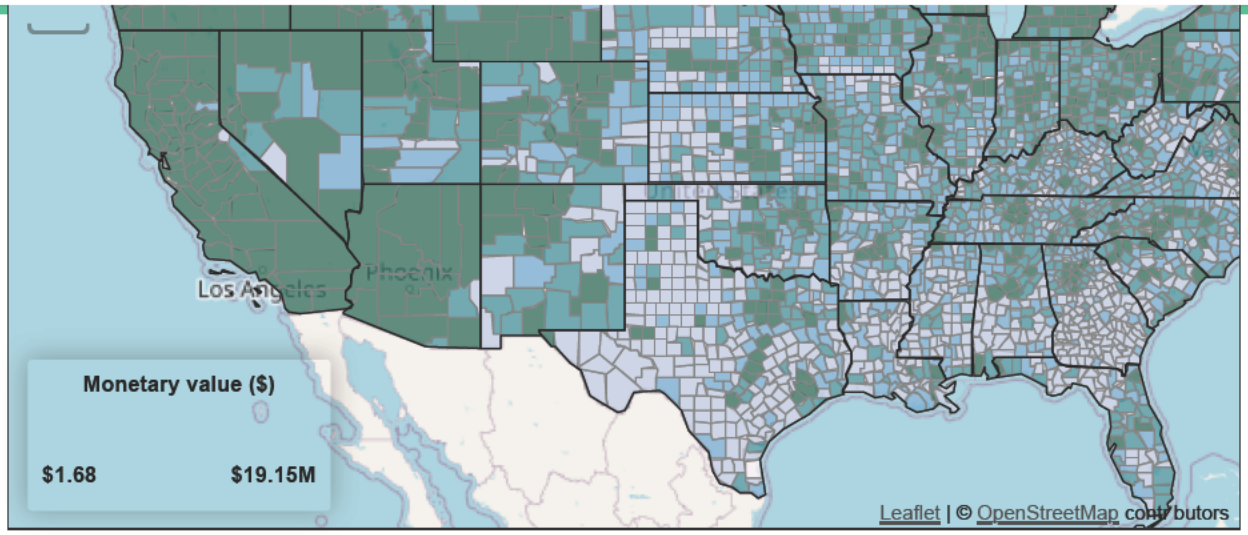
Use the filter below to change the map's data layer. Click on a county on the map to explore the data.

Select the map's data layer:

Total Health Benefits ($, low estimate)

Displaying: Total Health Benefits ($, low estimate)





LAST UPDATED ON APRIL 12, 2021

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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Exhibit 1-12:
Washington Agencies Winter Readiness Meeting Materials Website as of November 9, 2025

The Wayback Machine - https://web.archive.org/web/20251109040601/https://www.utc.wa.gov/regulated-industries/utilities/energy/resource-adequacy-was...

Resource Adequacy in Washington State

The UTC and the Washington State Department of Commerce co-host resource adequacy meetings to help ensure Washington has a reliable and affordable electricity supply.

Resource adequacy means having enough electricity available to meet customer needs at all times, even during extreme weather. The UTC and Commerce bring together utilities, regional planners, other experts, and the public to discuss how to plan for future electricity demand, improve coordination, and make sure the state has the power it needs.

State law (RCW 19.280.065) requires the UTC and Commerce to hold at least one of these meetings every year. Topics include electricity demand and supply, how utilities are working together to keep the grid reliable, and steps being taken to prepare for the future. A summary of each meeting is sent to the governor and the Legislature within 60 days.

CONTACT INFORMATION

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Upcoming Meetings

A shorter-term winter readiness and gas-electric system coordination meeting is scheduled from **8:30 a.m. to noon on Nov. 4, 2025.** For details on attendance, speakers, and topics, see the notice, agenda, and presentation materials below, and in Docket UE-210096.

Meeting Materials and Presentations

Materials from past and upcoming meetings, including presentations, reports, and supporting documents, can be accessed below:

November 4, 2025 - Meeting Resources

- Notice of Winter 2025 Resource Adequacy Meeting - UE-210096
- Winter 2025 Resource Adequacy Meeting Agenda
- Winter 2025 Resource Adequacy Presentation - NWGA + WECC + NERC
- Winter 2025 Resource Adequacy Presentation - PacifiCorp
- Winter 2025 Resource Adequacy Presentation - Seattle City Light
- Winter 2025 Resource Adequacy Presentation - NW Natural
- Winter 2025 Resource Adequacy Presentation - Cascade Natural Gas
- Winter 2025 Resource Adequacy Presentation - Avista
- Winter 2025 Resource Adequacy Presentation - Puget Sound Energy

- Winter 2025 Resource Adequacy Presentation - NWGA + PNUCC

Previous 2025 Resource Adequacy Materials

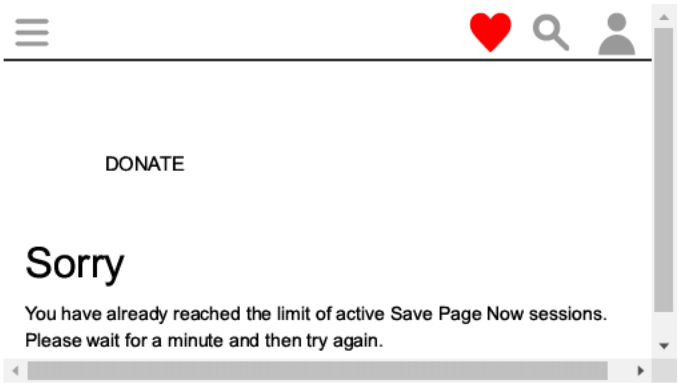
2024 Meeting Resources

Past Meeting Resources

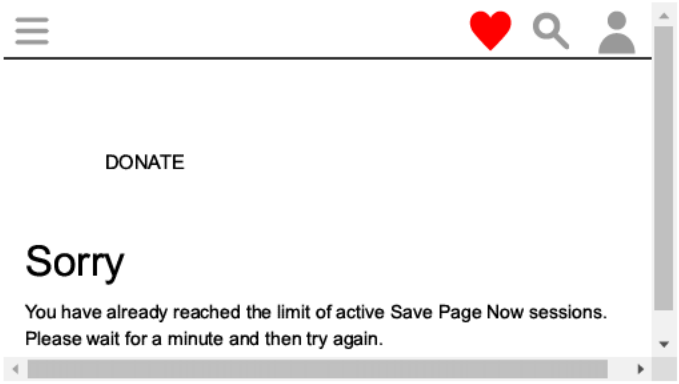
Meeting Recordings

A recording of the most recent resource adequacy meeting is available below, in addition to within the docket housing these meetings, UE-210096:

Video URL



Video URL



Previous Meeting Recordings

Washington's Resource Adequacy Efforts

Washington's electricity system is undergoing significant changes as the state transitions to 100% clean energy under the Clean Energy Transformation Act (CETA). The UTC and Commerce play a critical role in ensuring that utilities can provide sufficient electricity while meeting clean energy mandates.

For more details about resource adequacy efforts in Washington state, visit the Commerce Resource Adequacy page.

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Exhibit 1-13:
DOE Order No. 202-22-4

Department of Energy
Washington, DC 20585

Order No. 202-22-4

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated by email correspondence (Dec. 23, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in the electricity grid operated by PJM Interconnection, LLC (PJM) due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On December 24, 2022, PJM, the Regional Transmission Operator (RTO) for 65 million people in thirteen states and the District of Columbia (the PJM Region), filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system."

The PJM Region, like many regions across the country, is currently being affected by a severe winter weather system. PJM states that this weather system caused a significant drop in temperatures across the PJM Region on December 23, 2022, accompanied by high winds in excess of 40 mph. As a consequence of the impact of wind and decreasing temperatures, the demand for electricity in the PJM Region rose to an unusually high peak load on the evening of December 23, 2022, in excess of 135,000 MW. This severely cold weather is expected to last through Sunday morning.

While the vast majority of generating units in the PJM Region continue to function adequately under these stressed conditions, some units have experienced operating difficulties due to cold weather or fuel limitations, primarily gas. Specifically, approximately 45,000 MW of generating units (the majority of which are thermal) are currently outaged or derated. PJM has expressed its concern that these units will be unable to return to service over at least the next 48 hours, which coincides with the time period for which PJM is requesting this Order. Since these units may not promptly return to service, and in the event PJM experiences additional generating unit outages, PJM states that it may need to curtail some amount of firm load on December 24, December 25, or December 26, 2022 in order to maintain the security and reliability of the PJM system.

Description of Mitigation Measures

In its Application, PJM identifies the measures it is taking to ensure the supply of generation will continue to be sufficient to meet system demand and reserve requirements. On December 20, 2022, PJM issued a cold weather advisory in the PJM Region in anticipation of the forecasted weather conditions. Then on December 23, 2022, PJM issued

a PJM Region-wide cold weather alert which further highlighted PJM's expected need to call higher-than-normal generation resources in light of the anticipated weather.

On December 23, 2022, generating reserves diminished to a level that required PJM to declare an Energy Emergency Alert (EEA) Level 2 and take other emergency actions. PJM states that after having exhausted economic operation, PJM triggered a Maximum Generation Emergency Action to increase the PJM Region generation above the maximum economic level. Further, PJM triggered its load management reduction actions to provide additional load relief by using PJM-controllable load management programs. PJM called on demand response providers and curtailment service providers to reduce load. PJM also issued public appeals for consumers to reduce usage. PJM has continued to employ these emergency actions through December 24, 2022, and anticipates needing to continue them through the order end date that it has requested.

Since December 23, 2022, PJM has also taken additional measures to provide additional reserves, including:

- Reducing exports to neighboring regions and requested shared reserves for neighboring regions; consistent with joint operating agreements and other regulatory requirements, PJM has continued to communicate and collaborate with its interconnected neighboring systems when the demand on the PJM system has exceeded expected energy and reserve requirements and when emergency transfers were required to support PJM's interconnected neighboring systems;
- Issuing additional public conservation appeals;
- Running uneconomic generation during lower load periods to ensure their availability during peak conditions;
- Utilizing its Emergency Procedures to assist in maximizing the pumped storage hydro generation levels;
- Communicating and preparing transmission and distribution service providers to implement distribution voltage reduction measures; and
- Communicating and preparing transmission and distribution service providers to implement firm load shed.

In its Application, PJM committed to continue to take such actions, including utilizing other supply resources before calling upon any generators to operate in excess of permitting levels. According to PJM, it is nevertheless possible that the measures it has and will take may not be sufficient to avoid the need to curtail firm load in order to ensure system reliability.

Request for Order

PJM requests that the Secretary issue an order immediately, effective today, December 24, 2022, through 12:00 p.m. Eastern Time on Monday, December 26, 2022, authorizing the electric generating units identified in Exhibit A, as well as any other

generating units subject to emissions or other permit limitations in the PJM Region to operate up to their maximum generation output levels under the limited circumstances described in this Order, notwithstanding air quality or other permit limitations. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-22-4 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet the additional load, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current cold weather event threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the PJM Region demonstrate the need for the Specified Resources to contribute to the reliability of the PJM Region.
- PJM is responsible to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the additional load resulting from the cold weather event is enhanced.

In line with the anticipated circumstances precipitated by the cold weather event, this Order is limited to the period beginning with the issuance of this Order on December 24, 2022 through 12:00 pm Eastern Time on December 26, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. PJM anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

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

A. From the time this Order is issued on December 24, 2022, to 12:00 pm Eastern Time on December 26, 2022, in the event that PJM determines that generation from the Specified Resources is necessary to meet the electricity demand that PJM anticipates in the PJM Region during this event, I direct PJM to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements. Specified Resources are those generating units set forth on the Order 202-22-4 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

(i) For any generation resource whose operator notifies PJM that the unit is unable, or expected to be unable, to produce at its maximum output due to an emissions or other limit in any federal environmental permit, and during the pendency of a PJM-triggered Maximum Generation Emergency Action, at any point before 12:00 Eastern Time on Monday, December 26, 2022, the unit will be allowed to exceed any such limit only during any period for which PJM has declared an Energy Emergency Alert (EEA) Level 2 or Level 3 (during which time PJM will have triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that the EEA Level 2 event has ended, the unit would be required to immediately return to operation within its permitted limits. And at all other times, the unit would be required to operate within its permitted limits, except for the limited exceptions provided herein for operations in anticipation of an EEA Level 2 to prevent the cycling of units or facilitate the charging or pumping of other resources necessary for the EEA Level 2.

(ii) For any generation resource whose operator notifies PJM that the unit is offline or would need to go offline at any point before 12:00 Eastern Time on Monday, December 26, 2022, due to an emissions or other limit in any

federal environmental permit, PJM may direct the unit operator to bring the unit online, or to keep the unit online, and to operate at the level consistent with its permits but subject to the exceptions set forth in this Order. In this circumstance, the operator is allowed to make all of the unit's capacity available to PJM for dispatch during any period for which PJM has declared an EEA Level 2 or 3 (during which time PJM has triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that such an EEA Level 2 event has ended and the Maximum Generation Emergency Action is discontinued, the unit would be required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

(iii) PJM is hereby granted authority to operate the Specified Units that are combined cycle generating units in certain limited circumstances in advance of declaring an EEA Level 2, Maximum Generation Emergency, or in between such events, where such operation or continued operation of the Specified Resource is reasonably necessary to avoid shutting down and restarting the Specified Unit. PJM has represented that such cycling of units can cause reliability issues regarding restarting, delays, and increased emissions during start up. PJM is further authorized to operate the Specified Units in certain limited circumstances in advance of the declaring an EEA Level 2, Maximum Generation Emergency where such operation or continued operation of the Specified Resource is reasonably necessary to facilitate charging storage resources or pumping for pumped storage facilities that will needed during an anticipated EEA Level 2. PJM is required to take measures to dispatch units for which cycling would otherwise be required in a manner reasonably intended to limit the duration and operating level of those units in such a way as to minimize exceedance of permit limitations consistent with the security and reliability of the PJM Region.

(iv) To minimize adverse environmental impacts as set forth herein, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, and notwithstanding standard merit order dispatch, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response and identified behind-the-meter generation resources selected to minimize an increase in emissions to the extent that such resources provide support to maintain grid reliability prior to dispatching the Specified Resources at levels above their permitted emissions levels. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

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

D. In the event that PJM identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements, PJM shall provide prompt written notice to the Department of Energy at AskCR@hq.doe.gov with the name and location of those units that PJM has identified, as well as additional notice by the same means through updating Exhibit A to its Application with such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 09:00 Eastern Time or 21:00 Eastern Time, whichever follows closest in time to the unit identification by PJM to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department updating Exhibit A, and PJM may dispatch such additional generation units, provided that if the Department of Energy notifies PJM that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-22-4 Resource List as soon as practicable following notification from PJM under this paragraph.

E. PJM shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By January 26, 2023, PJM shall report all dates between December 24, 2022, and December 26, 2022, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. PJM shall submit a final report by February 27, 2023, with any revisions to the information reported on January 26, 2023. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g., "Generator #1; December 25, 2022; 4 hours; 04:00-08:00 CT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, PJM shall provide information to the Department quantifying the net revenue in aggregate associated with generation in excess of environmental limits in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. PJM shall take reasonable measures to inform affected communities where all Specified Resources operate that PJM has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows PJM to do. At a minimum, PJM shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of Specified Resources covered by this Order, as the Specified Resources may be updated pursuant to paragraph D above. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by PJM with respect to the cold weather event and will include a reference to the website posting required by the preceding sentence for further information. PJM shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph E above.

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

H. PJM shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

I. This Order shall be effective upon its issuance, and shall expire at 12:00 Eastern Time on Monday, December 26, 2022, with the exception of the reporting requirements in

paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 5:30 PM Eastern Standard Time on this 24th day of December 2022.

Kathleen B. Hogan

Digitally signed by Kathleen B. Hogan
Date: 2022.12.24 17:38:01 -05'00'

Undersecretary of Energy for Infrastructure

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-14:
DOE Order No. 202-17-4 Summary of Findings

Summary of Findings
Department of Energy Order No. 202-17-4

September 14, 2017

Section 202(c) of the Federal Power Act (FPA) (codified at 16 U.S.C. § 824a(c)), through section 301(b) of the Department of Energy Organization Act (codified at 42 U.S.C. § 7151(b)), authorizes the Secretary of Energy, upon finding "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes," to issue an order "requir[ing] . . . such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1). If the order "may result in a conflict with [an] environmental law or regulation," then the Secretary must "ensure that such order requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable . . . environmental law or regulation and minimizes any adverse environmental impacts." *Id.* § 824a(c)(2). Orders issued under FPA section 202(c) "that may result in a conflict with [an] environmental law or regulation" expire 90 days after they are issued, but the Secretary "may renew or reissue such order[s] . . . for subsequent periods, not to exceed 90 days for each period, as [the Secretary] determines necessary to meet the emergency and serve the public interest." *Id.* § 824a(c)(4)(A).

The Department's regulations implementing FPA section 202(c) define the term "emergency" to mean, among other situations, "a specific inadequate power supply situation." 10 C.F.R. § 205.371. The regulations do not exhaustively list what qualifies as an emergency, but they note specifically that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations." *Id.*

On June 13, 2017, PJM filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Order Application) (included in the docket[1] of this Order) with the Department "to preserve the reliability of [the] bulk power transmission system in the North Hampton Roads area." Virginia Electric and Power Company[2] (Dominion), the electric utility serving the area, owns the coal-fired, power generating Units 1 and 2 at the Yorktown Power Station in Yorktown, Virginia. In November 2011 and October 2012, Dominion notified PJM of its plan to deactivate Units 1 and 2, respectively, effective December 31, 2014, because the units were not equipped to

[1] The docket of this Order is available at https://www.energy.gov/oe/downloads/federal-power-act-section-202c-dominion-energy-virginia-june-2017.
[2] *See* Dominion Energy, Inc., Form 10-Q filing, at 1 (Aug. 3, 2017), included in the docket of this Order.

comply with the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS), 40 C.F.R. part 63 subpart UUUUU. On June 24, 2014, pursuant to 40 C.F.R. § 63.6(i)(4)(i)(A), the Virginia Department of Environmental Quality granted Dominion a one-year MATS compliance extension for Yorktown Units 1 and 2.

On April 16, 2016, pursuant to section 113(a) of the Clean Air Act, 42 U.S.C. § 7413(a)(3) and (4), the EPA issued an Administrative Compliance Order (ACO) through April 15, 2017. The ACO implemented a 2011 MATS Enforcement Policy regarding issuance of section 113(a) administrative orders to sources that are unable to comply with the MATS but that may need to operate for up to a year to address a specific and documented reliability concern. The 2011 MATS Enforcement Policy was limited in application to units critical for reliability purposes. The EPA found that operation of Yorktown Units 1 and 2 met the policy criteria, as verified by the Federal Energy Regulatory Commission (FERC). Dominion has not achieved full compliance with the MATS for Yorktown Units 1 or 2 since the ACO expired, and section 113(a) of the Clean Air Act bars further compliance extensions.

Since Dominion's decision to retire the coal-fired Yorktown units, PJM has planned for their permanent deactivation by including required transmission upgrades in its own Regional Transmission Expansion Planning Process. PJM is subject to federal reliability standards enforced by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization designated by FERC. PJM holds the highest-level reliability responsibilities for the system it manages as a certified Reliability Coordinator, Balancing Authority, and Transmission Operator. PJM is also registered with NERC as a Planning Coordinator and Transmission Planner, among other functions. NERC Compliance Registry Active Entities List (updated Sept. 7, 2017), included in the docket of this Order. PJM applies reliability criteria to evaluate transmission system conditions and then develops the transmission solutions needed to ensure compliance with the reliability standards. The PJM Board of Managers approves those solutions in a Regional Transmission Expansion Plan (RTEP). Through its Transmission Expansion Advisory Committee (TEAC) and Sub-Regional RTEP Committees, PJM works with stakeholders throughout the RTEP's development. PJM Manual 14B, "Regional Planning Process," included in the docket of this Order. The PJM Board of Managers approved the transmission upgrades necessitated by the retirement of Yorktown Units 1 and 2 on May 17, 2012. TEAC Recommendations to the PJM Board (PJM Staff Whitepaper), May 2012, at 12, included in the docket of this Order.

PJM's approved solution was the Skiffes Creek Transmission Project, which consists of three components: a 500kV line, a 230kV line rebuild, and a new switching station. United States Army Corps of Engineers (Army Corps), Memorandum for the Record re: Department of the Army Environmental Assessment and Statement of Findings for the Above-Referenced Standard Individual Permit Application, CENAO-WR-RS (NAO-2012-00080 / 13-V0408), at 1, included in the docket of this Order. A

number of issues in the North Hampton Roads area, many of which are interrelated, needed to be addressed to avoid overloading transmission lines with too much power, as detailed in PJM's Deactivation Study. Yorktown Units 1 and 2 Generator Deactivation Notification: Deactivation Study Results – updated June 26, 2017 (PJM Deactivation Study), included in the docket of this Order. *See also Va. Elec. & Power Co.*, Commission Comments on Requests for EPA Administrative Orders, Docket No. AD16-11-000, 153 FERC ¶ 61,265 at PP 14-16 (2015).

PJM completed a series of analyses consistent with RTEP procedures, finding that only the Skiffes Creek Transmission Project—and none of the stakeholder-proposed alternatives—addressed the full range of potential reliability violations. Order Application, app. I, at 16. For example, reliance on operation of the oil-fired Yorktown Unit 3 generator would not address thermal overload and voltage violations on the 230kV and 115kV bulk electric system that PJM identified because of significant environmental operating restrictions and other plant operation constraints associated with that unit, including an 8 percent capacity factor limitation. *See id.*, app. II, at 18. As a result, PJM did not recommend reliance on Yorktown Unit 3 as a sustainable alternative solution to the identified reliability criteria violations. *Id.*

As part of PJM's analyses, Dominion transmission staff provided PJM with an analysis of system needs as well as potential solutions to the retirement of generating units at Yorktown and elsewhere. Dominion Update to Retirement Study Results (Mar. 10, 2012), included in the docket of this Order. Dominion's analysis, which was based on PJM's initial determination of reliability criteria violations that needed to be addressed, was independently validated by PJM and publicly vetted through the PJM stakeholder process before PJM staff recommended that the Board of Managers approve the Skiffes Creek Transmission Project. PJM Staff Whitepaper at 12, included in the docket of this Order.

PJM, as the Regional Transmission Organization (RTO) responsible for transmission system operation across multiple states, including Virginia, maintains its expert determination that the Skiffes Creek Transmission Project is the most effective and efficient solution to address the identified reliability criteria violations. Order Application, app. I, at 16. As recently as March 1, 2017, PJM provided the Army Corps with an analysis of proposed alternatives and found that none of them sufficiently resolved the identified violations. Letter to Col. Jason E. Kelly, U.S. Army Corps of Engineers (Mar. 1, 2017), included in the docket of this Order. PJM's subsequent RTEP materials reaffirm the need for the Skiffes Creek Transmission Project, even considering the updated, steadily rising load forecasts in the recently released 2017 PJM Load Forecast Report (included in the docket of this Order). *See* PJM Interconnection, L.L.C., 2017 RTEP Process Scope & Input Assumptions, rev. 1, at 25-27 (Aug. 3, 2017), included in the docket of this Order.

Construction of the Skiffes Creek Transmission Project began in July 2017 and is expected to take approximately 18-20 months. *Order No. 202-17-2 Renewal Application Filing* (Renewal Application) at 3. Until the Project is completed, a plan known as the North Hampton Remedial Action Scheme (RAS) remains in effect. According to NERC's Glossary of Terms, a RAS is "[a] scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation ([megawatts] and [megavolt amperes (reactive)]), tripping load, or reconfiguring a System(s)." Glossary of Terms Used in NERC Reliability Standards (updated Aug. 1, 2017), at 24, included in the docket of this Order.

To preserve the grid's reliability, the North Hampton RAS would allow PJM, the grid operator, to drop load—that is, shut off power to certain customers—to prevent voltage collapse. Dominion presented this RAS to PJM in January 2017, and the SERC Reliability Corporation, the NERC-delegated regional reliability enforcement entity, approved it that same month. *See* Dave Rees, *Dominion Virginia Power Sets Plan for Emergency Blackouts*, Daily Press, Jan. 13, 2017, included in the docket of this Order. If Yorktown Units 1 and 2 were unavailable, many N-1-1 contingencies could result in voltage collapse and thermal overloads. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 4, included in the docket of this Order; PJM Deactivation Study, included in the docket of this Order. According to FERC, "An N-1-1 contingency is a sequence of events consisting of an initial loss of a single generator or transmission element, followed by system adjustment, followed by another loss of a single generator or transmission element." *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD14-14-000, 153 FERC ¶ 61,221 at P 30 n.61 (2015).

The North Hampton RAS is on standby for use at PJM's discretion. If PJM detects the loss of certain facilities, it could trip the remaining feeds to the Yorktown area and drop service to approximately 150,000 customers, preventing voltage collapse. Rotating outages would follow until the system returns to normal operating parameters. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 6, included in the docket of this Order. According to U.S. Census estimates, the region PJM identifies as the North Hampton Roads load area in its Order Application had a population of more than 660,000 as of July 2016. At a minimum, rotating outages under the RAS would therefore impact, directly or indirectly, several hundred thousand people. United States Census Bureau, QuickFacts database, available at https://www.census.gov/quickfacts/fact/table/US/PST045216.

On July 3, 2017, the Army Corps issued a permit to Dominion for the Skiffes Creek Transmission Project pursuant to section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403) and section 404 of the Clean Water Act (33 U.S.C. § 1344). On July

10, 2017, Dominion commenced construction of the Skiffes Creek Transmission Project. Renewal Application at 3.

On August 24, 2017, PJM filed its Renewal Application with DOE. The filing included all reports required by Order No. 202-17-2 (included in the docket of this Order). PJM said that construction of the Project was still expected to take 18-20 months, and that periodic transmission outages would be necessary to proceed apace with the Project. The same day, Dominion wrote to the Department that it "agrees with the Renewal Application and will operate in accordance with its provisions." Further, Dominion acknowledged that a 202(c) order "is not a long term solution to the reliability issues in the North Hampton Roads area on the Virginia Peninsula." The Skiffes Creek Transmission Project, underway as of July 2017, is the long-term solution.

On September 7, 2017, the Department received comments from Sierra Club opposing PJM's renewal request. On September 13, 2017, the Department received an answer to Sierra Club's comments from PJM. Both documents are included in the docket of this Order.

Discussion

Order No. 202-17-2 directs operation of Yorktown Units 1 and 2 as needed to address reliability issues, subject to a dispatch methodology submitted to the Department for review. The reliability issues noted in Order No. 202-17-2 were described as Scenario One, increased load due to weather-related temperature extremes, and Scenario Two, decreased transmission capacity required by the RTEP upgrade. Scenario Two was contemplated but not yet applicable when Order No. 202-17-2 was issued because the Army Corps permit application for the Skiffes Creek Transmission Project was still pending. On July 3, the Army Corps issued Permit No. NAO-2012-00080, resulting in the potential need to operate Yorktown Units 1 and 2 to address both Scenario One and Two reliability issues. To date, in accordance with Order No. 202-17-2, PJM has directed operation of Yorktown Units 1 and/or 2 for all or part of 13 days. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1, included in the docket of this Order; Telephone call to Steven Pincus, Associate General Counsel, PJM, Sept. 11, 2017.

Scenario One applies when load conditions exceed a certain threshold due to local transmission issues that would cause PJM to operate the system outside its normal operating parameters.[3] Weather-related temperature extremes are one example of such a local transmission issue. Scenario Two is also triggered when load conditions exceed a certain threshold, but the threshold is lowered depending on the particular construction-related transmission outages in effect as the Skiffes Creek Transmission Project is built.

[3] Exact load thresholds were submitted as critical electric infrastructure information and are thus not described here so as not to provide vulnerability information on critical infrastructure.

Because the Project minimizes environmental impacts by utilizing existing transmission line rights-of-way to the extent possible, portions of existing transmission lines must be taken offline for upgrades. Under either scenario, when the relevant thresholds are exceeded, to prevent system overload and uncontrolled power disruptions, PJM must implement the North Hampton RAS. The only sufficient alternative to the RAS and its resulting outages for up to approximately 150,000 customers is the emergency operation of Yorktown Units 1 and 2. The demand response available to PJM is a small fraction of the load threshold and is "not sufficient to ensure reliable service." Order Application, app. II, at 18. Likewise, Dominion has limited demand-side management and curtailment capabilities, insufficient for reliability purposes even when fully deployed. *See id.*, app. III, at 21.

Activating the RAS would immediately interrupt service to load in the North Hampton Roads area. PJM asserts that, according to the RAS, during certain high load conditions, this "load shedding" could result in the loss of roughly 950 MW of electric power—that is, the loss of service to over 150,000 North Hampton Roads area customers. Order Application at 9. This service interruption could last hours or even days. *See* North Hampton RAS Presentation to PJM, at 8, included in the docket of this Order. Activating the RAS is not a gradual approach that presents a wide range of likely impacts; it is an extreme measure with immediate consequences to 150,000 customers. While the RAS is designed to prevent more catastrophic, uncontrolled grid impacts from occurring, load shedding of this magnitude is significant, and would trigger mandatory reporting both to DOE and FERC. DOE Form OE-417 requires reporting within one hour for "[l]oad shedding of 100 Megawatts or more implemented under emergency operational policy," and within six hours for "[l]oss of electric service to more than 50,000 customers for 1 hour or more." This is the same level of reporting triggered by a cyber or other hostile attack on grid resources. Form OE-417, Electric Emergency Incident and Disturbance Report, https://www.oe.netl.doe.gov/docs/OE417_Form_03312018.pdf. Similarly, FERC and NERC mandate notification for a variety of serious events including when a bulk electric system emergency triggers automatic load shedding of 100 MW or more, as in the RAS. *See* North American Electric Reliability Corporation, Reliability Standard EOP-004-3 (Event Reporting), http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-004-3&title=Event%20Reporting.

To underscore the potential impact of RAS activation, the estimated 150,000 impacted customers are counted by meter, not individual. One or more meters could translate to large household or commercial or industrial facilities, including those critical to health and safety systems. Whether counted as 150,000 or that amount multiplied several times over, the anticipated impact of this emergency situation is on par with or exceeds the impacts described in prior 202(c) orders. *Crisp Cnty. Power Comm'n v. Ga. Power Co.*, 35 FPC 629, 630-31 (1966) (ordering interconnection to prevent, in part,

outages lasting more than an hour and affecting 500 to 2,000 customers on Crisp County, Georgia's system). *City of Cleveland, Ohio v. Cleveland Elec. Illuminating Co.*, 47 FPC 747, 749 (1972) (ensuring reliable service was provided to the approximately 20% of the city's consumers). Cleveland's 1970 Census-reported population was 750,903, suggesting that just over 150,000 individuals were affected by the 1972 202(c) order. *See* https://www.census.gov/population/www/documentation/twps0027/tab20.txt. As described earlier, the U.S. Census estimated the population of the North Hampton Roads load area at nearly 661,000 people just over a year ago.

A benefit of the planning efforts mandated by federal reliability standards is that entities such as PJM can accurately forecast the impacts to the bulk power system in steady-state and various contingency event situations. Thus, as reliability planning continues to mature, there should be fewer electric energy shortages that take bulk power system owners, operators, and regulators by surprise. That planners can identify conditions under which shortages may occur, however, does not rule out electric energy shortages constituting emergencies under FPA section 202(c) and the Department's implementing regulations. It is impossible to plan for every contingency, and challenges may arise even when implementing the most prudent plans. FPA section 202(c) affords the Secretary of Energy discretion in finding when an emergency exists and how best to meet the emergency and serve the public interest.

Here, an emergency exists due to the imminent possibility of implementing the North Hampton RAS under a range of both steady-state and contingency events, including potential transmission congestion preventing the delivery of available generation to the North Hampton Roads area. PJM Deactivation Study at 1-2, included in the docket of this Order. The RAS would leave approximately 150,000 customers without power, including residential, industrial, commercial, health and safety facilities, major national defense, and educational institutions. *See* Order Application, app. IV, at 30-31. That creates serious health and safety issues. Issuance of today's Order meets the emergency and serves the public interest.

In these circumstances, transmission outages, like those contemplated for or otherwise in connection with the construction of the Skiffes Creek Transmission Project, constitute an emergency for purposes of a section 202(c) order. As stated earlier, the Department's implementing regulations, in their current form since 1981, contemplate that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities [may create] an emergency." 10 C.F.R. § 205.371. The regulations add that "[i]n such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed." *Id.* PJM, the impacted entity in this case, requested today's Order. Through the RTEP, PJM made firm arrangements to resolve the problem through the Skiffes Creek Transmission Project, which is now permitted and under construction. That construction was delayed due to events beyond

PJM's control has no bearing on the likelihood of power outages for 150,000 customers. Such a power loss event would also constitute an emergency as contemplated by FERC in its Public Utility Regulatory Policies Act of 1978 regulations, which define "system emergency" as "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." 18 C.F.R. § 292.101(b)(4). The risk faced by 150,000 customers will continue, assuming the Skiffes Creek Transmission Project construction schedule is met, for approximately another 18 months. Today's Order is limited in time and specifically tailored to address an emergency contemplated both in the authorizing statute and the Department's implementing regulations.

Between 2005 and 2007, DOE issued orders under similar circumstances, directing the Mirant Potomac River Generation Station to operate until two new 230kV transmission lines could be built to ensure reliability to a portion of the District of Columbia. *See* Order No. 202-5-3 (relying on DOE regulatory definition of emergency as including extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities). In a series of orders under FPA section 202(c), the Secretary ordered operation of the generation units while the two existing 230kV lines that supplied the central District of Columbia area were temporarily and sequentially removed from service to connect the new lines. Neither the problems leading up to the closure of the generating units nor the need for a particular transmission solution were unexpected. Nevertheless, the Department found that imminent power shortages, faced if contingency events occurred, constituted an emergency under the Federal Power Act. Order Nos. 202-5-3, 202-6-1, 202-6-2, 202-7-1, and 202-7-2.

In this matter, the likelihood of RAS activation is not theoretical. While Order No. 202-17-2 was in effect, PJM had to call upon Yorktown Units 1 and/or 2 on 13 days over three months. Absent Order No. 202-17-2, the RAS would have been activated instead. The alternatives available to PJM and Dominion are not sufficient to ensure reliability without available capacity from Yorktown Units 1 and 2. As described, PJM and Dominion cannot mobilize adequate alternatives to counter the loss of transmission during construction of the Skiffes Creek Transmission Project. For example, demand response resources, while potentially helpful at the margin, are insufficient to address either Scenario One or Scenario Two. *See* Order Application, app. II, at 18. Further, PJM's recent RTEP Input Assumptions and Scope Whitepaper indicates that Dominion theoretically has up to 130 MW of distributed solar generation available during the summer. 2017 RTEP Process Scope and Input Assumptions, rev. 1, tbl.3.2, at 18 (Aug. 3, 2017), included in the docket of this Order. Outside of ramp-up and ramp-down times, each Yorktown Unit typically ran at 100 MW output or higher, day or night, when operational while Order No. 202-17-2 was in effect. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1. Distributed generation is an intermittent resource; even under ideal conditions, with full-capacity, daytime generation and load reduction at the height of the

summer, distributed generation generally would still not have offset the baseload generating capacity needed to ensure reliability on the North Hampton Roads area grid. And any flexibility for scheduling the Skiffes Creek Transmission Project's construction during historically low-load periods ended when the EPA ACO expired, as expeditious completion of the Project is now the priority. Therefore, even if PJM and Dominion made full use of available alternatives, capacity from Yorktown Unit 1, 2, or both would still be necessary to meet the emergency and serve the public interest.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law or regulation be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, [be] consistent with any applicable . . . environmental law or regulation and minimize[] any adverse environmental impacts." Certain load conditions may necessitate operation of Yorktown Units 1 and 2.

To minimize the hours of operation and adverse environmental impacts, the Order contains certain limitations. First, DOE maintains consistency with EPA's approach in the 2016 ACO by authorizing operation of Yorktown Units 1 and 2 only when called upon by PJM for reliability purposes. The Department consulted with EPA and has reviewed data provided by PJM and Dominion on operations, air emissions, and water usage. This Order will continue the operational limitations described in EPA's above-referenced ACO, AED-CAA-113(a)-2016-0005. Second, DOE requires that PJM and Dominion, consistent with good utility practice, first exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, before operating Yorktown Units 1 and 2. Third, DOE requires continued compliance with the June 27 dispatch methodology, which was reviewed by the Department, and which remains subject to continuing oversight by the Department. In particular, the dispatch methodology establishes Yorktown Units 1 and 2 commitment procedures, describes the utilization and trip conditions of the North Hampton RAS for mitigating congestion on the Virginia Peninsula or North Hampton Roads area, and describes Dominion's mitigation options for the existing James River tower contingency. The dispatch methodology is an operating protocol that limits the ability of PJM to dispatch Yorktown Units 1 and 2 only when needed to mitigate reliability issues associated with scheduled and emergency transmission outages directly related to the Skiffes Creek Transmission Project and other local transmission issues. The EPA ACO recognized that such a dispatch methodology, under which PJM determines when the Yorktown units are needed for reliability issues, serves the objective of minimizing emissions. ACO at 8-9, included in the docket of this Order. Fourth, to track when Yorktown Units 1 and 2 are operated to maintain grid reliability and to monitor associated air emissions and water usage, reports will be required every two weeks going forward. If the Department becomes concerned with PJM or Dominion's compliance with this Order, enforcement actions are available, up to and including termination of the underlying order.

While DOE has constrained PJM's operations with regard to Yorktown Units 1 and 2, it is necessary to preserve reasonable discretion for PJM, as a Transmission Operator, to address the second-to-second operational challenges of grid management. This follows DOE's practice in earlier orders issued under FPA section 202(c), which prioritized reliability concerns as identified and assessed by the operator. For example, Order No. 202-02-1 (Aug. 16, 2002) ordered Cross-Sound Cable Company, LLC to operate a cable across Long Island Sound, limiting "transmission and delivery of . . . electric capacity and/or energy [to that] necessary in the judgment of the New York Independent System Operator [ISO] to meet the supply and essential reserve margin needs of the Long Island Power Authority [LIPA]," but only "in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice." Order No. 202-03-1 (Aug. 14, 2003) directed operation of the same cable, but specifically ordered the New York ISO and ISO New England to require Cross-Sound Cable Company to operate the cable. That order also required both RTOs to "consult with each other and with appropriate reliability organizations." Today's Order similarly requires PJM to identify and mitigate reliability issues in accordance with DOE's specified operational limitations.

In considering renewal or reissuance of an order under FPA section 202(c) that may conflict with an environmental law or regulation, DOE is required to "consult with the primary Federal agency with expertise in the environmental interest protected by such law or regulation" and to include "conditions as such Federal agency determines necessary . . . to the extent practicable." 16 U.S.C. § 824a(c)(4). The EPA is the primary federal agency in this case with expertise in the protected environmental interest, specifically MATS and section 316(b) of the Clean Water Act, and the Department consulted with EPA after receiving the Renewal Application. Email from Acting Assistant Administrator Starfield, Office of Enforcement and Compliance Assurance, to Acting Under Secretary for Science and Energy Hoffman (Sept. 11, 2017), included in the docket of this Order. After consulting with EPA, and consistent with that consultation, the Department found that the only appropriate short-term emissions limitation on Yorktown Units 1 and 2 would be to curtail operating hours to the maximum extent practical for reliability purposes.

Pursuant to the National Environmental Policy Act of 1969, the Department has determined that issuance of this Order fits within the category of actions included in Categorical Exclusion (CX) B4.4 and otherwise meets the requirements for application of a CX. The Order fits within the category of actions because it authorizes "[p]ower marketing services and power management activities (including, but not limited to, storage, load shaping and balancing, seasonal exchanges, and other similar activities), provided that the operations of generating projects would remain within normal operating limits." Records of Categorical Exclusion Determination, Order No. 202-17-4, Sept. 11, 2017, included in the docket of this Order.

For the reasons stated above, the Secretary of Energy finds that an emergency exists threatening imminent electric energy shortages, and that this Order is necessary to address the emergency and serve the public interest in the North Hampton Roads area. The limitations on operation set forth in Order No. 202-17-4 and outlined above are, to the maximum extent practicable, consistent with applicable environmental laws or regulation and minimize any adverse environmental impacts, and the reporting requirements for operations and estimated emissions ensure transparency of implementation.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-15:
DOE Order No. 202-02-1

Department of Energy
Washington, DC 20585

Order No. 202-02-1

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act, 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. 7151(b), I hereby determine that an emergency exists on Long Island in the State of New York due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will alleviate the emergency and serve the public interest. Based on this determination, I hereby order:

From the effective date and time of this order until 12:01 a.m. Eastern Daylight Time, October 1, 2002, Cross-Sound Cable Company, LLC is directed to operate the Cross-Sound Cable and related facilities connecting substations in New Haven, Connecticut and Shoreham, Long Island, New York, to transmit and deliver electric capacity and/or energy when, as and in such amounts as may be scheduled and purchased by the Long Island Power Authority (LIPA), and to take such actions as are necessary in order to enable it to do so, including but not limited to energizing and continuing to energize the facilities of Cross-Sound Cable Company, LLC; *provided*, that this order otherwise shall be limited to requiring the transmission and delivery of such electric capacity and/or energy as is necessary in the judgment of the New York Independent System Operator to meet the supply and essential reserve margin needs of LIPA, in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice, including curtailing and/or terminating service to interruptible customers, public appeals for conservation, reducing 30 minute reserves to zero, and implementing voltage reductions; *and provided further*, that prior to exercising its judgment as required by this order, the New York Independent System Operator must consult with ISO New England, Inc. to ensure that the scheduling of such electric capacity and/or energy will not violate system operating criteria, and the New York Independent System Operator should, as practicable, consult with appropriate reliability organizations. If necessary, just and reasonable terms for the transmission and delivery of electric capacity and/or energy pursuant to this order, including the compensation therefor, shall be established by a supplemental order issued pursuant to Federal Power Act section 202(c).

Nothing in this order shall preclude use of the energized Cross-Sound Cable and its related facilities connecting substations in New Haven, Connecticut and Shoreham, Long Island, New York, to transmit and deliver electric capacity and/or energy from Long Island to Connecticut or from Connecticut to Long Island in accordance with the operating and scheduling protocols and decisions of the New York Independent System Operator and ISO New England, Inc.

This order shall be effective upon its issuance.

Issued in Washington, D.C. at 2:38PM this 16th day of August, 2002.

Spencer Abraham
Secretary of Energy

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-16:
DOE Order No. 202-20-2

Department of Energy
Washington, DC 20585

Order No. 202-20-2

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated to the Deputy Secretary of Energy by paragraph 1.11(A) of Delegation Order No. 00-001.00G (Apr. 10, 2018), and re-delegated to the Assistant Secretary for Electricity on September 6, 2020, and for the reasons set forth below, I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

On September 6, 2020, the California Independent System Operator (CAISO), the Regional Transmission Organization whose service territory includes California and a portion of Nevada, filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of bulk electric power system."

Since August, California has experienced several periods of extreme heat, some of which have resulted in rolling blackouts. On September 2, 2020, California Governor Gavin Newsom issued an emergency proclamation to help alleviate the stress on the state's power grid due to an "Extreme Heat Event." In declaring a statutory emergency, the proclamation cited a number of factors and observations, including the following:

- "[B]eginning on September 2, 2020, a significant heat wave struck California, bringing widespread temperatures well in excess of 100 degrees throughout the State;"
- "[T]he National Weather Service [has] issued multiple Excessive Heat Warnings within [California];"
- "[T]he Extreme Heat Event has and will continue to put significant demand and strain on California's energy grid; and"
- "[T]he Extreme Heat Event is expected to last through at least September 7, 2020."

The proclamation authorizes emergency use of stationary generators, portable generators, and "auxiliary engines by ocean-going vessels berthed in California ports," and directs the state's Air Resources Board to "exercise maximum discretion to permit the use of stationary and portable generators or auxiliary ship engines to reduce the strain on the energy infrastructure and increase energy capacity." The proclamation also

suspends "[a]ny permit, regulation or law prohibiting, restricting or penalizing the use of stationary or portable generators or auxiliary ship engines" as allowed by the proclamation order.

On September 3, the CAISO issued a statewide flex alert for September 5-7, encouraging voluntary load reduction between 3:00 p.m. and 9:00 p.m. local time each day. The alert warns that consumers should "be prepared for potential power outages, both planned and unplanned during heat waves, especially in extremely high temperatures that last multiple days," noting that "[h]ot weather can also impact generation and transmission equipment, as it runs harder and longer with less time to cool, which can cause machinery failure." The alert explains that there is little energy available to import due to high heat predicted throughout the West, and that the wildfires in the state may take out transmission lines or cause lines to be shut down for the safety of firefighters in the area.

The CAISO notes that "[e]lectric demand forecasts have continued to increase since the issuance of the California Governor's emergency proclamation and the CAISO balancing authority area has lost additional generation supply because of wildfires." Application at 3. To address the situation, the "CAISO has started to direct all generators in its balancing authority area to produce to their maximum capability during certain times of the day," and has gone so far as to allow, when reliable and safe based on currently operating conditions, "certain generators to generate more than their interconnection capacity to provide additional power to the grid." *Id.* at 3. The impetus for the Application, however, arose on September 5, 2020, when the operator of the natural gas-fired resources identified in Exhibit A of the Application informed the CAISO that it could not produce to its maximum generation capability without exceeding its federal air quality or other permit limitations. *Id.* "The CAISO is informed and believes these limitations involve both permit limitations under federal law for nitrogen oxide emissions and ammonia releases as well as a limitations regarding fuel and ammonia throughput." *Id*.

The CAISO requests "that the Secretary issue an order immediately, effective September 6, 2020, authorizing specific electric generating units located within the CAISO balancing authority area to operate at their maximum generation output levels when directed to do so by the CAISO, notwithstanding air quality or other permit limitations." *Id.* at 1. The generating units specified are units 1 - 5 at the Walnut Creek Energy Park in the City of Industry, California; units 5/6 and 7/8 at the El Segundo Energy Center in El Segundo, California; and units 1 - 4 at the Long Beach Generating Station located in Long Beach, California. *Id.* For purposes of this Order, these units are referred to as the "Specified Resources." Collectively, they represent up to as much as 100 MW. The CAISO requests "such order be entered today, September 6, 2020, and remain effective for a period of seven (7) days, without prejudice to the possible issuance of further orders as necessary to address the emergency…[to] ensure additional supply is

available during a period in which California may continue to experience extreme weather and wildfires that have forced generation out of service." *Id*. at 2.

Given the emergency nature of the expected load stress, the responsibility of the CAISO to ensure maximum reliability on its system, and the ability of the CAISO to identify and dispatch generation necessary to meet the additional load, I have determined that additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. The CAISO anticipates that this Order may result in exceedance of National Ambient Air Quality Standards under the Clean Air Act and notes that the Specified Resources are located in different communities within California and should not result in any disproportionate impact on a single community. *Id.* at 4. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by the CAISO for reliability purposes.

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

A. From September 6, 2020, to September 13, 2020, in the event that the CAISO determines that generation from the Specified Resources is necessary to meet the exceptional levels of electricity demand that the CAISO anticipates in California, I direct the CAISO to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in California between the hours of 14:00 Pacific Daylight Time and 22:00 Pacific Daylight Time on days when the demand on the CAISO system exceeds expected energy and reserve requirements.

B. The CAISO shall select the combination of units that meets the reliability emergency and minimizes environmental impact. Consistent with good utility practice, the CAISO shall exhaust all reasonably and practically available resources, including demand response and identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources.

C. By September 21, 2020, the CAISO shall report all dates between September 6, 2020, and September 13, 2020, on which the Specified Resources were

operated, the hours of operation, and the estimated air emissions (including nitrogen oxides and ammonia releases) and fuel and ammonia throughput associated with operating each unit. The CAISO shall submit a final report by October 13, 2020, with any revisions to the information reported on September 21.

D. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Daylight Time on September 13, 2020, with the exception of the reporting requirements in paragraph C. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. this 6th day of September, 2020.

Bruce J. Walker

Digitally signed by Bruce J. Walker
Date: 2020.09.06 17:19:49 -04'00'

Bruce Walker
Assistant Secretary for Electricity

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-17:
DOE Order No. 202-22-2

Department of Energy
Washington, DC 20585

Order No. 202-22-2

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated to the Deputy Secretary of Energy by paragraph 1.12(A) of Delegation Order No. S1-DEL-S2-2022 (Mar. 14, 2022), and further delegated by the Deputy Secretary by email correspondence (Sept. 2, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On September 2, 2022, the Balancing Authority of Northern California (BANC) filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department or DOE) "to preserve the reliability of the bulk electric power system in California," and more specifically to allow the BANC Balancing Authority Area (BAA) to request the dispatch of generation within the BANC BAA "that may be necessary for BANC to meet demand in the face of extreme heat." BANC is a joint powers authority whose members include the Sacramento Municipal Utility District and other municipalities, irrigation districts, and public utilities districts. BANC is a registered Balancing Authority with the North American Electric Reliability Corporation and operates as a neighboring BAA to the California Independent System Operator Corporation (CAISO) BAA. On September 4, 2022, BANC filed an *Amended, Supplemented and Clarified Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Amended Application) in response to questions from DOE.

California has experienced several periods of extreme heat, drought conditions, and threat of wildfires. Such conditions are expected to occur over the next several days and threaten the reliable operation of the bulk electric power system in California. The loads from the forecasted heat wave over the next week are expected to push demand for electric energy by BANC members to at or over historical peaks and higher than normally expected planning targets for this time of year. Amended Application at 2.

On August 31, 2022, California Governor Gavin Newsom issued a proclamation declaring a state of emergency regarding electricity from September 2 through September 7, 2022.[1] In declaring a statutory emergency, the proclamation cited a number of factors and observations, including the following:

- A significant heat wave will bring temperatures "in excess of 100 degrees throughout the State and is forecast to bring record temperatures 10–20 degrees

[1] GSS_9534-1E-20220831133826 (ca.gov)

above normal throughout the State, exceeding 110 degrees in some areas (the 'Extreme Heat Event');"

- The extreme heat will put a significant demand and strain on California's energy grid and is forecast to be a "West-wide event" meaning that energy demand will be high across the region and "California will have limited ability to import energy from out-of-state;"

- The CAISO issued a Heat Bulletin forecasting high electric demand during the extreme heat event that will "stress the energy grid, with peak load for electricity projected to reach its highest level of the year, exceeding 48,000 megawatts on September 5, 2022;" and

- The CAISO is forecasting supply deficiencies of "over 3,000 megawatts during evening hours from September 4, 2022, through September 6, 2022" and advised that emergency interventions would allow energy customers to make contingency plans ahead of the Labor Day holiday weekend.

The proclamation authorizes several measures aimed at mitigating the emergency and avoiding jeopardizing public health or safety, including directing the California Air Resources Board (CARB) to "implement its State-funded Climate Heat Impact Response Program (CHIRP) to mitigate emissions from any operation pursuant to this Proclamation." The proclamation also directs the California Energy Commission (CEC) to "provide information requested by [CARB] to assist with its implementation" of CHIRP.

BANC noted that it "has prepared this request in consultation with the California Energy Commission (CEC), the California Governor's Office, and the CAISO." Application at 2.

Description of Mitigation Measures

In its Application, BANC described actions it has taken in order to alleviate the generation shortfall. Electric utilities within BANC, in coordination with CEC, CAISO, and the California Governor's Office, have implemented conservation and other extraordinary efforts to procure additional supply. BANC members have been able to obtain some purchases from the Pacific Northwest (PNW) bilateral wholesale markets to help offset the additional need, but the physical interties with PNW are near physical limits. BANC members have also been making use of demand-side programs, including commercial interruptible load programs, residential peak shaving programs, and public appeals for conservation. Amended Application at 2.

Request for Order

BANC has requested an emergency order to allow the BANC BAA to dispatch the Covered Resource described below within the BANC BAA that may be necessary for

the BANC to meet demand in the face of extreme heat, subject to the terms set forth herein.

The generators for which BANC is seeking this emergency order consist of 24 diesel-fired generator units owned by NTT Global Data Centers Americas (NTT), located at 1312 Striker Ave, Sacramento, CA 95834, known as "CA 2" and more fully described in the Application Exhibit A – List of Covered Resources (NTT Generators or Covered Resource). The Covered Resource plans to participate in the CEC-administered Demand Side Grid Support program that facilitates availability of resources for emergency purposes. Application at 3; Amended Application at 3-4. Therefore, while the Covered Resource has an aggregate installed capacity of 48MW, BANC requests that this emergency order apply only to capacity necessary to supply the load at the NTT facility served by the Covered Resource, up to 26.1 MW (Covered Maximum Output). Amended Application at 3-4.

BANC has requested that the Secretary issue the requested emergency order by Sunday, September 4, 2022, or as soon as possible thereafter, authorizing the Covered Resource to operate at the Covered Maximum Output level between 2:00 p.m. and 10:00 p.m., when directed to do so by BANC, notwithstanding air quality or other permit limitations.

ORDER

Given the emergency nature of the expected load stress and generation shortfall, the responsibility of BANC as the Balancing Authority to balance generation and load in its BAA to ensure maximum reliability on its system, and the ability of BANC to identify and dispatch generation necessary to meet additional load if an order is issued, I have determined that, under the conditions specified below, generation from the Covered Resource is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c) up to the Covered Maximum Output. This determination is based on, among other things:

- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the State of California and within the BANC BAA, including as declared in the Governor's August 31 emergency proclamation and as described in the Application and Amended Application, demonstrate the need for the Covered Resource to contribute to the reliability of the BANC BAA.

- The availability of 26.1 MW of reduced load as enabled by generation from the Covered Resource up to the Covered Maximum Output provides significant assistance by freeing up system generating resources to help alleviate the shortage of generation and meet demand in the BANC BAA.

- The Covered Resource is enrolled in CEC's Demand Side Grid Support (DSGS) program. The DSGS program establishes procedures for qualification, operation, and reporting to ensure that enrolled generation such as the Covered Resource

provides verifiable load reduction and thereby increase available system capacity during energy emergency events.

- The conditions in CEC's DSGS and those specified below restrict operation of the Covered Resource to those circumstances necessary to avoid load shed.

In line with the emergency proclamation's anticipation of near-term energy shortages, this Order is limited to a 5-day period, from September 4, 2022, through September 8, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, under the conditions and with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law, and minimize any adverse environmental impacts. BANC anticipates that this Order may result in exceedance of National Ambient Air Quality Standards (NAAQS) under the Clean Air Act and other conflicts with environmental law. This Order would permit operation of the Covered Resource and corresponding emissions of volatile organic compounds (VOCs), nitrogen oxides (NOx), sulfur dioxide (SO_2), coarse particles (PM10), and carbon monoxide (CO), in circumstances not contemplated by the units' Title V permit. Namely, under its Title V permits, the Covered Resource is permitted to operate at certain emission rates during maintenance and when electric service from the serving utility is interrupted by an unforeseeable event, but not in order to assist the utility in avoiding service interruptions for other customers. The Order would permit operation under grid emergency conditions; however, under the conditions specified below, it would not permit exceedance of the emission limits otherwise applicable to the units constituting the Covered Resource, including limits on the pounds of VOC, NOx, SO_2, PM10, and CO emitted per year.

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

A. From September 4, 2022, to September 8, 2022, in the event that BANC determines that generation from the Covered Resource is necessary to preserve the reliability of the bulk electric power system in California, I direct BANC to dispatch such unit or units and to order their operation solely under the following conditions: the issuance and continuation of an Energy Emergency Alert Level 2[2] condition or greater between the hours of 14:00 Pacific Time and 22:00 Pacific Time after exhausting all reasonably and practically available resources.

B. Consistent with good utility practice, BANC shall exhaust all reasonably and practically available resources, including other demand response and

[2] For the purposes of this Order, "Energy Emergency Alert Level 2" has the meaning set forth in Section 3.6.3 of the California ISO System Emergency Operating Procedure, Procedure No. 4420, Version 14.0, Effective Date May 1, 2022 (CAISO Emergency Operating Procedure).

identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Covered Resource.

C. All operation of the Covered Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators. The Covered Resource must comply with the requirements of the CARB Mandatory Reporting Regulation and California's Cap-and-Trade regulation, to the extent applicable. This Order allows operation of the Covered Resource under operating conditions not otherwise permitted by the Covered Resource's Title V permit but does not provide relief from the obligation to operate the Covered Resource within the equipment-specific or cumulative emission limit requirements specified in the Covered Resource's Title V permit.

D. BANC shall 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. By October 10, 2022, BANC shall report source-specific data for all dates between September 4, 2022, and September 8, 2022, on which the Covered Resource was operated, including, for each unit, (1) the hours of operation, as well as the hours in which any permit limit was exceeded, and (2) a preliminary description of each permit term that was exceeded and the manner in which such exceedance occurred. BANC shall also submit a final report by November 14, 2022, with any revisions to the information reported on December 12, 2022. The environmental information submitted in the final report shall also include the following information:

i. Emissions data in pounds per hour for each Covered Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO_2;

ii. Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

iii. The number and actual hours each day that each Covered Resource unit operated in excess of permit limits or conditions, e.g. "Generator #1; September 5, 2022; 4 hours; 18:00-22:00 PT";

iv. Amount, type and formulation of any fuel used by each Covered Resource;

v. All reporting provided over the last three years to the United States Environmental Protection Agency or Sacramento Metropolitan Air Quality Management District pursuant to operating permit requirements;

vi. Information provided to the CARB in response to the CARB's development and implementation of the plan to mitigate the effects of additional emissions authorized by the August 31, 2022 proclamation;

vii. Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

viii. Information provided by the Covered Resource describing how the requirements in paragraph C above were met by the Covered Resource while operating under the provisions of this Order.

E. BANC shall inform all affected communities where the Covered Resource operates that BANC has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explain clearly what the Order allows BANC to do, including potential impacts to the community where the Covered Resource is located and communities adjacent to the Covered Resource. BANC shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph D above.

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

G. BANC shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

H. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Time on September 8, 2022, with the exceptions of paragraphs F and G and the reporting and analysis requirements in paragraphs D and E. Renewal or amendment of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 16:20 Eastern Time on this 4th day of September, 2022.



Kathleen Hogan
Acting Under Secretary for
Infrastructure

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-18:
DOE Order No. 202-21-1

Department of Energy
Washington, DC 20585

Order No. 202-21-1

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Texas due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

On February 14, 2021, the Electric Reliability Council of Texas (ERCOT), the Independent System Operator (ISO) whose service territory includes 90 percent of the electric customers in the state of Texas, filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of bulk electric power system."

ERCOT is in the beginning stages of an unprecedented cold weather event brought on by a rare, southward excursion of the jet stream into the South Central United States. Temperatures for Sunday and Monday in many parts of Texas are forecasted to drop well below the lowest temperatures experienced in several decades, and abnormally low temperatures are expected to persist for several more days. This weather event is expected to result in record winter electricity demand that will exceed even ERCOT's most extreme seasonal load forecasts.

On February 12, 2021, Greg Abbott, the Governor of the State of Texas declared a state of disaster in all 254 Texas counties due to severe weather posing an "imminent threat of widespread and severe property damage, injury, and loss of life due to prolonged freezing temperatures, heavy snow, and freezing rain statewide." On the morning of February 14, ERCOT issued a system-wide conservation notice addressing the expected system emergency and describing steps that homeowners and businesses can take to reduce system demand.[1] ERCOT has also worked with state agencies to take measures that maximize generation availability in Texas. For example, on February 12, the Railroad Commission of Texas issued an Emergency Order pursuant to Texas Utilities Code affecting the gas utility systems in the state. The order specified increasing the priority of gas supplies to ERCOT generators. ERCOT's application also noted that the "Texas Commission on Environmental Quality has indicated that it will provide enforcement discretion to generators in the ERCOT region that may exceed state emissions requirements during emergency conditions."

According to ERCOT, the measures taken by ERCOT and other state agencies may not prove sufficient to avoid rotating outages of as much as 4,000 MW. Moreover,

[1] ERCOT, *Grid Operator Requests Energy Conservation for System Reliability*, www.ercot.com/news/releases/show/225151.

ERCOT has been alerted that numerous generation units will be unable to operate at full capacity without violating federal air quality or other permit limitations.

ERCOT requests that the Secretary issue an order immediately, effective February 14, 2021 through February 19, 2021, authorizing "the provision of additional energy from all generation units subject to emissions or other permit limits" in the ERCOT region. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-21-1 Resources List, as described below.

Given the emergency nature of the expected load stress, the responsibility of ERCOT to ensure maximum reliability on its system, and the ability of ERCOT to identify and dispatch generation necessary to meet the additional load, I have determined that additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. ERCOT anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by ERCOT for reliability purposes.

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

A. From February 14, to February 19, 2021, in the event that ERCOT determines that generation from the Specified Resources is necessary to meet the electricity demand that ERCOT anticipates in Texas during this event, I direct ERCOT to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the ERCOT region when the demand on the ERCOT system exceeds expected energy and reserve requirements. Specified Resources are those natural gas, coal, or distillate fuel oil generating units set forth on the Order 202-21-1 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov. ERCOT is directed to update Exhibit A to its Application with the anticipated category of environmental impact (i.e. sulfur dioxide, nitrogen oxide, mercury, carbon monoxide emissions, wastewater release, other air pollutants) by 21:00 Central Standard Time on February 15, 2021.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by ERCOT for reliability purposes. Consistent with good utility practice, ERCOT shall exhaust all reasonably and

practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. ERCOT shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

(i) with respect to any Specified Resource that is an ERCOT Generation Resource or Settlement Only Generator whose operator notifies ERCOT that the unit is unable, or expected to be unable, to produce at its maximum output due to an emission or effluent limit in any federal environmental permit, ERCOT shall ensure that such Specified Resource is only allowed to exceed any such limit during a period for which ERCOT has declared an Energy Emergency Alert (EEA) Level 2 or Level 3. This incremental amount of restricted capacity would be offered at a price no lower than $1,500/MWh. Once ERCOT declares that such an EEA Level 2 or Level 3 event has ended, the unit is required to immediately return to operation within its permitted limits; and

(ii) with respect to any Specified Resource that is an ERCOT Generation Resource whose operator notifies ERCOT that the unit is offline or would need to go offline due to an emission or effluent limit in any federal environmental permit, and to which ERCOT has issued a Reliability Unit Commitment (RUC) instruction, the operator may make all of the unit's capacity available to ERCOT for dispatch during a period for which ERCOT has declared an EEA Level 2 or Level 3. This incremental amount of restricted capacity would be offered at a price no lower than $1,500/MWh. Once ERCOT declares that such an EEA Level 2 or Level 3 event has ended, the unit is required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

In the event ERCOT identifies the need to exceed other relevant environmental permitting levels, ERCOT shall specifically identify such permitting levels and DOE will consider ERCOT's request in good faith.

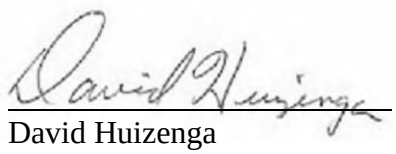
C. All entities must comply with environmental requirements to the maximum extent necessary to operate consistent with the emergency conditions. This Order does not provide relief from an entity's obligations to purchase allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. In the event that ERCOT identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the ERCOT region when the demand on the ERCOT system exceeds expected energy and reserve requirements, including any such entity to which ERCOT intends to issue a Reliability Unit Commitment (RUC), ERCOT shall provide prompt written notice to the Department of Energy at AskOE@hq.doe.gov identifying in an updated Exhibit A to its Application such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 9:00 Central Standard Time or 21:00 Central Standard Time, whichever follows closest in time to the unit identification by ERCOT to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department, and ERCOT may dispatch such additional generation units, provided that if the Department of Energy notifies ERCOT that its does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-21-1 Resource List as soon as practicable following notification from ERCOT under this paragraph.

E. ERCOT shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By March 1, 2021, ERCOT shall report all dates between February 14, 2021, and February 19, 2021, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. ERCOT shall submit a final report by March 31, 2021, with any revisions to the information reported on March 1, 2021. In addition, ERCOT shall provide information to the Department quantifying the net revenue associated with generation in excess of environmental limits accruing to non-RUC units in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. This Order shall be effective upon its issuance, and shall expire at 11:59 p.m. Central Standard Time Friday, February 19, 2021, with the exception of the reporting requirements in paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 8:51 PM Eastern Standard Time on this 14th day of February, 2021.



David Huizenga
Acting Secretary of Energy

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-19:
FERC Energy Primer



Energy Primer

A Handbook for Energy Market Basics

FEDERAL ENERGY REGULATORY COMMISSION
Office of Energy Policy and Innovation

Energy Primer

A Handbook for Energy Market Basics

FEDERAL ENERGY REGULATORY COMMISSION
Office of Energy Policy and Innovation
December 2023

This report is a product of the staff of the Federal Energy Regulatory Commission (Commission or FERC). The opinions and views expressed in this paper represent the preliminary analysis of the Commission staff. This report does not necessarily reflect the views of the Commission, its Chairman, or individual Commissioners, and is not binding on the Commission.

ACKNOWLEDGMENT

The Energy Market Primer was originally issued in 2012 and has been updated several times since its first issuance. This update to the Energy Market Primer is the result of the combined efforts of many dedicated individuals throughout the Federal Energy Regulatory Commission (FERC or Commission). The team consisted of individuals from the Commission's Office of Energy Policy and Innovation, Office of Enforcement, Office of Energy Market Regulation, and Office of External Affairs. We specifically wanted to recognize the primary contributors to each chapter.

Chapter 1: Wholesale Natural Gas Markets – Eric Primosch

Chapter 2: Wholesale Electricity Markets – Patricia Schaub

Chapter 3: Gas-Electric Interdependency – Thomas Pinkston

Chapter 4: U.S. Crude Oil and Petroleum Products Markets – Eric Primosch

Chapter 5: Trading and Capital Markets – Astrid Rapp and Gareth Jones

Chapter 6: Market Manipulation – Thomas Olson

IN MEMORIAM



Lance Hinrichs

Federal Energy Regulatory Commission
Office of Energy Policy and Innovation

Lance was instrumental in the creation and publication of the Energy Market Primer. He will forever be remembered as a dedicated public servant whose knowledge of energy markets was unsurpassed.



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INTRODUCTION

Natural gas, electricity, and crude oil are forms of energy that are of particular interest to the Federal Energy Regulatory Commission (FERC) pursuant to its authority under the Natural Gas Act, the Federal Power Act, and the Interstate Commerce Act. This primer explores the workings of the wholesale markets for these forms of energy, as well as energy-related financial markets.

Energy markets consist of both physical and financial elements. The physical markets contain the natural resources, infrastructure, institutions and market participants involved in producing energy and delivering it to consumers. The financial markets include the buying and selling of financial instruments that derive value from the price of the physical commodity. These financial markets have their own set of market structures and institutions, market participants, and traded products which have their own drivers of supply and demand. In general, physical and financial markets can be distinguished by the products and by the intentions of the market participants involved.

Much of the wholesale natural gas and electric power industry in the United States trades competitively, while some markets and their prices are established through administrative processes based on the cost of providing service. In competitive markets, prices are largely driven by the economic concepts of supply and demand. Underlying the supply and demand for energy are physical fundamentals - the physical realities of how markets produce and deliver energy to consumers and how they form prices. These physical fundamentals will be covered in Chapter 1 (Wholesale Natural Gas Markets), Chapter 2 (Wholesale Electricity Markets), and Chapter 4 (U.S. Crude Oil and Petroleum Products Markets).

The significant shift in the U.S. fuel mix has heightened the importance over the past decade of the interdependence of the natural gas and electric systems. Given the importance of natural gas in electricity generation, integration of market operations between the natural gas and electricity industries is critical. The primer provides an overview of natural gas and electric system interdependencies in Chapter 3, Gas-Electric Interdependency.

Market participants buy and sell energy based financial contracts for a number of reasons. Physical market participants, such as producers and large consumers, usually use financial contracts to manage price risk and to protect against price volatility. That is, financial contracts can serve as a tool for managing risk akin to insurance. Other market participants use the energy markets to speculate, or to assume a market risk in hope of profiting from market fluctuations. Additionally, companies turn to the capital markets if they need to raise or invest money. This primer explores the market participants, products, market mechanisms and trading at work for natural gas and electricity in the financial markets in Chapter 5, Financial Markets and Trading.

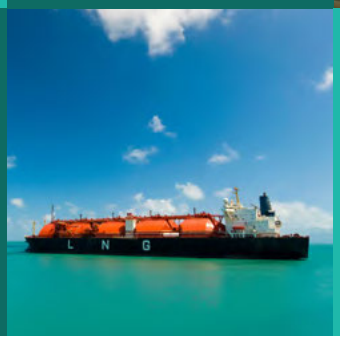
Where there are markets, there will be those who attempt to manipulate the markets for their own benefit. These practices undermine the market's ability to operate efficiently, reduce other market participants' confidence in the markets and distort market outcomes, including prices. Some of these practices are discussed in Chapter 6, Market Manipulation.

This primer is written to be used either as a traditional text – read front to back – or as a reference guide. Consequently, some material is repeated in different sections and references are provided to other parts of the primer where a concept is addressed in greater detail.

Further information about various aspects of energy markets and FERC regulation can be found at www.ferc.gov; then navigate to the Market Oversight tab. You can find the market oversight pages here: https://www.ferc.gov/market-assessments.







Chapter 1
Wholesale Natural Gas Markets

WHOLESALE NATURAL GAS MARKETS

Natural gas markets have a significant effect on the economy and on the individuals who rely on the fuel for electric generation, manufacturing, heating, cooking, and other purposes. The Department of Energy's (DOE) Energy Information Administration (EIA) estimates that natural gas supplies approximately 32 percent of the energy used in the U.S.[1] Under the Natural Gas Act (NGA), the Federal Energy Regulatory Commission (FERC) has jurisdiction over the transportation and sale of natural gas in interstate commerce and the companies engaged in those activities.

The natural gas market is an amalgamation of a number of subsidiary markets. There is a physical market, in which natural gas is produced, transported, stored, and consumed. There is also a financial market that focuses on the purchase and sale of financial instruments whose price is linked to the price of natural gas in the physical market, but that rarely result in the physical delivery of natural gas. Additionally, natural gas markets are regional, with prices for natural gas varying with the demand characteristics of the market, the region's access to different supply basins, pipelines, and storage facilities.

FERC Jurisdiction

FERC is responsible for the regulation of the siting, construction and/or abandonment of interstate pipelines, gas storage facilities, and Liquified Natural Gas (LNG) terminals, regulation of the transmission and sale of natural gas for resale in interstate commerce, establishing rates for pipeline and storage services and assessing the safe operation and reliability of LNG facilities. We explain FERC's jurisdiction over natural gas related activities in more detail throughout this chapter.

Natural Gas

Natural gas is primarily methane, which is a molecule made of one carbon atom and four hydrogen atoms (CH4), and is among the materials known as hydrocarbons. Natural gas is colorless and odorless in its natural pure form, but is often odorized with mercaptan or other odorants to allow for easy detection. It is also highly combustible, giving off a great deal of energy and fewer emissions than fuels such as coal and oil. Natural gas occurs in geological formations in different ways: as a gas phase associated with crude oil, as a gas dissolved in the crude oil, as a gas phase not associated with any significant crude oil, or as a supercritical fluid. Natural gas is "rich" or "wet" if it contains significant amounts of natural gas liquids (NGL) – e.g., ethane, propane and pentane[2]– mixed with the methane. In contrast, natural gas is "lean" or "dry" if it consists of mostly methane.[3] Excess NGLs are separated from the methane and sold separately. Natural gas reservoirs often contain other elements and compounds, such as carbon dioxide, hydrogen sulfide, nitrogen, helium, water, dissolved salts, and other dissolved gases. The natural gas is further processed to remove the impurities from the methane to make the natural gas suitable for sale. While natural gas is typically a gas, it can be cooled to a liquid and transported in trucks or ships. In this form, it is referred to as liquefied natural gas, or LNG.

1 Derived from EIA, *Monthly Energy Review*, *Primary Energy Consumption by Source*, *Table 1.3* (accessed August 2022), https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf.

2 Natural gas liquids (NGLs) are hydrocarbons—in the same family of molecules as natural gas and crude oil— composed exclusively of carbon and hydrogen. Ethane, propane, butane, isobutane, and pentane are all NGLs. There are many uses for NGLs, including inputs for petrochemical plants, burned for space heat and cooking, and blended into vehicle fuel.

3 Dry gas contains "insufficient quantities of hydrocarbons heavier than methane to allow their commercial extraction or to require their removal in order to render the gas suitable for fuel use." Society of Petroleum Engineers, *Glossary of Terms Used in Petroleum Reserves and Resources Definitions* (n.d.), https://www.spe.org/en/industry/terms-used-petroleum-reserves-resource-definitions/.

Natural Gas Industry

The markets of the natural gas industry are both physical and financial. This chapter focuses on the physical natural gas markets, but it should be noted that financial markets can have a significant influence on the physical natural gas market.

The natural gas industry has three major segments, the upstream (supply), the midstream (transportation), and the downstream (consumption). The upstream segment includes exploration, which is the process of attempting to find accumulations of natural gas resources, production, which includes recovering natural gas resources through drilling and extraction at the wellhead, and finally gathering. Gathering entails using small diameter pipeline systems to transport the gas from the wellhead to local pooling points or to natural gas processing facilities, where impurities and NGLs are removed to create pipeline-quality natural gas. The midstream segment includes transportation on intrastate and interstate pipeline systems that move natural gas through large-diameter pipelines to storage facilities and a variety of consumers. The downstream segment includes large gas consumers, such as power plants and industrial facilities, and local distribution companies (LDCs), which deliver the natural gas to retail consumers.

Each component of the supply chain is critical in serving customers. The quantity of reserves and production can affect market participants' expectations about current and future supply, and thus can affect prices. Similarly, the availability of pipeline and storage capacity determines which supply basins are used and the amount of gas that can be transported from producers to consumers. All of these factors affect the supply chain, but they also affect the supply-demand balance, both nationally and regionally. More specifically, the differences in supply and demand result in different prices for natural gas at various locations. Prices have historically tended to be lower in regions supplied by multiple production areas with robust pipeline infrastructure, such as the Gulf Coast, Southwest, and Midwest. In contrast, prices tend to be highest in areas where production or transportation and storage are limited and demand is high, such as New England and Southern California. Transportation costs and limitations in pipeline capacity from supply to demand areas are generally the major factors driving regional price differentials.

Various factors have shifted the dynamics of natural gas supply and demand since 2007, when shale gas production began to grow significantly. These include, but are not limited to:

1. Development of modern hydraulic fracturing and horizontal drilling techniques that have enabled producers to access unconventional resources, such as those in shale formations. These techniques have expanded the amount of available economically accessible natural gas reserves and have increased domestic natural gas production. These newer resources are located closer to eastern population centers and have provided those regions with access to lower cost natural gas supplies and transportation costs.
2. Natural gas demand for power generation has expanded considerably over the past decade. Power plant demand for natural gas reflects the operating flexibility of natural gas-fired generators and the environmental benefits of the fuel. Natural gas-fired power plants emit less air pollution than power plants using coal or oil. These plants are also relatively easier to site, can be built in a range of sizes, and can increase or decrease output flexibly. The ability to quickly change output provides electric system grid operators with the flexibility to support variations in output from renewable energy resources, changes in demand from customer load, as well as unexpected power system events and disruptions.
3. Pipeline expansions linking the new supply regions to markets have enabled regions such as the Northeast and Mid-Atlantic to access new supply sources, expanding the amount of natural gas that can flow from traditional supply sources, and enhancing the amount of natural gas that can flow to markets.

4. Rising natural gas production combined with increasing international natural gas demand has led to the construction of several LNG export terminals. As a result, U.S. LNG export capacity and international cargo deliveries have grown significantly since 2016.

Natural Gas Demand

Natural gas is the fuel of choice for many sectors of the U.S. economy. Over the long-term, natural gas use is driven by overall economic and population growth, environmental policy, energy efficiency, technological changes and prices for natural gas and substitute energy sources such as oil, coal and electricity. In the short-term, natural gas demand can fluctuate substantially due to weather, economic activity, and competition from other fuel sources such as coal and oil.

WEATHER

Weather is the most significant factor affecting seasonal natural gas demand, which can swing considerably within a given day, especially during periods of extreme temperatures. Short-term changes in weather, such as heat waves and winter storms, can send demand and prices soaring – or dropping – within the course of a day, sometimes unexpectedly. The weather's unpredictability challenges suppliers and pipelines, especially when demand is high and pipelines are full.

ECONOMIC ACTIVITY AND GROWTH

Economic growth can increase the amount of natural gas used by industry, power plants, and commercial entities as consumers want more of their products and services. During a recession, natural gas use typically declines.

Structural changes in the economy can also affect natural gas demand, such as varying levels of manufacturing and service sector activity. Additionally, new domestic markets for products and services may increase the consumption of natural gas, whereas movement of manufacturing overseas may reduce demand. Lastly, demand for exports of natural gas, to Mexico and Canada via pipeline and globally via LNG shipping, have also had a significant effect on aggregate demand.

Daily and weekly economic activity creates cyclical demand patterns. During the work day, demand rises as people get up and go to work or school. Similarly, it declines as they go to sleep. On the weekend, demand tends to vary less over the course of the day.

PRICES OF NATURAL GAS AND COAL

Just as a homeowner may decide to invest in a furnace and associated piping to use natural gas for heating, so, too, a power producer may decide to make long-term investments in natural gas-fired generators. Decisions requiring long-term capital investments are easiest to make at the time a home or power plant is being built and are more complicated to changelater. Thus, over the long term, demand for natural gas can be affected by the expected costs of alternative energy sources: the cost of a natural gas furnace versus an electric one; the cost of a coal-fired generating plant versus one fueled by natural gas.

In the short-term, the opportunity for fuel switching has been significant in power generation. Electric grid operators have choices as to which power plant to dispatch to meet electric demand. As explained in greater detail in the electric chapter, dispatch is often based on the marginal cost of generation at each available plant in the generation fleet. While the degree to which these fuels are used varies regionally, plants with lower marginal costs, such as nuclear plants, are typically dispatched before plants with higher marginal costs, such as natural gas plants. As natural gas prices drop relative to coal prices, natural gas-fired generation may be dispatched ahead of coal-fired generation, increasing natural gas demand from the power sector.

DEMOGRAPHICS AND SOCIAL TRENDS

Long-term demand can also be affected by shifting demographics and social trends. Population growth in warmer climates and population declines in certain areas of the North have affected natural gas use. So has the trend toward larger houses, which have greater

heating and cooling needs, yet are generally more energy efficient.

ENVIRONMENTAL CONCERNS AND ENERGY EFFICIENCY

Natural gas emits much fewer pollutants than other competing fossil fuels, including carbon and other greenhouse gases, which has been an important factor in some decisions to use natural gas for power generation. This is particularly significant in states and regions that have experienced challenges in meeting air quality standards.

The natural gas emissions profile has also encouraged some urban mass transit bus systems, West Coast port operations, and other vehicle fleets to shift to natural gas from gasoline or diesel fuel.

CUSTOMER SECTORS AND DEMAND

On an annual basis, power generation makes up about 37 percent of total U.S. natural gas demand.[4] Industrial, residential, and commercial consumers represent approximately 27 percent, 15 percent, and 11 percent of total U.S. natural gas demand, respectively.[5] An additional 6 percent is used for lease and plant fuel operations and 3 percent is used for pipeline and distribution activities.[6] See FERC's *State of the Markets Report* and *Seasonal Assessments* for analyses on recent natural gas demand sector trends.[7]

Each customer sector has a unique demand profile, both in the amount that the demand varies over a season and whether its peak demand coincides with the overall system peak. Residential demand, for example, can be highly variable in colder climates, and its peak coincides with the overall system peak. Power generation's peak does not coincide with the overall winter gas-demand peak, but the use of natural gas to produce electricity for air conditioning has created robust summer demand, which competes with natural gas supply that traditionally would flow into underground storage for later use. Industrial demand is fairly constant year-round.

In the short term, residential and commercial natural gas use tends to be inelastic – consumers use what they need, regardless of the price. Power plant demand, on the other hand, is more price-responsive as natural gas competes with other fuels, especially coal. Price inelasticity implies that a potential for price spikes exists during periods of supply constraints. In the longer term, residential and commercial natural gas use can change, with changes in space heating or cooking from fuel oil to natural gas (increasing demand for natural gas) or from natural gas to electric (decreasing demand for natural gas).

Consequently, the mix of customers in a region can affect system operations and costs. Pipelines and other equipment are sized to account for peak demand. Load that has fairly constant demand presents fewer operational challenges to suppliers and usually enjoys lower prices. Highly variable demand will result in pipelines and equipment being used at less than full capacity for much of the year. As a result, the cost to provide service may be higher because the pipelines may become constrained during peak times and because the capacity is not consistently utilized.

POWER GENERATION

Natural gas-fired generators can flexibly manage their output and are frequently called on to respond to changes in demand or when called upon by power grid operators. Seasonally, generating plants tend to consume more natural gas in the summer to meet air conditioning loads, but also increase output in the winter to provide electric heating and lighting. Generation demand can also be influenced by the

4 Derived from EIA, *Natural Gas Consumption by End Use, U.S., Annual* (accessed October 2022), https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

5 *Id.*

6 *Id.*

7 *See* FERC, *Reports & Analyses* (n.d.), https://www.ferc.gov/reports-analyses.

relative prices for natural gas and other fuels, especially coal. Since late 2008, natural gas-fired generators generally have been dispatched before many of the less efficient coal plants because of the relatively low natural gas prices seen over the past decade. In 2016, electricity generation from natural gas overtook coal generation for the first time on an annual basis.[8]

INDUSTRIAL

Natural gas as a fuel is used to produce items such as steel, glass, paper, clothing and brick. It also is an essential raw material for paints, fertilizer, plastics, antifreeze, dyes, medicines, and explosives. As noted earlier, industrial load tends to show the least seasonal variation of natural gas use.

RESIDENTIAL

Despite population growth, natural gas used in the residential sector has remained fairly flat over the past decade. This has primarily occurred because homes and appliances like furnaces, water heaters, and clothes dryers have become more energy efficient. Slightly more than half of the homes in the U.S. use natural gas as their main heating fuel.[9] Separately, much of the year-to-year demand variation in this sector can be attributed to the weather during a particular year. A year with a long, cold winter will see higher gas demand than a year with a mild winter, especially in cold-winter regions where demand soars during winter months as consumers turn on their furnaces.

COMMERCIAL

Like the residential sector, commercial consumption experiences year-to-year variation based on weather. Commercial consumers include hotels, restaurants, wholesale and retail stores, and government agencies, which use natural gas primarily for heat. Consequently, its demand varies over the seasons, weeks, and days.

Natural Gas Supply

NATURAL GAS RESOURCES, RESERVES AND PRODUCTION

The amount of natural gas in the ground is estimated by a variety of techniques, including seismic studies and drilling exploration wells. Estimating the technically recoverable oil and natural gas resources in the U.S. is an evolving process. Analysts use different methods and systems to make natural gas estimates. Natural gas supplies are broadly characterized as resources, proved reserves, and production.

Resources, the largest category of supply, refers to the quantity of a natural resource that is known to exist with a reasonable degree of certainty and can be extracted using existing or feasibly commercial technology. Proved reserves are a subset of resources which are known to exist with a reasonable degree of certainty and can be economically extracted under current or assumed prices. Resources and proved reserves are dynamic as both change when new natural resources are discovered via exploration, as natural resources are extracted, and as prices fluctuate. All estimates of proved reserves involve some degree of uncertainty, which depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate. According to the Society of Petroleum Engineers, "proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with a reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions,operating methods, and government regulations."[10] Lastly, production describes the amount of a natural gas that is actually extracted over a period of time.

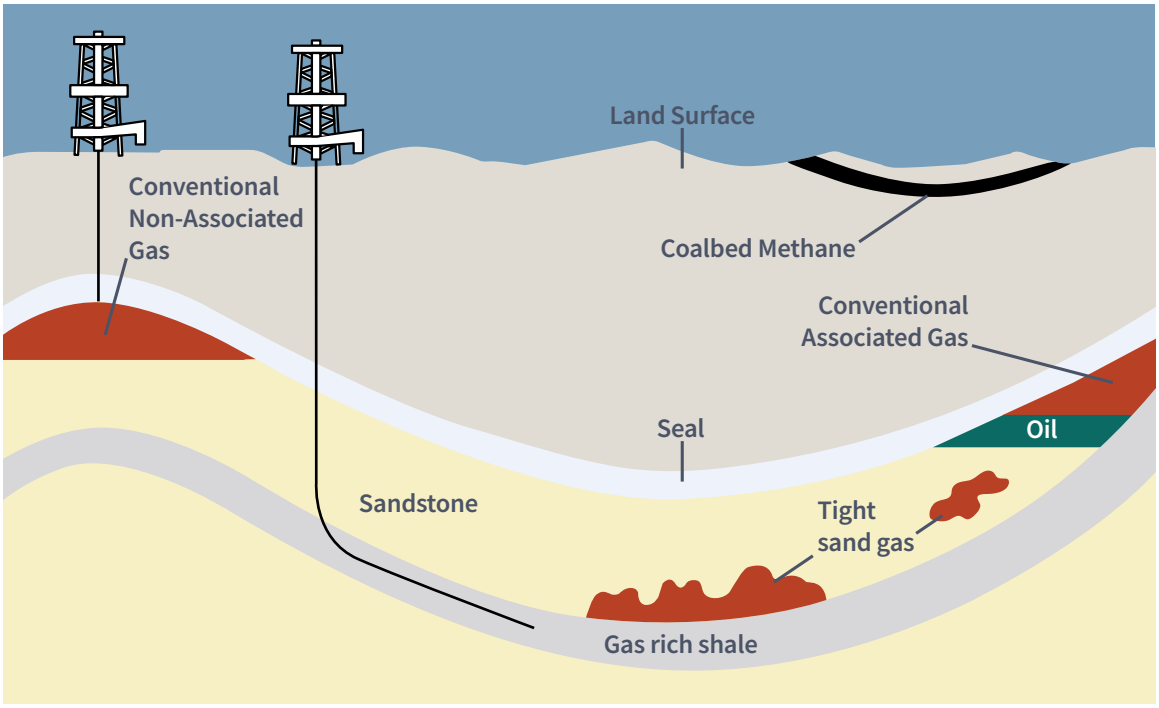
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8 *See* EIA, *Total Energy, Electricity, Table 7.2b Electricity Net Generation: Electric Power Sector* (accessed October 2022), https://www.eia.gov/totalenergy/data/browser/?tbl=T07.02B.

9 EIA, *Natural gas explained* (May 24, 2022), https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php.

10 Probabilistic reserves are often used, for instance a P90 reserve figure indicates there should be at least a 90 percent probability that quantities actually recovered will equal or exceed the estimate. Society of Petroleum Engineers, World Petroleum Congresses, and American Association of Petroleum Geologists, Guidelines for the Evaluation of Petroleum Reserves and Resources, at 45 (2001), https://www.spe.org/industry/docs/Guidelines-Evaluation-Reserves-Resources-2001.pdf.

Figure 1-1: Schematic Geology of Natural Gas Resources



Source: U.S. Energy Information Administration and U.S. Geological Survey[11]

FERC Jurisdiction

Section 1(b) of the Natural Gas Act (NGA) exempts production and gathering facilities from FERC jurisdiction. Moreover, the Wellhead Decontrol Act of 1989 completely removed federal controls on new natural gas and eventually all wellhead price controls, except sales for resale of domestic natural gas by interstate pipelines, LDCs, or their affiliates.[12] In Order No. 636, FERC required interstate pipelines to separate, or unbundle, their sales of gas from their transportation service, and to provide comparable transportation service to all shippers whether they purchase natural gas from the pipeline or another gas seller.

UNCONVENTIONAL AND CONVENTIONAL NATURAL GAS

Natural gas is a fossil fuel. It has historically been found in underground reservoirs formed when organic material was buried and pressurized. The remains of that organic material were trapped in the surrounding rock as oil or natural gas, and the two fuels are often found together. The depth of the organic materials and the temperatures at which they are buried often determine whether the organic matter turns into oil or natural gas. Oil is generally found at depths of 3,000 to 9,000 feet, while organic materials at greater depths and higher temperatures result in natural gas.

11 EIA, *Today in Energy*, *The geology of natural resources* (February 14, 2011), https://www.eia.gov/todayinenergy/detail.php?id=110.

12 Pub. L. No. 101-60 (1989); 15 U.S.C. § 3431(b)(1)(A). The Natural Gas Wellhead Decontrol Act of 1989 amended the Natural Gas Policy Act of 1978 to declare that the price guidelines for the first sale of natural gas do not apply to: (1) expired, terminated, or post-enactment contracts executed after the date of enactment of this Act; and (2) certain renegotiated contracts. Specifically, as of May 15, 1991, the act, decontrolled natural gas produced from newly spudded wells and also repealed permanently wellhead price controls beginning on January 1, 1993.

Natural gas basins are frequently referred to as unconventional or conventional basins or plays. These basins differ in the geology of the basin and the depth at which gas can be found. The schematic illustrates differing geologic formations in which natural gas can be found.

UNCONVENTIONAL NATURAL GAS

Innovations in exploration and drilling technology have led to rapid growth in the production of unconventional natural gas. The majority of unconventional natural gas production in the U.S. comes from shale and tight sands.

Unconventional natural gas is a found in shale, and tight, low-permeability rock formations (also referred to as tight sands) and coal seams (also referred to as coal beds). The National Petroleum Council (NPC) defines unconventional gas as "natural gas that cannot be produced at economic flow rates nor in economic volumes unless the well is stimulated by a large hydraulic fracture treatment, a horizontal wellbore, or by using multilateral wellbores or some other technique to expose more of the reservoir to the wellbore [13]

SHALE AND TIGHT SANDS

Shale gas is natural gas found in fine-grained sedimentary rock with low permeability, including mudstone, clay stone, and what is commonly known as shale. Natural gas in shale formations tends to concentrate in natural fractures and the rock adjacent to them. Historically, extraction of natural gas from shale formations has been difficult to achieve. Growth in shale resources is discussed further below (see "The Shale Revolution").

Tight sands gas is natural gas contained in sandstone, siltstone, and carbonate reservoirs of such low permeability that it will not naturally flow at economic production rates when a well is drilled. There are about 20 shale and tight sands basins in the U.S. (see map).

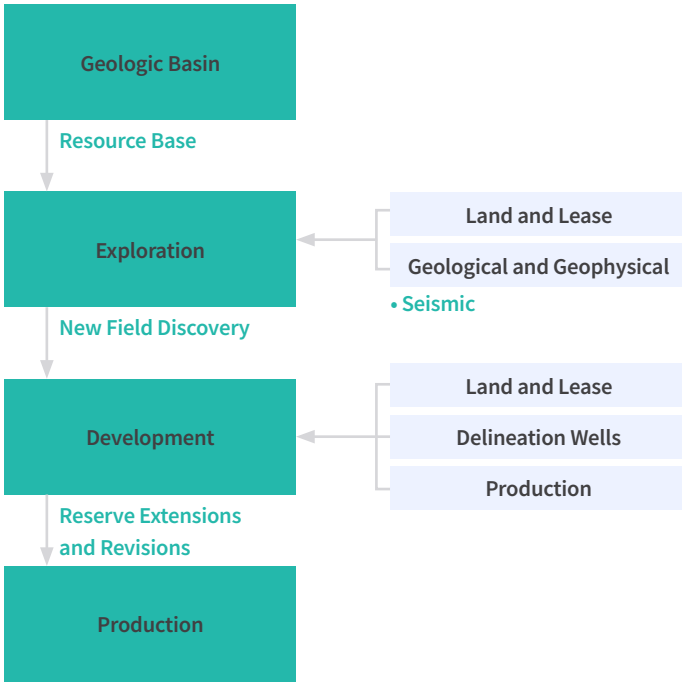
Horizontal and Directional Drilling with Hydraulic Fracturing

The presence of natural gas in unconventional plays had been common knowledge for decades. Historically, the lower permeability of rock in shale formations typically yielded too little natural gas for a company's investment when using traditional drilling methods. In the early 1990s, after years of experimenting in the Barnett Shale in Texas, George Mitchell and Mitchell Energy Co. developed new techniques that made production from these types of formations more economically feasible. The new techniques combined horizontal drilling with slickwater hydraulic fracturing (slickwater hydraulic fracturing fluids are water-based fluids, generally containing a friction reducer, that facilitate rapid pumping of the fluid into the well), allowing Mitchell to drill into specific target areas and release the natural gas trapped in the formation. Horizontal drilling allows producers to target the specific cross-sections of rock formations where the natural gas is trapped, greatly improving the likelihood of a productive well.



13 *See* National Petroleum Council Global Oil & Gas Study, *Topic Paper #29 Unconventional Gas*, at 5 (July 18, 2007), http://www.energybc.ca/cache/naturalgas/www.npc.org/Study_Topic_Papers/29-TTG-Unconventional-Gas.pdf.

Figure 1-2: Natural Gas Exploration and Development Process



Source: FERC staff, 2012

Growth in shale gas in particular has been substantial since 2007 and has contributed to a significant increase in U.S. proved natural gas reserves. Proven shale reserves are approximately 13 times larger than 2007 levels.[14]

Shale and tight sands require a special technique known as hydraulic fracturing (fracking) to release the natural gas. This technique involves fracturing the rock in the horizontal shaft using a series of radial explosions and water pressure. Since 2007, the processes for finding geological formations have improved, and producers have accumulated knowledge of subsurface oil and gas deposits over that span of time. As a result, most wells targeting shale and tight sands formations result in drill contact with formations and successful new natural gas production. Improved exploration techniques, coupled with improved drilling and production methods, have lowered the cost of finding and producing shale gas, and have resulted in a significant increase in production.

The largest gas producing unconventional shale plays in the U.S. are the Appalachia, Permian, Haynesville, Eagle Ford, Anadarko, Niobrara, and Bakken basins (see map below for shale locations).[15] Other shale formations have experienced heavy exploration activity and depending on economic conditions may become major contributors of natural gas supply.

THE SHALE REVOLUTION

The estimated resources, proven reserves, and production of shale gas has risen rapidly since 2005, and the development of shale gas has transformed gas production in the U.S. Shale gas continues to be the dominant source of domestically produced gas, providing 70 percent of the gross production of natural gas. By comparison, coalbed methane accounts for about 2 percent of production, while nearly 11 percent of the natural gas came from oil wells and 17 percent was produced from conventional natural gas wells.[16]

Production from shale gas plays is 13 times larger than 2007 levels.[17] According to the EIA, shale gas and production from tight formations will account for greater than 92 percent of U.S. natural gas production by 2050.[18]

SHALE GAS PRODUCTION BY REGION

Shale gas well productivity improved considerably since 2007, with technological advances in drilling and fracking technology reducing exploration, drilling,

14 Derived from EIA, *U.S. Shale Proved Reserves, Annual* (accessed October 2022), https://www.eia.gov/dnav/ng/hist/res_epg0_r5301_nus_bcfa.htm.

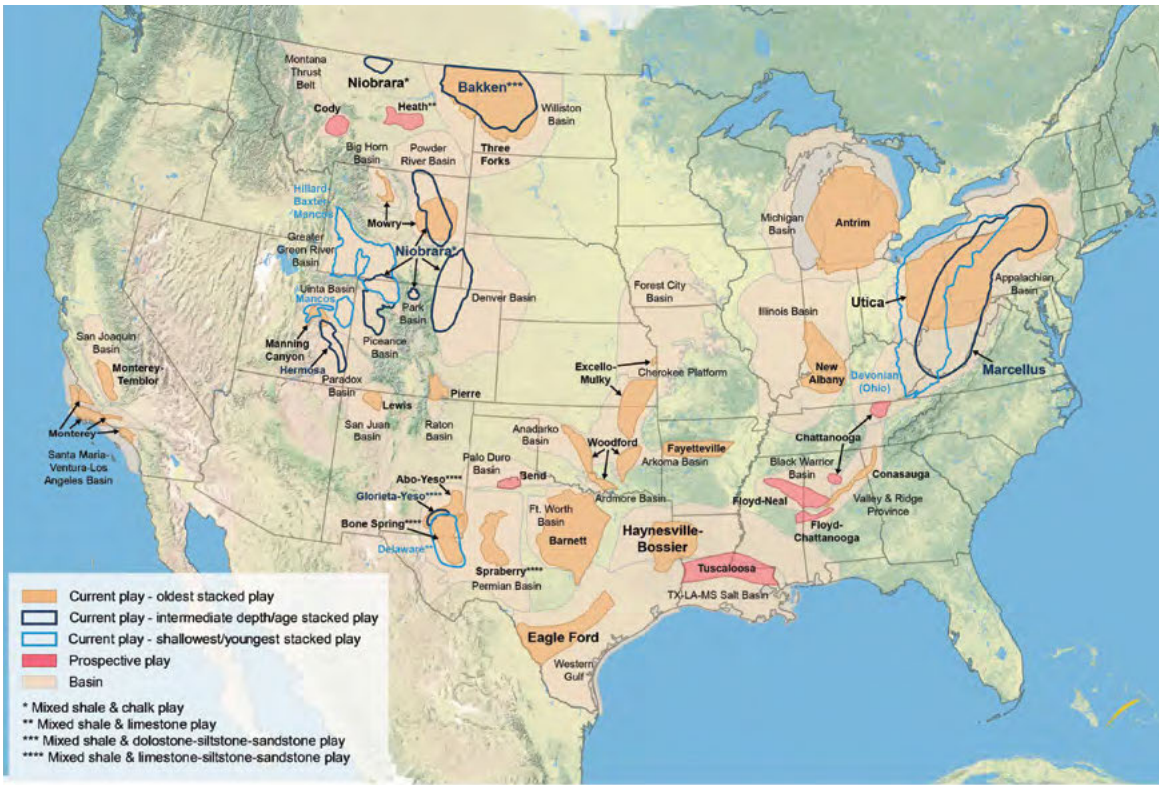
15 *See* EIA, *Drilling Productivity Report, Production by Region* (accessed October 2022), https://www.eia.gov/petroleum/drilling/#tabs-summary-2.

16 Derived from EIA, *Natural Gas Gross Withdrawals and Production, U.S., Annual-Million Cubic Feet* (accessed October 2022), https://www.eia.gov/dnav/ng/ng_prod_sum_dc_NUS_mmcf_a.htm.

17 Derived from EIA, *Natural Gas Gross Withdrawals and Production, Gross Withdrawals from Shale Gas, Annual-Million Cubic Feet* (accessed October 2022), https://www.eia.gov/dnav/ng/NG_PROD_SUM_A_EPG0_FGS_MMCF_A.htm.

18 *See* EIA, *Annual Energy Outlook 2022, Table 14. Oil and Gas Supply* (March 3, 2022), https://www.eia.gov/outlooks/aeo/tables_ref.php.

Figure 1-3: Lower 48 States Shale Plays



Source: U.S. Energy Information Administration[19]

and production expenses. Rising well productivity and falling costs resulted in larger amounts of shale gas production at lower costs to the producers.

The presence of NGLs, or natural gas liquids, in addition to natural gas in many shale gas plays, may add to shale gas well profitability. NGL prices are more closely linked to oil prices than natural gas prices, and natural gas wells with high liquids content are often more profitable than wells producing natural gas alone. A typical barrel of NGL might contain 40-45 percent ethane, 25-30 percent propane, 5-10 percent butane and 10-15 percent natural gasoline (gasoline derived from natural gas).[20] This can make the production of NGLs from so-called "wet shale gas wells" less sensitive to natural gas prices than wells solely producing natural gas, as NGLs tend to trade at higher prices than natural gas. Thus, there may be an incentive to drill from wet shale gas wells even when natural gas prices are relatively low because of the relatively high value of the associated NGLs that are also produced when drilling.

The Marcellus Shale formation in Appalachia is particularly noteworthy because of its location, size and resource potential. The formation extends from West Virginia to New York, near the high population centers of the Northeast and Mid-Atlantic. Although the Marcellus Shale has produced gas for decades, it has produced significant amounts of gas only since 2008, where production has been prolific, with high initial well pressures and high production rates.

19 EIA, *Maps: Exploration, Resources, Reserves, and Production* (June 2016), https://www.eia.gov/maps/images/shale_gas_lower48.pdf.

20 *See* EIA, *NGL 101 – The Basics* (June 6, 2012), https://www.eia.gov/conference/ngl_virtual/eia-ngl_workshop-anne-keller.pdf.

The growth in production in the Marcellus Shale has significantly affected U.S. natural gas transportation. As more natural gas has flowed out of Marcellus, less has been needed from the Rockies or the Gulf Coast to serve the eastern U.S. This has resulted in changing flow patterns of natural gas on pipelines that traditionally served eastern and midwestern markets. In some instances, pipelines that transport natural gas into northeastern markets and have relied on production from outside of the region, have reversed flow direction to export natural gas produced in the Marcellus and Utica to markets across the U.S.

COALBED METHANE

Coalbed methane (CBM) is natural gas trapped in coal seams. Coalbeds are usually filled with water that naturally enter coal seams through fractures in the formation; the deeper the coalbed, the less water is present. To release the gas from the coal, pressure in the fractures is created by removing water from the coalbed. While the venting of methane from coal mines had been in practice for years, commercial production of this resource began in earnest in the 1980s. According to a U.S. Geological Survey released in October 2000, there is more than 700 Tcf of domestic CBM, but less than 100 Tcf of it may be economically recoverable.[21] Most CBM production in the U.S. is concentrated in the Rocky Mountain area, although there is also some activity in the Midcontinent and Appalachian area.

CONVENTIONAL NATURAL GAS

Natural gas has been historically produced from what is traditionally known as conventional natural gas resources. These supplies are found in geologica basins or reservoirs made of porous and permeable rock, holding significant amounts of natural gas in spaces in the rock.[22] For more

Rig Count and Rig Productivity

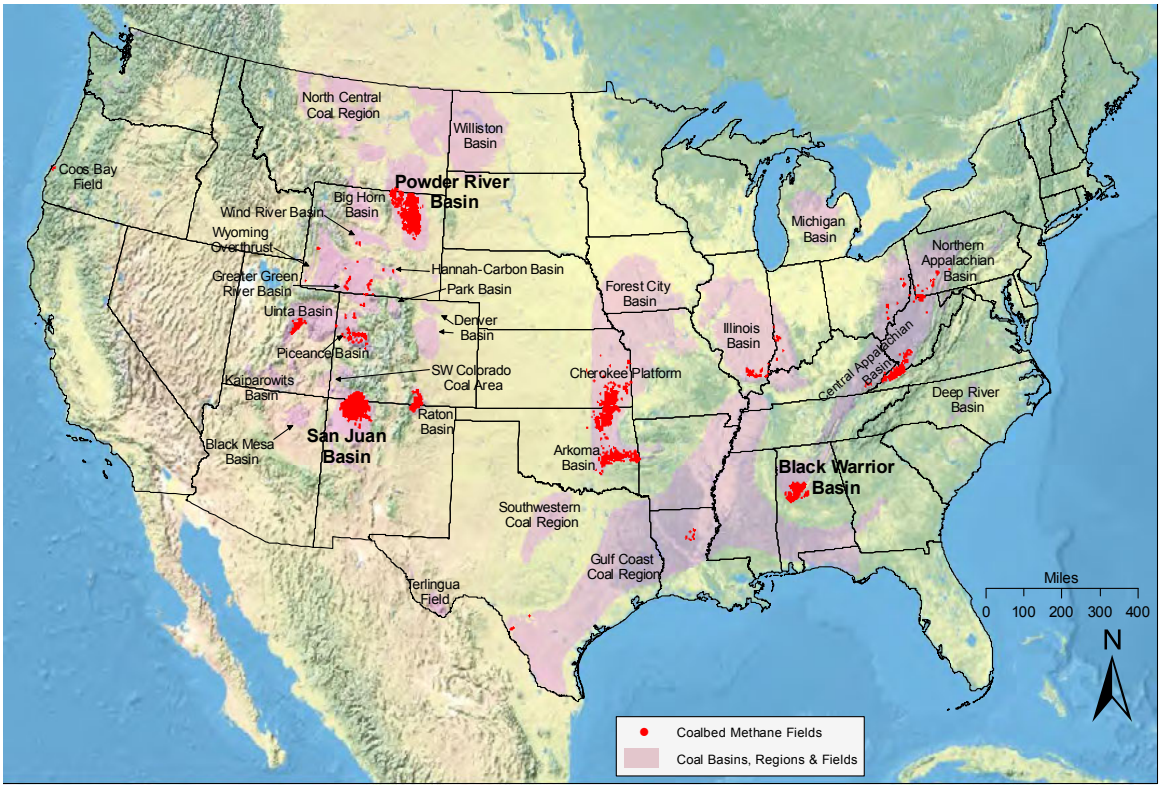
The rig count is used to measure exploration activity by assessing the number of rotary drilling rigs actively drilling for oil and gas. Historically, rig counts were used as a rough predictor of future production. However, improvements in drilling technology and practices have caused a decoupling between rig count and production. The adoption of horizontal drilling significantly increased production per rig, making historical comparisons of rig counts problematic as horizontal rigs are considerably more productive than vertical rigs. Within the total rig count, the use of horizontal drilling rigs, used in the production of natural gas and oil in shale formations, has been growing for years, while the traditional vertical rig count has steadily declined.



21 *See* U.S. Geological Society, *Coal-Bed Methane: Potential and Concerns* (October 2000), https://pubs.usgs.gov/fs/fs123-00/fs123-00.pdf.

22 Permeability refers to the ability of a porous medium to transport a fluid. The natural gas found in permeable rock formations contains trapped or slowly migrating natural gas molecules, where the migration of the gas molecules takes place over the course of millions of years.

Figure 1-4: Coalbed Methane Fields, Lower 48 States



Source: U.S. Energy Information Administration[23]

than a century, up until the early 2000s, nearly all of the country's production of natural gas was obtained from conventional sources.

Conventional resources have been found both on land and offshore (see map below), with the major fields in an arc from the Rocky Mountains to the Gulf of Mexico to Appalachia. The largest conventional fields reside in Texas, Wyoming, Oklahoma, New Mexico, and the federal offshore area of the Gulf of Mexico. In 2000, offshore natural gas production represented 24 percent of total U.S. production; it has since fallen to 3 percent of total U.S. production.[24]

Federal offshore natural gas wells are drilled into the ocean floor off the coast of the U.S. in waters that are jurisdictional to the federal government. Most states have jurisdiction over natural resources within three nautical miles of their coastlines; Florida and Texas claim nine nautical miles of jurisdiction.[25]

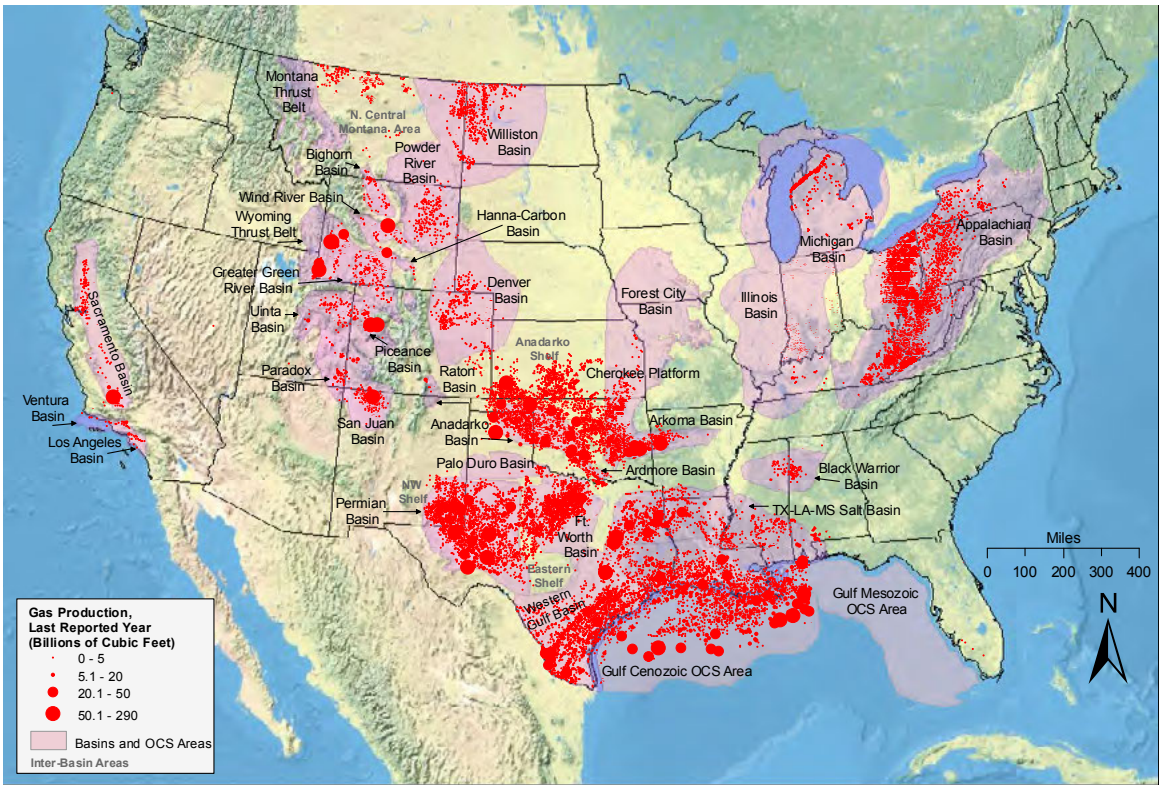
Roughly 1,650 oil and gas platforms are producing in federal waters at water depths approaching 7,500 feet (at total well depths of 25,000-30,000 feet) and at distances

23 EIA, *Maps: Exploration, Resources, Reserves, and Production* (April 8, 2009), https://www.eia.gov/oil_gas/rpd/coalbed_gas.pdf.

24 Derived from EIA, *U.S. Natural Gas Gross Withdrawals and Production* (accessed October 2022), https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm.

25 Florida and Texas were provided an exemption to the federal government's jurisdiction over natural resource beyond three nautical miles of state coastlines, up to a 9 nautical mile limit, because each state proved the further boundary based on its constitution or laws prior to when it came into the Union or was approved by Congress. *See* Submerged Lands Act of 1953. 43 U.S.C. § 1301-1315 at § 1312 (2002).

Figure 1-5: Gas Production in Conventional Fields, Lower 48 States



Source: U.S. Energy Information Administration[26]

as far as 200 miles from shore.[27] Most of these offshore wells are in the Gulf of Mexico.

Offshore wells have produced natural gas for decades. As close-in, shallow-water wells became less economic to produce, companies looked to reserves at greater water depth. Technological improvements contributed to continuing production from deep offshore wells.

IMPORTS AND EXPORTS

The U.S. has historically been a net importer of natural gas by pipeline from Canada, with shipments of LNG from foreign nations playing an important role in serving pipeline capacity-constrained regions during periods of peak natural gas demand. However, the increase in U.S. natural gas production, spurred by the shale revolution, has reduced the need for imports and enabled greater exports.

Net natural gas imports peaked in 2007, when natural gas imports represented approximately 20 percent of the natural gas used in the U.S.[28] Since then, imports have declined and now represent approximately 9 percent of total U.S. consumption.[29] The vast majority of imports are delivered by pipeline from Canada, with additional waterborne shipments of liquefied

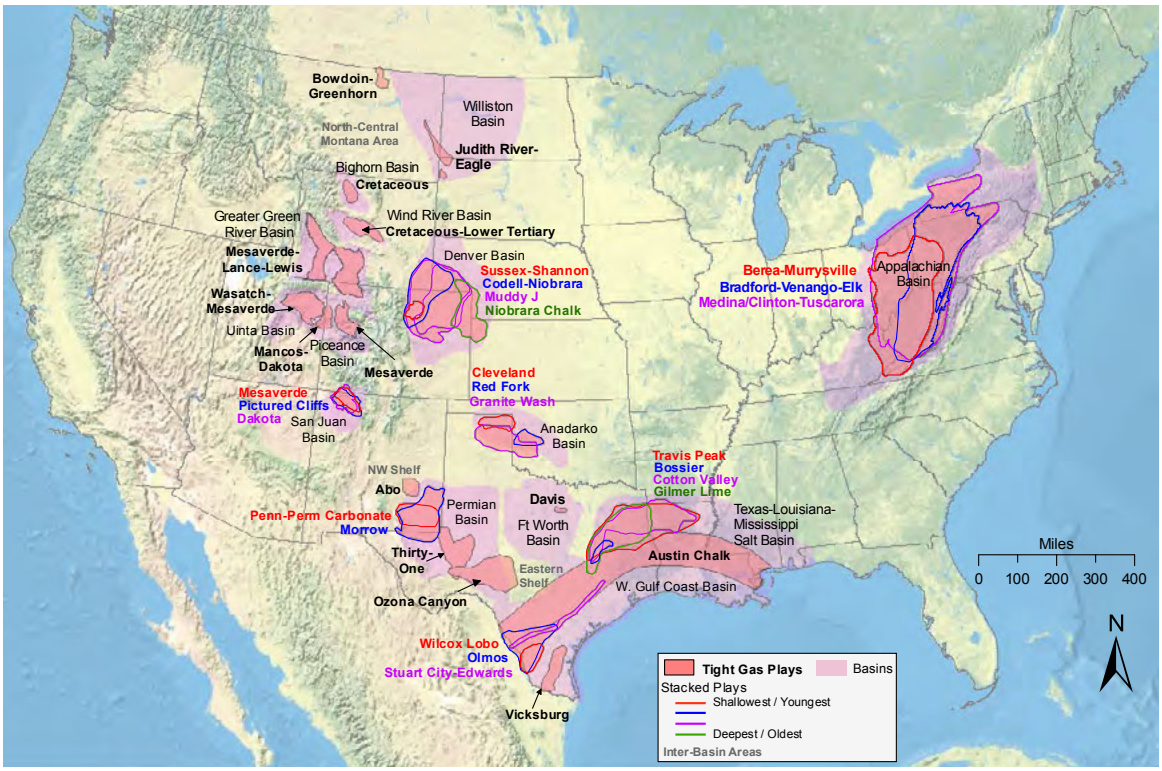
26 EIA, *Maps: Exploration, Resources, Reserves, and Production* (April 8, 2009), https://www.eia.gov/oil_gas/rpd/conventional_gas.pdf.

27 Derived from Bureau of Safety and Environmental Enforcement, Offshore Statistics by Water Depth, Totals table (accessed October 2022), https://www.data.bsee.gov/Leasing/OffshoreStatsbyWD/Default.aspx.

28 Derived from EIA, *Natural Gas Summary, Imports and Exports, U.S., Annual* (accessed October 2022), https://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm.

29 *Id.*

Figure 1-6: Major Tight Gas Plays, Lower 48 States



Source: U.S. Energy Information Administration[30]

natural gas from Trinidad and Tobago and other gas-exporting nations.[31]

Although the U.S has flowed natural gas through pipelines to Canada and Mexico for decades, total exports only began to rise following the first large scale exports of LNG that started in 2015 and ramped up in 2016 (see discussion on LNG following). Since then, exports have risen by nearly 4 times its 2016 levels.[32] As a result of these developments, the U.S. became a net exporter of natural gas in 2017 for the first time since 1957.[33] FERC staff provides locations for existing, FERC-approved and proposed LNG Import and Export terminals on FERC's website.[34]

Liquefied Natural Gas

Liquefied natural gas (LNG) is natural gas cooled to minus 260 degrees Fahrenheit to liquefy it, which reduces its volume by 600 times. The volumetric reduction makes it possible to economically transport natural gas in ships and trucks to locations not connected by a pipeline network.

FERC JURISDICTION

FERC has exclusive authority under section 3 of the NGA, 15 U.S.C. § 717b, to authorize applications for the siting, construction, expansion, and operation of facilities for imports or exports of LNG. This

30 EIA, *Maps: Exploration, Resources, Reserves, and Production* (June 6, 2010), https://www.eia.gov/oil_gas/rpd/tight_gas.pdf.

31 Derived from EIA, U.S. Natural Gas Imports by Country, *Annual* (accessed October 2022), https://www.eia.gov/dnav/ng/NG_MOVE_IMPC_S1_A.htm.

32 *See* EIA, *U.S. Natural Gas Exports and Re-Exports by Country, Annual* (accessed October 2022), https://www.eia.gov/dnav/ng/ng_move_expc_s1_a.htm.

33 Derived from EIA, *Natural Gas Summary, Imports and Exports, U.S., Annual* (accessed October 2022), https://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm.

34 *See* FERC, *Existing and Proposed Terminals* (October 26, 2022), https://www.ferc.gov/natural-gas/lng.

authorization, however, is conditioned on the applicant's meeting of other statutory requirements not administered by FERC for various aspects of the project. In addition, the DOE has authority over the issuing of permits to import and export the commodity. The U.S. Coast Guard (USCG)[35] and Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA)[36] also have regulatory authority over LNG facilities. Under NGA section 3, FERC shares ongoing oversight over the safety of LNG facilities in operation.

THE LNG SUPPLY CHAIN

Natural gas is sent through the pipeline network to liquefaction facilities for conversion to LNG. These liquefaction facilities, which convert methane from a gas to a liquid, are major industrial complexes, typically costing $10 billion or more, with some costing as much as $50 billion.[37] Once liquefied, the LNG is typically transported by specialized ships with cryogenic, or insulated, tanks.

When LNG reaches an import (regasification) terminal, it is unloaded and stored as a liquid until ready for sendout. To send out the gas, the regasification terminal warms the LNG to return it to a gaseous state and then sends it into the pipeline transportation network for delivery to consumers. Currently, global regasification is approximately 2.15 times the amount of liquefaction capacity.[38] Excess regasification capacity provides greater flexibility to LNG suppliers, by enabling them to deliver cargoes to the highest-priced markets.

The cost of the LNG process is $2-$10 per million British thermal units (MMBtu), depending on the costs of natural gas production and liquefaction and the distance over which the LNG is shipped. Liquefaction and shipping form the largest portion of the LNG supply chain costs, while regasification is the least of any of the cost components. The cost of a regasification facility varies considerably; however, the majority of these costs arise from the development of the port facilities and the storage tanks. A 700 MMcfd regasification terminal, which converts methane from a liquid to a gas, may cost $500 million or more.[39]

LNG IN THE UNITED STATES

The U.S. was historically an importer of LNG, with greater regasification capacity than any other country except Japan. As of 2022, there were 10 LNG receiving or regasification terminals in the continental U.S., with approximately 18 Bcfd of import capacity.[40] All of these facilities are on the Gulf or East coasts, or just offshore. Additionally, the U.S. can import regasified LNG via pipeline into New England from the Saint John LNG terminal (formerly Canaport) in New Brunswick, Canada. The Energia Costa Azul LNG terminal in Baja California, Mexico, which became operational in 2008, provided for the flow of re-gasified LNG from Mexico into Southern California. In 2019, Energia Costa Azul received DOE

35 The USCG exercises regulatory authority over LNG facilities which affect the safety and security of port areas and navigable waterways. Specifically, the USCG is responsible for matters related to navigation safety, vessel engineering and safety standards, and all matters pertaining to the safety of facilities or equipment located in or adjacent to navigable waters up to the last valve immediately before the receiving tanks. The USCG also has authority for LNG facility security plan review, approval, and compliance verification and siting as it pertains to the management of vessel traffic in and around the LNG facility.

36 PHMSA has exclusive authority to establish and enforce safety regulations for onshore LNG facilities. PHMSA inspects LNG facilities and operators to enforce compliance with the safety standards for LNG facilities used in the transportation of gas by pipeline.

37 *See, for example*, Cheniere Energy Partners, L.P., Annual Report, SEC Form 10-K, at 4 (February 24, 2017), https://www.sec.gov/Archives/edgar/data/1383650/000138365017000011/cqp2016form10-k.htm#s569b7029a90e4dd19894f10c84a51e70.

38 Derived from International Group of LNG Importers, *The LNG Industry: GIIGNL Annual Report 2022, Key Figures 2021*, at 4, https://giignl.org/wp-content/uploads/2022/05/GIIGNL2022_Annual_Report_May5.pdf.

39 EIA, *Understanding Natural Gas and LNG Options*, at 218 (November 2016), https://www.energy.gov/sites/prod/files/2016/12/f34/Understanding%20Natural%20Gas%20and%20LNG%20Options.pdf.

40 *See* FERC, *North American LNG Import Terminals – Existing, Approved not Yet Built, and Proposed* (October 26, 2022), https://www.ferc.gov/natural-gas/lng.

authorization to export natural gas from the U.S. to Mexico and re-export LNG to Free Trade Agreement (FTA) and Non-FTA countries.

Between 1999 and 2012, the U.S. met between 1 to 3 percent of its natural gas demand through LNG imports.[41] LNG imports to the U.S. peaked at about 99 Bcf/month in the spring of 2007.[42] Subsequently, competition from relatively low-cost U.S. shale gas production has trimmed imports, affecting Gulf Coast terminals the most. Currently, less than 1 percent of U.S. natural gas demand is met through LNG imports.[43] Roughly 90 percent of the total LNG delivered to the United States and Puerto Rico was under long-term contracts in 2021.[44] The remainder of the LNG enters the U.S. under short-term contracts or as spot cargoes. The cost for the natural gas commodity to be liquified and exported is generally tied to the closest trading hub to where the terminal is located. For instance, the cost of natural gas feeding into the Sabine Pass export terminal may be priced off of the Henry Hub trading point.[45]

Starting in 2010, numerous proposals to export domestically produced LNG were prompted by increased U.S. natural gas production, largely due to shale gas. No large-scale liquefaction facilities existed in the continental U.S. at the time, though the now non-operational Kenai LNG plant in Nikiski, Alaska had produced small volumes since the late 1960s. Cheniere's Sabine Pass LNG was the first LNG export terminal in the lower 48 US states, shipping its first cargo in 2015. The facility is a large LNG terminal which is capable of processing over 4.55 Bcfd of natural gas. Sabine Pass was formerly an import terminal, from which the developers utilized common facilities like docks and storage tanks to add liquefaction trains.

LNG export capacity continues to grow. FERC staff tracks existing and proposed LNG export terminals. As of 2022, there were seven export terminals operating in the continental U.S., with approximately 14 Bcfd of export capacity. See FERC's website for up-to-date information on LNG export terminal projects.[46]

Natural Gas Processing and Transportation

Most natural gas production must be transported via pipeline to natural gas consumers. To get gas from the wellhead to consumers requires a vast network of processing facilities and a national network of the more than 2.6 million miles of pipelines.[47]

Efficient markets require this network to be robust and allow consumers to access gas from more than one production center. Supply diversity tends to improve reliability and moderate prices, while supply constraints have the effect of increasing prices during peak demand periods.

FERC JURISDICTION

The NGA gives FERC comprehensive regulatory authority over companies that engage in either the sale in interstate commerce of natural gas for resale or the transportation of natural gas in interstate commerce. FERC regulates entry into the transportation market by

41 Derived from EIA, *Natural Gas Summary, Imports and Exports, Consumption, U.S., Annual (*accessed *October 2022),* https://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm.

42 Derived from EIA, *Natural Gas Summary* (accessed October 2022), https://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm.

43 Derived from EIA, *Natural Gas Summary, Imports and Exports, Consumption, U.S., Annual* (accessed October 2022), https://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm.

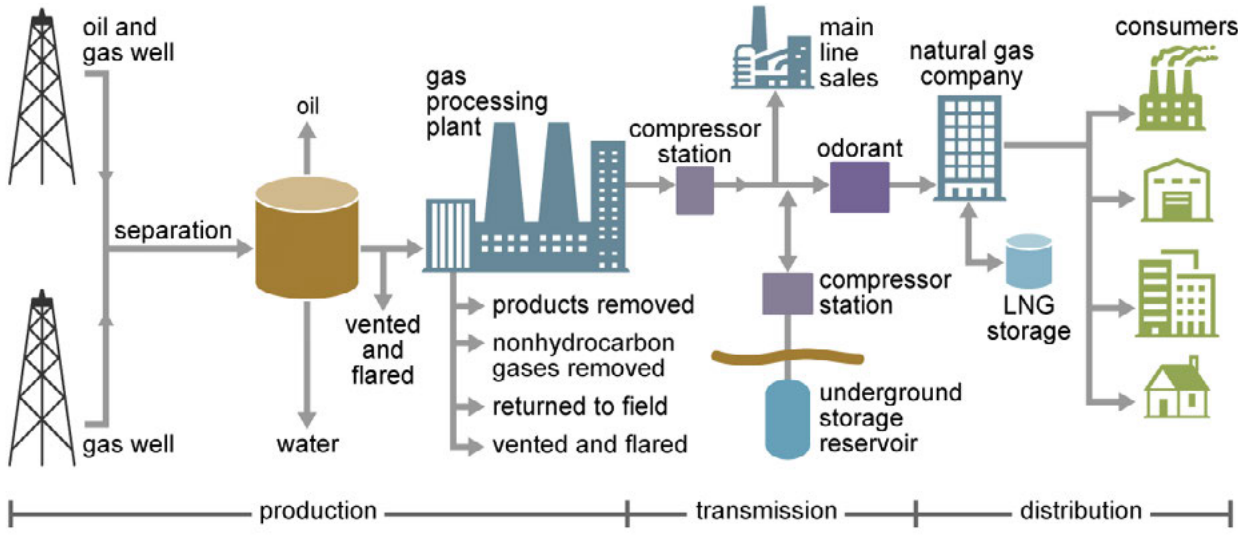
44 Derived from Department of Energy, Office of Fossil Energy and Carbon Management, *LNG Monthly 2021* (accessed December 2021), https://www.energy.gov/fecm/articles/lngmonthly-2021.

45 The Sabine Pass export terminal is located along the coast of the Gulf of Mexico in Cameron Parish, Louisiana. The Henry Hub trading point represents natural gas shipped from the distribution hub in Erath, Lousiana.

46 *See* FERC, *North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed* (October 26, 2022), https://www.ferc.gov/natural-gas/lng.

47 *See* U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, *2010+ Pipeline Mileage and Facilities, Gas Pipeline Miles by System Type* table (January 28, 2020), https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-mileage-and-facilities.

Figure 1-7: Natural Gas Production and Delivery



Source: U.S. Energy Information Administration[48]

issuing certificates of public convenience and necessity under section 7 of the NGA, 15 U.S.C. § 717f, subject to such conditions as FERC deems appropriate. To this end, FERC reviews applications for the construction and operation of interstate natural gas pipelines. FERC has no jurisdiction over pipeline safety or security, but actively works with other agencies (such as USCG and PHSMA) with safety and security responsibilities, particularly when FERC is overseeing restoration efforts along the pipeline right-of-way which may take years after a pipeline goes into service. Applicants for a certificate must certify in their applications that they will comply with PHMSA safety standards. The USCG provides FERC with a recommendation on the suitability of the waterway to support marine traffic associated with the proposed LNG facility. FERC also regulates market exit through its authority to abandon certificated service and facilities, 15 U.S.C. § 717f(b).

PROCESSING

The midstream segment of the natural gas industry, between the wellhead and pipelines, is shown in the graphic above. This involves gathering the gas from the wellhead, processing the gas to remove liquids and impurities, and moving the processed (dry) natural gas to pipelines. The composition of raw, or wellhead, natural gas differs by region. Consequently, processing will differ depending on the quality of the natural gas.

Once a well is constructed and production starts, the natural gas moves into gathering pipelines, typically small-diameter lines that move the gas from the wellhead to either a processing plant or a larger pipeline. Natural gas may also be dissolved in oil underground, but separates out from the oil as it comes to the surface due to reduced pressure. In these instances, the oil and natural gas are sent to separate processing facilities. Where it does not separate naturally, processing is required.

At the processing plant, various products (NGLs) and contaminants (e.g., sulfur and carbon dioxide) are removed from the incoming wet natural gas stream and the gas is dehydrated. The extracted NGLs are then

48 EIA, *Natural Gas Explained: Delivery and Storage of Natural Gas* (February 18, 2020), https://www.eia.gov/energyexplained/natural-gas/delivery-and-storage.php.

Natural Gas Infrastructure

The United States natural gas market relies on extensive infrastructure:

- Roughly 303,000 miles of large-diameter, high-pressure inter- and intrastate pipelines make up the mainline pipeline transportation network, run by more than 210 companies.
- More than 1,400 compressor stations maintain pressure on the natural gas pipeline network.
- More than 5,000 receipt points, 11,000 delivery points, and 1,400 interconnection points implement the flow of gas across the United States.
- More than 20 hubs or market centers provide additional interconnections.
- Over 400 underground natural gas storage facilities increase the flexibility of the system.
- 49 Pipeline border crossings enable natural gas to be imported or exported.
- There are 10 LNG import facilities and 100 LNG peaking facilities (stored gas held for peak demand periods).
- More than 1,300 local distribution companies deliver natural gas to retail customers.

Source: U.S. Energy Information Administration[49]

separated into individual components by fractionation, which uses the different boiling points of the various hydrocarbons to separate them. The extracted liquids are high-value products used by the petrochemical industry, refineries, and other industrial consumers. Once processing is completed, the natural gas is of pipeline quality and is ready to be moved by intrastate and interstate pipelines. There were about 480 natural gas processing plants operating in the U.S. in 2017.[50]

NATURAL GAS TRANSPORTATION

Interstate pipelines account for approximately two thirds of the natural gas pipeline miles in the U.S. and carry natural gas across state boundaries. Intrastate pipelines account for the remaining one third, and have similar operating and market characteristics.[51]

The interstate network moves dry natural gas from producing areas to LDCs, large industrial customers, electric power plants, and natural gas storage facilities. The pipelines, which generally range in diameter from 16 inches to as large as 48 inches, move gas between major hubs to lateral lines. Smaller diameter delivery laterals then transport gas to end-users and LDCs.

The large pipelines are known as mainline transmission pipelines and typically consist of steel sufficient to meet standards set by PHMSA. These pipes are also coated to reduce corrosion. Smaller distribution lines, which operate under much lower pressures, may be made of plastic materials, which provide flexibility and ease of replacement.

49 EIA, *About U.S. Natural Gas Pipelines* (2007/2008), https://www.eia.gov/naturalgas/archive/analysis_publications/ngpipeline/index.html.

50 *Derived from* EIA, *Natural Gas Annual Respondent Query System, EIA-757 data through 2017* (January 2019), https://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP9&f_sortby=&f_items=&f_year_start=&f_year_end=&f_show_compid=&f_fullscreen.

51 *See* U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, *2010+ Pipeline Mileage and Facilities, Gas Distribution Pipeline Miles, Gas Gathering Pipeline Miles, and Hazardous Liquid Pipeline Miles and Tanks* tables (January 28, 2020), https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-mileage-and-facilities.

Compressor stations are typically located every 50-100 miles along the pipe to add or maintain the pressure of the natural gas, propelling it through the pipeline. Natural gas travels through pipelines at high pressures, ranging from 200 pounds per square inch (psi) to 1,500 psi. The natural gas is compressed by turbines, motors, or engines. Most facilities power the compressors with turbines and reciprocating natural gas engines that use some of the gas from the line to fuel their operations, while others rely on very large electric motors.

See the EIA's website[52] for a map of interstate and intrastate pipelines and the Interstate Natural Gas Assocation of America's (INGAA) website[53] for an interactive map of major interstate natural gas pipelines in the U.S.

Metering stations are placed along the pipelines to measure the flow of natural gas as it moves through the system. Movement of natural gas along a pipeline is controlled in part by a series of valves, which can be opened to allow the gas to move freely or closed to stop gas flow along a section of pipe. Large valves may be placed every 5 to 20 miles along the pipeline.

Pipeline operators and engineers use supervisory control and data acquisition (SCADA) systems to track and control the natural gas as it travels through the system. SCADA is a centralized communication system that collects, assimilates, and manages the meter and compressor station data.

HUBS AND CITYGATES

A key element of the pipeline transmission and distribution network is the natural gas hub. Typically, a hub is a specific point where pipeline interconnections allow the transfer of gas from one pipeline to another. Hubs also provide a convenient location to establish natural gas prices.

There are dozens of natural gas hubs in the country, with over 20 major hubs. The dominant benchmark point in the physical natural gas market is the Henry Hub, which is strategically located in the Gulf Coast's producing area at a series of pipeline connections to the East Coast and Midwest consumption centers. It is located in south central Louisiana, in the town of Erath, and comprised of 12 delivery points and 4 major receipt points. More than a dozen major natural gas pipelines converge and exchange gas at the Henry Hub.

In addition to market hubs, other major pricing locations include citygates. Citygates are the locations at which distribution companies receive gas from a pipeline. Citygates at major metropolitan centers offer another convenient point at which to price natural gas.

Physical natural gas can be bought and sold at the Henry Hub or other hubs around the country in daily and monthly markets. In addition, the New York Mercantile Exchange (NYMEX) established a natural gas futures contract[54] centered at the Henry Hub in 1990 that gained widespread acceptance and is generally used as the reference price for natural gas in the U.S.

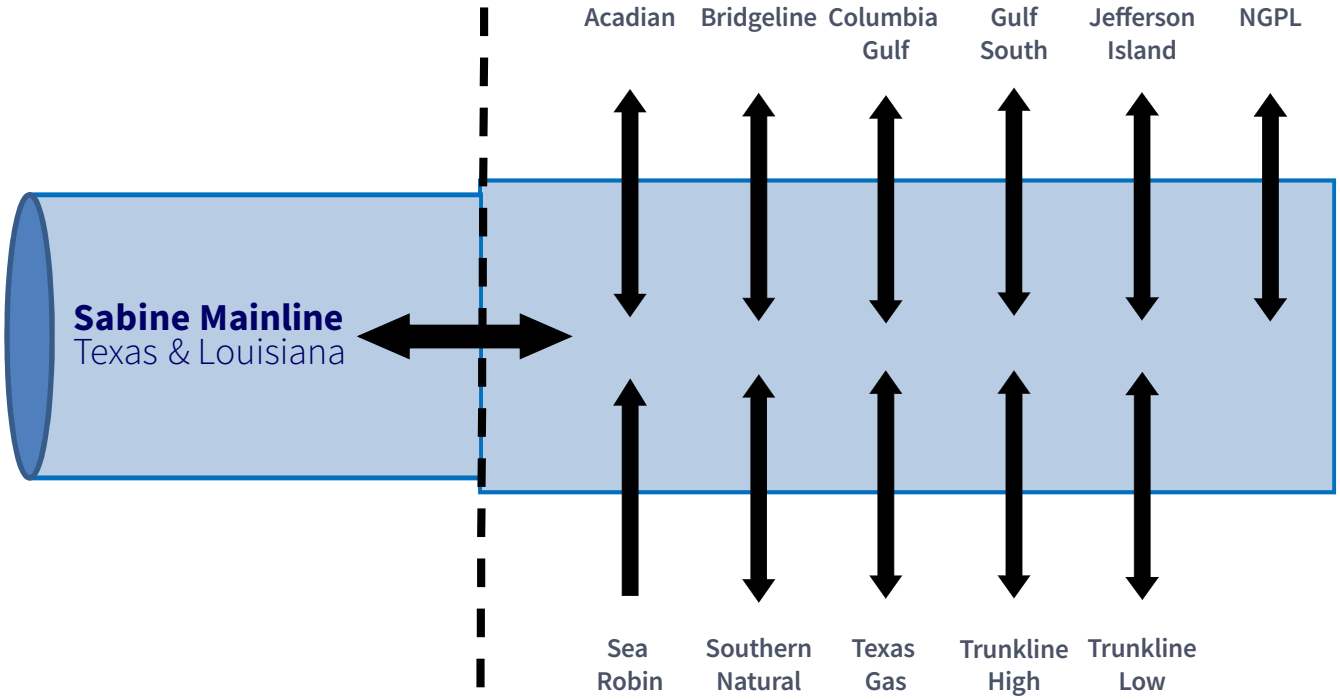
Distribution lines typically take natural gas from the large transportation pipelines, reduce the pressure, odorize the gas, and deliver the gas to retail customers. While some large consumers – industrial and electric generation, for example – may take service directly off a transmission pipeline, most receive their natural gas through their local gas utility, or LDC. These companies typically purchase natural gas and ship it on behalf of their customers, taking possession of the natural gas from the pipelines at local citygates and delivering it to customers at their meters.

52 *See* EIA, *Natural gas explained, Natural gas pipelines* (November 5, 2021), https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php.

53 *See* INGAA, *Natural Gas Pipelines* (n.d.), https://custom.envisionmaps.net/ingaa/default.html.

54 Futures contracts allow market participants to manage price risk and to protect against price volatility. See Chapter 5: Trading and Capital Markets for more information on futures contracts.

Figure 1-8: Sabine Pipe Line LLC., Henry Hub



NOTE: Arrows indicate direction of flow

Source: EnLink Midstream[55]

Some states allow competition in natural gas service at the local level. In these circumstances, natural gas marketers purchase the natural gas and arrange for it to be shipped over both the interstate pipeline network and the LDC system.

PIPELINE SERVICES

Customers or shippers have a choice between a variety of services on interstate pipelines. One is firm transportation service in which an agreement is executed directly between the pipeline and a customer, providing the customer with rights to transport natural gas from primary receipt point(s) to delivery points. Shippers with firm transportation service receive priority to use their capacity over those customers without firm capacity.

A shipper can also contract for interruptible transportation service, which is offered to customers on an as-available basis. This service may not be available during periods of peak demand. Due to the interruptible nature of the service, customers pay lower rates than those that contract for firm service.

A secondary market for firm transportation rights enables shippers to sell their pipeline capacity to a third party through FERC's capacity release program.[56] Services offered in the primary market can be offered in the secondary market by the holder of the primary service. Released capacity offers market participants the opportunity to buy and sell from each other as well as from the pipeline. Holders of firm capacity can release segments rather than their full holdings, provided segmentation is operationally feasible on the interstate pipeline's system. In addition, firm capacity holders can also make deliveries on their own to secondary points on the pipeline system to the extent capacity is available.

55 *See* https://sabinepipeline.enlink.com/wp-content/uploads/2019/12/Sabine-Pipe-Line-LLC-Henry-Hub-Schematic-PDF.pdf.

56 *See* Order No. 636, FERC Stats. & Regs. ¶ 30,939 at P 88 (1992).

Some interstate pipelines also provide "no-notice service" which enables pipeline customers to receive delivery of natural gas on demand up to their firm entitlements on a daily basis without incurring daily balancing and scheduling penalties. No-notice service enables customers to receive natural gas volumes that have not been scheduled and thereby helps meet unexpected requirements caused, for example, by unexpected changes in temperature.[57] This service is especially helpful to LDCs that must serve their load without knowing their exact load level each day. No-notice service is generally priced at a premium to firm transportation service and is provided through a combination of storage and transportation services. Shippers may temporarily release this service to other parties, using FERC-approved capacity release guidelines.

Finally, natural gas pools are points on a pipeline's system where natural gas suppliers aggregate supplies for sale to buyers. They can be physical points on the pipeline system, such as the Henry Hub in Louisiana, but they are most often "paper" points, such as the TCO Pool on Columbia Gas Transmission's system. A paper pool (also called a virtual point) is not a physical point but is used solely for nomination and scheduling purposes. Pooling is an administratively efficient process that allows suppliers to aggregate supply together at one location on the pipeline system, rather than having to tie each individual well or receipt point to a buyer, and deliver from the pool to multiple delivery points. Each interstate pipeline is required to have a pooling service and the service is often free. Natural gas prices are often set for the market at the major pooling points on the interstate pipeline systems. Thus, adding capacity to enable additional volumes to access pooling points benefits and enhances the efficiency of the domestic natural gas market.

FERC JURISDICTION

The NGA requires that interstate natural gas pipelines charge just and reasonable rates for the transportation and sale of natural gas. To promote compliance with this mandate, the NGA requires natural gas pipelines to file rate schedules with FERC and to notify FERC of any subsequent changes in rates and charges. On submission of a pipeline tariff revision, FERC may hold a hearing to determine whether the pipeline has met its burden to show that the amended rates and charges are just and reasonable.

Under sections 4 and 5 of the NGA, 15 U.S.C. §§ 717c and 717d, FERC regulates the rates, terms, and conditions of jurisdictional transportation and sales, ensuring that rates and charges for such services, as well as all rules, regulations, practices, and contracts affecting those rates and charges, are just and reasonable and not the product of undue discrimination (15 U.S.C. §§ 717c(a) and (b)).

INTERSTATE TRANSPORTATION RATES

Pipeline transportation rates can be priced on zones or miles, or be a fixed postage stamp rate. In zonal pricing, the price of transportation varies by the location of the receipt and delivery points across a series of geographic zones, and the rate is fixed within each zone and across different zones. Transco Gas Pipe Line is an example of a pipeline that uses zonal pricing. Under postage stamp rates, shippers pay the same rate for transportation regardless of how far the natural gas is moved, similar to the way a postage stamp costs the same amount regardless of whether a letter is sent to New York or California. Pipelines using postage stamp rates include Northwest Pipeline, Colorado Interstate Gas, and Columbia Gas Transmission.

With mileage-based rates, shippers pay based on the distance between where the gas enters the pipeline and where it is taken out of the pipeline. The rate is designed to reflect the distance involved in transporting the gas. Gas Transmission Northwest (GTN), for example, uses mileage-based rates.

Other pipelines use hybrid or mixed-rate systems. Northern Natural Gas, for example, uses both a zonal rate for upstream receipts and a postage stamp rate for market area deliveries.

57 *Id*.

Figure 1-9: Pipeline Capacity Scheduling



Cycle	Cycle Description
T	**Timely:** Nomination sent by 1 p.m. (Central Clock Time), to be confirmed by 4:30 p.m., and to be effective for gas flow starting at 9 a.m. next gas day.
E	**Evening**: Nominations sent by 6 p.m., to be confirmed by 8:30 p.m. for gas flow at 9 a.m.
ID1	**Intraday 1**: Nominations sent by 10 a.m., to be confirmed by 12:30 p.m. for gas flow at 2 p.m.
ID2	**Intraday 2**: Nominations sent by 2:30 p.m. to be confirmed by 5 p.m. for gas flow at 6 p.m.
ID3	**Intraday 3**: Nominations sent by 7 p.m. to be confirmed by 9:30 p.m. for gas flow at 10 p.m.

Source: FERC[58]

Although pipelines are required to have a cost-based transportation rate stated in their tariff, many pipelines offer shippers service at negotiated rates. These negotiated rates are generally below the pipeline's cost-based rates, and pipelines are required to file these negotiated rate contracts with FERC

SCHEDULING

Pipelines have rigorous schedules that shippers must follow. Typically, shippers nominate natural gas deliveries in the day-ahead market, and may update their nominations at various points during the day in which the natural gas flows. The Pipeline Capacity Scheduling graphic illustrates a particular schedule.

PIPELINE USAGE OR LOAD FACTOR

Load factor measures the use of a pipeline network. It is the average capacity used at a given point or segment relative to a measurement of maximum or peak available capacity. Customers with a 100 percent load factor use their maximum capacity every day; one with a 50 percent load factor uses its capacity only half the time. Different types of customers use pipeline capacity differently. Historically, industrial customers have exhibited high load factors and residential customers that primarily rely upon seasonal natural gas to heat homes have had lower load factors.

58 FERC, Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities, Order No. 809, FERC Stats. & Regs. ¶ 31,368, at Appendix (2015).

Pipelines are accustomed to serving different demands, which can affect how much of their capacity is used at various times. For example, Kern River Gas Transmission has operated at around 86 percent of capacity since 2005, while Algonquin Gas Transmission's (Algonquin) load factor can be considerably less at times. Algonquin's pipeline is used more seasonally than Kern River's, with Algonquin's pipeline utilization averaging 90 percent of the pipeline's capacity during the winter (nearing full utilization on very cold days) and averaging 77 percent during the summer, spring, and fall. This utilization pattern reflects the seasonal demand in the Northeast.[59]

PARK AND LOAN SERVICE

Park and loan service (PAL) is a way for shippers to balance their takes of natural gas with their supply, by providing a short-term load-balancing service to help shippers meet their load. Using the PAL service, shippers can take less natural gas than scheduled, thus parking their excess supply in the pipeline at times when the demand is lower than anticipated. If demand is higher than expected, shippers can adjust their take upward, in effect borrowing natural gas from the pipeline.

PAL characteristics include:

- Park and loan services typically generate low revenue and are offered with the lowest service level priority among all pipeline services.
- Market centers, or hubs, routinely offer these services.
- Charges are usually commensurate with interruptible service rates.

PIPELINE CONSTRAINTS AND CAPACITY GROWTH

Pipeline capacity limits the amount of natural gas supply that can be delivered to a specific region and, therefore, is a key factor in regional prices. In recent years, the natural gas pipeline network has expanded significantly, which has removed many bottlenecks and enabled access to previously unreached supply areas.

This development includes a considerable amount of new pipeline capacity in the Northeast, where natural gas production has increased significantly. New pipelines have also increased the flow of Barnett Shale gas into the interstate network and have reduced congestion across the Texas-Louisiana border.

New England, on the other hand, experiences pipeline constraints on peak demand days during the winter months. Most of the year, there is excess pipeline capacity into New England. However, when high demand from the power sector coincides with peak heating demand from LDC customers, customers without firm (priority) pipeline service compete for the scarce remaining pipeline capacity. This can lead to substantial price volatility in the natural gas spot market.

The Florida Panhandle and Northern California were also some of the most frequently constrained regions of the country, but each region constructed significant new pipeline capacity. Conversely, since 2018, natural gas production has outpaced pipeline capacity in the Permian Basin, the second largest shale gas-producing region in the U.S., due to associated natural gas production rising with increasing crude oil production.[60] In addition, technological advancements in drilling and completion techniques have continuously increased productivity of new wells in the Permian Basin since 2010.[61] The lack of available infrastructure to transport the abundant natural gas to high-demand regions has frequently contributed to prices at the local Waha Hub falling below prices at the Henry Hub.[62] To help reduce pipeline constraints, two new intrastate pipeline projects

59 Derived from S&P Global Platts Natural Gas Pipeline Flow data (October 2022).

60 *See* EIA, *The Waha Hub natural gas price continues to fall below the Henry Hub price* (Sep. 20, 2022), https://www.eia.gov/todayinenergy/detail.php?id=53919#.

61 *See* EIA, *Advances in technology led to record new well productivity in the Permian Basin in 2021* (Sep. 30, 2022), https://www.eia.gov/todayinenergy/detail.php?id=54079.

62 *See* EIA, *The Waha Hub natural gas price continues to fall below the Henry Hub price* (Sep. 20, 2022), https://www.eia.gov/todayinenergy/detail.php?id=53919#.

Kinder Morgan Energy Partners' Permian Highway Pipeline and WhiteWater's Whistler Pipeline, and one interstate pipeline project, Summit Midstream Partners' Double E Pipeline came online in 2021. The additional pipeline capacity in 2021 increased the amount of natural gas flowing out of the basin into nearby consuming regions and narrowed the price difference between the Waha Hub and the Henry Hub.[63] All three pipelines have announced expansion projects intended to further expand pipeline capacity.[64] In addition, Kinder Morgan's Gulf Coast Express Pipeline Expansion, and EnLink Midstream's Matterhorn Express Pipeline will likely add additional takeaway capacity in 2023 and 2024, respectively.[65] The Oasis Pipeline Modernization Project was completed in early 2023 will also add additional capacity.[66] The additional pipeline capacity in the Permian Basin would allow producers to flow additional natural gas to demand centers in Mexico and along the Texas Gulf Coast.[67]

Building a pipeline project requires careful planning, as the projects typically entail significant costs that must be recovered over years of operations. However, unanticipated changes in supply and demand patterns can have unexpected effects on even the best-planned projects. For example, one of the largest additions to the natural gas infrastructure came when the 1.8-Bcfd Rockies Express Pipeline (REX) was completed in 2009.[68] REX was designed to move natural gas from Wyoming to eastern Ohio in order to relieve pipeline constraints that bottled up production and depressed prices in the Rockies, while at the same time providing needed supplies into the East. When REX first went into service, Rockies producers saw a rise in prices. The Rockies gas flowing eastward displaced natural gas from the Permian Basin. Permian natural gas, in turn, began moving to the Southern California market. Consequently, regional price differences moderated. However, the rapid increase in Marcellus Shale production pushed Rockies supplies away from the Northeast and caused flows on REX to decrease sharply, putting the pipeline at financial risk. In 2014, REX began the process of reversing flows on parts of the pipeline to move natural gas from the East to the Midwest. This development makes more Rockies natural gas available to western markets, and more Midcontinent production available for the Gulf Coast and Southeast states.

LOCAL DISTRIBUTION

Distribution lines typically take natural gas from the large interstate pipelines and deliver the natural gas to retail customers. While some large consumers – industrial and electric generators, for example – may take service directly off an interstate pipeline, most receive their natural gas through their LDC. The LDCs typically purchase natural gas and ship it on behalf of their customers, taking possession of the natural gas from interstate pipelines at local citygates and deliver the natural gas to their customers at the customer's meter. According to PHMSA, this distribution involves a network of smaller pipelines, as well as smaller scale compressors and meters.

63 *Id*.

64 Summit Midstream Partners' Double E Pipeline's Red Hills Lateral was approved in February 2023.

65 *See* EIA, *EIA expects that natural gas production in the Permian Basin will increase in 2022 and 2023* (May 26, 2022), https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/05_26/#itn-tabs-0.

66 *See* EIA, *Pipeline Projects announced to expand Permian Natural gas capacity* (August 4, 2022), https://www.eia.gov/todayinenergy/detail.php?id=53319.

67 *See* EIA, *EIA expects that natural gas production in the Permian Basin will increase in 2022 and 2023* (May 26, 2022), https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/05_26/#itn-tabs-0.

68 Tallgrass Energy and Phillips 66, *Rockies Express Pipeline (REX), Rockies Express System Map* (n.d.), https://pipeline.tallgrassenergylp.com/Content/REX/REX_FERC_Web_Map.pdf.

Natural Gas Storage

Although natural gas production has risen steadily since 2005 because of the increase in shale gas production, day-to-day production remains relatively steady throughout the year. Demand, however, changes considerably with the seasons. Natural gas storage enables producers and purchasers to store gas during periods of relatively low demand – and low prices – then withdraw the natural gas during periods of relatively higher demand and prices.

Working gas storage capacity, as tracked by EIA, totaled more than 4,844 Bcf in 2020.[69] The amount injected or withdrawn is the difference between production and demand. Storage capacity adds flexibility to pipeline and distribution systems and helps moderate prices by providing an outlet for excess natural gas during periods of low demand. Storage facilities also provide a readily accessible supply in periods of high demand. Some natural gas can also be stored in the pipelines as linepack, in which more molecules of gas are held in a segment of pipeline under greater-than-normal pressure.

EIA's weekly storage report provides a high-level snapshot of the natural gas supply and demand balance. EIA releases its storage report at 10:30 a.m. eastern time (ET) on Thursdays. The price for natural gas futures can change dramatically within seconds of the report's release. If the reported injection or withdrawal significantly differs from market expectations, the price for natural gas futures may rise or fall.

FERC JURISDICTION

The underground storage of natural gas has historically been critical in assuring that the needs of natural gas customers are met. The Energy Policy Act of 2005 added a new section to the NGA stating that FERC may authorize natural gas companies to provide storage and storage-related services at market-based rates for new storage capacity, even though the company cannot demonstrate it lacks market power (15 U.S.C. § 717c(f)). To make this authorization, FERC must determine that market-based rates are in the public interest and are needed to encourage the construction of new capacity, and that customers are adequately protected.

STORAGE FACILITIES

The bulk of the storage capacity in the U.S. is below ground. Differing cost and operational characteristics affect how each facility is used:

- Deliverability rate is the rate at which inventory can be withdrawn. The faster the natural gas can be removed from storage, the more suitable the storage facility is to helping serve rapidly changing demand.
- Cycling capability is the ability of the resource to quickly allow injections and withdrawals, which is useful for balancing supply and demand. Salt caverns tend to have high withdrawal and injection rates, enabling them to handle as many as a dozen withdrawal and injection cycles each year. LNG storage also demonstrates these capabilities.

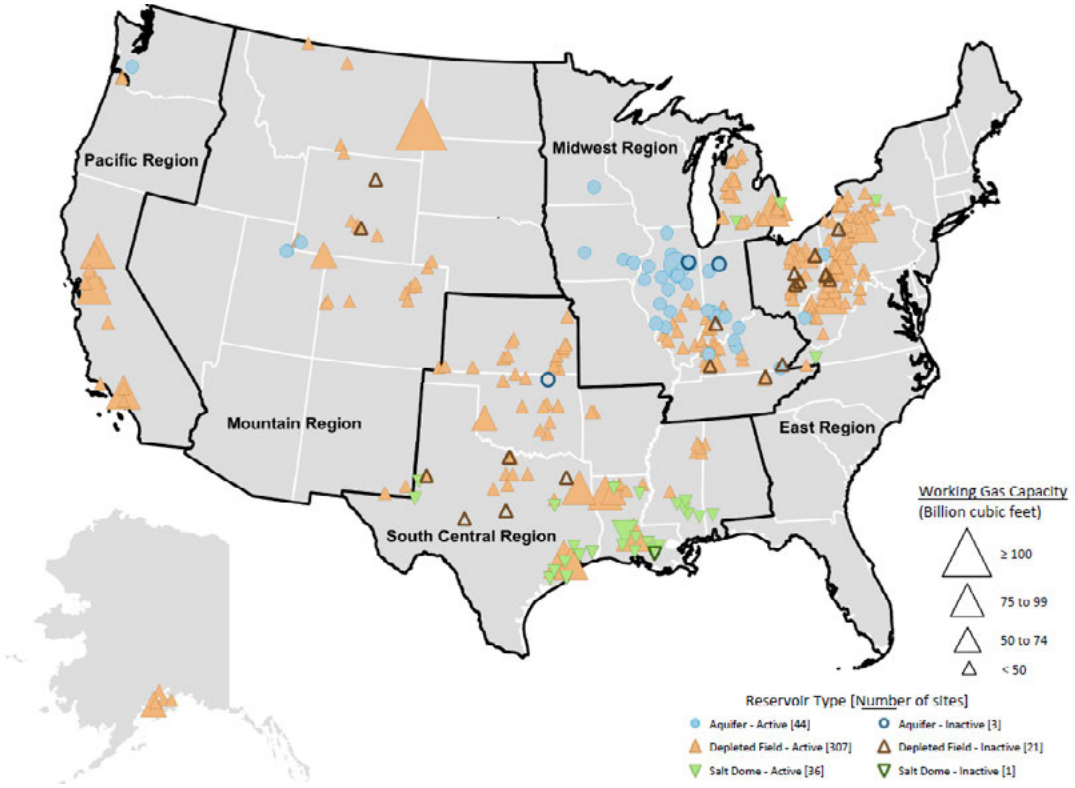
Natural gas in an underground storage facility is divided into two general categories, base gas and working gas. Base gas is the volume of natural gas, including native gas[70], needed as a permanent inventory in a storage reservoir to maintain adequate reservoir pressure and deliverability rates throughout the withdrawal season. Working gas is the volume of natural gas in the reservoir above the designed level of base gas and that can be extracted during the normal operation of the storage facility.

Most of the nation's natural gas storage is in depleted reservoirs (former oil and gas fields). These facilities reuse the infrastructure – wells, gathering systems,

69 *See* EIA, *Underground Natural Gas Storage Capacity, Total Working Gas Capacity, Annual* (October 2022), https://www.eia.gov/dnav/ng/ng_stor_cap_a_EPG0_SACW0_Mmcf_a.htm.

70 Native gas refers to natural gas found in its original or natural state in underground reservoirs. Native gas is not associated with crude oil or other hydrocarbon resources.

Figure 1-10: Underground Natural Gas Storage Facilities in the Lower 48 States



Source: U.S. Energy Information Administration[72]

and pipeline connections – originally created to support the field when it was producing. About 50 percent of total capacity goes to base gas used to maintain operating pressure at the facility, and inventory usually turns over once or twice a year.

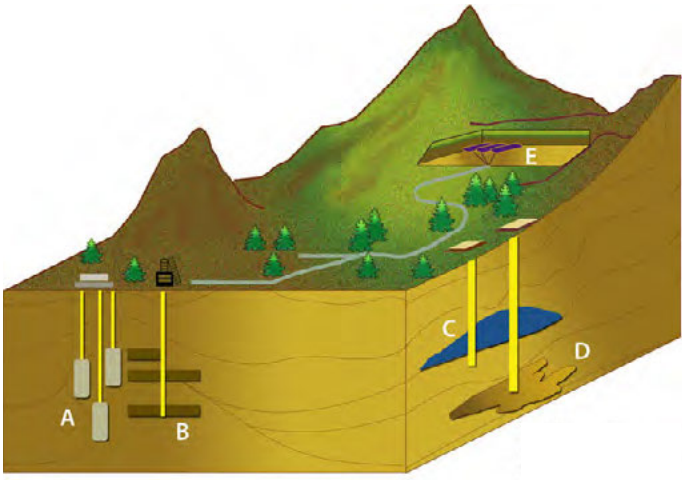
Other storage facilities reside in aquifers that have been transformed into natural gas storage facilities. These are mostly in the Midwest. These aquifers consist of water-bearing sedimentary rock overlaid by an impermeable cap rock. Aquifers are the most expensive type of natural gas facility because they do not have the same retention capability as depleted reservoirs. Therefore, base gas can be well over 50 percent of the total natural gas volume. This makes the facility more sensitive to withdrawal and injection patterns, so inventory usually turns over just once a year.

Salt cavern formations exist primarily in the Gulf Coast region. These air- and water-tight caverns are created by removing salt through solution-mining, leaving a cavern that acts as a pressurized vessel. Little basegas is required, which allows inventory to turn over as many as a dozen times during the year, and results in high injection and withdrawal rates. Salt caverns generally hold smaller volumes than depleted-reservoir or aquifer gas storage facilities.

Natural gas may also be stored in above-ground tanks as LNG. There is LNG storage at all of the onshore LNG-receiving terminals, and there are about a hundred standalone LNG storage facilities in the U.S., as well. LNG ships can also serve as storage, depending on timing and economics. LNG storage is

71 *See* EIA, *Map of Storage Facilities* (2020), https://www.eia.gov/naturalgas/ngqs/images/storage_2020.png.

Figure 1-11:Types of Underground Storage Facilities



A. Salt Caverns
B. Mines
C. Aquifers
D. Depleted Reservoirs
E. Hard-Rock Caverns

Source: U.S. Energy Information Administration[72]

highly flexible, allowing multiple inventory turns per year with high injection and withdrawal rates.

REGIONAL STORAGE

The EIA divides the U.S. into five storage regions: East, Midwest, South Central, Mountain, and Pacific.[73] Currently, about a third of the underground storage in the U.S. sits in the South Central region in a mix of depleted reservoirs, aquifers, and high-deliverability salt caverns. Close to one third of the South Central region's working gas capacity is in these purpose-built salt caverns. The East and Midwest each represent about a quarter of working gas capacity, generally near major population centers. The remaining roughly 1/5 of working gas capacity is located in depleted fields throughout the Mountain and Pacific regions.[74] Depending on storage levels at the end of the previous winter, and the temperatures over the injection season, U.S. working gas in storage will typically be between 80 and 90 percent full when the official winter season begins on November 1.

STORAGE SERVICE AND USES

Approximately 133 entities – including interstate and intrastate pipeline companies, LDCs, and independent storage service providers – operate the approximately 412 underground storage facilities active in the continental U.S.[75] Facilities operated by interstate pipelines and many others are operated on an open-access basis, with much of the working gas capacity available for use on a nondiscriminatory basis.

The ability to store large quantities of natural gas improves reliability and usually has a moderating influence on natural gas prices. Storage inventory augments natural gas supply during the winter, and acts as an additional demand component during the summer injection season. The storage injection season typically starts April 1 and continues through October 31, when demand for natural gas heating is lowest. Storage withdrawals generally start in November and last throughout the winter.

The ability to use storage to provide for winter peaks creates an intrinsic storage value. This is the value from buying during cheaper periods of the year for use during higher-cost seasons. Depleted reservoirs or aquifers – with limited ability to turn over inventory – support this type of use. Local distribution companies or pipelines store their natural gas in these facilities to ensure adequate supplies for peak seasons, balance load, and diversify their resources.

Storage may be priced at cost-based or market-based rates. FERC may approve market based rates for storage

72 *See* EIA, *The Basics of Underground Natural Gas Storage, Figure 1* (November 16, 2015), https://www.eia.gov/naturalgas/storage/basics/.

73 EIA, *Weekly Natural Gas Storage Report, Notes and Definitions* (n.d.), http://ir.eia.gov/ngs/notes.html.

74 Derived from EIA, *Underground Natural Gas Working Storage Capacity, data for November 2021* (August 31, 2021), https://www.eia.gov/naturalgas/storagecapacity.

75 Derived from EIA, *Natural Gas Annual Respondent Query System, EIA-191 data through 2021* (accessed October 2022), https://www.eia.gov/naturalgas/ngqs/#?report=RP7&year1=2021&year2=2021&company=Name.

operators that lack market power.[76] Pricing mechanisms for low-cycling depleted fields and aquifers may use a traditional cost-of-service structure, including:

- Capacity charges for firm contract rights to physical storage capacity
- Deliverability charges for transportation to and from the storage facility
- Withdrawal charges for the removal of natural gas from storage
- Injection charges for the injection of natural gas into storage

A salt cavern, with its ability to turn over inventory frequently and quickly, allows for additional uses, enabling users to capture extrinsic value. Many salt dome facilities can cycle between injection and withdrawal at almost a moment's notice, giving users greater flexibility. Entities contracting for storage capacity may move natural gas in and out of storage as prices change in attempts to maximize profits or minimize costs. Storage may be a component in producer or consumer hedging strategies, helping them to manage the risk of price movements. Further, storage helps shippers avoid system imbalances and associated penalties, and supports swing gas supply services, which are short-term contracts that provide flexibility when either the supply of gas from the seller, or the demand for natural gas from the buyer, are unpredictable. Storage also facilitates title transfers and parking and lending services. This helps shippers balance daily receipts and deliveries, manage their overall supply portfolio, or take advantage of price movements. Consequently, storage operators have begun offering a more varied menu of services, and users have begun using storage as a commercial tool and as part of a comprehensive supply portfolio strategy.

Merchant storage, frequently using salt caverns, uses market-based prices, recognizing the dynamics affecting value at any given point in time. Prices often take into account the prices at which the NYMEX futures contracts are trading. They may also reflect the storage volume, the number of times the natural gas will be cycled, the length of the contract and the timeframe it covers and the maximum daily quantity that may be injected or withdrawn. Energy marketers have increasingly used these facilities as they try to profit from price volatility. It is also attractive to shippers, industrial consumers with uncertain loads, and natural gas-fired generators whose needs change rapidly.

Pipelines also offer storage service, both firm and interruptible, as part of their open access transportation service under FERC rules. Rates are rarely market-based. Instead, prices are based on cost of service, with rates containing reservation and usage components for firm service and a usage component for interruptible.

MARKET EFFECTS

Storage can mitigate large seasonal price swings by absorbing natural gas during low demand periods and making it available when demand rises.

Further, storage levels can affect the market's expectations about prices during the coming winter high-demand season. The amount of natural gas in storage in November is a key benchmark of the natural gas industry's ability to respond to changes in winter weather. Higher storage levels tend to reduce natural gas futures prices; lower storage levels tend to increase them, all other market conditions being equal.

Although the Shale Revolution has added significant supplies to the U.S. natural gas market, it has also reduced the seasonal value of natural gas somewhat. The price differentials between winter and summer have been reduced and this has had an impact on storage development in the U.S. Several storage developers that received a certificate from FERC have elected not to build their storage facility due to this development.

76 *See* Order No. 678, Rate Regulation of Certain Natural Gas Storage Facilities, 18 CFR Part 284 (2006).

Natural Gas Markets and Trading

The natural gas industry in the U.S. is highly competitive, with thousands of producers, consumers, and intermediate marketers. Some producers have the ability to market their natural gas and may sell it directly to LDCs, to large industrial buyers and to power plants. Other producers sell their natural gas to marketers who aggregate natural gas into quantities that fit the needs of different types of buyers and then transport the natural gas to their buyers.

Most residential and commercial customers purchase natural gas from a LDC. In contrast, many industrial customers and most power plants have the option to purchase natural gas from a marketer or producer instead of from the LDC, thereby avoiding any LDC charges.

Historically, natural gas pipelines served as natural gas merchants, buying natural gas at the wellhead and selling the transportation and commodity as a bundled product directly to consumers. However, in 1992, FERC Order No. 636 restructured the natural gas market by regulating interstate pipelines as open access transporters.[77] Although interstate pipelines may buy and sell natural gas, they now do so for operational reasons and no longer act as merchants. As noted earlier, interstate pipelines transport natural gas at rates approved by FERC.

NATURAL GAS MARKETERS

Most natural gas trading in the U.S. is performed by natural gas marketers. Any party engaging in the sale of natural gas can be termed a marketer; however, marketers are usually specialized business entities dedicated solely to transacting in the physical and financial energy markets. It is commonplace for natural gas marketers to be active in a number of energy markets, taking advantage of their knowledge of these markets to diversify their business.

Marketers can be producers of natural gas, pipeline marketing affiliates, LDC marketing affiliates, independent marketers, financial institutions, or large-volume users of natural gas. Some marketing companies may offer a full range of services, marketing numerous forms of energy and financial products, while others may be more limited in their scope. For instance, most marketing firms affiliated with producers do not sell natural gas from third parties; they are more concerned with selling their own production and hedging to protect their profit margin from these sales.

Generally speaking, there are five categories of marketing companies: major nationally integrated marketers, producer marketers, small geographically focused marketers, aggregators, and brokers.

- Nationally integrated marketers offer a full range of services, and market numerous different products. They operate on a nationwide basis and have large amounts of capital to support their trading and marketing operations.
- Producer marketers are those entities generally concerned with selling their own natural gas production or the production of their affiliated natural gas production company.
- Smaller geographically focused marketers target particular regional areas and specific natural gas markets. Many marketing entities affiliated with LDCs are of this type, focusing on marketing natural gas for the geographic area in which their affiliated distributor operates.
- Aggregators generally gather small volumes from various sources, combine them and sell the larger volumes for more favorable prices and terms than would be possible selling the smaller volumes separately.
- Brokers are a unique class of marketers because they never take ownership of natural gas themselves. They simply act as facilitators, bringing buyers and sellers of natural gas together.

77 *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol,* Order No. 636, FERC Stats. & Regs. ¶ 30,939 (1992).

Most marketing companies have significant operations capabilities in addition to the core trading group. These support staff are responsible for coordinating everything related to the sale and purchase of physical and financial natural gas, including arranging transportation and storage, posting completed transactions, billing, accounting, and any other activity that is required to complete the purchases and sales arranged by the traders. These companies also have risk-management operations that are responsible for ensuring that the traders do not expose the marketing company to excessive risk. These companies also have risk-management operations that are responsible for ensuring that the traders do not expose the marketing company to excessive risk.

HUB PRICES AND BASIS

Natural gas is traded at different locations throughout the country and the prices at specific hubs and citygates are determined by the relative supply and demand for natural gas at the particular locations. Additionally, the difference between the Henry Hub price and another hub (or citygate) is called the location differential, or basis.

Basis usually reflects the variable cost to transport natural gas between the Henry Hub and another hub. Basis can change, sometimes dramatically, depending on local market conditions, and can widen considerably when pipelines between two points are congested. Basis in excess of transportation costs results from pipeline constraints and lack of pipeline competition. The natural gas price at a hub in Florida, for example, would be the price at the Henry Hub and the basis to the Florida hub.

In addition to being the country's benchmark hub, the Henry Hub is also the delivery point for the NYMEX natural gas futures contract. Historically, changes in price at the Henry Hub provided a good indicator of how prices were generally changing across the country, however, over the past few years, the price at the Henry Hub as become less reflective of regional price trends outside of the Gulf Coast.

PHYSICAL TRADING OF NATURAL GAS

Physical natural gas contracts are negotiated between buyers and sellers. There are many types of physical natural gas contracts, but most share some standard specifications, including the buyer and seller, the price, the amount of natural gas to be sold (usually expressed in a volume per day), the receipt and delivery points, the tenure of the contract (usually expressed in number of days, beginning on a specified day), and other terms and conditions. Other special terms and conditions can outline such things as the payment dates, quality of the natural gas to be sold, and any other specifications agreed to by both parties. Physical natural gas contracts are negotiated between buyers and sellers over the phone or executed on electronic bulletin boards and e-commerce trading sites.

There are three main types of physical natural gas contracts: swing contracts, baseload contracts, and firm contracts:

- Swing (or interruptible) contracts are usually short-term contracts between one day and one month in length. These contracts are the most flexible, and are usually put in place when either the supply of gas from the seller, or the demand for natural gas from the buyer, are not guaranteed.
- Baseload contracts are similar to swing contracts. Neither the buyer nor seller is obligated to deliver or receive the exact volume specified. However, it is agreed that both parties will attempt to deliver or receive the specified volume, on a best-efforts basis.
- Firm contracts are different from swing and baseload contracts in that both parties are legally obligated to either receive or deliver the amount of natural gas specified in the contract. These contracts are used primarily when both the supply and demand for the specified amount of natural gas are unlikely to change.

Price Discovery

SPOT (CASH) MARKET

The U.S. natural gas marketplace has a highly competitive spot, or cash, market where brokers and others buy and sell natural gas daily in short-term deals for next-day delivery. The daily spot market for natural gas is active, and trading can occur 24 hours a day, seven days a week. These points include market centers, where brokers actively trade and prices are established. In addition to these market centers, natural gas is actively traded at many other locations, including segments of individual pipelines and locations where pipelines interconnect with LDCs.

Spot market transactions are normally conducted on electronic exchanges or by telephone, with the buyer agreeing to pay a negotiated price for the natural gas to be delivered by the seller at a specified point on the next day. Natural gas spot prices reflect daily supply and demand balances and can be volatile.

BIDWEEK

Bidweek is the name given to the last five business days of a month, when producers sell their core production and consumers buy natural gas for their core needs for the upcoming month. In 2021, some publications condensed the bidweek trading period to the first three days from within the full, five-day bidweek timeframe.[78]

INDEX PRICES

Several publications, such as Platts Gas Daily, Natural Gas Intelligence, and Natural Gas Week, survey the market for daily physical transactions that are used to form daily indices that are made available the night before or the morning of the next business day. Market participants voluntarily provide this information to publications, some of which also incorprate ICE trades in their indices. Many market participants voluntarily report their monthly bidweek transactions to publications as well. Publications convert these transactions into monthly locational price indexes that are available on the first business day following the last day of bidweek. These daily and monthly indexes, in turn, are referenced in contracts for those firms that do not choose to enter into fixed-price contracts (or are prohibited from using them by state or local regulators). The majority of the natural gas that is physically traded is priced off of index prices.

THE FINANCIAL MARKET

In addition to trading physical natural gas, there is a significant market for natural gas derivatives and financial instruments in the U.S. In the financial market, market participants are interested in profiting from the movement of the price of natural gas rather than delivering or receiving natural gas. Financial trades also market participants to hedge a price exposure without having to make or take physical delivery of the natural gas commodity. The pricing and settlement of these financial products are tied to physical natural gas. It is estimated that the value of trading that occurs on the financial market is at least a dozen times greater than the value of physical natural gas trading.

Derivatives are financial instruments that derive their value from an underlying fundamental – in this case, the price of natural gas. Derivatives can range from being quite simple to being exceedingly complex. Traditionally, most derivatives were traded on the over-the-counter (OTC) market, although most are now traded via exchange-cleared, standardized contracts. Derivatives can be used to speculate, or seek to profit from market fluctuations, or to hedge price exposure in other financial or physical positions.

More information on financial markets appears in Chapter 5.

78 *See* NGI, *NGI Adopting Three-Day Natural Gas Bidweek Trading Period, Making Other Changes to Price Index Listings* (May 7, 2021), https://www.naturalgasintel.com/ngi-adopting-three-day-natural-gas-bidweek-trading-period-making-other-changes-to-price-index-listings/.







Chapter 2
Wholesale Electricity Markets

WHOLESALE ELECTRICITY MARKETS

Electricity is a physical product – the flow of electrical power. It is a secondary energy source, in that it results from the conversion of other energy forms such as natural gas, coal or uranium, or the energy inherent in wind, sunshine or the flow of water in a river. Electricity is not visible or directly observable, but it can be turned on and off and measured.

Quick Facts:
Measuring Electricity

A key measure of electricity used in industry is the rate at which it is produced, transferred, or consumed – how much energy per unit of time a generator produces, with the units of electricity called watts. Similar measures are kilowatts (kW) – 1,000 watts, and megawatts (MW) – 1,000 kilowatts. A watt, kilowatt, or megawatt is a unit of power.

The amount of electric energy generated, transmitted, or used over time is measured as the number of watt-hours (also expressed as kilowatt-hours, megawatt-hours, or gigawatt-hours).

The amount of electricity a generator can produce in an hour is its capacity, which is typically noted as megawatts. For example, a generator with a capacity of 100 MW can produce 100 MW in an hour. The amount of power consumed at any location is the demand at that point.



Electricity markets have retail and wholesale components. Retail service involves the sales of electricity to consumers and may involve retail markets; wholesale markets typically involve the sales of electricity among electric utilities and electricity traders before it is eventually sold to consumers. Because the Federal Energy Regulatory Commission (FERC) has jurisdiction over wholesale electric rates and not retail electric rates, this document focuses on wholesale electricity markets, although it does address retail demand and other instances where retail markets strongly influence wholesale markets.

Most wholesale electric markets rely upon competitive markets to set prices, but some prices are based on the service provider's cost of service. For wholesale markets, FERC either authorizes jurisdictional entities to sell at market-based rates or at cost-based rates.

Both market-based and cost-of-service prices are affected by physical factors or conditions that drive electric supply and demand – these factors are known as physical fundamentals. For example, weather affects both supply and demand. Fuel costs, capital costs, transmission capacity and constraints, and the operating characteristics of power plants affect the cost at which supply can be provided. The actual price for power is determined by the interaction of supply and demand. For example, extreme heat can drive up demand and require grid operators to activate less-efficient, more-expensive power plants, and consequently drive prices up.

Electric Power Industry

ELECTRICITY ON DEMAND

In the United States and other developed countries, consumers expect electricity to be available whenever they need it. Electricity use has grown as consumers integrate various devices and amenities such as lighting, refrigerators and computers into their everyday lives. Consumers also expect to pay reasonable prices for the electricity that they use.

Meeting these customer expectations requires substantial effort and activity. While technology continues to develop and advance, electric markets can only store a portion of the electricity required to serve electric loads. Thus, the vast majority of electricity must be produced instantaneously as needed. Further, unlike most other markets, electricity's historically inelastic demand does not move with prices. To provide electricity on demand, electric system operations have to be planned and conducted with that goal in mind. In the absence of significant amounts of storage and price responsive demand, operators must plan and operate power plants and the transmission grid so that demand and supply exactly match, every moment of the day, every day of the year, in every location.

ECONOMIES OF SCALE

Electric power is one of the most capital-intensive industries. Generation, transmission and distribution require significant investment in capital intensive equipment, the costs of which are fixed. Spreading these significant fixed costs over more customers helps bring down the cost that each customer pays.

Thomas Edison's first street lighting project in the 1880s grew to electrifying whole neighborhoods, towns, and cities. Providing service over larger areas allowed utilities to take advantage of economies of scale and the cost per unit of production dropped as power plants grew larger and larger. The companies building these facilities were generally self-contained and not connected to each other. They owned and operated generation, transmission, and distribution facilities and were vertically integrated.

While successful for launching the electric utility industry, this market structure had limitations. The larger generating units were difficult to replace if they experienced unexpected shutdowns. As a result, the utilities held and maintained excess capacity in reserve (reserves) to ensure reliable electric service. These reserves were able to quickly replace electricity lost due to an unexpected shutdown or an unexpected increase in electric loads.

RESERVE SHARING

The solution to high reserve costs was to share reserves with adjacent utilities. Instead of building and maintaining all of the capacity required to provide energy and sufficient reserves, utilities were able to pool their reserves and could buy power from their neighbors in times of need cutting their costs significantly as a result. To facilitate reserve sharing, utilities built interconnecting transmission lines between their transmission systems to deliver electricity in the event of a generator outage or some other system disruption. Today's bulk power grid began as a way to maintain reliable service while lowering costs. The value of reserve-sharing agreements led to the formation of power pools, the forerunners of today's regional transmission organizations.

Coordinating exchanges of energy and reserves also led to closer coordination of other utility functions, such as the process of determining which generating units to use to serve electric loads. Operators want to commit just enough capacity to ensure reliability, but no more than is needed. Over time, this coordination ultimately led to the creation of regional transmission organizations that use markets to determine the set of resources to reliably serve electric loads at least cost. These wholesale electricity markets operate over large regions of the country.

Regional coordination also was spurred by special circumstances, particularly in the West. Large federally owned dams on the Columbia and Colorado river systems generate power from the spring runoff of melting mountain snow. When the reservoirs are full and hydroelectric plants are generating plentiful amounts

of power, there is not enough local demand to use the available supply. Since hydropower was cheaper than any alternative, long distance transmission lines were built to deliver the excess power from the Northwest and Southwest to load centers in California. With these transmission interconnections in place, northwestern utilities found that they could get cheaper power from southern power generation at other times of the year. These seasonal and regional disparities in availability and price introduced a lively bilateral trading market.

In the 1960s, the electric power industry created an informal, voluntary organization of operating staff to aid in coordinating the reliable operation of the bulk electric system. Then, in 1965, the largest power blackout until that time hit the northeastern United States and southeastern Ontario, Canada, affecting 30 million people. The blackout led to the development of the National Electric Reliability Council in 1968, shortly thereafter renamed the North American Electric Reliability Council (NERC), and nine regional reliability councils.[74] Rather than serving as a power pool or other entity for sharing reserves, NERC focused on reliability. In 2006, using authority granted in the Energy Policy Act of 2005 (EPAct 2005), FERC certified NERC as the electric reliability organization for the United States, and reliability standards became mandatory and enforceable.

ECONOMY ENERGY TRADE

Transmission interconnections between adjacent utilities were originally built for the primary purpose of delivering reserves in emergencies. However, this created excess transmission capacity, since these events were rare. The interconnections allowed utilities to trade power, which became profitable when the marginal cost of operating their generation was higher or lower than that of their neighbors. Transmission availability provided opportunities for utilities to save money by buying energy when it was cheaper than generating and selling energy to utilities with higher costs. This is called economy energy trading.

EVOLVING PUBLIC POLICIES

Evolving public policies, regulatory constructs and organizational structures shaped the electric power industry over its history. Five concepts that helped shape the electricity industry and markets are outlined below, and still affect the industry today.

REGULATED MONOPOLIES

In the early years of the industry, investors provided funds and took ownership shares in the power stations and electric distribution systems. These utilities became regulated – typically by state agencies – to overcome concern they were natural monopolies in the areas they served, lacking competition, and to bring stability to a capital-intensive industry. Stability came from granting exclusive service territories (or franchises), transparent financial statements, and the formulaic setting of electricity rates that were subject to regulatory oversight and approval. Over time, many of the utilities issued stock, which gave stockholders a share of the company's ownership, commonly referred to as investor-owned utilities (IOUs). The regulatory model for setting electricity rates was almost exclusively cost of service-based until about 30 years ago. Today, retail electric rate regulation is largely still based on cost-of-service, while wholesale electric rate regulation has become increasingly market-based. State regulators are responsible for approving retail rates, as well as utilities' investments in generation and distribution facilities. Some states eventually developed elaborate integrated resource planning (IRP) processes to determine what facilities should be built.[75]

NOT-FOR-PROFIT UTILITIES

Another approach to serving customers emerged in the form of nonprofit electric providers. In the early years of the industry, electrification started in towns and cities

74 In 2006, the North American Electric Reliability Council changed its name to the North American Electric Reliability Corporation (also referred to as NERC).

75 For additional background and context on the early years of the electrification of the U.S., National Museum of American History, *Powering a Generation of Change, Emergence of Electrical Utilities in America* (2002), http://americanhistory.si.edu/powering/past/h1main.htm.

where utility service was provided by municipal power agencies or city governments. The federal government also stepped in to develop and market electricity from the nation's significant hydroelectric resources. Finally, the Depression-era rural electrification program promoted customer-owned rural electric cooperatives and low-interest government loans. There are currently more than 1,700 municipal and almost 900 cooperative utilities in the United States.

POWER POOLS

Power pools are multilateral arrangements with members ceding operational control over their generating units and transmission facilities to a common operator. Members provide incremental cost data about their units and system status data to the operator. The operator then runs an energy management system that uses the unit cost data to optimize the overall unit commitment and economic dispatch.

The first of the power pools was PJM, which began in 1927 for utilities to share their generating resources. The Electric Reliability Council of Texas (ERCOT) and the Southwest Power Pool (SPP) formed in 1941 to pool resources for the war effort. Later, the New York Power Pool was formed in 1966 and the New England Power Pool in 1971, in response to the 1965 Northeast blackout.

COMPETITION, PART 1: COMPETITIVE GENERATION AND OPEN ACCESS

Environmental policy and initiatives to open the airline and trucking industries to competition helped shape the energy industry in the 1970s. A provision in President Carter's energy plan led to passage of the Public Utility Regulatory Policies Act of 1978 (PURPA), which ushered in the next era.

PURPA established a program implemented by states and overseen by FERC to encourage the use of efficient cogeneration (using the heat from industrial or other processes to generate electricity) and small-scale renewable generation. FERC's role was to issue regulations for the program and certify that qualifying facilities (QFs) met statutory requirements. States administratively set the price to be paid to these generators at the cost the utilities would avoid by purchasing the power rather than generating it themselves. Such prices are referred to as avoided-cost rates.

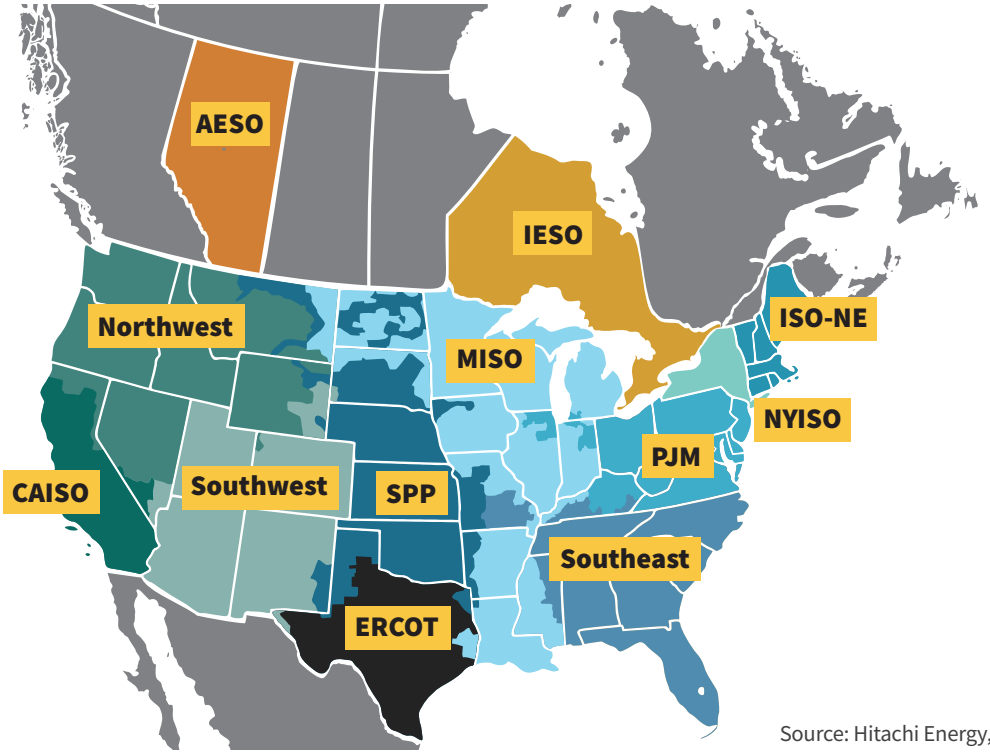
Most states set their avoided-cost rates so low that they got little QF capacity. However, California, Texas, and Massachusetts set relatively generous avoided-cost rates, and were overwhelmed with QF capacity, much of which received prices that turned out to be higher than the actual costs avoided by the purchasing utilities. The rapid growth and size of the QF industry surprised many policymakers and entrepreneurs and got them thinking about the viability of generation independent of regulated monopolies.

Under the original regulated monopoly model, utilities owned and operated the transmission lines with no obligation to allow others to use them. This posed a significant barrier to the development of an independent power industry. FERC started conditioning approval in merger cases on the utility's voluntary provision of open transmission access. The Energy Policy Act of 1992 gave FERC the authority to grant transmission access on request. These approaches to open access resulted in a patchwork of transmission access.

By the mid-1990s, support for opening the transmission grid to all users encouraged FERC to pursue a generic solution. FERC issued Order No. 888 in 1996 and required mandatory open transmission access by all transmitting utilities and a reciprocity provision successfully extended open access to non-jurisdictional entities (municipal, cooperative and federal utilities).

Order No. 889 addressed matters needed to implement open access. The rule established the Internet-based Open Access Same-Time Information System (OASIS) for posting available transmission capacity and reserving transmission capacity. These rules required significant changes to utility control room operations and limited the ability of companies to share transmission-related information with their own power marketing operating units.

Figure 2-1: North American Regional Transmission Organizations, Independent System Operators and Bilateral Regions



Source: Hitachi Energy, Velocity Suite

COMPETITION, PART 2: INTEGRATING MARKETS AND OPERATIONS – ISOS AND RTOS

While the industry had historically traded electricity through bilateral transactions and power pool agreements, Order No. 888 promoted the concept of independent system operators (ISOs). Along with facilitating open access to transmission, an ISO would operate the transmission system independently of wholesale market participants and foster competition for electricity generation. Several groups of transmission owners formed ISOs, some from existing power pools.

In Order No. 2000, FERC encouraged utilities to join regional transmission organizations (RTOs) which, like ISOs, would operate the transmission systems and develop innovative procedures to manage transmission equitably. FERC's proceedings in Order Nos. 888 and 2000, along with the efforts of the states and the industry, led to the voluntary formation of ISOs and RTOs. Each of the ISOs and RTOs subsequently developed full-scale energy and ancillary service markets in which buyers and sellers could bid for or offer generation. Both organizations use bid-based markets to determine economic dispatch. Throughout the subsequent sections of the primer, when referring to the organized RTO and ISO markets generally and collectively, the term RTO/ISO is used.

Major parts of the country operate under more traditional market structures, notably the West (excluding California) and the Southeast. Two-thirds of the nation's electricity load is served in RTO/ISO regions.

Electricity Demand

Americans consume electricity for an ever-increasing range of uses. While consumption has grown over the years, it varies annually based on many influences, such

as weather, economic activity, and other factors. Total generation at utility-scale facilities reached 4,108,303 gigawatt hours in 2021.[76]

Vertically-integrated IOUs, federal entities, municipally owned, and electric cooperatives sell the majority of electric generation to retail consumers. Additionally, some retail consumers generate all or part of the power that they consume. The rest of the electricity ultimately consumed by customers is bought and sold through wholesale electricity markets.

DEMAND CHARACTERISTICS

The amount of electricity consumed (demand) is continuously varying and follows cycles throughout the day and year. Regionally, electric demand may peak in either the summer or the winter. Spring and fall are considered shoulder months, with lower peak demand. Seasonal peaks vary regionally, although the highest levels of power load in almost all regions of the United States occur during summer heat waves, in the late afternoon. However, a minority of regions reach their peak load when the weather is extremely cold. These are primarily areas with significant space-heating requirements and little summer air conditioning load, such as the far northern areas of the United States.

Throughout the year, and in most locations, daily demand typically peaks in the late afternoon, as commercial and domestic activities peak, and in the winter, when lighting needs grow. Electricity use also varies between weekdays and weekends. Commercial and industrial activities are lower on weekends and peoples' noncommercial activities change with their personal schedules. The load on different weekdays can also show distinct usage. For example, Mondays and Fridays, being adjacent to weekends, may have different loads than Tuesday through Thursday. This is particularly true in the summer.

Since supply must rise and fall to provide exactly the amount of electricity customers need, the cost of providing power typically rises as demand grows and falls as demand declines. This is because higher levels of demand require activation of increasingly expensive sources of power generation, and reductions as demand declines. As a result, power prices are typically highest during periods of peak demand.

DEMAND DRIVERS

The amount of electricity demanded is insensitive to prices in the short-term. Electricity is a necessity to most people and businesses. While they may be able to reduce their demand in the short-term – by turning down the thermostat or turning off lights, for example – electricity consumers find it difficult to do without electricity altogether. Further, most customers – especially smaller customers – do not get price signals to which they can respond. A vast majority of residential customers are billed monthly on a preset rate structure. Large industrial customers, on the other hand, may receive real-time price signals.

In the longer-term, options for reducing electricity use include installing insulation and implementing other energy efficiency measures. Larger consumers may also consider building their own generation facilities.

As discussed below, utilities, at the direction of government, have developed demand-response programs, which can provide reduced rates or other compensation to customers who agree to reduce load in periods of electric system stress.

Climate and Weather

Weather is one of the primary factors affecting demand. General climatic trends drive long-term consumption patterns and therefore the infrastructure needed to ensure reliable service.

Weather also can have extreme short-term effects on electricity usage. A sudden cold snap can drive heating use up quickly and a heat wave can push up air conditioning loads. Other, less obvious weather patterns affect demand

76 Derived from EIA, *Electric Power Annual, Table 3.1.A* (released November 8, 2022), www.eia.gov/electricity/annual/html/epa_03_01_a.html.

– rain and wind, for example, may result in sudden cooling, affecting heating or air conditioning usage.

Economic Activity

The overall level of economic activity affects power demand. During periods of robust activity, loads increase. Conversely, loads drop during recessions. These changes are most evident in the industrial sector, where businesses and plants may close, downsize, or eliminate factory shifts. In addition to reducing overall demand, these changes affect the pattern of demand; for example, a factory may eliminate a night shift, cutting off-peak use but continue its use of power during peak hours. In some cases, these effects can be significant. For example, the COVID-19 pandemic changed how consumers used electricity as communities and companies implemented social distancing and stay-at-home measures to combat the spread of COVID-19 in the spring of 2020. Electricity demand shifted from commercial and industrial uses to residential consumption. Overall, electricity demand in the U.S. dropped about 4% in 2020, as commercial and industrial demand dropped 6% and 8%, respectively, and residential demand rose 1%.[77]

Energy Policies and Regulations

State regulatory agencies, such as public utility commissions, oversee retail electric rates and set policies affecting retail customer service. Some states allow utilities to offer retail rate structures that enable customers to receive more accurate price signals. They include, among other things, rates that vary with the time of day and the cost of providing electricity.

Efforts to reduce overall demand by improving energy efficiency are also supported by governmental and utility programs. These include rebates for the purchase of energy efficient appliances and home improvements, as well as capacity market payments for load reductions, also known as demand response, that are made available in certain markets.

Quick Facts: *Heating and Cooling Degree Days*

In the United States, engineers developed the concept of heating and cooling degree days to measure the effects of temperature on demand. Average daily temperatures are compared to a 65°F standard - those in excess of 65° yield cooling degree days; those below 65° yield heating degree days. For example, a day with an average temperature of 66° would yield one cooling degree day.



Retail Customer Mix

Most electric utilities serve three distinct classes of customers: residential, commercial, and industrial. Each class uses electricity differently, resulting in a differing load profile, or the amount of energy each customer class uses throughout the day. If a consumer uses electricity consistently throughout the day and seasons, the load shape is flat. Another consumer may use more at some times than others. More variable demand is typically more expensive to serve, especially if the peak occurs at the same time as other customers' use peaks. Consequently, the mix of customer types affects a region's overall demand and costs.

77 EIA, *Short-Term Annual Outlook*, at 3 (January 2020).

Residential consumers form one of the top two customer segments in the United States at approximately 39 percent of electricity demand in 2021. Residential consumers use electricity for air conditioning, refrigerators, space and water heating, lighting, washers and dryers, computers, televisions, and other appliances. Prices for residential service are typically highest, reflecting both residential customers' load shape and their service from lower-voltage distribution facilities, meaning that more power lines and related assets are needed to provide service to them.

Commercial use, the next largest customer segment, represented approximately 35 percent of electricity demand in 2021.[78] This customer segment includes office buildings, hotels and motels, restaurants, street lighting, retail stores, wholesale businesses, and medical, religious, educational, and social facilities. More than half of commercial consumers' electricity use is for heating and lighting.

Industrial consumers use about 26 percent of the nation's electricity.[79] This customer segment includes manufacturing, construction, mining, agriculture and forestry operations. Industrial customers often see the lowest rates, reflecting their relatively flat load profile and their ability to take service at higher voltage levels.

Transportation demand for electricity stems primarily from trains and urban transportation systems. This is less than 1 percent of total electricity demand.[80] However, state and federal policies that advance electrification of the transportation fleet are expected to increase electric load growth in the near future.

LOAD FORECASTING

Demand is constantly changing, which challenges grid operators and suppliers who are responsible for ensuring that supply will meet demand at all times. Consequently, they expend considerable resources to forecast demand.

Load forecasting uses mathematical models to predict demand across a region, such as a utility service territory or an RTO/ISO footprint. Forecasts can be divided into three categories: short-term forecasts, which range from one hour to one week ahead; medium-term forecasts, usually a week to a year ahead; and long-term forecasts, which are longer than a year. It is possible to predict the next-day load with an accuracy of approximately one to three percent of what will actually happen. The accuracy of these forecasts is limited by the accuracy of the weather forecasts used in their preparation and the uncertainties of human behavior.

The forecasts for different time horizons are important for different operations within a utility company. Short-term load forecasting can help to estimate transmission system power flows and to make decisions that can prevent overloading of transmission systems. Timely implementation of such decisions leads to the improvement of network reliability and to reduced occurrences of equipment failures and blackouts. Forecasted weather parameters are the most important factors in short-term load forecasts, with temperature and humidity as the most commonly used load predictors.

The medium- and long-term forecasts take into account historical load and weather data, the number of customers in different customer classes, appliances used in the area and their characteristics, economic and demographic data, and other factors. For the next-year peak forecast, it is possible to provide an estimated peak load based on historical loads and weather conditions. Long-term forecasts extending 10 to 20 years into the future are used for system infrastructure planning and are meant to ensure that there are sufficient resources available to meet the needs of the expected future peak demand.

Forecasts are necessary for the variety of actions that must occur to ensure that sufficient supply is available in the immediate and long term. These include the

78 Derived from EIA, *Electric Power Annual, Table 2.5* (November 7, 2022), www.eia.gov/electricity/annual/html/epa_02_05.html.

79 *Id*.

80 *Id*.

planning of long-term infrastructure, purchasing fuel and other supplies, and ensuring adequate staffing of specific personnel. Load forecasts are also extremely important for suppliers, financial institutions, and other participants in electric energy generation, transmission, distribution, and trading. Missed forecasts, when actual demand differs significantly from the forecast, can cause wholesale prices to be significantly higher or lower than they otherwise might have been.

DEMAND RESPONSE

Electricity demand is generally insensitive to price, meaning that demand does not typically fall when prices rise. This occurs for several reasons, including that most end-use consumers of electricity are not exposed to real-time electricity prices. However, some utilities and grid operators have developed ways to stimulate a response from consumers through demand-response programs.

Demand response is the reduction in consumption of electricity by customers from their expected consumption levels, in response to either reliability needs or price signals. Customers will forego power use for short periods, shift some energy use from peak periods to other times, or use on-site generation in response to price signals or incentives for load reduction. The signals to respond to electric power system needs or high market prices may come from a utility or other load-serving entity, an RTO/ISO, or an independent provider of demand response. Both retail and wholesale entities administer these programs. Demand response has the potential to lower system-wide power costs and assist in maintaining reliability. It can also mitigate system stress and allow operators to resolve shortages, avoid operating inefficient power plants, or relieve transmission congestion. There can also be environmental benefits, such as lower levels of power plant-related emissions that result from not operating peaking units.

Measuring and verifying the amount of reduced consumption during a demand response activation requires development of consumers' baseline usage, against which their actual use is measured.

Demand-Response Programs

Programs generally fall into three categories: curtailing, shifting, or on-site generation.

Curtailing, or forgoing, involves reducing power use (load) during times of high prices or threats to reliability without making up the use later. For example, residential customers might turn off lights or raise thermostats during hot weather. Commercial facilities may turn off office equipment, lower building lighting or change thermostat settings by a few degrees.

Shifting involves moving or rescheduling high energy-use activities in response to high prices or demand response program events to off-peak periods – evenings, nights, or weekends. Industrial customers might reschedule batch production processes to evening hours or the next day. Commercial establishments may delay high-energy operations. Residential customers may wait until evening or night to use high energy consuming appliances, such as clothes dryers or dishwashers. In shifting, the lost amenity or service is made up at a subsequent time.

On-site generation is when customers respond by turning on an on-site or backup emergency generator to supply some or all of their electricity needs. Although these customers may have little or no interruption to their electrical usage, their net load and requirements from the power system are reduced. The ability to use on-site generation is most common for institutional customers, such as hospitals, large schools, or data centers.

Demand response programs can be further distinguished by whether they are controlled by the system operator (dispatchable) or the customer (non-dispatchable). Dispatchable demand response refers to programs where the system operator can direct the customer to reduce its energy use, such as direct load control of residential appliances or directed reductions to industrial customers. Dispatchable demand response programs can be used for both reliability and economic reasons. Non-dispatchable demand response lets the retail customer decide whether and when to reduce

consumption in response to the price of power. This includes time-sensitive pricing programs that are based on rates that charge higher prices during high-demand hours and lower prices at other times.

As a result of technological innovations and policy directions, new types and applications of demand response are emerging that encompass the use of smart appliances that respond in near real-time to price or other signals. These models may allow customers to respond more easily, as they require little customer monitoring or interaction.

Retail Demand Response Programs

Utilities and third-party aggregators offer a variety of demand response programs that include time-based rates and interruptible contracts. Also, some states mandate energy efficiency resource standards that include peak load reduction targets.

Time-based rates include time-of-use rates and dynamic pricing. Time-based rates depend on advanced meters at customer premises that can record usage over short increments, typically groupings of hours or individual hours. In time-of-use programs, customers are charged different prices at different times of the day, with hours on or near peak demand costing more than off-peak hours. Dynamic pricing is a category of programs where rates change frequently to better reflect system costs. The practice of adjusting prices as costs change provides an incentive for consumers to shift load to other periods or to reduce peak load. One form of dynamic pricing is termed real-time pricing. In these programs, customers are charged prices reflecting the immediate cost of power. Industrial or very large commercial customers are the most likely to choose real-time tariffs.

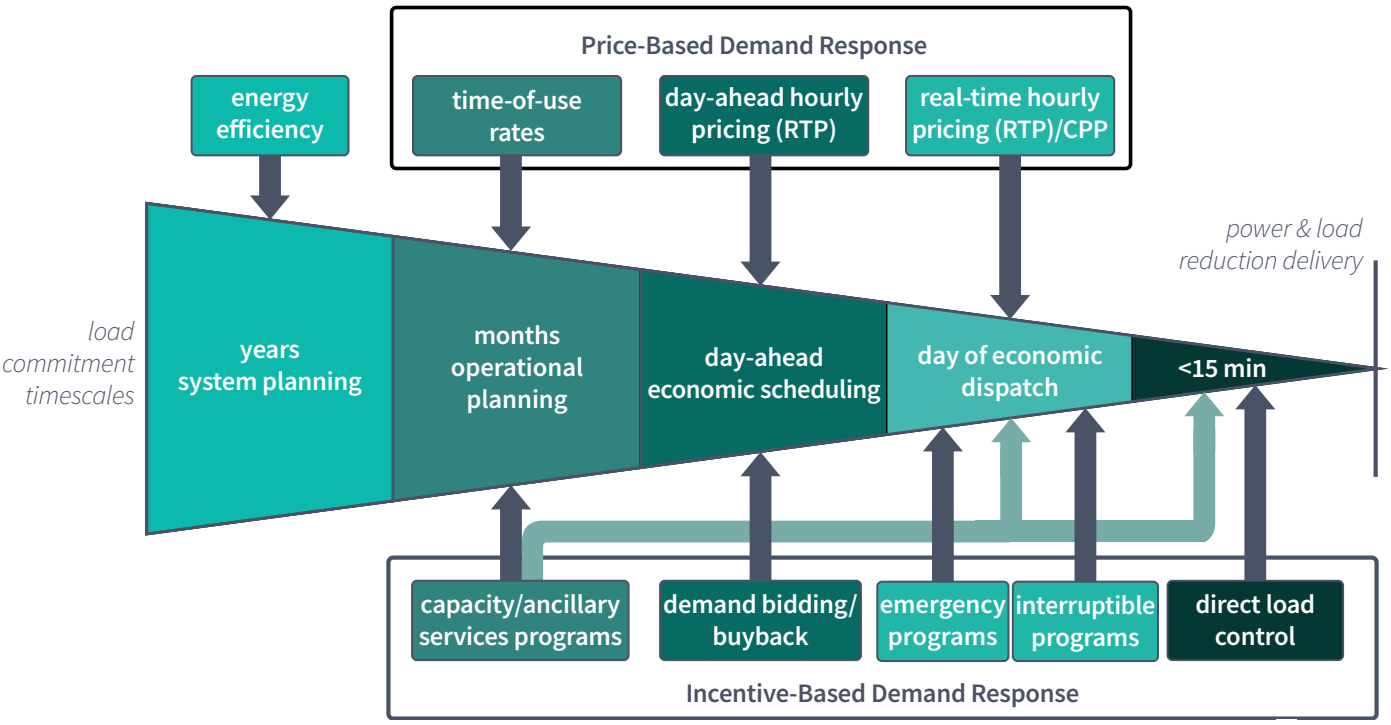
Another form of dynamic pricing is critical peak pricing. These programs use real-time prices at times of extreme system peak but are restricted to a limited number of hours annually. They feature higher prices than time-of-use prices during the critical peak. Consumers do not know in advance when a critical peak might be called. Critical peak programs for residential customers typically use rebates as an incentive to participate in the program, but customers take the risk of paying higher prices or reducing load during critical peak periods. These programs seek to have customers respond to price signals, as opposed to penalizing them, if they do not lower their use in the critical peak hours.

Interruptible contracts are used by utilities to control load and address potential reliability issues, such as reducing stress on the electric system during heat waves. The two primary forms of this category of demand response are direct load control and interruptible rates. Direct load control entails the utility curtailing a portion of customer load as described above. Under interruptible rates, customers agree to turn off equipment or switch their energy supply to an on-site generator.

Energy efficiency resource standards exist in 25 states, while five states and the District of Columbia. have energy efficiency goals.[81] The standards typically require utilities to achieve electric energy savings, and many include peak load reduction targets. These mandates provide incentives for utilities to reduce customers' energy consumption and include mechanisms that decouple profits from the amount of electricity sold or performance bonuses for utilities that meet or exceed reduction targets.

81 DSIRE, N.C. Clean Energy Technology Center, *Energy Efficiency Resource Standards (and Goals)* at 1 (September 2021), https://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2021/09/Energy-Efficiency-Resource-Standards_Sept-2021.pdf.

Figure 2-2: Demand Response and Energy Efficiency in Electric System Planning and Operations



Source: U.S. Department of Energy[82]

Wholesale Market Demand Response Programs

On the wholesale level, market operators have some programs that dispatch the demand response resources. Other demand response programs are dispatched by the utilities or aggregators that sponsor the programs, rather than the market operator. Note that with most retail demand response programs, which can also aid wholesale markets, market operators may not be able to invoke them or even see the specific amount of response that occurs.

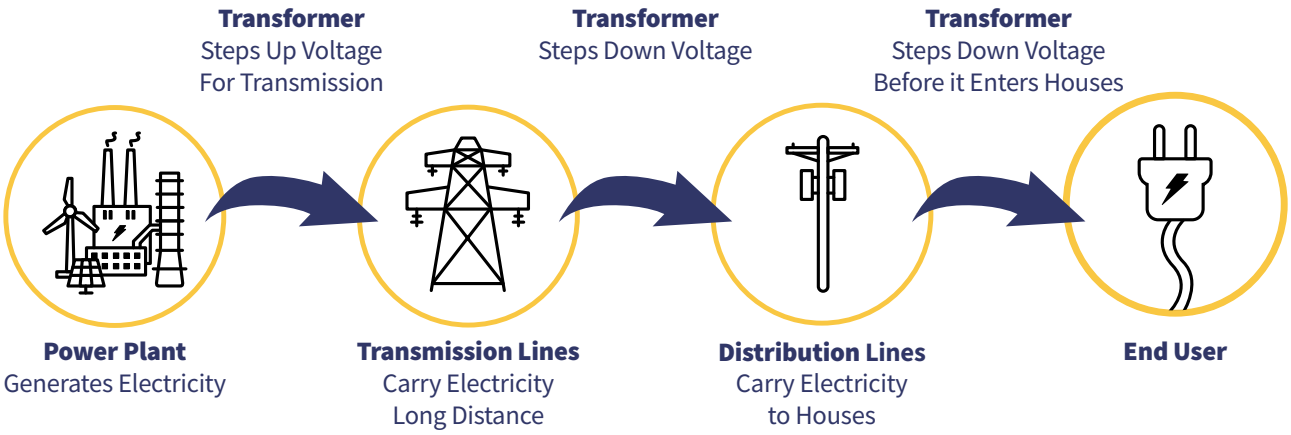
Demand response participation in RTO/ISOs has been encouraged in U.S. national energy policy and by various FERC orders.[83] Overall, approximately 30.8 GW of demand response participated in RTOs/ISOs in 2020.[84] These resources primarily participate in RTO/ISOs as capacity resources and receive advance reservation payments in return for their commitment to participate when called upon or activated. Additionally, demand resources may offer into the RTO/ISO day-ahead markets, specifying the hours, number of MWs and price at which they are willing to curtail.

82 U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005*, at 15, (2006), https://www.energy.gov/oe/articles/benefits-demand-response-electricity-markets-and-recommendations-achieving-them-report.

83 EPAct 2005 included policy encouraging time-based pricing and other forms of demand response and the elimination of barriers to demand response participation in the energy, capacity, and ancillary services markets. Examples of FERC orders include Order No. 719, 128¶61,059, (July 16, 2009); Order No. 745, 134¶61,187 (March 15, 2011); and Order No. 2222, 174¶61,197, (March 18, 2021).

84 *See* FERC, *Assessment of Demand Response and Advanced Metering Staff Report,* at 3 (December 2021), https://www.ferc.gov/media/2021-assessment-demand-response-and-advanced-metering.

Figure 2-3: Electricity Supply and Delivery



Source: The NEED Project[85]

Some of the RTO/ISO demand response comes from individual entities; the rest is accumulated through third-party aggregators, or curtailment service providers, who recruit customers too small to participate on their own, such as schools, commercial chains or groups of residential customers. In aggregating small customers, curtailment service providers have increased customer participation in many wholesale reliability and emergency programs.

Demand Response and Energy Efficiency in Planning and Operations

Different demand response programs can be used at various times to support planning and operations (see Figure 2-2). Energy efficiency programs that reduce baseload or peak demand over the long-term are incorporated into system planning. Dispatchable programs that are quickly implemented and targeted for short-term peak reductions – such as direct load control – lie on the other end of the spectrum and are used in the moment of operation.

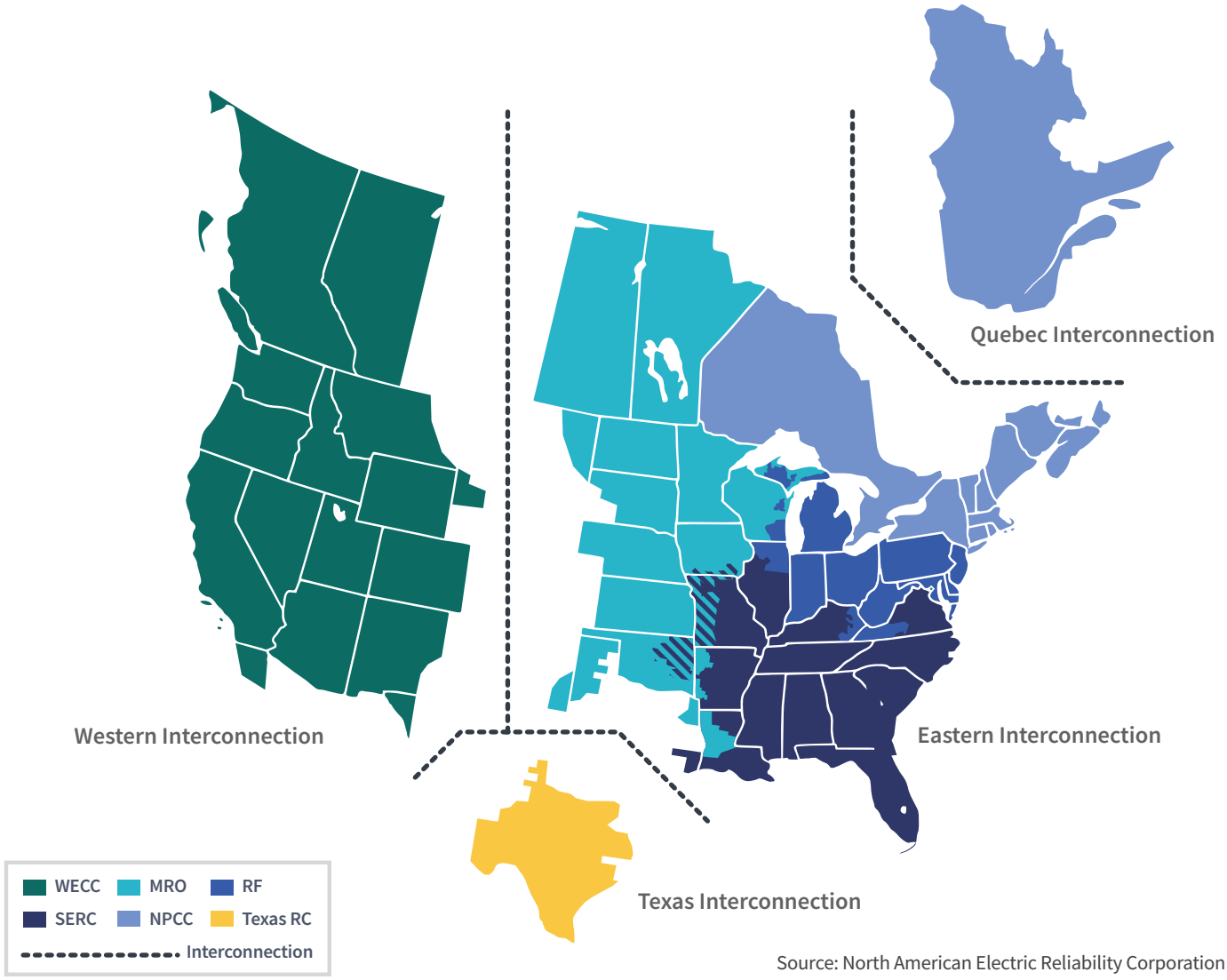
Electricity Supply and Delivery

Unlike many other products, electricity cannot be stored in any appreciable quantity relative to the total consumed across the country each day. Further, electricity is a necessity for most consumers, whose use responds little to price changes. Finally, electric equipment and appliances are tuned to very specific standards of power, measured as voltage and frequency. For example, deviations in voltage can cause devices to operate poorly or may even damage them. Consequently, the supply side of the electricity market must provide and deliver exactly the amount of power customers want at all times, at all locations. This requires constant monitoring of the grid and close coordination among industry participants.

Electricity service relies on a complex system of infrastructure that falls into two general categories: generation and delivery services of transmission and distribution. Together, the power generation and high-voltage transmission lines that deliver power to distribution facilities constitute the bulk power system. Transmission and distribution facilities are also referred to as the power grid. These are coordinated, and at times operated by, a grid coordinator.

85 National Energy Education Development Project, *Electricity,* at 56 (2017), http://www.need.org/Files/curriculum/infobook/Elec1S.pdf.

Figure 2-4: North American Electric Reliability Corporation Regions



Source: North American Electric Reliability Corporation

Nationally, the grid is geographically split into three main sections – the Western, Eastern and Texas Interconnections. These sections operate independently and have limited interconnections between them.

The nation, along with Canada and a small part of Mexico, is also divided into regional entities for reliability purposes. The regional reliability entities fall under the purview of North American Electric Reliability Corporations (NERC), which was designated by FERC as the nation's electric reliability organization, and which develops and enforces mandatory reliability standards to better ensure the reliable operation of the nation's bulk-power system (the interconnected transmission grid). The reliability standards, once approved by FERC, must be met by applicable industry participants as designated in each reliability standard. Consequently, the grid is planned and operated to meet these standards.

NERC's regions include:

- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability First Corporation (RFC)
- SERC Reliability Corporation (SERC)
- Texas Reliability Entity (TRE)
- Western Electricity Coordinating Council (WECC)

FERC JURISDICTION

Under the Federal Power Act (FPA), FERC regulates the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce. The FPA requires that every public utility file with FERC all rates and charges for any transmission or sale subject to the jurisdiction of FERC. Under Sections 205 and 206 of the FPA, 16 U.S.C. §§ 824d, 824e, FERC ensures that the rates and charges made, demanded, or received by any public utility for, or in connection with, the transmission or sale of electric energy subject to the jurisdiction of FERC, and all rules and regulations affecting, or pertaining to, such rates or charges are just and reasonable and not unduly preferential or unduly discriminatory.

GENERATION

Power generators are typically categorized by the fuel that they use and subcategorized by their specific operating technology. In 2021, the United States had approximately 1,218 GW of total generating capacity.[86] The majority of power generation is produced from coal, natural gas, nuclear fuels, and renewables.

Power plants each have differing costs and operational characteristics, both of which determine when, where and how plants will be built and operated. Plant costs fall into two general categories: capital investment costs, which are amounts spent to build the plant, and operational costs, the amounts spent to maintain and run the plant. In general, there is a trade-off between these expenses: more capital-intensive plants tend to be cheaper to run – they have lower variable costs – and, conversely, the least capital intensive plants tend to be more expensive to run – they have higher variable cost. For example, nuclear plants produce vast amounts of power at low variable costs but are expensive to build. Conversely, natural gas-fired combustion turbines are far less expensive to build but can be more expensive to run. Grid operators dispatch plants – or call them into service – with the simultaneous goals of providing reliable power at the lowest cost. Because various generation technologies have differing variable costs, plants are dispatched only when they are part of the most economic combination of plants needed to supply the customers on the grid. For plants operating in RTOs/ISOs, this cost is determined by the price that generators offer. In other areas, it is determined by the marginal cost of the available generating plants.

CONVENTIONAL GENERATION

Generation is often described as conventional or renewable (described further in the Renewable Generation section below). Conventional generation typically includes natural gas-, oil-, coal- or nuclear-powered generation.

Natural Gas-Fired Generation

Natural gas power plants consist of three major technologies, each with its distinct set of market advantages and limitations. They are steam boilers, gas turbines and combined cycle generators. Natural gas fuels nearly a third of U.S. electricity generation.

Steam boiler technology is an older design that burns gas in a large boiler furnace to generate steam at both high pressure and high temperature. The steam is then run through a turbine that is attached to a generator, which spins and produces electricity. Typical plant size ranges from 300 MW to 1,000 MW. Because of their size and the limited flexibility that is inherent in the centralized boiler design, these plants require fairly long start-up times to become operational and are limited in their flexibility to produce power output beyond a certain range. Furthermore, these plants are generally not as economical or easy to site as some newer technologies – which explains why few have been built in recent years.

86 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), https://www.eia.gov/electricity/data/eia860m/.

Gas turbines (GT) are small, quick-start units similar to an aircraft jet engine. These plants are also called simple cycle turbines or combustion turbines (CT). GTs are relatively inexpensive to build but are expensive to operate because they are relatively inefficient, providing low power output for the amount of gas burned, and have high maintenance costs. They are not designed to run on a continuous basis and are used to serve the highest demand during peak periods, such as hot summer afternoons. GTs also run when there are system-wide shortages, such as when a power line or generator trips offline. GTs typically have a short operational life due to the wear-and-tear caused by cycling. The typical capacity of a GT is 10-50 MW, and they are usually installed in banks of multiple units.

Combined cycle power plants (CCPPs) are a hybrid of the GT and steam boiler technologies. Specifically, this design incorporates a gas-combustion turbine unit along with an associated generator, and a heat recovery steam generator along with its own steam turbine. The result is a highly efficient power plant. They produce negligible amounts of SO2, and particulate emissions and their NOx and CO2 emissions are significantly lower than a conventional coal plant. CCPPs, on average, require 80 percent less land than a coal-fired plant, typically 100 acres for a CCPP versus 500 acres for comparable coal plant, and CCPPs also use modest amounts of water compared to other technologies.

Coal-Fired Generation

Coal plants produced approximately 22 percent of the electricity in the United States in 2021.[87] These facilities generate power by creating steam which is used to spin a very large turbine. These plants tend to be used as baseload units, meaning that they run continuously and are not especially flexible in raising or lowering their power output. They have high initial capital costs, with complex designs and operational requirements. However, coal plants have low marginal costs and can produce substantial amounts of power. Most of the coal-fired plants in the United States are located in the Southeast and Midwest.

Oil-Fired Generation

Oil plants generally produce only a small amount of the total electricity generated in the U.S. power markets. These facilities are expensive to run and also emit more pollutants than natural gas plants. They are frequently uneconomic and typically run at low-capacity factors. Like natural gas-fired generators, there are several types of units that burn oil; primarily, these are steam boilers and combustion turbines. Most dual-fuel power plants are located in the eastern half of the United States, especially on the East Coast.[88]

Generally, two types of oil are used for power generation: number 2 and number 6 (bunker) fuel oil. Number 2 is a lighter and cleaner fuel. It is more expensive, but because it produces fewer pollutants when burned, it is better for locations with stringent environmental regulations such as major metropolitan areas. Conversely, number 6 fuel oil is cheaper, but considered dirty because of its higher emissions. It is highly viscous (thick and heavy), and it comes from the bottom of the barrel in the refining process.

Nuclear Generation

Nuclear plants provided roughly 19 percent of the nation's electricity in 2021, when 93 nuclear plants operated in the United States with a total capacity of approximately 100 GW.[89] Like generating units that use coal, nuclear plants tend to be large, baseload units that run continuously. Nuclear plants have high capital and fixed costs, but low variable costs, which includes fuel cost. They typically run at full power for 18 or 24 months, which is the duration of a unit's fuel cycle, and are then taken offline for refueling and maintenance. Outages

87 EIA, *Electric Power Annual* (November 7, 2022), *Generation at Utility Scale Facilities*, *Tables 3.1A. and 3.1.B*, (accessed December 2022), www.eia.gov/electricity/annual/html/epa_01_02.html.

88 Derived from Hitachi Energy, Velocity Suite data (Accessed March 28, 2023).

89 EIA, *Form EIA-860* (November 2022), www.eia.gov/electricity/data/eia860/.

typically last from 20 days to significantly longer, depending on the work needed. Of the 92 operating nuclear plants, most reside in the eastern United States. Only six are in the West, four in Texas. Illinois had the largest number of plants at 11, followed by Pennsylvania at eight, and South Carolina at seven.[90]

RENEWABLE GENERATION

Renewable resources use fuels that are naturally replaced, such as wind, solar, hydroelectric and geothermal or which use fuels that are readily replaceable, such as biomass and biogas.

Such generation (generation termed renewable generation or renewables) is an increasingly important part of total U.S. supply, accounting for 29 percent of electric energy produced in 2021.[91] As total generation from all fuels has remained relatively constant in recent years, renewable generation's share has risen, spurred by technological advancements, state policy, and federal tax credits.[92]

Wind and solar capacity have grown faster than other renewable resources in recent years. Wind capacity grew substantially, from approximately 10 GW in 2006 to 193 GW in 2021.[93] Utility-scale solar capacity grew even faster, from approximately 0.1 GW to 61 GW over the same period. [94]

Additions of renewable generation capacity are usually reported in megawatts of nameplate capacity. Actual capability varies from the nameplate for any unit type due to such factors as age, wear, maintenance and ambient conditions. But as renewable resources are often weather-dependent, their capacity factors – the ratio of average generation to the nameplate capacity for a specific period – have been lower (for example, approximately 30 percent), depending on the technology type, than for fossil-fuel generation. Grid operators pay close attention to the difference between nameplate and capacity factor values when they evaluate capacity available to cover expected load, however, capacity factors have risen with technological innovation and improved manufacturing processes.

Wind

Wind generation is among the fastest-growing renewable resource, in part due to cost declines and technology improvements, as well as receipt of federal tax credits. Increases in average hub heights and rotor diameters have increased average wind turbine capacity. Because the best wind resources are often located far from load centers, obtaining sufficient transmission presents a challenge to delivering wind output. Other market challenges for future wind development include its variable output, which is often inversely correlated to demand (seasonally and daily); system operators' limited ability to dispatch wind resources to meet load increases; difficulties related to accurately forecasting its ramping; and the need for companion generation (usually fossil-fueled) or energy storage to be available to balance wind generation when the wind is not blowing.

Solar

Solar generation transforms sunlight into electricity using one of two technologies: photovoltaic (PV) or concentrating solar power (CSP). PV modules, or panels, transform sunlight directly into power using cells made of silicon or thin-film materials. They can be installed on roofs of buildings or at ground-level PV farms. CSP plants use a two-step process to transform the sun's energy. First, mirrors direct sunlight towards a receiver that captures

90 EIA, *Form EIA-860M* (February 2023), www.eia.gov/electricity/data/eia860M/.

91 Derived from EIA, *Electricity Annual* (September 2022), www.eia.gov/electricity/annual/html/epa_01_01.html.

92 Lawrence Berkeley National Lab, *U.S. State Renewables Portfolio and Clean Electricity Standards: 2023 Status Update* (June 2023), https://eta-publications.lbl.gov/sites/default/files/lbnl_rps_ces_status_report_2023_edition.pdf.

93 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), https://www.eia.gov/electricity/data/eia860m/.

94 *Id.*

the heat. CSP then employs a thermal process to create steam, driving an engine or turbine to produce electricity. CSP plants, which are dispatchable, can include low-cost energy storage that extends their availability later in peak hours. PV growth has increased greatly as a result of policy incentives and cost declines. Total PV generation for 2021 was 161.5 GW, with approximately two-thirds of that generation coming from utility-scale facilities and one-third from small-scale generation.[95]

By the end of 2021, 1.5 GW of CSP was operational – a decline from 2017 when CSP capacity was 1.8 GW.[96] Total CSP capacity is significantly lower than PV owing to PV's lower costs.[97] Seven western and southwestern states have extensive CSP potential: Utah, New Mexico, Arizona, Nevada, Texas, California and Colorado.[98] Developing that potential will require overcoming challenges of cost, siting, transmission, and the need for extensive water supplies to clean mirrors.

Hydroelectric

Hydroelectric generation is powered by the kinetic energy of falling water that drives turbine generators, which convert the energy into electricity. There are two types of hydroelectric projects: conventional and pumped storage. Conventional projects, which use a dam in a waterway, can operate in a run-of-river mode, in which water outflow from the project approximates inflow, or in a peaking mode, in which the reservoir is mostly drained to generate power during peak periods when energy is more valuable. Pumped storage projects use bodies of water at two different elevations. Water is pumped into elevated storage reservoirs during off-peak periods when pumping energy is cheaper; the water is then used to generate power during peak periods as it flows back to the lower elevation reservoir. In 2021, total U.S. hydro-electric capacity (including conventional and pumped-storage capacity) reached 246 GW. Conventional hydro-electric capacity was 285.3 GW and pumped storage hydro-electric capacity was 5.1 GW.[99]

Geothermal

Geothermal generation taps into reservoirs of steam and hot water deep beneath the earth's surface to produce power. The majority of the plants are based in California and Nevada. Geothermal potential is determined by thermal conductivity, thickness of sedimentary rock, geothermal gradient, heat flow and surface temperature. Geothermal generation, which stood at 16 GW in 2021, increased from 0.6 GW in 2011, but has decreased as a portion of total renewable output, due to the growth of other renewables. California hosts about 76 percent of geothermal U.S. operating capacity.[100]

Biomass

Biomass generation includes power production from many waste byproducts, such as agricultural residues, landfill gas, municipal solid waste, and wood resources. The largest biomass category is wood waste, burned for heat and power in the lumber, pulp and paper industries. Challenges to biomass production include impacts on food supplies (for example, converting corn into ethanol), conserving natural resources, and minimizing water pollution. In 2021, net utility-scale power generation using biomass fuel sources was 54.3 GWh - composed of 36.5 GWh from wood and wood-derived fuels as well as 17.8 GWh from other biomass sources.[101]

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95 Derived from EIA, *Electric Power Annual, Tables 3.1.A. and 3.1.B* (released November 7, 2022 and accessed December 2022), www.eia.gov/electricity/annual/html/epa_01_02.html.

96 Derived from EIA, See table 4.3 in *Electric Power Annual 2021 and Electric Power Annual 2017*, www.eia.gov/electricity/annual/html/epa_04_03.html and www.eia.gov/electricity/annual/archive/pdf/03482017.pdf.

97 *See* National Renewable Energy Laboratory, *Annual Technology Baseline* (July 2018), https://atb.nrel.gov/electricity/2018/summary.html

98 EIA, *Form EIA-860*, (September 13, 2018), https://www.eia.gov/electricity/data/eia860/.

99 Derived from EIA, *Electric Power Annual* (November 7, 2022), *Generation at Utility Scale Facilities, Tables 3.1.A and 3.1.B* (accessed December 2022), www.eia.gov/electricity/annual/html/epa_01_02.html.

100 Derived from EIA, *Form EIA-860* (accessed November 2017), https://www.eia.gov/electricity/data/eia860/.

101 *Id.*

Biogas

Biogas energy is created through the anaerobic (without oxygen) bacterial decomposition of biodegradable waste, which is turned into a gas containing 60-70 percent methane. Biogas recovery is typically installed at farms and used to run farm operations and reduce methane emissions from natural manure decomposition.

Renewable Energy Policies

Renewable generation development is frequently tied to policies promoting their use, which include tax credits, low-cost loans, rebates and production incentives. Federal funding of research and development has played an important role in lowering the costs or reducing the time it takes for renewable technologies to become commercially viable.

Congress has provided tax incentives to spur renewable resource investments. Originally enacted in 1992, federal production tax credits (PTC) are available for wind, biomass, geothermal, and other forms of renewable generation based on a facility's production. An inflation-adjusted credit, the PTC generally has a duration of 10 years from the date the facility goes online. The PTC has been revised several times, most recently in August 2022 under the Inflation Reduction Act, which extended the PTC for projects that begin construction before 2025, including solar projects that had previously been excluded from the PTC program.[102] After 2024, the PTC becomes technology neutral and emission based, and phases out starting in 2032, or when the U.S. electricity sector emissions are 75% below 2022 levels. If projects over 1 MW meet certain labor requirements, their PTC is 2.6 c/kWh; if the projects do not meet the labor requirements, the PTC would be 0.3 c/kWh. A further 10% adder on the PTC and ITC can be obtained if a project uses U.S. steel and roughly half the of manufactured components (as measured by cost) are sourced in the United States.

Another form of tax credit for renewables, including solar and other types of projects, has been a federal investment tax credit (ITC). The ITC has generally been set at 30 percent of a project's equipment and construction costs. The Inflation Reduction Act also revised the ITC, with the same terms as for the PTC. Projects meeting labor requirements may receive a 30% ITC, otherwise the ITC drops to 6%. Projects may also receive a 10% increase in the ITC if they use U.S. components, as described for the PTC.

State renewable portfolio standards (RPS) and renewable energy standards (RES) have been significant drivers in the growth of investment in renewable generation. An RPS requires a certain percentage of energy sales measured by megawatt-hours (MWh) to come from renewable resources. Percentages usually increase incrementally from a base year to an ultimate target. Currently, 30 states plus Washington, D.C., have an RPS with financial penalties for non-achievement.[103] As utilities and independent developers build more renewable-powered generation, the markets in which they participate continue to address the integration of renewable output into their day-ahead and real-time operations, and incorporate the expected growth of renewable generation in their long-term transmission-planning processes.

Renewable energy certificates (RECs) allow state regulators to track compliance with mandatory RPS targets or verify progress in voluntary state renewable programs. They also allow compliance entities to purchase credits – subject to state-imposed limits on amount and price – if they have not generated or bought enough renewable energy to meet their annual requirements.

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102 Congress.gov, *H.R. 5376-Inflation Reduction Act of 2022*, (became law August 4, 2022) https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

103 Barbose, Galen. Lawrence Berkeley National Laboratory, *U.S. Renewables Portfolio Standards: 2021 Status Update: Early Release* (February 2021), https://eta-publications.lbl.gov/sites/default/files/rps_status_update-2021_early_release.pdf.

ELECTRIC STORAGE

Historically, utility-scale storage of electricity for later use had been limited to pumped-hydro storage facilities. Recent advances in technology have made other types of electric storage resources, including batteries and flywheels, more economically feasible. The lower costs and improved capabilities of electric storage, along with favorable state and federal policies, increased penetration of variable energy resources, and a continued focus on grid reliability have helped spur the development of electric storage resources.[104]

As of 2021, the combined capacities of utility-scale electric storage and battery storage represented less than 2 percent of total generating capacity in the United States.[105] The majority of storage capacity consists of pumped-hydro storage (21 GW in 2021), which has grown very slowly. Battery storage capacity, in contrast, has grown from 3 MW in 2016 to 4,482 MW in 2021.[106] EIA projects that total U.S. battery storage capacity could reach 30 GW by 2025.[107]

Electric storage projects are increasingly available to help balance supply and demand particularly during periods of high demand or excess supply. These resources can charge during periods of low demand or excess generation, when electricity is less expensive, and discharge when demand is high and electricity is more expensive. Batteries, flywheels, and other fast-acting electric storage technologies can also provide ancillary services which help maintain grid reliability. The vast majority of battery storage capacity in the electricity markets is used to provide ancillary services or capacity, because these applications provide the most revenue for storage owners.[108]

Some states have passed legislation to incentivize investment in storage projects. In 2013, California adopted targets for utilities to procure 1,325 MW of energy storage capacity by 2024 and subsequently increased the capacity requirement target and compressed the timeline for reaching that target.[109] As of May 2021, five states besides California also set energy storage requirements or targets: Oregon, Massachusetts, New York, New Jersey and Virginia. Additionally, some states which do not have formal energy storage requirements offer financial incentives such as grants and tax incentives, while others have begun requiring utilities to include storage in integrated resource plans.

DISTRIBUTED ENERGY RESOURCES

In Order No. 2222, the Commission defined Distributed Energy Resources (DERs) as any resource located on the distribution system, any subsystem thereof or behind a meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment.[110] In most instances, these resources are located close to the

104 FERC has issued various orders to help remove barriers to the participation of electric storage resources in FERC-jurisdictional markets. *See, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, *Order No. 841, 162 FERC ¶61,127 (2018); Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 2222*, 172 FERC ¶ 61,247 (2020).

105 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), https://www.eia.gov/electricity/data/eia860m/.

106 *Id.*

107 EIA, *U.S. battery storage capacity will increase significantly by 2025* (December 8, 2022), https://www.eia.gov/todayinenergy/detail.php?id=54939#:~:text=As%20of%20October%202022%2C%207.8%20GW%20of%20utility-scale,add%20another%2020.8%20GW%20of%20battery%20storage%20capacity.

108 EIA, *U.S. Battery Storage Market Trends*, 13-15 (August 2021), https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf.

109 California Public Utilities Commission, *Energy Storage* (accessed December 1, 2022), www.cpuc.ca.gov/industries-and-topics/electrical-energy/energy-storage.

110 Order No. 2222, 172¶61,247, (September 17, 2020), at 4.

end user of power. While individual installations of DER tend to have capacities much smaller than that of central station power plants (for example DER installations may range from a fraction of a kW to systems producing less than 10 MW), the overall quantity of DER installations has grown tremendously, particularly in states with beneficial policies toward DERs.

One such policy is known as net metering, which is a system in which DERs are connected behind the meter to a distribution system and any surplus power is transferred onto the grid, allowing customers to offset the cost of power drawn from a distribution utility. Such surplus flow typically occurs during periods when the DER's production outstrips the customer's total demand. Under one measure of DER, as tracked by EIA, total net-metered capacity grew by approximately 277 percent between 2014 and 2020, from approximately 7.5 GW of capacity to 28.3 GW. The bulk of this capacity was solar PV, which made up 94 percent of net-metered capacity in 2020, with 62 percent of that capacity owned by residential customers.[111] In some cases, surplus power from a large DER or a set of net metered DERs may flow onto the transmission system.

TRANSMISSION

The alternating current (AC) power grid operates like an interconnected web, where, with a few exceptions, the flow of power is not specifically controlled by the operators on a line-by-line basis. Instead, power flows from sources of generation to consumers across any number of lines simultaneously, following the path of least resistance. There are also a limited number of direct current (DC) lines, which are set up as specific paths with definite beginning and end points for scheduling and moving power. These lines are controllable by operators and have other characteristics that make them attractive to grid planners and operators, such as providing greater grid stability and lower line losses. However, DC lines cost significantly more than AC lines to construct. Consequently, DC lines are typically built for certain specialized applications such as the movement of large amounts of power over long distances, for example the Pacific Intertie, which extends between the Northwest and California.

Transmission lines provide a certain amount of resistance to the flow of power as electricity travels through them. This resistance is not unlike the wind resistance that a car must overcome as it travels along a highway. The resistance in power lines creates losses: the amount of power injected into a power line diminishes as it travels through the line. The amount of these losses is contingent on many factors including the voltage of the transmission facilities.

111 EIA, *Electric Power Annual* (December 2022), (March 2022), www.eia.gov/electricity/annual/html/epa_04_10.html.

Wholesale Electricity Markets and Trading

Electric markets encompass different organizational structures and different mechanisms for buying and selling power at the wholesale level. Electric systems for delivering power to consumers in the United States are split into two structures: traditional systems and those run by RTO/ISOs. Traditional systems are typically vertically integrated, rely on management to make operational decisions, and sell electricity to retail customers based on their cost of service. In general, RTO/ISOs use their markets to make operational decisions, such as generator dispatch, and to price the resulting electricity. Load-serving entities then buy the power through the RTOs/ISOs for resale to retail customers.

Both traditional systems and RTOs/ISOs conduct certain functions, although they may perform these functions in different ways. These include:

- Ensuring the electric grid operates reliably in a defined geographic footprint
- Balancing supply and demand instantaneously and maintaining sufficient operating reserves
- Dispatching system resources as economically as possible
- Coordinating system dispatch with neighboring balancing authority areas (BAAs)
- Planning for transmission in its footprint
- Coordinating system development with neighboring systems and participating in regional planning efforts
- Providing non-discriminatory transmission access

Buying and selling electricity in the wholesale markets – trading – occurs through bilateral and RTO/ISO transactions, as discussed below. Bilateral transactions occur in both traditional systems and in RTO/ISO regions. Pricing for bilateral transactions in both RTO/ISO and traditional regions incorporates both cost-based and market-based rates.

SUPPLYING LOAD

Load serving entities (LSE) serve customer load through a combination of self-supply, bilateral market purchases and purchases from RTO/ISO markets. Self-supply means that the LSE generates power from plants it owns or operates to meet demand. With bilateral purchases, the LSE buys power from a supplier. RTO/ISO market purchases means the supplying company purchases power through the RTO's/ISO's markets.

LSEs' sources of energy vary considerably. In ISO-NE, NYISO, and CAISO, the LSEs have divested much or all their generation. In these circumstances, LSEs supply their customers' requirements through bilateral and RTO/ISO market purchases. In PJM, MISO, and SPP, LSEs may own significant amounts of generation, either directly or through affiliates, and therefore use self-supply as well as bilateral and RTO market purchases.

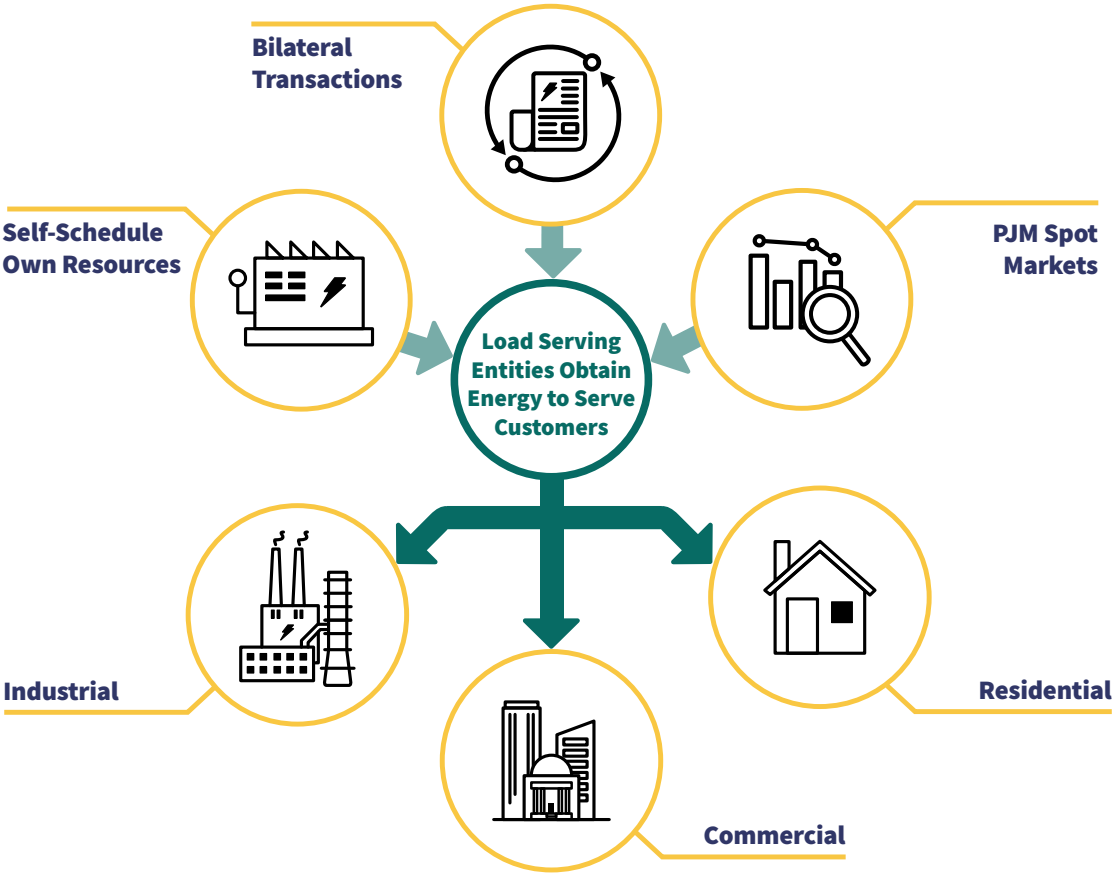
BILATERAL TRANSACTIONS

Bilateral transactions between two parties do not occur through an RTO/ISO and can occur through direct contact and negotiation, through a voice broker or through an electronic brokerage platform, such as the Intercontinental Exchange (ICE). The deals can range from standardized contract packages, such as those traded on ICE, to customized, complex contracts known as structured transactions. In bilateral transactions, buyers and sellers know the identity of the party with whom they are doing business.

Whether the trade is done on ICE, directly between parties or through another type of broker, the trading of standard physical and financial products, such as next-day on-peak firm or swaps, allows index providers to survey traders and publish price indexes. These indices provide price transparency.

Physical bilateral trades involving the movement of energy from one point to another require the parties to reserve transmission capacity to move the power over the transmission grid. Transmitting utilities are required to post the availability of transmission capacity and offer

Figure 2-5: Options for Energy Supply



Source: PJM Traditional Wholesale Electricity Markets

service on an OASIS website. Traders usually reserve transmission capacity on OASIS at the same time they arrange the power contract.

Transfers of power between Balancing Authority Areas (BAAs) require one of the parties to the transaction to submit a request for interchange, also known as an eTag.[112] The receiving BAA (the entity to which the power is transferred or sinks), or its agent, will process the eTag, ensure a reliability assessment has been completed, and send it to all parties named on the eTag. This ensures an orderly transfer of energy and provides transmission system operators with the information that they need to institute curtailments, as needed. Curtailments may be necessary when a change in system conditions reduces the capability of the transmission system to move power and requires some transactions to be reduced or cut.

Bilateral physical transactions that are conducted in RTO/ISOs are settled financially. Generators offer their power into the markets, and load is served through the power dispatched by the RTO/ISO. The RTO/ISO then settles bilateral transactions based on the prices in the contracts and the prices that occurred in their markets.

112 A BAA is a collection of generation, transmission, and loads within the metered boundaries of the entity (a Balancing Authority) that is responsible for balancing load, generation, and net interchange between other BAAs. Glossary of Terms Used in NERC Reliability Standards (March 2022), https://www.nerc.com/files/glossary_of_terms.pdf.

COST-BASED RATES

Cost-based rates are used to price most transmission services and some electricity when FERC determines that market-based rates are not appropriate, or when an entity does not seek market-based rate authority. Cost-based rates are set to recover costs associated with providing service and give a fair return on capital. These rates are typically listed in a published tariff.

The following are major inputs to setting cost-based electricity rates:

- Determining used-and-useful electricity plant costs. This may include the cost of generation facilities, transmission facilities, distribution plants and office and related administration facilities.
- Determining expenses for the production, transmission and distribution of electricity, including fuel and purchased power, taxes and administrative expenses.
- Establishing a fair return on capital, known as the cost of capital. This includes determining the cost of debt, common equity, preferred stock and commercial paper and other forms of short-term borrowing, such as lines of credit used to finance projects and provide cash for day-to-day operations.
- Allocating electric plant and other expenses among various customer classes and setting the rate structure and rate levels.

MARKET-BASED RATES

Under market-based rates, the terms of an electric transaction are negotiated by the sellers and buyers in bilateral markets or through RTO/ISO market operations. FERC grants market-based rate authority to electricity sellers that demonstrate that they and their affiliates lack, or have adequately mitigated, horizontal market power (typically based on whether the seller is a pivotal supplier and on the percent of generation owned by the seller relative to the total amount of generation available in a market). Sellers must also show that they lack, or have adequately mitigated, vertical market power (the ability to erect barriers to entry or influence the cost of production for competitive electricity suppliers). Wholesale sellers who have market-based rate authority and sell into day-ahead or real-time markets administered by an RTO/ISO do so subject to the specific RTO/ISO market rules approved by FERC. Thus, a seller in such markets must have an authorization from FERC and must also abide by the additional rules contained in the RTO/ISO tariff.

TRANSMISSION SERVICE

FERC requires that public utilities that own transmission lines used in interstate commerce offer transmission service on a nondiscriminatory basis to all eligible customers. The rates and terms of service are published in each utility's Open Access Transmission Tariff (OATT). Each utility's OATT specifies the transmission services available. Customers submit requests for transmission service through the OASIS. Utilities evaluate each transmission-service request using a model of the grid called a state estimator. Based on the model's estimation of the effects on the system, the request for transmission service is either approved or denied.

The two most common types of transmission service are network and point-to-point service. Network service allows a transmission customer the use of the entire transmission network to deliver generation from specified resources to specified loads. The price for service is cost-based and published in the OATT. Network service has higher priority than point-to-point service.

Point-to-point service involves paying for and reserving a fixed quantity of transmission capacity and moving power up to the reservation amount from one location, the point of receipt (POR), to another location, the point of delivery (POD). The POR and POD may be outside the transmission operator's footprint. Depending on availability, customers may purchase firm or non-firm point-to-point service for durations of one hour to multiple years.

Customers holding firm point-to-point transmission capacity may sell that capacity in a secondary market – such a sale is known as capacity reassignment. An entity holding transmission rights may want to resell

that capacity to another transmission customer in the secondary market because it is unneeded, or to make a profit. Resellers of transmission capacity are permitted to charge market-based rates for capacity reassignments, instead of the original cost-based rate at which they purchased the capacity. Most capacity reassignments are hourly, although capacity can also be reassigned on a daily, weekly, monthly, or yearly basis.[113]

If the market price of energy is greater at the POD than at the POR, the transmission has value. The transmission holder can capture this value by using the transmission – buying energy at the POR, moving it to the POD and selling it. Alternatively, the transmission holder can sell the transmission through a capacity reassignment. Thus, the price of a capacity reassignment should be consistent with, and rarely exceed, the expected price differential between the POD and the POR.

Transmission Planning

Each transmission-operating utility must participate in regional planning processes that identify transmission system additions and improvements needed to maintain reliability. Studies are conducted to test the transmission system against mandatory national reliability standards, as well as regional reliability standards. Planning studies may look 10-15 years into the future to identify transmission overloads, voltage limitations, and other reliability problems.

GRID OPERATIONS

Grid operators dispatch their systems using the least costly generation, consistent with the constraints of the transmission system and reliability requirements. The dispatch process occurs in two stages. For RTOs/ISOs, the market determines a day-ahead unit commitment, then updates the unit commitment and dispatches in real time. Grid operators in traditional utilities plan for the next day's dispatch, then update and implement that dispatch in real time.

Dispatch Planning

Grid operators decide which generating units should be committed in advance of actual operations. For RTOs/ISOs, this is done, in part, through the day-ahead markets and forecasts. For operators in traditional utilities, this is done through various planning and forecasting processes. Planning dispatch in advance of real-time operations is needed because some generating units need to obtain fuel or require several hours of lead time before they are brought online. In selecting the most economic generators to commit, operators take into account forecast load requirements and each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels and the minimum time a generator must run once it is started. Operators must also take into account each generating unit's cost factors, such as fuel and nonfuel operating costs, and the cost of environmental compliance.

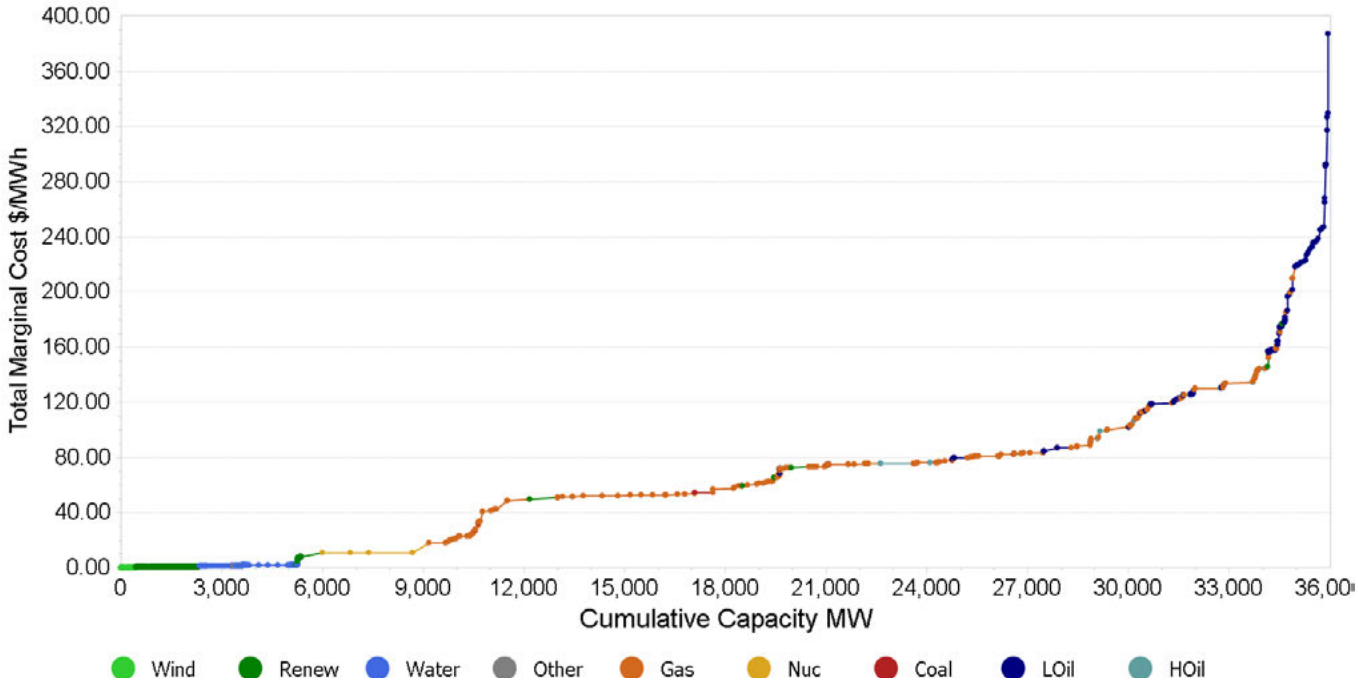
Forecast conditions can also affect how the transmission grid is optimally dispatched to reliably meet load. This is the security aspect of commitment analysis. The factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels and flow direction, and weather conditions. If the security analysis indicates that the optimal economic dispatch cannot be carried out reliably, relatively expensive generators may have to be called upon to replace less-expensive units.

System and Unit Dispatch

Grid operators must decide the actual level at which each available resource should be operated, given the actual real-time load and grid conditions, so that reliability is maintained and overall production costs are minimized. Actual conditions will vary from those forecast prior to real-time, and grid operators must adjust the dispatch accordingly. As part of real-time operations, demand, generation and interchange (imports and exports) must be continually kept in balance to maintain a system frequency of 60 hertz.

113 FERC, *Electric Quarterly Reports, Downloads, Quarterly Filings* (2021), https://eqrreportviewer.ferc.gov.

Figure 2-6: Market Supply Curve for NYISO (Illustrative)



Source: Hitachi Energy, Velocity Suite[114]

This is typically done by automatic generation control (AGC) to change the generation dispatch as needed.

In general, dispatch occurs based on the cost of generation from given resources, with the lowest-cost resources dispatched first and the higher-cost resources dispatched last. The chart above is a depiction of the market supply curve for the New York Independent System Operator (NYISO). This is also commonly called the supply stack. In it, all the generating units in the New York market are shown, sorted according to their marginal cost of production. Their cost of production is shown on the vertical axis in terms of dollars per MWh. The cheapest units to run are to the left and the most expensive to the right.

Dispatch in New York, for example, first calls upon wind generating units, followed successively by hydroelectric, nuclear and coal-, gas- and oil-fired generating units.

This assumes that the generating units have sufficient resources – enough wind for the wind-powered generators or enough river flow for the hydroelectric plants, for example – and that sufficient transmission capability exists to deliver generator output and meet reliability needs.

In addition to these considerations, transmission flows must be monitored to ensure that the grid operates within voltage and reliability limits. If transmission flows exceed accepted limits, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch or shedding load. Operators may check conditions and issue adjusted dispatch instructions as often as every five minutes.

ANCILLARY SERVICES

Ancillary services maintain electric reliability and support the transmission of electricity. These services

114 Derived from Hitachi Energy, Velocity Suite, *Supply Curve Analyst, Form EIA 860, NERC Electric Supply and Demand database, FERC Form 1, FERC Form 714, ISO Load Data, Hitachi Energy Primary Research, et al* (February 2023).

are produced and consumed in real-time, or in the very near term. NERC and regional entities establish the minimum amount of each ancillary service that is required for maintaining grid reliability.[115]

Regulation matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal, typically every few seconds. The changes to output are designed to maintain system frequency at 60 hertz. Failure to maintain a 60-hertz frequency can result in systemic failure of an electric grid.

Operating reserves are needed to restore load and generation balance when a supply resource trips offline. Operating reserves are provided by generating units and demand resources that can act quickly, by increasing output or reducing demand, to make up a generation deficiency. There are three types: spinning reserves, non-spinning reserves and supplemental reserves.

Spinning reserves are provided by generators that are online (synchronized to the system frequency) with some unloaded (spare) capacity and capable of increasing its electricity output within a specified period, such as 10 minutes. During normal operation, these reserves are provided by increasing output on electrically synchronized equipment or by reducing load on pumped storage hydroelectric facilities. Synchronized reserve can also be provided by demand-side resources.

Non-spinning reserves are provided by generating units that are not necessarily synchronized to the power grid but can be brought online within a specified amount of time, such as 10 minutes. Non-spinning reserve can also be provided by demand-side resources.

Supplemental reserves are provided by generating units that can be made available within a specified amount of time, such as 30 minutes and are not necessarily synchronized with the system frequency.

Blackstart generating units have the ability to go from a shutdown condition to an operating conditi on and start delivering power without any outside assistance from the electric grid. Hydroelectric facilities and diesel generators predominately have this capability. These are the first facilities to be started up in the event of a system failure or blackout to restore the rest of the grid.

Reactive power: Electricity consists of current, the flow of electrons, and voltage, the force that pushes the current through the wire. Reactive power is the portion of power that establishes and maintains electric and magnetic fields in AC equipment. It is necessary for transporting AC power over transmission lines, and for operating magnetic equipment, including rotating machinery and transformers. It is consumed by current as it flows. As the amount of electricity flowing on a line increases, so does the amount of reactive power needed to maintain voltage and move current. Power plants can produce both real and reactive power and can change the output of both. Special equipment installed on the transmission grid is also capable of injecting reactive power to maintain voltage.

WEATHER

Weather is the single most important factor affecting the level of electricity demand and, thus, is a major factor in grid operations. System operators therefore rely heavily on weather forecasts to ensure they have the right generation, in the right locations, to run the grid reliably.

Weather affects grid operations in other ways, as well. Primary among these is on the productivity of certain types of power generators: wind and hydroelectric. Wind turbines' power output changes

115 For additional information on the definitions of ancillary services, NERC, *Glossary of Terms Used in NERC Reliability Standards*, (March 2022), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

with wind availability and speed, which affects cost of wholesale power. Solar generation declines with cloud cover, which not only decreases available generation but can increase demand as behind-the-meter solar, such as residential and commercial installations, decrease their supply to retail users.

Hydroelectric plants rely on rain and snowfall to provide the river flow needed for their output. Geographically, this is most important in the Pacific Northwest, where seasonal hydroelectric plant output is a critical source of power. Rain and the melting of winter snowpack feed the Columbia and Snake River systems. Surplus power from these generators is typically exported to California to help meet summer peak demand, increase reliability and lower prices.

Temperature can also affect the output of other power plants and capacity of transmission lines. Thermal plants that use a turbine – coal, gas, oil, and nuclear plants – become less efficient at higher temperatures. Additionally, the capacity of transmission lines is limited by heat because the conductive material used in fabrication becomes more electrically resistant as they heat up, limiting their throughput capability.

Traditional Electricity Systems

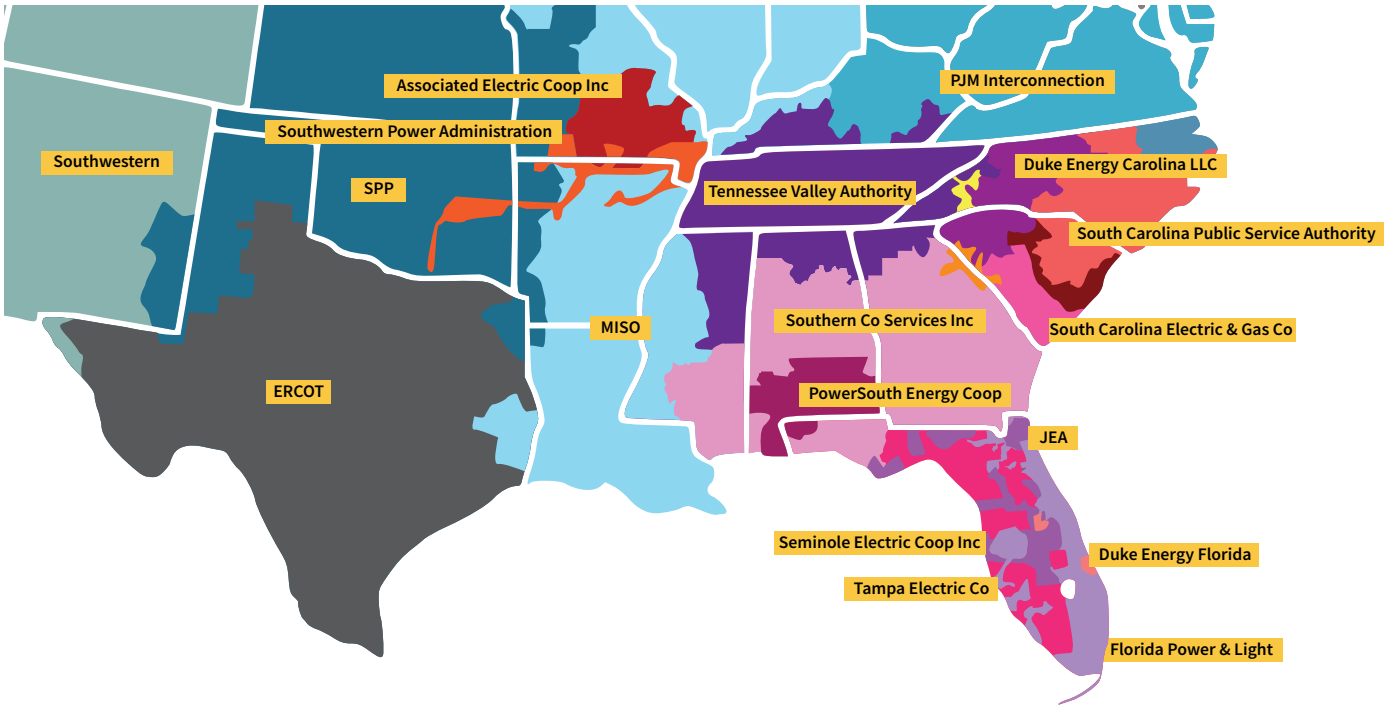
Traditional wholesale electricity markets exist primarily in the Southeast and the West outside of California, where utilities are responsible for system operations and management, and, typically, for providing power to retail consumers. Utilities in these markets are frequently vertically integrated – they own the generation, transmission and distribution systems used to serve electricity consumers. They may also include federal systems, such as the Bonneville Power Administration (BPA), the Tennessee Valley Authority and the Western Area Power Administration. Wholesale physical power trading typically occurs through bilateral transactions. In addition to the responsibilities listed in the overview to this section, a utility in a traditional region has the following responsibilities:

- Generating or obtaining the power needed to serve customers (this varies by state)
- Dispatching resources based on some cost minimizing algorithm
- Ensuring the reliability of the transmission grid

Southeast Wholesale Market Region

The Southeast electricity market is a bilateral market that includes all or parts of Florida, Georgia, Alabama, Mississippi, North Carolina, South Carolina, Missouri, and Tennessee. It encompasses the Southeastern Electric Reliability Council (SERC) NERC region. Major hubs include Into Southern and the Tennessee Valley Authority (TVA). The Southeast region's hourly peak demand is greater than 203 GW.[116] While traditional bilateral trading continues in the Southeast, some utilities in the region have created a trading platform, the Southeast Energy Exchange Market (SEEM), discussed further below. Southern Company also conducts an auction for some of its available generation, also discussed further below.

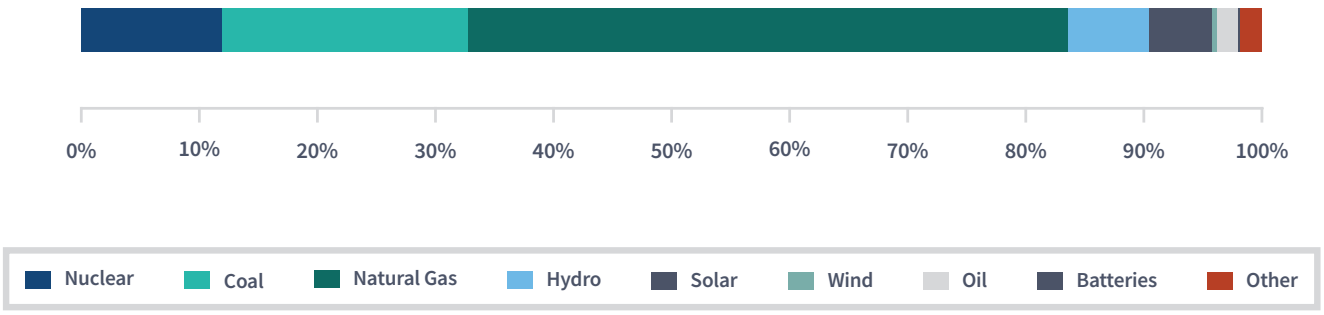
Figure 2-7: Southeast Electric Region



Source: Hitachi Energy, Velocity Suite

116 The hourly peak demand observed between 2000 and 2020. Based on FERC Form 714, Annual Electric Balancing Authority Area and Planning Area Report. Derived from the Balancing Authority Areas within the SERC NERC region, using the Hitachi Energy, Velocity Suite, Balancing Authority Area Net Energy for Load & Peak Demand dataset.

Figure 2-8: Southeast Electric Region Capacity Mix



Source: EIA Form 860-M[117]

Supply Resources

The total generating capacity in the Southeast Electric Region is over 256 GW and is predominately composed of natural gas and coal-fired generators. Hydroelectric and nuclear capacity are also substantial resources in the region.

The Southeast generates most of its electricity from coal, nuclear, and natural gas-fired plants, as shown in the bar chart above.

The TVA sub-region has a majority of its capacity and output from coal and nuclear, while the Virginia-Carolina (VACAR) sub-region has the highest utilization of nuclear generation in the Southeast.

TRADING AND MARKET FEATURES

Physical sales in the Southeast are done bilaterally and long-term energy transactions are particularly prominent, compared to short-term transactions. Many long-term agreements involve full-requirements contracts or long-term power purchase agreements. For example, Southern Company's short-term transactions account for around 30 percent of its total wholesale energy sales in 2021.[118]

Short-term energy is traded among various entities, including investor-owned utilities, municipal utilities, public utility districts, independent power producers, and marketers. Some of the largest sellers of short-term power include Southern Company, North Carolina Municipal Power Agency, Cargill, and Exelon.

Industry-referenced trading points for short-term bilateral transactions in the Southeast include the following locations: Into Southern, TVA, VACAR, and Florida. Volumes for short-term transactions can be low, particularly under normal weather conditions. Overall demand for short-term transactions tends to rise during periods of system stress, for example summer heat waves or winter cold snaps.

The Southeast has relatively low volumes of short-term trades compared to the Western regions. Thus, there is limited data on that price index publishers have on which to base their price reporting. Given the bilateral nature of wholesale power transactions in the Southeast, and a relatively small market for short-term transactions, interest in financial power products in the Southeast is weak.

117 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory* (based on Form EIA-860M) (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

118 FERC, *Electric Quarterly Reports, Downloads, Quarterly Filings* (2021), https://eqrreportviewer.ferc.gov.

SOUTHEAST ENERGY EXCHANGE MARKET

The Southeast Energy Exchange Market (SEEM) launched on November 9, 2022. However, on July 14, 2023, the U.S. Court of Appeals for the D.C. Circuited remanded to FERC orders addressing the Seem. Consequently, the SEEM proposal is now pending before the Commission once again.

SOUTHERN COMPANY AUCTION

Southern Company has held daily and hourly auctions for power within its balancing area since April 2009 as a requirement of Southern Company's market-based rate tariff. This BAA encompasses the service territories of Southern Company utilities: Georgia Power, Alabama Power, Mississippi Power, and Gulf Power. The products included in the auction are day-ahead power and real-time power.

According to the auction rules, Southern Company must offer all of its available uncommitted thermal generation capacity into the auction, after regulation and contingency reserves are met. The auction is intended to mitigate the potential ability of Southern Company to exercise market power within its balancing authority area and certain adjacent balancing authority areas. In February 2017, Southern Company revised its market-based rate tariff to cap all market-based sales of less than one year outside of the auction at a cost-based tariff rate.[119]

Western Wholesale Market Regions

The power markets in the western United States are primarily bilateral markets. A key exception is most of California and portions of Nevada, which operate under CAISO. Further, several entities buy and sell electricity in a regional, short-term markets run by CAISO, called the Western Energy Imbalance Market (WEIM), and the SPP-run Western Energy Imbalance Service (WEIS). CAISO and SPP are discussed further in the RTO and ISO Markets section. The West includes the Western Power Pool (WPP), the Rocky Mountain Power Area, and the Arizona, New Mexico, Southern Nevada Power Area within the Western Electricity Coordinating Council (WECC), a regional entity. These areas contain over 30 balancing authority areas responsible for dispatching generation, procuring power, operating the transmission grid reliably, and maintaining adequate reserves.[120]

NORTHWEST ELECTRIC REGION

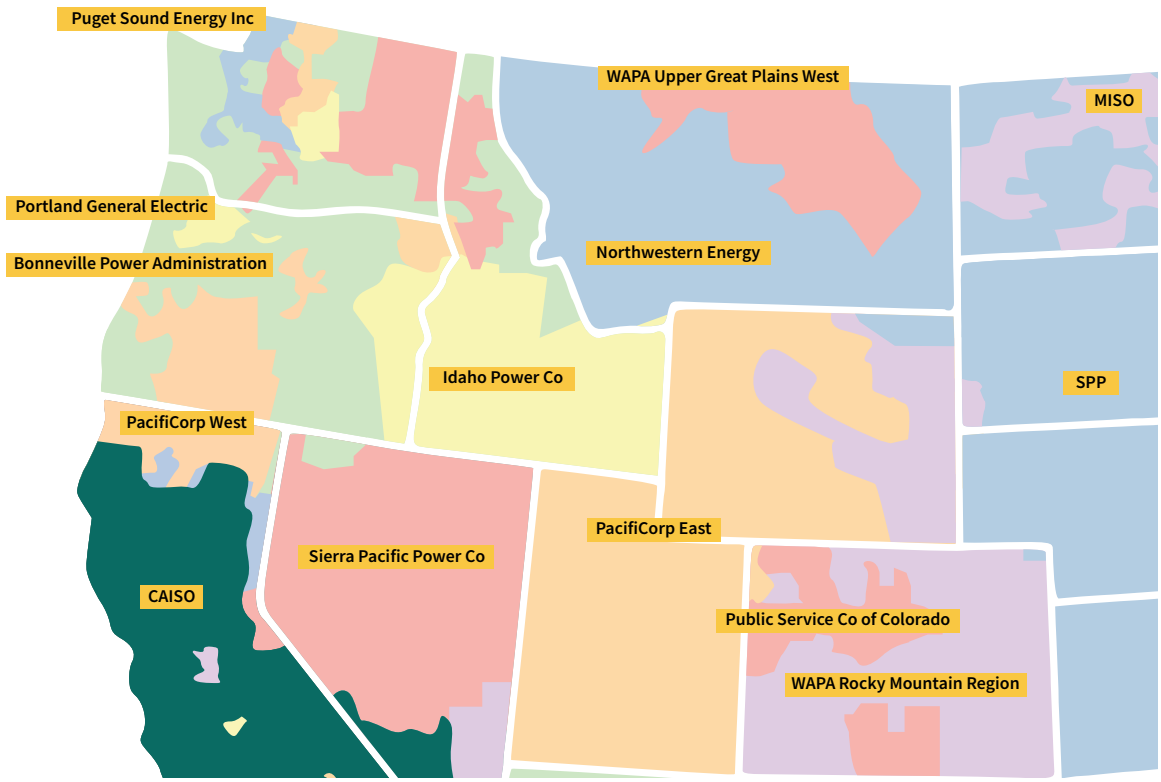
The Northwest Electric Region is composed of the Northwest Power Pool (NWPP) NERC region in the northwestern section of the Western Electric Coordinating Council (WECC) NERC region. The hourly peak demand is approximately 49 GW[121]

119 *Alabama Power Company*, 158 FERC ¶ 61,131 (2017) (February 2, 2017 Order) (order accepting market-based rate tariff revisions subject to condition).

120 Western Electricity Coordinating Council, *Western Interconnection Balancing Authorities* (accessed November 2022), https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/Balancing_Authorities_JAN17.pdf&action=default&DefaultItemOpen=1.

121 The hourly peak demand observed in a given month between 2000 and 2020. Based on FERC Form 714, *Annual Electric Balancing Authority Area and Planning Area Report*. Derived from the Balancing Authority Areas within the NWPP NERC subregion, using the Hitachi Energy, Velocity Suite, Balancing Authority Area Net Energy for Load & Peak Demand dataset.

Figure 2-9: Northwest Electric Region



Source: Hitachi Energy, Velocity Suite

Supply Resources

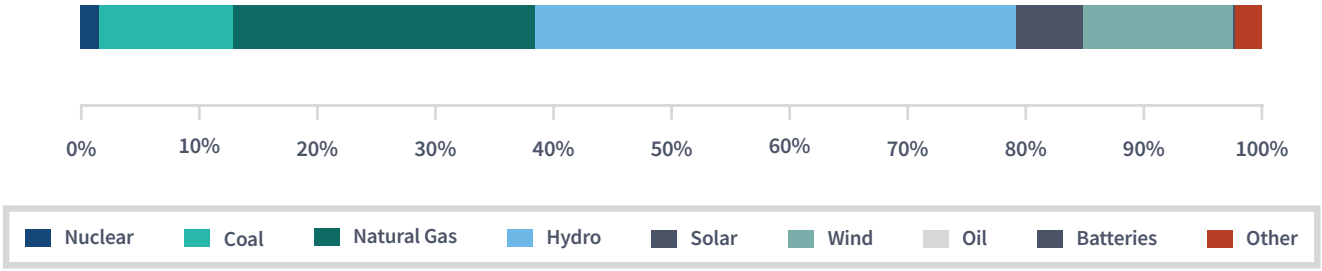
The total capacity in the Northwest Electric Region is approximately 79 GW and is primarily composed of hydroelectric, natural gas, and coal-fired generators, as shown in the bar chart below. Wind generator capacity is also a significant resource for the region.

The Northwest has a unique resource mix, as demonstrated in the bar chart below, with hydroelectric generation capacity comprising approximately 40 percent of the power supply, which is sourced from many dams that are in the Columbia River system. The largest dam, Grand Coulee, can produce up to as much power as six nuclear plants. Due to the large amount of hydroelectric generation, the Northwest typically has low-cost power during the spring and early summer. During these periods, the region exports power to neighboring regions, especially California, where power prices are typically higher.

The amount of hydroelectric power produced depends on a number of factors, some natural and some controllable. On a seasonal basis, the intensity and duration of the water flow is driven by snowpack in the mountains, the fullness of the reservoirs, and rainfall. On a short-term basis, the levels of hydroelectric power generation output are influenced by decisions to release water locally and upstream to generate power, as well as local water-use decisions that are independent of the economics of the power markets, based on recreation, irrigation, and wildlife considerations, for example. The peak hydroelectric power generation period begins in the spring, when the snow melts, and may last into early summer. When less water is available, the Northwest may rely more on its coal and natural gas generation, and occasionally import power from neighboring regions, including Canada, when loads are high.

Figure 2-10: Northwest Electric Region Capacity Mix

Source: EIA Form 860-M



Trading and Market Features

Two Canadian BAAs, Alberta Electric System Operator

The water forecast affects the forward market for electricity in the Northwest. Similarly, the daily water flow conditions influence the prices in the daily physical market. When there is an abundance of hydroelectric generation, the Northwest will export as much as possible on the transmission lines leading into California and elsewhere in the West. Sometimes in off-peak hours, more electricity is available than can move through transmission lines or be used locally, so electric prices become negative.

The largest seller of wholesale power in the region is the BPA, a federal agency that markets the output from federally owned hydroelectric facilities, as well as a non-federal nuclear plant and several other smaller non-federal power plants. BPA meets approximately one-third of the firm energy supply in its service territory and owns 75 percent of the region's high-voltage transmission.[122] BPA gives preference to municipal and other publicly owned electric systems in allocating and pricing its generation output.[123]

and British Columbia Hydro, are also substantial suppliers of energy to the United States via the Northwest Electric Region. These Canadian BAAs often import power to, and export power from, the United States, depending on market conditions. The Canadian BAAs generally import power from the United States when prices are low in order to save water in their hydroelectric reservoirs. The water is later released to generate and sell hydroelectric power during higher-priced periods[124]

The Northwest region trading points for bilateral transactions include Mid-Columbia (Mid-C), California-Oregon Border (COB), Nevada-Oregon Border (NOB), and Mona (Utah). Of these, Mid-C is the most actively traded location.

SOUTHWEST ELECTRIC REGION

The Southwest electric market encompasses Arizona, New Mexico, and Southern Nevada in the WECC NERC region. The hourly peak demand is approximately 25 GW.[125]

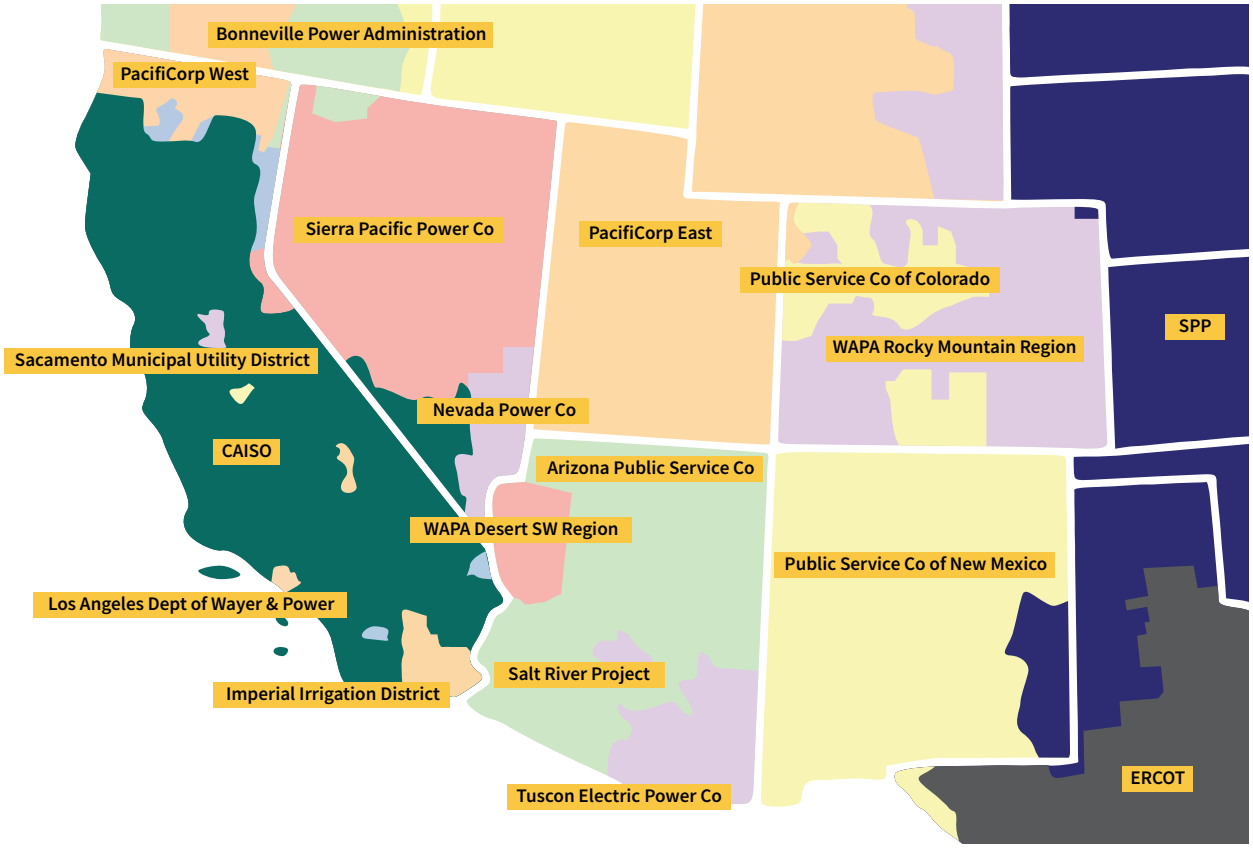
122 Bonneville Power Administration, *BPA Overview,* 45, https://energy.gov/sites/prod/files/2016/01/f28/0911review_ikakoula.pdf.

123 Bonneville Project Act, 16 U.S.C. §§ 832-832m (2000).

124 National Energy Board, *Market Snapshot: Which states trade electricity with British Columbia?* (September 2022) https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/; National Energy Board, *Market Snapshot: Why Canada is one of the world's largest electricity consumers* (August 2022), https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/

125 The hourly peak demand observed between 2000 and 2020. Based on *FERC Form 714, Annual Electric Balancing Authority Area and Planning Area Report*. Derived from the Balancing Authority Areas within the AZ/NM/SNV NERC subregion, using the Hitachi Energy, Velocity Suite, Balancing Authority Area Net Energy for Load & Peak Demand dataset.

Figure 2-11: Southwest Electric Region



Source: Hitachi Energy, Velocity Suite

Supply Resources

The total capacity in the Southwest Electric Region is over 40 GW and is predominately composed of natural gas and coal-fired generators. Hydroelectric, wind, solar, and nuclear capacity account for the majority of the remaining capacity, as shown in the bar chart below.

The majority of generation in the Southwest is produced from natural gas and coal, as demonstrated in the bar chart above. The coal generators are generally located in close proximity to coal mines, resulting in low delivered fuel costs. Some generation is jointly owned among multiple nearby utilities, including the Palo Verde nuclear plant, a plant with three units totaling approximately 4,000 MW,[126] which has owners in California and the Southwest.[127] The Southwest is also characterized by large amounts of solar capacity, as this region has the highest solar potential in the nation.[128]

Trading and Market Features

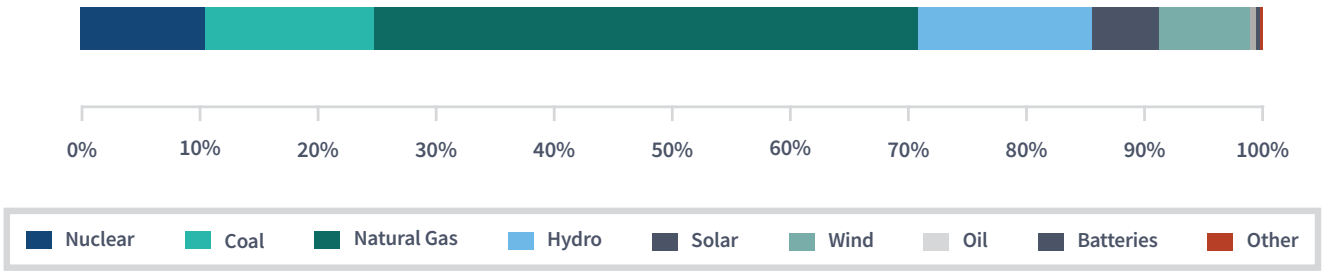
The Southwest region is summer-peaking and experiences peak loads coincident with air conditioning demand. The daily high temperature averages above 100 degrees from June through mid-September in Phoenix.

126 Derived from EIA, *Form EIA-860, 3-1-Generator_Y2021 Report*, (2021), https://www.eia.gov/electricity/data/eia860/.

127 Plant Operating License, Palo Verde, Unit 1, Current Facility Operating License NpF-41, Tech Specs, Revised 08/18/2022, https://www.nrc.gov/info-finder/reactors/palo1.html.

128 Western Electricity Coordinating Council, *State of the Interconnection*, at 9 (September 2017), https://www.wecc.biz/epubs/StateOfTheInterconnection/.

Figure 2-12: Southwest Electric Region Capacity Mix



Source: EIA Form 860-M[129]

However, power prices tend to be the highest when there is also hot weather in Southern California, creating competition for the region's generation resources. The Southwest trading points include Palo Verde, Four Corners, and West Wing. Of these, Palo Verde is the most actively traded location.

RTO and ISO Markets

Two-thirds of the population of the United States is served by electricity markets run by regional RTOs/ISOs. A key distinction between RTO/ISO markets and vertically integrated utilities, municipal utilities and co-ops is that RTO/ISO markets deliver electricity through competitive market mechanisms coordinated by a non-profit entity over a large geographic footprint. Further, RTOs/ISOs do not own or conduct maintenance on the transmission or other resources involved in providing electric service.

Currently, seven RTO/ISOs operate in the United States, listed below in order of the size of their all-time peak load.[130] FERC regulates all RTOs/ISOs except ERCOT. In addition to operating RTOs/ISOs, SPP and CAISO also operate regional short-term or imbalance energy markets, which, while not RTOs/ISOs, provide markets for real-time energy sales and purchases. SPP operates the WEIS and CAISO runs the WEIM, which are discussed at the end of the SPP and CAISO sections below.

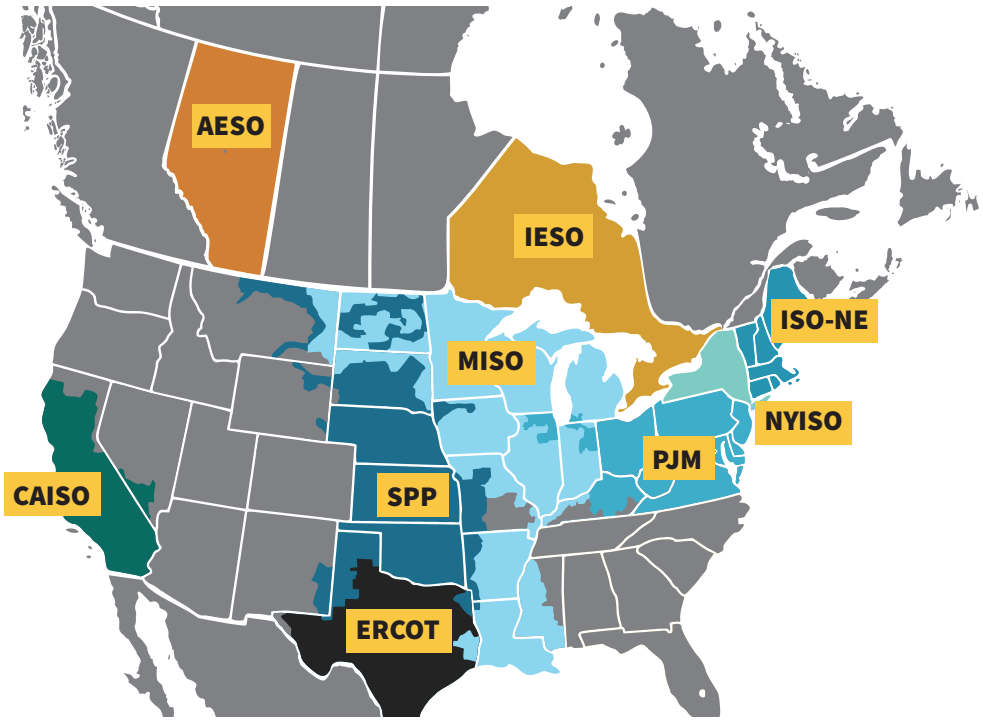
- PJM, 165 GW (summer of 2006)
- MISO, 127 GW (summer of 2011)
- ERCOT, 80 GW (summer of 2022)
- SPP, 53 GW (summer of 2022)
- CAISO, 52 GW (summer of 2022)
- NYISO, 34 GW (summer of 2013)
- ISO-NE, 28 GW (summer of 2006)

Unlike traditional electricity systems, RTOs/ISOs also operate competitive, nondiscriminatory electricity markets, which allow resource owners to offer resources and load-serving entities to submit bids for generation. These markets are the primary mechanism for dispatching resources, managing transmission congestion and pricing electricity. RTOs/ISOs work in conjunction with the resources and transmission-owning resources that participate in the RTO/ISO to maintain reliability. RTOs/ISOs also coordinate the maintenance of generation and transmission systems and oversee a transmission planning process to identify needed upgrades in both the near- and long-term.

129 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. EIA, *Preliminary Monthly Electric Generator Inventory* (based on Form EIA-860M) (February 2022), https://www.eia.gov/electricity/data/eia860m/.

130 For source information on the peak load statistics for PJM Interconnection, Midcontinent ISO, Southwest Power Pool, California ISO, New York ISO, and New England ISO, see the individual region's description later in this chapter. For ERCOT, see *ERCOT, Fact Sheet*, (October 2022), https://www.ercot.com/files/docs/2022/02/08/ERCOT_Fact_Sheet.pdf.

Figure 2-13: North American Regional Transmission Organizations and Independent System Operators



Source: Hitachi Energy, Velocity Suite

RTO/ISO FEATURES

All RTOs/ISOs function as non-profit entities that operate markets to dispatch and price electricity across a large, defined footprint. To do this, the RTOs/ISOs perform functions such as operating day-ahead and real-time markets, but also perform an array of functions not directly part of the markets, but essential to allow their efficient performance. For example, RTOs/ISOs manage the flow of payments between market participants. The next section discusses markets operated by RTOs/ISOs. The remainder of this section discusses key RTO/ISO support features or functions.

Governance

RTOs/ISOs, resource owners and operators, investor-owned, public and cooperative utilities, marketers and financial entities participate in the RTO/ISO under a governance structure and rules determined through RTO/ISO-run processes.[131] RTO/ISO governance typically involves a board of directors and stakeholder committees, which, among other things, review rule revisions. Rules underlying RTO/ISO functions are included in the RTO's/ISO's tariff and are subject to FERC's approval. Details on rule implementation can be found in RTO's/ISO's Business Practice Manuals.

Financial Policies

Financial settlement is the process through which payments due from customers, and to generators, are calculated. Such settlements are based upon day-ahead schedules, real-time metering, interchange schedules, internal energy schedules, ancillary service obligations, transmission reservations, energy prices, Financial Transmission Rights (FTR) positions, and capacity positions. Each market participant's invoice of charges and credits includes the costs of services used to serve load and the costs for operating the RTO/ISO.

131 Order No. 2000, *Regional Transmission Organizations*, 89¶61,285, (December 20, 1999).

Generally, customers receive weekly or monthly invoices stating their charges and credits. Weekly invoices must be settled within a few days of being issued, while monthly invoices must be paid within either one or two weeks, depending on the policies of each RTO/ISO. All payments are made electronically.

While RTO/ISO energy and ancillary service markets operate to price electricity at a level that compensates resources for their energy supply and meet other requirements of their tariffs, instances do occur where additional cost recovery is needed – this is commonly known as uplift. The need for uplift may arise, for example, when unplanned transmission and generation outages occur, resulting in actual operations differing from the assumptions included in the market models underlying the energy and ancillary service markets.[132]

Credit Policies

RTOs/ISOs settle the many financial charges that are paid by, or to, market participants. As RTOs/ISOs are non-profit entities with no financial interest in the markets they operate, any financial shortfall or over-collection goes to the various market participants. To protect the RTO/ISO and its market participants, each RTO/ISO has tariff provisions and other policies to ensure that market participants have the ability to pay, known as credit policies.[133] Defaults by market participants in RTOs/ISOs are rare and the costs have generally been spread across the market. Credit policies contain provisions related to credit evaluations, credit limits, forms of collateral, and the consequences of violations or defaults.

Transmission Planning

RTO/ISOs coordinate transmission planning for their footprint as required under Order 1000, a comprehensive transmission rule issued by FERC in 2011.[134] Each of the RTO/ISOs has system-wide or regional planning processes that identify transmission system additions and improvements that are needed to keep electricity flowing. Studies are conducted to test the transmission system against mandatory national reliability standards, as well as regional reliability standards. The RTO/ISO transmission planning studies may look 10-15 years into the future to identify transmission overloads, voltage limitations, and other reliability problems. RTO/ISOs then develop transmission plans in collaboration with transmission owners to resolve potential problems that could otherwise lead to overloads and blackouts. This process culminates in one recommended plan for the entire RTO/ISO footprint.

RTO/ISO MARKETS AND ASSOCIATED FUNCTIONS

RTOs/ISOs operate several markets and functions that address the physical supply of electricity and its pricing – energy and capacity markets. To physically provide the supply of electricity at all times in all places, RTOs/ISOs operate energy markets that LSEs use to procure energy and ancillary services. Some RTOs/ISOs also operate capacity markets, which, along with underlying resource adequacy rules, ensure sufficient capacity is available. RTOs/ISOs also operate financial markets associated with the energy markets – financial transmission rights and virtual transactions.

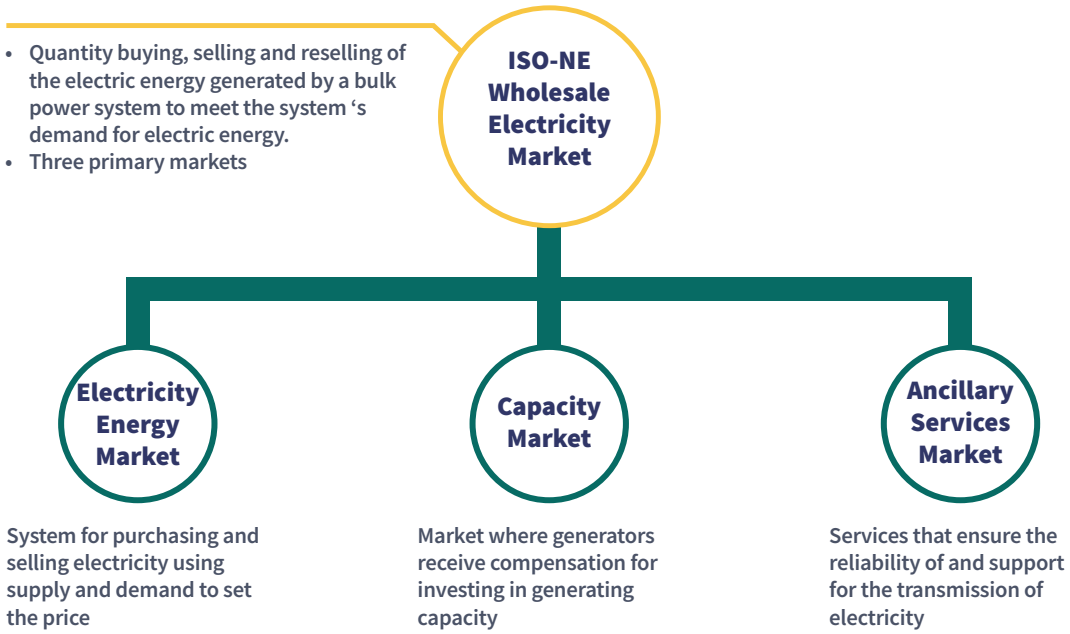
RTOs/ISOs must define rules and operate programs needed to ensure efficient market operations. The operations of the markets are discussed further below. Underlying these market operations are an extensive list of detailed rules and functions. For example, these rules detail what types of resources can participate, at limits on what prices resources can offer, and the operation of an independent market monitoring program:

132 Order No. 844, *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 163¶61,041, (April 19, 2018).

133 Order No. 741, *Credit Reforms in Organized Wholesale Electric Markets*, 133¶61,060, (October 21, 2010).

134 Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 135¶61,051, (July 21, 2011).

Figure 2-14: ISO-NE Wholesale Electricity Market



Source: ISO-NE

Resource Participation In addition to generation, demand response resources (DR), DER, energy efficiency and batteries may participate in RTO/ISO markets.[135]

Offer Caps Each RTO/ISO caps a resource's supply offer at $1,000. If a resource's costs exceed $1,000, they may request authority to offer at a higher price that reflects their verified costs. Offers up to $2,000 may be used by the RTO/ISO to set the locational marginal price.[136]

Market Monitoring Each RTO/ISO must have independent market monitors which oversee various aspects of the RTO's/ISO's markets and performance, such as market power mitigation, assessment and referral of market manipulation and assessing and reporting on the competitiveness of market operations.[137]

Energy Markets

All RTOs/ISOs have day-ahead and real-time markets. The day-ahead market schedules electricity production, ancillary services commitments and consumption before the operating day, whereas the real-time market reconciles any differences between the schedule in the day-ahead market and the real-time conditions. Both the day-ahead and real-time markets reflect reliability criteria and infrastructure conditions, such as transmission topology and limitations, resource outages, and resource operating limits.

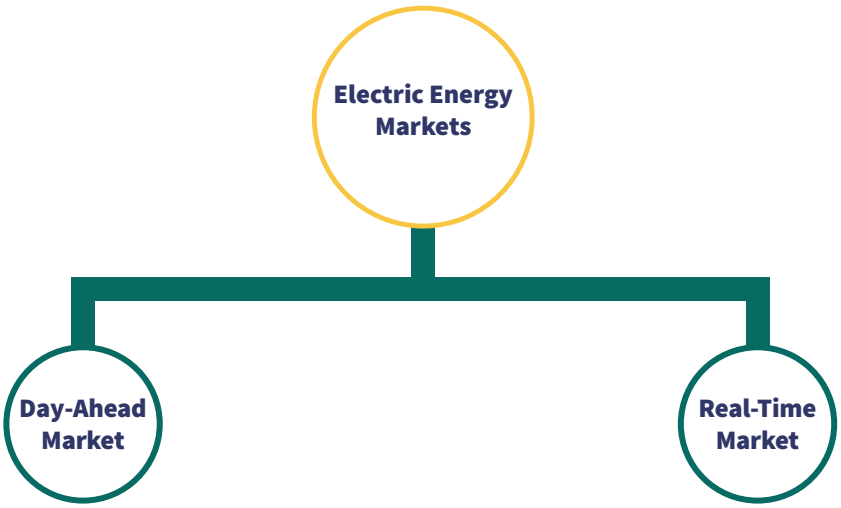
Energy markets operate to match the supply options offered by resource oprators to the demand bid in by LSEs and RTO/ISO demand forecasts. The market models select the most economic supply offers available,

135 Order No. 2222, *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172¶61,247; Order No. 841, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 162¶61,127 (2018); Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, 134¶61,187, (March 15, 2011).

136 Order No. 831, *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157¶61,115, (November 17, 2016).

137 Order No. 719, *Wholesale Competition in Regions with Organized Electric Markets*, 125¶61,071.

Figure 2-15: ISO-NE Wholesale Electricity Market



Source: ISO-NE

recognizing physical resource and transmission limitation. The overall market price for electricity is determined by the highest offer accepted. However, transmission limitations may require the market to adjust the offers selected, which can change the price for different locations in the RTO/ISO – the locational marginal price (LMP). The RTO/ISO markets calculate the LMP at each location on the power grid. The LMP reflects the marginal cost of serving load at the specific location, given the set of resources that are being dispatched and the limitations of the transmission system. LMP has three elements: an energy charge, a congestion charge, and a charge for transmission system energy losses.

If there are no transmission constraints, known as transmission congestion, LMPs will not vary significantly across the RTO/ISO footprint. However, when transmission congestion occurs, LMPs will vary across the footprint because operators are not able to dispatch the least-cost generators across the entire region and some more expensive generation must be dispatched to meet demand in the constrained area.

When transmission is constrained, the highest variable cost unit that must be dispatched to meet load within transmission-constrained boundaries will set the LMP in that area. All sellers receive the LMP for their location and all buyers pay the price for their location.

The primary means used for relieving transmission congestion constraints is by changing the output of generation at different locations on the grid. The market-based LMP sends price signals that reflect congestion costs to market participants. Thus, LMPs take into account both the impact of specific generators on the constrained facility and the cost to change (redispatch) the generation output to serve load. This process is known as security-constrained economic dispatch.

This redispatch could be implemented by using non-market procedures, such as transmission loading relief (TLR). NERC established the TLR process for dealing with reliability concerns when the transmission network becomes overloaded and power flows must be reduced to protect the network. A TLR is used to ration transmission capacity when the demand for transmission is greater than the available transmission capacity (ATC). The rationing is a priority system that cuts power flows

based on size, contractual terms and scheduling.

Day-Ahead Energy Markets

The day-ahead energy market produces financially binding schedules for the production and consumption of electricity one day before its production and use (the operating day). The purpose of the day-ahead market is to give generators and load-serving entities a means for scheduling their activities with sufficient lead time to procure fuel or bring up resources with longer start times. The day-ahead bids and offers are based on a forecast of loads and are consistent with resources' business strategies.

In day-ahead markets, offers of supply and demand bids are compiled hours ahead of the beginning of the operating day. The RTO/ISO then runs a computerized market model that matches demand and supply throughout the market footprint for each hour of the day. Additionally, the model must account for changing system capabilities that occur, based on weather and equipment outages, transmission and resource capabilities, and the rules and procedures that are used to ensure system reliability.[138] The market rules dictate that generators submit supply offers and that loads submit demand bids to the RTO/ISO by a deadline that is typically in the morning of the day-ahead scheduling. Typically, 95 percent of all load is scheduled in the day-ahead market and the rest is scheduled in real-time. Generation and demand bids that are scheduled in the day-ahead market are settled at the day-ahead market prices.

Inputs into setting a day-ahead market schedule include:

- Generators' offers to sell electricity for each hour
- Load-serving entities' bids to buy electricity for each hour
- Demand-response offers by customers to curtail usage of electricity
- Virtual demand bids and supply offers
- Operational information about the transmission grid and generating resources, including planned or known transmission and generator outages, the physical characteristics of generating resources including minimum and maximum output levels and minimum run time, and the status of interconnections to external markets.

Real-Time Energy Markets

The real-time market is used to balance the differences between the day-ahead scheduled amounts of electricity cleared in the day-ahead market and the actual real-time load and supply. The real-time market is run in five-minute intervals and clears a much smaller volume of energy and ancillary services than the day-ahead market (some RTOs/ISOs also run hour-ahead and 15 minutes- ahead of the operating interval). The real-time market also provides supply resources additional opportunities for offering energy into the market. When the real-time generation and load are different from the day-ahead cleared amount, the difference is settled at the real-time price.

Real-time market prices are significantly more volatile than day-ahead market prices. This stems from demand uncertainty, transmission and generator forced outages, and other unforeseen events. Since the day-ahead market generally is not presented with these events, it produces more stable prices than in real-time. Also, because the volumes in the real-time market are much smaller, there is an increased likelihood of supply and demand imbalances, which can lead to both positive and negative price movements.

Ancillary Services

RTOs/ISOs procure ancillary services, which are described in the Electricity Supply and Delivery Section, through the day-ahead and real-time market dispatch. RTOs/ISOs primarily procure ancillary service through their market mechanisms, although they compensate blackstart and voltage service based on the cost of providing the service (cost-of-service). Changes in the

138 In evaluating which generators provide the power to meet hourly load, the market model assesses whether the power flows can travel without exceeding the physical capability of any transmission path. If the model shows such a violation of transmission capability, the combination of assigned generators will be changed in a process known as redispatch.

resources providing supply have necessitated changes in ancillary service procurement and compensation. For example, the advent of faster-ramping resources led to changes in compensation for frequency regulation.[139]

While not an ancillary service, ramping capacity is a service for which some RTOs/ISOs have developed products. The growth of renewable generation has increased the need for generation that can increase its production rapidly to offset swings in generation or load.

Shortage Pricing

RTO/ISO markets dispatch energy and ancillary services to meet demand and reserve requirements. However, the markets may find that not enough supply is available. If the RTOs/ISOs cannot procure sufficient generation to meet demand and reserve requirements in the real-time market, they trigger shortage pricing[140] to send price signals to incentivize resources to increase the supply offered. Shortage events can be caused by unexpectedly high electric loads, supply disruptions, or both.

The common method that RTO/ISOs employ to implement shortage pricing is through the use of an operating reserve demand curve. The demand curve specifies price levels for the degree of the shortages.[141] The price of the reserves, reflecting shortage as determined by the demand curves, sets the price for ancillary services and energy.

Market Power Mitigation

RTO/ISO energy and capacity markets are typically competitive, allowing the markets to set the price. However, situations may occur that result in certain resources being essential to serving demand, thus enabling those resources to increase prices in a specific area – in other words, the ability to exercise market power. Typically, this occurs when a transmission constraint limits the amount of electricity that can flow into an area, rendering generation located inside that area essential to serving that local load. RTOs/ISOs have mechanisms for determining whether such market power may occur, and if appropriate, to mitigate the price at which affected resources may offer their supply. RTO/ISO market power mitigation typically examines whether a resource has the potential to exert market power; whether they actually offer in a way that could be an exertion of market power (conduct test); and whether any potential exertion of market power actually affected the market price (impact test).

RTO/ISO Capacity Markets and Resource Adequacy

RTO/ISOs, like other electric systems, are required to maintain adequate generation and demand-resource capacity to meet load and reliability requirements. LSEs have typically satisfied their reserve obligations with owned generation or bilateral contracts with other suppliers. In general, LSEs are required to procure sufficient capacity to meet their load. Some RTOs/ISOs also have mechanisms through which LSEs can obtain capacity commitments, such as capacity auctions and capacity payments.

Most RTOs/ISOs run a capacity market that allows LSEs to satisfy their reserve obligation. The markets cover short-term capacity, such as a month, season or year. PJM and ISO-NE run capacity auctions up to three years prior to when the capacity is needed. The capacity markets are intended to provide more certainty for investment in new capacity resources while including an opportunity for all resources to recover their fixed costs over time.

Other ISOs/RTOs, such as SPP and CAISO, rely on resource adequacy programs, in which the RTO/ISO determines the capacity each LSE is required to provide

139 Order No. 755, Frequency Regulation Compensation in the Organized Wholesale Power Markets, 137¶61,064, (October 20, 2011).

140 Order No. 825, *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 155¶61,276 (June 16, 2016).

141 RTO/ISOs apply shortage pricing in the LMP for all intervals in which the operating software indicates that there is insufficient available energy to provide system or localized demand and reserves. *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 81 Fed. Reg. 42,882 (June 30, 2016), FERC Stats. & Regs. ¶ 31,384 (2016).

at different times of the year. These programs require each LSE to show the RTO/ISO that it has procured the required capacity for different times of the year.

Special Provisions for Essential Resource Retirements
Reliability must-run (RMR) units are generating plants that would otherwise retire but that the RTO/ISO has deemed necessary to ensure reliability. They can also be units that have market power due to their location on the grid. RTO/ISOs enter into cost-based contracts with these generating units and allocate the cost of the contract to transmission customers. In return for these payments to the generator, the RTO/ISO may call on the owner of an RMR generating unit to run the unit for grid reliability. The payment must be sufficient to pay for the cost of owning and maintaining the unit, even if it does not operate. Transmission upgrades can reduce the need for RMR units by increasing generation deliverability throughout the RTOs/ISOs.

Financial Transmission Rights

Financial transmission rights (FTRs) are contracts that give market participants an offset, or hedge, against transmission congestion costs in the day-ahead market.

FTRs were originally developed in part to give native LSEs in the nascent RTOs/ISOs price certainty similar to that available to traditional vertically integrated utilities operating in non-RTO/ISO markets. This practice continues, as FTRs are allocated to load-serving entities, transmission owners, or firm transmission right holders in RTOs/ISOs, typically based on historical usage. Entities that fund the construction of specific new transmission facilities may also be eligible to receive FTRs. The details of the allocations vary by RTO/ISO.

FTRs allow customers to protect against the risk of congestion-driven price increases in the day-ahead market in the RTOs/ISOs. Specifically, FTRs grant their holders the right to day-ahead congestion revenues over specific paths and periods of time. Congestion costs occur as the demand for scheduled power over a transmission path exceeds that path's flow capabilities. This causes the price at the source to decline or the price at the sink to increase, or both, causing the congestion cost of serving Point B from Point A to increase. By buying an FTR over the path from Point A to Point B, the FTR holder is paid the difference of the congestion price components at the sink and source, thus allowing it to hedge against the congestion costs incurred in the day-ahead market.

FTRs are acquired through allocations and purchases. Purchases take place in the RTO-administered auctions or in a secondary market. Allocations stem from a related product, the auction revenue rights (ARR). ARRs provide the firm transmission capacity holders, transmission owners or LSEs with the rights to revenue from the FTR auctions. In general, ARRs are allocated based on historical load served and, in some RTO/ISOs, ARRs can be converted to FTRs. If ARRs are converted to FTRs, the holder receives revenue from congestion. If ARRs are kept as such, the holder receives revenue from the FTR auction.

The main method for procuring FTRs is through an auction, which typically includes an annual (or multiyear) auction of one-year FTRs and monthly (or semiannual) auctions of shorter-term FTRs provided by existing FTR holders or made available by the RTO/ISO. The auctions are scheduled and run by the RTO, which requires bidding parties to post credit to cover the positions taken. FTR auction revenues are used to pay the holders of ARRs and assist the funding of future congestion payments to FTR holders. There is also a secondary market for FTRs (such as PJM's eFTR), but historically only a small number of transactions have been reported.

The quantity of FTRs made available by the RTO/ISO is bounded by the physical limits of the grid, as determined by a simultaneous feasibility test across all potential flowgates. This test is performed by the RTO/ISO prior to making FTRs available at auction and takes into account existing FTR positions and system constraints. The resulting portfolio of FTRs allocated or offered at auction represents an absolute constraint on the size of the net positions that can be held by the market. Participants in FTR auctions can procure counterflow FTRs, which directly offset prevailing flow FTR capacity, thereby allowing the

value at risk on a given path to exceed the physical limits of the line. However, such bids are physically constrained, as the net position held on the path must always conform to the simultaneous feasibility test.

FTRs can also be purchased by a creditworthy entity seeking their financial attributes as a speculative investment. In this regard, FTRs are similar to financial swaps that are executed as a contract for differences between two day-ahead LMPs (swaps are explained in Chapter 5, Trading and Capital Markets). However, FTRs are substantially different from swaps in that the quantity of FTRs is linked to physical constraints in the transmission grid, while the quantity of swaps is not. Further, FTRs are procured by allocation or FTR auction, while swaps are procured through financial over-the-counter markets or exchanges.

All six FERC-jurisdictional RTOs/ISOs trade FTRs or FTR-equivalent products. However, the types and qualities of the rights traded across the organized markets vary, as do the methods used to allocate, auction, and transfer these rights. These attributes of the FTR markets are discussed below.

Flow Type: Prevailing Flow and Counterflow. A prevailing flow FTR generally has a source in a historical generation-rich location and a sink that is in a historical load-heavy location. Alternatively, the source of a prevailing flow FTR is on the unconstrained side of a transmission interface and the sink on the constrained side. Auction clearing prices for prevailing flow FTRs are positive. Conversely, a counterflow FTR often has a source in a historical load-heavy location and a sink in a historical generation-rich location. As a result, auction clearing prices for counterflow FTRs are negative; bidders are paid to take the counterflow FTR position.

Peak Type: On-peak, Off-peak, 24-hour. FTRs can be purchased for either 16-hour on-peak blocks, 8-hour off-peak blocks or around-the-clock. Only PJM offers all three peak-type products. NYISO offers only the 24-hour product. The other RTO/ISOs offer on-peak and off-peak products.

Allocated Rights: The RTO/ISOs allocate transmission rights to transmission owners or load-serving entities within their markets. In PJM, MISO, SPP, and ISO-NE, these are allocated as auction revenue rights (ARRs), which give their holders the right to receive a share of the funds raised during the FTR auctions. CAISO allocates congestion revenue rights (CRR), which provide their holders a stream of payments based on the actual congestion occurring on associated paths. NYISO allocates both auction-based and congestion-based rights through multiple instruments. PJM and MISO allow ARR holders to convert all these rights to FTRs; NYISO allows only a portion of ARR-equivalent instruments to be converted to its version of FTRs, called Transmission Congestion Credits (TCCs). ISO-NE does not allow such conversions, while CAISO's allocation is already in a form equivalent to an FTR. Converted ARRs are fully fungible in PJM, MISO, and NYISO; CAISO only allows the sale of allocated CRRs in its secondary market, and ISO-NE has no converted instruments to sell.

Auctioned Rights: All RTOs provide FTRs (or equivalent CRRs or TCCs) for sale to the public through two or more auctions held at various times of the year. The products vary by market and by auction, with some products made available only at specific auctions.

Secondary Markets: With the exception of NYISO, each of the markets that auction FTRs also operates a bulletin board or similar venue designed to enable a secondary trading platform for FTRs. However, none of these platforms has had significant volume. NYISO offered to create a bulletin board for its participants, if requested, but received no requests.

Virtual Transactions

Virtual bids and offers (collectively, virtuals) are a form of financial trading used by market participants to hedge physical positions and by speculative traders to profit from differences between day-ahead and real-time prices. The quantity of MW purchased or sold in the day-ahead market is offset by a sale or purchase of an identical quantity of MW in the real-time, so that the net effect on the market quantity traded is zero. A virtual

trader pays (or is paid) the day-ahead price while being paid (or paying) the real-time price.

Although a trader does not have to deliver power, the transaction is not strictly financial as virtual transactions can set LMPs; the price is applied to physical as well as financial transactions. Virtual transactions can also affect the resource selection in the day-ahead market.

For each hour in the day-ahead market, virtual trades are added to the demand – day-ahead scheduled load – if virtual demand is greater than virtual supply. This has the effect of raising the price in the day-ahead market and, more importantly, increasing the amount of generation resources procured by the RTO/ISO. Since these generation resources will be available to the real-time market, the fact that virtual load does not carry forward into the real-time market will decrease the real-time demand below day-ahead scheduled load, thus placing downward pressure on real-time prices. The placement of virtuals affects the dispatch of physical capacity.

The primary benefits of virtual transactions are achieved through their financial impact on the markets. Virtuals sometimes are referred to as convergence bidding, as a competitive virtual market should theoretically cause the day-ahead and real-time prices to converge in each hour. The convergence of day-ahead and real-time prices within the RTOs/ISOs is intended to mitigate market power and improve the efficiency of serving load.

Figure 2-16: New England Independent System Operator



Source: Hitachi Energy, Velocity Suite

ISO-New England (ISO-NE)

MARKET PROFILE

ISO-NE serves the six New England states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. As the RTO for New England, ISO-NE is responsible for operating wholesale power markets that trade electricity, capacity, transmission congestion contracts, and related products, in addition to administering auctions for the sale of capacity.[142] ISO-NE operates the region's high-voltage transmission network and performs long-term planning for the New England system. ISO-NE operates its master control center in Holyoke, Mass.

Peak Demand

New England's all-time peak demand was 28 GW in summer 2006.[143]

Imports and Exports

ISO-NE is interconnected with the NYISO, TransEnergie (Québec), and the New Brunswick System Operator and imports around 15 percent of its annual energy needs. New England receives imports from Québec and New

142 ISO-New England Inc. Internal Market Monitor, *An Overview of New England's Wholesale Electricity Markets, A Market Primer* (June 5, 2023), https://www.iso-ne.com/static-assets/documents/2023/06/imm-markets-primer.pdf.

143 ISO New England, *Key Grid and Market Stats*, https://www.iso-ne.com/about/key-stats/.

Brunswick in most hours, and power flows in alternate directions between New England and New York, depending on market conditions.

Market Participants

The ISO-NE participants consist of end-users, IOUs, publicly owned utilities, generators, transmission owners, and financial institutions.

Membership and Governance

ISO-NE is a not-for-profit entity governed by a 10-member, independent, non-stakeholder board of directors. The sitting members of the board elect people to fill board vacancies.

NEPOOL is the principal stakeholder organization for the ISO-NE and is authorized to represent its more than 440 members in proceedings before FERC. It was organized in 1971 and its members include all the electric utilities rendering or receiving services under the ISO-NE Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers, developers, end users, and a merchant transmission provider.

Transmission Owners

ISO-NE's largest transmission owners include:

- Central Maine Power Company
- Cross Sound Cable Company, LLC
- Emera Maine, Inc.
- Eversource Energy Service Company
- Maine Electric Power Company
- National Grid USA
- NSTAR Electric Company
- The United Illuminating Company
- VT Transco, LLC

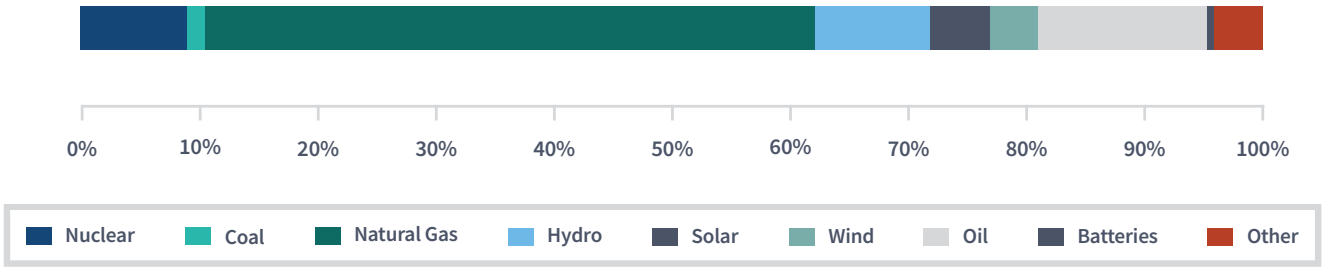
Chronic Constraints

Overall, transmission upgrades have reduced transmission constraints in ISO-NE. Constraints in ISO-NE may occur in regions affected by intermittent resources (notably wind), or by major interconnections with New Brunswick, Hydro-Quebec, and New York.[144]

Transmission Planning

Each year, ISO-NE prepares a comprehensive 10-year regional system plan (RSP) that reports on the results of ISO system planning processes. Each plan includes forecasts of future loads (the demand for electricity measured in megawatts) and addresses how this demand may be satisfied by adding supply resources; demand resources, including demand response and energy efficiency; and new or upgraded transmission facilities. The plans also summarize the region's overall needs, as well as the needs in specific areas, and includes solutions and processes required to ensure the

Figure 2-17: ISO-NE Capacity Mix



Source: EIA Form 860-M[146]

144 ISO-New England Internal Market Monitor, *2021 Annual Markets Report* (May 26, 2022), https://www.iso-ne.com/static-assets/documents/2022/05/2021-annual-markets-report.pdf.

145 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory* (based on Form EIA-860M) (February 2022), https://www.eia.gov/electricity/data/eia860m/.

reliable and economic performance of the New England power system.

Supply Resources

The total capacity in ISO-NE is over 38 GW and is predominately composed of natural gas-fired, oil-fired, and nuclear generators, as shown in the bar chart below. The region has a substantial proportion of oil-fired generation that is a particularly important resource to address potential power plant fuel shortages in the winter months during periods of local natural gas market stress.

Demand Response

ISO-NE administers the following demand-response programs for the New England wholesale electricity market:

- Real-Time Demand Response Resources (RTDR): These resources are required to respond within 30 minutes of the ISO's instructions.
- Real-Time Emergency Generation Resources that the ISO calls on to operate during a 5-percent voltage reduction that requires more than 10 minutes to implement. They must begin operating within 30 minutes of receiving a dispatch instruction.
- Transitional Price-Response Demand: An optional program that allows market participants with assets registered as RTDRs to offer load reductions in response to day-ahead LMP. The participant is paid the day-ahead LMP for the cleared interruptions, and real-time deviations are charged or credited at the real-time LMP.
- Price Responsive Demand (PRD): In June 2018, ISO New England launched a new PRD structure that fully integrates active demand resources into the regional wholesale electricity marketplace. With PRD, ISO-NE deploys its active demand resources as part of the energy dispatch and reserve-designation process along with generating resources. PRD incorporates demand response into the energy market, the reserves market and the capacity market.[146]

MARKET FEATURES

Energy Markets

ISO-NE operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. In the real-time market, ISO-NE uses 5-minute intervals. Market participants can offer imports or request exports of electricity from neighboring control areas with at least one hour's notice throughout the day.

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. ISO-NE procures and sets prices for ancillary services in the real-time and forward reserve markets.

Market Power Mitigation

In ISO-NE, market power mitigation is applied for physical withholding, economic withholding, uneconomic production, certain types of virtual transactions and other conduct, if the activity has a material effect on prices or uplift payments. The market monitor uses defined thresholds to identify physical and economic withholding and uneconomic generation. Additionally, defined thresholds determine whether bids and offers would, if not mitigated, cause a material effect on LMPs or uplift charges.

Capacity Markets

ISO-NE's capacity market is termed the Forward Capacity Market (FCM). The FCM includes annual Forward Capacity Auctions (FCA) where both generator and demand resources offer capacity three years in advance of the period for which capacity will be supplied. The three-year lead time is intended to encourage new resource entry by affording market participants additional time to plan and make decisions relative to the forward market prices. Resources whose capacity clears the FCA acquire capacity supply obligations (CSOs). ISO-NE held its first two FCAs in 2008 for the 2010-11 and 2011-12 delivery years. The first full year of

146 ISO-NE, *Price-responsive demand explained: Q&A with Henry Yoshimura, ISO Director of Demand Resource Strategy* (June 6, 2018), http://isonewswire.com/updates/2018/6/6/price-responsive-demand-explained-qa-with-henry-yoshimura-is.html.

capacity market commitments began on June 1, 2010. The FCA process includes the modeling of transmission constraints to determine if load zones will be import- or export-constrained.

The FCM includes rules known as Pay-for-Performance, which mandate performance-based financial incentives for capacity resources during times of system stress.[147] Under Pay-For-Performance, resource owners are subject to charges or incentive payments, based on performance during shortage conditions. Those resources unable to fulfill their CSOs are penalized and compensate the overperforming resources that relieve the capacity shortfall. ISO-NE additionally requires the owners of capacity resources to offer into the day-ahead and real-time energy markets.

Special Provisions for Essential Resource Retirements

When a resource owner requests to withdraw from the capacity market (termed a delist bid) or to retire the resource (termed a non-price retirement request), the ISO evaluates whether the resource is needed for reliability, such as when a resource's withdrawal could lead to a violation of a reliability requirement, such as inadequate reserve margins or a loss of electric system stability.

In New England, the resource owner has the option to retire the unit or continue to operate it while the ISO works with regional stakeholders to find alternate supply or engineering solutions that could allow the resource to retire and still maintain grid reliability. Alternative solutions might include obtaining emergency sources of generation or more expensive generation from outside the region. If no other alternative is available, the ISO may compensate the unit through certain payment provisions of the capacity market or by entering into a cost-of-service agreement with the resource owner while other options are pursued.

Financial Transmission Rights

New England FTRs are monthly and annual products that provide market participants with a means to offset or hedge against transmission congestion costs in the day-ahead energy market. An FTR is an instrument that entitles the FTR holder to a payment for costs that arise with transmission congestion over a selected path, or source-and-sink pairs of locations on the grid. The FTR also requires its holder to pay a charge for those hours when congestion occurs in the opposite direction of the selected source-and-sink pair. The RTO holds FTR auctions to allow market participants the opportunity to acquire FTRs or to sell FTRs they currently hold. In New England, ARRs represent the right to receive revenues from the FTR auctions. ISO-NE allocates ARRs to both LSEs, in relation to historical load, and to entities who make transmission upgrades that increase the capability of the transmission system.

Virtual Transactions

New England's market includes a virtual transaction feature, as generally described in the Virtual Transactions part of the RTO/ISO Features section.

Credit Requirements

ISO-NE's tariff includes credit requirements for participants that assist in mitigating the potential effects of defaults that would otherwise be borne among all market participants. ISO-NE assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. ISO-NE then establishes a credit limit for each market participant in accordance with tariff formulas that include various creditworthiness-related specifications, such as tangible net worth and total amounts due to the ISO-NE market.

147 ISO-NE's Pay-For-Performance rules became effective June 1, 2018, for Forward Capacity Auction 9. ISO-NE, Internal Market Monitor, *2017 Annual Markets Report*, at 138 (2018), https://www.iso-ne.com/static-assets/documents/2018/05/2017-annual-markets-report.pdf.

Figure 2-18: New York Independent System Operator



Source: Hitachi Energy, Velocity Suite

New York Independent System Operator (NYISO)

MARKET PROFILE

The NYISO footprint covers the entire state of New York. Prior to restructuring of the electric industry in the 1990s, New York's private utilities and public power authorities owned and operated New York's electric system. Operation of the electric grid was coordinated by a voluntary collaboration of the utilities and power authorities known as the New York Power Pool (NYPP). The creation of the NYISO was authorized by FERC in 1998. The formal transfer of the NYPP's responsibilities to the NYISO took place on Dec. 1, 1999. NYISO operates its system from control centers in Rensselaer, NY, and Guilderland, NY.

NYISO is responsible for operating wholesale power markets that trade electricity, capacity, transmission congestion contracts, and related products, in addition to administering auctions for the sale of capacity. NYISO operates New York's high-voltage transmission network and performs long-term planning. NYISO also serves as the reliability coordinator for its footprint.

Peak Demand

NYISO's all-time peak demand was 34 GW in summer 2013.[148]

Imports and Exports

NYISO imports and exports energy through interconnections with ISO-NE, PJM, TransEnergie (Quebec) and Ontario.

Market Participants

NYISO's market participants include generators, transmission owners, financial institutions, traditional local utilities, electric co-ops, and industrials.

Membership and Governance

NYISO is governed by an independent 10-member board of directors, ISO management, and the business issues and operating committees. Each committee oversees its own set of working groups or subcommittees. These committees comprise transmission owners, generation owners and other suppliers, consumers, public power, and environmental entities. Tariff revisions on market rules and operating procedures filed with FERC are largely developed through consensus by these committees. The members of the board, as well as all employees, must not be directly associated with any market participant or stakeholder.

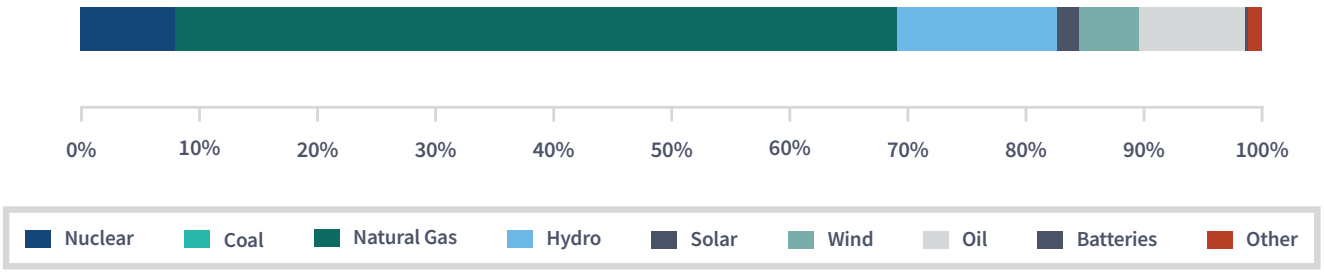
Transmission Owners

NYISO's largest transmission owners include:

- Central Hudson Gas & Electric Corp.
- Consolidated Edison Co. of New York
- Long Island Power Authority (LIPA)

148 New York Independent System Operator, Gold Book, *2022 Load & Capacity Data Report 67* (April 2022), https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf/cd2fb218-fd1e-8428-7f19-df3e0cf4df3e.pdf.

Figure 2-19: NYISO Capacity Mix



Source: EIA Form 860-M[150]

- New York Power Authority (NYPA)
- New York State Electric and Gas Corp. (NYSEG)
- National Grid
- Orange & Rockland Utilities
- Rochester Gas and Electric Corp.

Chronic Constraints

The chronic transmission constraints in NYISO are in the southeastern portion of the state, leading into New York City and Long Island. As a result of their dense populations, New York City and Long Island are the largest consumers of electricity. Consequently, energy flows from the west and the north towards these two large markets, frequently requiring transmission facilities to operate near their limits. This results in transmission constraints in several key areas, often resulting in higher prices in the New York City and Long Island markets.

Transmission Planning

NYISO conducts a biennial transmission planning process with stakeholders that includes both short-term and long-term projects as part of its Comprehensive System Planning Process. This work evaluates the adequacy and security of the bulk power system in New York over a ten-year study period. Reliability needs are addressed through the development of a reliability plan. Planning focuses on congestion on the bulk power system and possible projects to alleviate the congestion.

A component of NYISO's transmission planning includes evaluating proposals to meet transmission needs driven by public policy requirements identified by the New York Public Service Commission.

Supply Resources

The total capacity in NYISO is over 43 GW and is predominately composed of natural gas-fired, hydroelectric, nuclear and oil-fired generators, as shown in the bar chart below. The region's hydroelectric capacity is particularly important and includes the Niagara Falls and St. Lawrence facilities.

Demand Response

NYISO has four demand-response programs: the emergency demand-response program (EDRP), the installed capacity (ICAP) special case resources program (SCR), the Day-Ahead Demand-Response Program (DADRP) and the Demand-Side Ancillary Services Program (DSASP).

Both the emergency and special case programs can be deployed in energy shortage situations to maintain the reliability of the bulk power grid. The participants in these programs are paid by NYISO for reducing energy consumption when asked to do so and reductions are voluntary for EDRP participants.However, SCR participants are required to reduce power usage as part of their agreement and are compensated for this obligation.

149 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), https://www.eia.gov/electricity/data/eia860m/.

NYISO's DADRP program allows energy users to bid their load reductions into the day-ahead market and offers that are determined to be economic are paid the market clearing price. Under day-ahead demand-response, flexible loads may effectively increase the amount of supply in the market and moderate prices.

The DSASP provides retail customers that can meet telemetry and other qualifications with the ability to bid their load curtailment capability into either the day-ahead market or real-time market to provide reserves and regulation service. Accepted offers are paid the market clearing price for the supplied reserves or regulation services.

MARKET FEATURES

Energy Markets

NYISO operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. In the real-time market, NYISO uses 5-minute intervals. Market participants can offer imports or request exports of electricity from neighboring control areas with at least one hour's notice throughout the day. NYISO refers to LMPs as locational-based marginal prices, or LBMPs.

NYISO's real-time market also offers an hour-ahead feature. The hour-ahead market allows buyers and sellers of electricity to balance unexpected increases or decreases of electricity consumption after the day-ahead market closes. Bids and offers are submitted an hour ahead of time and prices are set based on those bids and offers, generally for use in matching generation and load requirements, but those prices are advisory only. Hour-ahead scheduling is completed at least 45 minutes prior to the beginning of the dispatch hour after NYISO reviews transmission outages, the load forecast, reserve requirements and hour-ahead generation and firm transaction bids, among other things.

Ancillary and Other Services

NYISO co-optimizes ancillary services with the energy through its markets. Operating reserves and regulation are typically provided by generators, but NYISO also allows demand-side providers to participate in these markets.

Ancillary services are those functions performed by electric generating, transmission and system-control equipment to support the transmission of electric power from generating resources to load. RTOs procure or direct the supply of ancillary services to maintain the reliability of the transmission system.

Market Power Mitigation

ISO-NE conducts automatic market power mitigation in its day-ahead and real-time markets. This automated mitigation performs conduct and impact tests and applies mitigation where it deems appropriate. The categories of conduct that may warrant mitigation by NYISO include physical withholding, economic withholding, and uneconomic production by a generator or transmission facility to obtain benefits from a transmission constraint. NYISO does not impose mitigation unless the conduct causes or contributes to a material change in prices, or substantially increases guarantee payments to participants.

Generators in New York City are subject to automated market power mitigation procedures because New York City is frequently separated by transmission congestion from other parts of New York. Additionally, generators in New York City have been deemed to have market power. These automated procedures determine whether any day-ahead or real-time energy bids, including start-up cost bids and minimum generation bids, but excluding ancillary services bids, exceed the tariff's thresholds for economic withholding. The protocols also determine whether such bids would cause material price effects or changes in guaranteed payments. If these two tests are met, mitigation is imposed automatically, and the applicable reference level is substituted for the entity's actual bid to determine the clearing price.

Capacity Markets

NYISO's capacity market requires LSEs to procure capacity through installed-capacity (ICAP) auctions, self-supply or bilateral arrangements based on their forecasted peak

load plus a margin. New York has capacity requirements for four zones: New York City, Long Island, Lower Hudson Valley, and New York-Rest of State. NYISO conducts auctions for three time periods: the capability period auction (covering six months), the monthly auction and the spot market auction. The resource requirements do not change in the monthly auctions and spot market auctions relative to the capability period auction. The shorter monthly auctions are designed to account for incremental changes in LSEs' load forecasts.

Under the NYISO capacity auction rules, entities that offer capacity into an auction that is subsequently purchased by load are required to offer that amount of capacity into the day-ahead energy market. This rule ensures that capacity sold through the capacity auctions is actually delivered into the market.

Capacity for New York City is subject to offer caps and floors. Offer caps in New York City are based on the projected clearing price for capacity in the spot market.[150] Capacity from generators within New York City must be offered in each ICAP spot market auction, unless that capacity has been exported out of New York or sold to meet ICAP requirements outside New York City.[151]

Special Provisions for Essential Resource Retirements

Generation owners within New York that seek to retire or suspend a generator must first obtain approval from state regulators. After an assessment, if the generator is found to be necessary for reliability purposes, the local transmission owner can be compelled to reach a contract with the generator that includes compensation to support continued operation of the plant until the reliability need is resolved.

Financial Transmission Rights

The NYISO refers to FTRs as Transmission Congestion Contracts (TCCs). A TCC is an instrument that entitles the holder to a payment for the costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations (or nodes) on the grid. The TCC also requires its holder to pay a charge for those hours when congestion is in the opposite direction of the selected source-and-sink pair. The payment, or charges, are calculated relative to the difference in congestion prices in the day-ahead market across the specified FTR transmission path.

Virtual Transactions

NYISO's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Virtual trading in NYISO takes place on a zonal level, not a nodal level.

Credit Requirements

NYISO's tariff includes credit requirements that assist in mitigating the effects of defaults that would otherwise be borne among all market participants. NYISO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions. NYISO must review the entity's request relative to various creditworthiness-related specifications such as investment grade or equivalency rating and payment history.

150 New York Independent System Operator, Inc., NYISO *MST - Market Administration and Control Area Services Tariff (MST) - 23MST Att H - ISO Market Power Mitigation Measures - 23.2 MST Att H Conduct Warranting Mitigation at 625* (accessed October 6, 2022), https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf; New York Independent System Operator, Inc., *NYISO MST - Market Administration and Control Area Services Tariff (MST) - 23 MST Att H - ISO Market Power Mitigation Measures - 23.4.5 MST Att Installed Capacity Market Mitigation Measures - 23.4.5.2 MST Att H at 705* (accessed October 6, 2022), https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf.

151 New York Independent System Operator, Inc., *NYISO MST - Market Administration and Control Area Services Tariff (MST) - 23 MST Att H - ISO Market Power Mitigation Measures - 23.4.5 MST Att Installed Capacity Market Mitigation Measures - 23.4.5.4 MST Att H* at 708 (accessed October 6, 2022), https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf.

PJM

MARKET PROFILE

PJM centrally dispatches generation and coordinates the movement of wholesale electricity in all or part of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia) and the District of Columbia. PJM operates two fully functional dispatch centers at Valley Forge and Milford, Pennsylvania. The control rooms operate simultaneously with parallel operations. PJM operates a competitive wholesale electricity market and manages the reliability of its transmission grid. PJM provides open access to the transmission system it manages and performs long-term planning. PJM's markets include energy (day-ahead and real-time), capacity and ancillary services.

PJM was founded in 1927 as a power pool of three utilities serving customers in Pennsylvania and New Jersey. In 1956, with the addition of two Maryland utilities, it became the Pennsylvania-New Jersey-Maryland Interconnection, or PJM. PJM became a fully functioning ISO in 1996 and, in 1997, it introduced markets with bid-based pricing and locational market pricing. PJM was designated an RTO in 2001.

Peak Demand

PJM's all-time peak demand was 165.6 GW in summer 2006.[152]

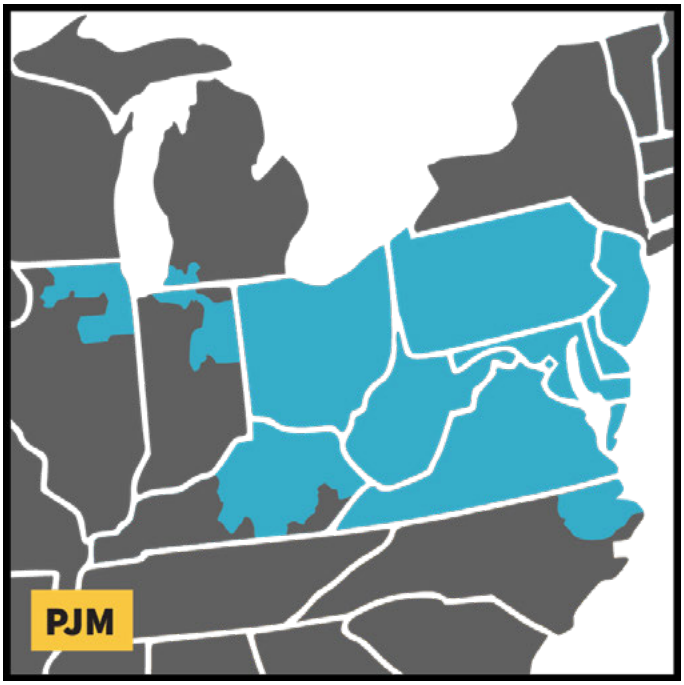
Imports and Exports

PJM has interconnections with MISO and the NYISO. PJM also has direct interconnections with TVA, Progress Energy Carolinas and the VACAR, among other systems. PJM market participants import energy from, and export energy to, external regions continuously. PJM is a primarily a net exporter of electricity, but occasionally is a net importer during periods of system stress.

Market Participants

PJM's market participants include power generators, transmission owners, electric distributors, power marketers, large consumers, and financial traders.

Figure 2-20: The PJM Interconnection



Source: Hitachi Energy, Velocity Suite

Membership and Governance

PJM has a two-tiered governance model consisting of a board of managers and the members committee. PJM is governed by a 10-member board, nine of whom PJM members elect. The board appoints the tenth, the president and CEO, to supervise day-to-day operations. The board is generally responsible for oversight of system reliability, operating efficiency and short- and long-term planning. The board ensures that no member or group of members exerts undue influence. The members committee, which advises the board, is composed of five voting sectors representing power generators, transmission owners, electric distributors, power marketers and large consumers.

Transmission Owners

PJM transmission owners eligible to vote in PJM

152 PJM Interconnection, PJM 2021 *Annual Report, Summer Performance by the Numbers*, https://services.pjm.com/annualreport2021/operations/.

stakeholder proceedings include:

- Appalachian Power Company, AEP Subsidiary[153]
- AMP Transmission, LLC
- Dayton Power & Light Company, AES Subsidiary
- Duke Energy Business Services, LLC[154]
- Duquesne Light Company
- East Kentucky Power Cooperative, Inc.
- Exelon Business Services Company, LLC[155]
- ITC Interconnection LLC
- Linden VFT LLC
- Monongahela Power d/b/a Allegheny Power, First Energy Subsidiary [156]
- Neptune Regional Transmission System, LLC[157]
- PPL Electric Utilities Corporation, d/b/a PPL Utilities[158]
- Public Service Electric and Gas Company
- Rockland Electric Company
- Virginia Electric and Power Company

Chronic Constraints

The most severe constraints occur on 230 kV transmission facilities moving power south from Pennsylvania and New Jersey to Maryland, Delaware, and Virginia. Local congestion also occurs on low-voltage lines near load centers in northern Illinois, New Jersey, eastern Pennsylvania, central and eastern Maryland, northern Virginia, the District of Columbia, and Delaware.

Transmission Planning

PJM's Regional Transmission Expansion Plan identifies transmission system additions and improvements needed to keep electricity flowing within PJM. Studies are conducted to test the transmission system against national and regional reliability standards. These studies look forward to identify future transmission overloads, voltage limitations, and other reliability standards violations. PJM then develops transmission plans to resolve violations that could otherwise lead to overloads and blackouts.

Supply Resources

The total capacity in PJM is over 219 GW and is predominately comprised of natural gas, coal, and nuclear generators, as shown in the bar chart below. Much of PJM's gas-fired capacity is located near the Marcellus and Utica shale formations. Of note, 40.6 gigawatts of coal-fired capacity are projected to retire in PJM between 2011 and 2026.[159]

Demand Response

End-use customers providing demand response have the opportunity to participate in PJM's energy, capacity, synchronized reserve, and regulation markets. PJM's demand response programs can be grouped into emergency or economic programs. The emergency program compensates end-use customers who reduce their usage during emergency conditions on the PJM system. Participation in the emergency program may be voluntary or mandatory and payments may include energy payments, capacity payments or both.

The economic program allows end-use customers to reduce electricity consumption in the energy markets and receive a payment when LMPs are high. Under this program, all hours are eligible and all participation is voluntary. Participation in the program takes three forms: submitting an offer into the day-ahead market

153 Transmission Companies represented: AEP Appalachian Transmission, AEP Energy Partners, AEP Energy, AEP Indiana Michigan Transmission, AEP Kentucky Transmission, AEP Ohio Transmission, AEP West Virginia Transmission, Appalachian Power, Indiana Michigan Power, Kentucky Power, Kingsport Power, Ohio Power, Ohio Valley Electric, PATH West Virginia Transmission, Transource Energy, Wheeling Power.

154 Transmission Companies represented: Duke Energy Kentucky, Duke Energy Ohio.

155 Transmission Companies represented: Commonwealth Edison, PECO Energy, Baltimore Gas and Electric.

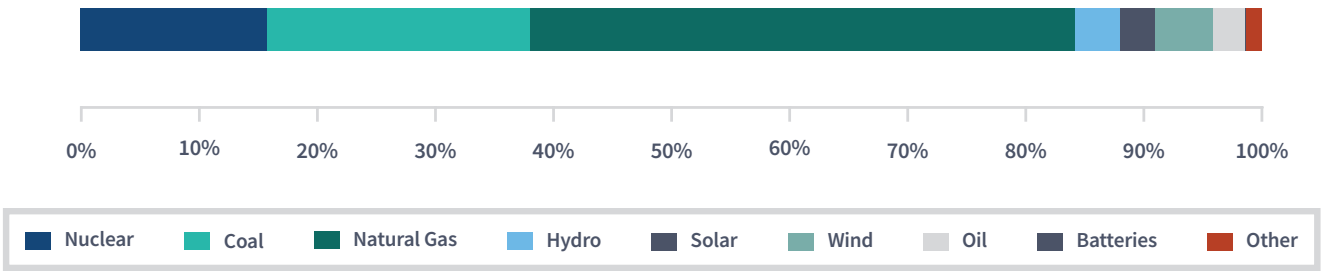
156 Transmission Companies represented: American Transmission Systems, Jersey Central Power & Light, Mid-Atlantic Interstate Transmission, PATH Allegheny Transmission, Potomac Edison, Trans-Allegheny Interstate Line, West Penn Power.

157 Transmission Companies represented: Hudson Transmission Partners.

158 Transmission companies represented: Louisville Gas and Electric, Kentucky Utilities.

159 Monitoring Analytics, *2022 Quarterly State of the Market Report, January Through June*, Section 12, p. 673 (https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022q2-som-pjm-sec12.pdf).

Figure 2-21: PJM Capacity Mix



Source: EIA Form 860-M[161]

that clears; submitting an offer into the real-time market that is dispatched; and self-scheduling load reductions while providing notification to PJM. End-use customers participate in demand response in PJM through members called curtailment service providers who act as agents for the customers. Curtailment service providers aggregate the demand of retail customers, register that demand with PJM, submit the verification of demand reductions for payment by PJM and receive the payment from PJM.

MARKET FEATURES

Energy Markets

Energy Markets: PJM operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. In the real-time market, PJM uses 5-minute intervals. Generators that are available but not selected in the day-ahead scheduling may alter their offers for use in the real-time market during the generation rebidding period from 4 p.m. to 6 p.m.; otherwise, their original day-ahead market offers remain in effect for the real-time market.

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. PJM procures most ancillary services via its energy markets. Blackstart service and reactive power are compensated on a cost-of-service basis.

Market Power Mitigation

PJM caps offers for any hour in which there are three or fewer generation suppliers available for redispatch that are jointly pivotal, meaning they have the ability to increase the market price above the competitive level. This is called the Three Pivotal Supplier Test. When this occurs, generator offers are adjusted to price levels reflecting short-run marginal cost.

Capacity Markets

PJM's capacity market is called the Reliability Pricing Model (RPM). The RPM market was implemented in 2007 and is designed to ensure the future availability of capacity resources, including demand-resources and energy-efficiency resources that will be needed to keep the regional power grid operating reliably. The RPM market design is based on three-year, forward-looking annual obligations for locational capacity, under which supply offers are cleared against a downward-sloping demand curve, called the variable resource requirement (VRR) curve. The VRR curve establishes the amount of capacity that PJM requires its LSE customers to purchase, and the price for that capacity, in each capacity zone (locational deliverability area or LDA). Under RPM, when an LDA is transmission-constrained in the auction (limited in the amount of generation that can be imported into those areas), capacity prices generally rise in that area relative to the overall PJM footprint.

160 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

Annual auctions are referred to as Base Residual Auctions (BRA). LSEs that are able to fully supply their own capacity needs can choose not to participate in the auctions. The largest amounts of capacity in PJM are procured through the BRA, with lesser quantities procured through self-supply and contracted (bilateral) resources.

Market power mitigation in PJM's capacity market includes rules delineating a must-offer requirement, offer caps, minimum offer prices, exceptions for competitive entry, among others. Demand resources and energy efficiency resources may be offered into RPM auctions and receive the clearing price without mitigation.

Specific RPM rules, termed Capacity Performance, provide performance incentives for power plants, demand response, and energy efficiency resources to provide electricity at peak demand regardless of extreme weather events and system emergencies. Capacity Performance rules provide performance bonus payments for resources that over-perform during system emergencies, and severe financial penalties for resources that do not perform during such events.

Existing generation that qualifies as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement option. The fixed resource option allows LSEs to meet their supply obligation outside PJM's capacity market, using, for example, resources they own.[161] Intermittent and capacity storage resources, including hydro, and demand response and energy efficiency, are also exempt from must-offer requirements. An administratively determined demand curve defines scarcity pricing levels and, with the supply curve derived from capacity offers, determines market prices in each BRA. Participation by load-serving entities is mandatory, except for those entities that elect the fixed resource requirement option. Also, any generator that has a commitment from the capacity market must submit an offer into the day-ahead energy market.

Special Provisions for Essential Resource Retirements

A generator owner who wishes to retire a unit must request permission from PJM to deactivate the unit at least 90 days in advance of the planned date. The request includes an estimate of the amount of project investment necessary to keep the unit in operation. PJM, in turn, analyzes if the retirement would lead to a reliability issue. Additionally, PJM estimates the period of time it would take to complete transmission upgrades necessary to alleviate the reliability issue.

If PJM requests the unit to operate past the desired deactivation date, the generator owner may file with FERC for cost recovery associated with operating the unit until it may be deactivated. Alternatively, the owner may choose to receive avoided cost compensation calculated according to PJM's tariff.

Financial Transmission Rights

PJM conducts auctions for selling and buying FTRs made available for the PJM transmission system. Proceeds from the auctions are paid to Auction Revenue Right (ARR) holders, where the ARRs are allocated to firm transmission service customers. PJM conducts its auctions on a long-term, annual, and monthly basis. In PJM, market participants are able to acquire financial transmission rights in the form of options or obligations. The RTO includes a secondary market for its FTRs, which facilitates bilateral trading of existing FTRs between PJM members through an internet-based computer application.

Virtual Transactions

PJM's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. In addition to the types of transaction discussed above, PJM offers Up to Congestion (UTC) transactions, a spread bid. In a UTC transaction, a market participant submits an offer to simultaneously inject energy at a specified source and withdraw the same megawatt

161 PJM, *Securing Fixed Resources,* (accessed December 2, 2022), https://pjm.com/-/media/about-pjm/newsroom/fact-sheets/securing-resources-through-fixed-resource-requirement-fact-sheet.ashx.

quantity at a specified sink in the day-ahead marketand specifies the maximum difference in locational marginal prices (LMP) at the transaction's source and sink that the market participant is willing to pay. PJM accepts the bid if the day-ahead LMP differential, i.e., the difference in day-ahead LMPs at the sink and the source, does not exceed the participant's UTC transaction bid. UTC positions are liquidated in the real-time energy market.

Credit Requirements

PJM's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions. The RTO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and credit scores.

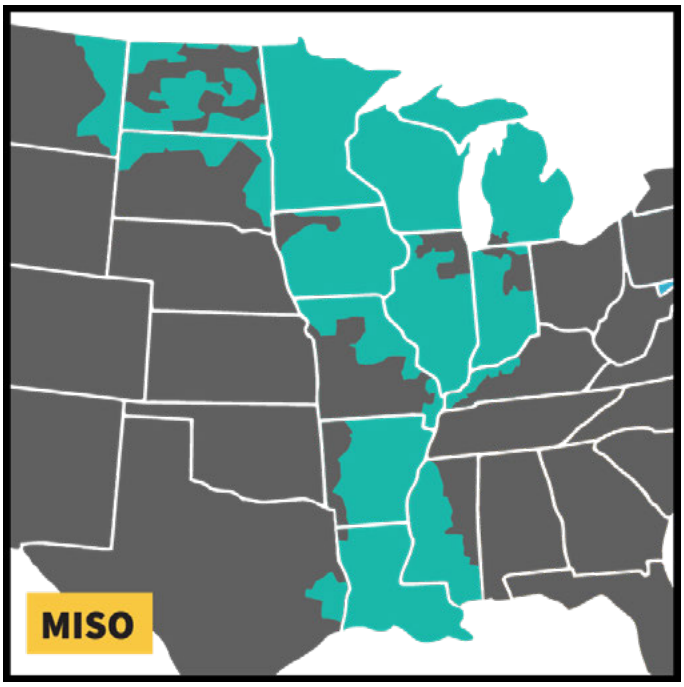
Midcontinent Independent System Operator (MISO)

MARKET PROFILE

MISO operates the transmission system and a centrally dispatched market in portions of 15 states in the Midwest and the South, extending from Michigan and Indiana to Montana and from the Canadian border to the southern areas of Louisiana and Mississippi. The system is operated from three control centers: Carmel, Indiana; Eagan, Minnesota; and Little Rock, Arkansas. MISO also serves as the reliability coordinator for additional systems outsideof its market area, primarily to the north and northwest of the market footprint.

MISO was not a power pool before organizing as an ISO in December 2001. It began market operations in April 2005.

Figure 2-22: Midcontinent Independent System Operator



Source: Hitachi Energy, Velocity Suite

In January 2009, MISO implemented a market redesign that added auctioned and optimized ancillary services along with energy. As part of the market update, MISO combined its 24 separate balancing areas into a single balancing area. In 2013, the RTO began operations in the MISO South region, including the utility footprints of Entergy, Cleco, and South Mississippi Electric Power Association, among others, in parts of Arkansas, Mississippi, Louisiana, and Texas.

Peak Demand

MISO's all-time peak demand was 127 GW in summer 2011.[162]

Imports and Exports

MISO has interconnections with the PJM and SPP RTOs. It is also directly connected to Southern Company, TVA, the electric systems of Manitoba and Ontario, and several smaller systems. MISO is a net importer of power overall, but the interchange with some areas can flow

162 MISO, Corporate Fact Sheet, at 1 (June 2022), https://www.misoenergy.org/about/media-center/corporate-fact-sheet.

in either direction, depending on the relative loads and prices in the adjoining regions. Manitoba Hydro supplies a large part of MISO's load with its excess capacity, particularly in the summer.

Market Participants

MISO includes approximately 56 transmission owners, whose assets define the MISO market area. MISO's market participants include generators, power marketers, transmission-dependent utilities and load-serving entities.[163]

Membership and Governance

An independent board of directors of ten members, including the CEO, governs MISO. Directors are elected by the MISO membership from candidates provided by the board.[164]

MISO relies upon a stakeholder process that works to find collaborative solutions to problems faced by the RTO. These entities have an interest in MISO's peration and include state regulators, consumer advocates, transmission owners, independent power producers, power marketers and brokers, municipal and cooperative utilities and large-volume customers.

Transmission Owners

MISO's largest transmission owners include:

- American Transmission Co.
- Ameren (Missouri and Illinois)
- American Transmission Systems
- Duke
- Cleco
- Entergy
- Indianapolis Power and Light
- ITC
- Michigan Public Power Agency
- NSP Companies (Xcel)
- Northern Indiana Public Service Co.
- Otter Tail Power
- MidAmerican Energy

Chronic Constraints

MISO has certain pathways that are more likely to become congested, but the likelihood and pattern of congestion in any area is subject to weather patterns, wind production, and interchange with external regions. When load is high in the eastern part of MISO and to the east in PJM, constraints occur on pathways from the Minnesota and Wisconsin areas through Chicago and across Indiana. A particular congestion point with this pattern is northern Indiana. When colder weather occurs in Minnesota and the Dakotas, there is often congestion in the northern direction, particularly in Iowa. Higher wind production can cause localized constraints in some areas and can cause congestion in pathways from southern Minnesota and western Iowa moving eastward. New Orleans and East Texas are two constrained areas in MISO South. Additionally, constraints frequently arise between MISO Midwest and MISO South.

Transmission Planning

The main vehicle MISO uses for transmission planning is the MISO Transmission Expansion Plan developed by the MISO planning department in collaboration with transmission owners and other stakeholders who form the planning advisory committee. The plan is updated annually. Once approved by the board, the plan becomes the responsibility of the transmission owners.

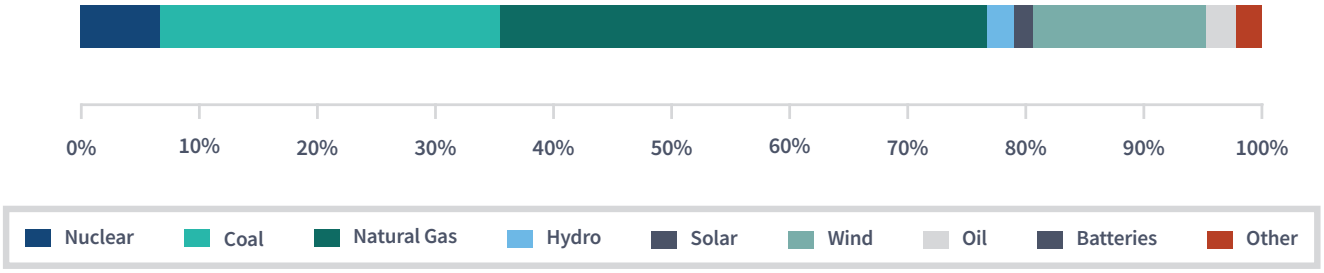
Supply Resources

The total capacity in MISO is over 197 GW and is predominately composed of coal and natural gas-fired generators, providing roughly 70 percent of the total capacity combined, as shown in the bar chart below. Nuclear and wind are also important resources for the region.

163 *Id.*

164 MISO, *Principals of Corporate Governance*, at 3, https://cdn.misoenergy.org/Principles%20of%20Corporate%20Governance110859.pdf.

Figure 2-23: MISO Capacity Mix



Source: EIA Form 860-M[165]

Demand Response

MISO has more than 12.2 GW of demand response resources, including behind-the-meter generation. A number of these resources are operated through local utility programs and are not under the direct control of MISO. MISO has provisions allowing demand-side resources to participate in the energy and reserve markets, but participation is a small part of demand response. Some of the demand response under MISO's direct control is only available under emergency conditions.[166]

MARKET FEATURES

Energy Markets

MISO operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. MISO's real-time market operates for 5-minutes intervals.

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. MISO procures ancillary services via the co-optimized energy and ancillary services market.

In addition to ancillary services, MISO has implemented a ramping product that provides capacity that can increase output rapidly to help offset shifts in generation or load, known as the Ramp Capability Product (RCP).

Market Power Mitigation

When congestion occurs, there may be limits on the number of generators that can satisfy load in some areas, so that they may be able to exercise market power. In response, MISO may impose mitigation for those generators whose offers are significantly higher than their costs and have a significant impact on one or more LMPs. When these conditions are met, MISO reduces the generator's offer to an offer that is consistent with a competitive result.

Capacity Markets

MISO maintains an annual capacity requirement on all LSEs based on the load forecast plus reserves. LSEs are required to specify to MISO what physical capacity, including demand-side resources, they have designated to meet their load forecast. This capacity can be acquired either through an annual capacity auction, bilateral purchase, or self-supply. For the capacity market, MISO is divided into 10 zones whose forecast demand must be met by internal generation, demand-side resources, or deliverable external capacity.

165 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

166 Potomac Economics, *2021 State of the Market Report for the MISO Electricity Markets,* at 100 (June 2022), https://www.potomaceconomics.com/wp-content/uploads/2022/06/2021-MISO-SOM_Report_Body_Final.pdf.

Resources used to meet LSEs' annual capacity requirements must offer that capacity into MISO's energy markets and, when qualified, into the ancillary services markets, for each hour of each day for the entire planning year. Must-offer requirements support MISO's mitigation process by providing an objective measure with which to identify physical withholding.

Special Provisions for Essential Resource Retirements

Power plant owners that seek to retire or suspend a generator must first obtain approval from MISO. The RTO evaluates plant retirement or suspension requests against reliability needs, and System Support Resource (SSR) designations are made where reliability is threatened. Once an agreement has been reached, SSRs receive compensation associated with remaining online and available.

Financial Transmission Rights

MISO holds FTR auctions to allow market participants the opportunity to acquire FTRs, sell FTRs that they currently hold, or to convert ARRs to FTRs. ARRs provide LSEs, and entities who make transmission upgrades, with a share of the revenues generated in the FTR auctions. MISO allocates ARRs to transmission customers relative to historical usage, or upgraded capability, of the transmission system. MISO FTRs are monthly and annual products.

Virtual Transactions

MISO's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Virtual transactions allow for more participation in the day-ahead, price-setting process, allow participants to manage risk, and promote price convergence between the day-ahead and real-time markets.

These transactions are a component of the day-ahead market where the bids and offers are included in the determination of the LMP along with physical resource offers and actual load bids. Market participants, whose virtual transactions clear in the day-ahead market, have their positions cleared in the real-time market at the real-time price. Virtual bids and offers are allowed in MISO at any pricing node or aggregate of pricing nodes.

Credit Requirements

MISO's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions. The RTO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and credit scores.

Southwest Power Pool (SPP)

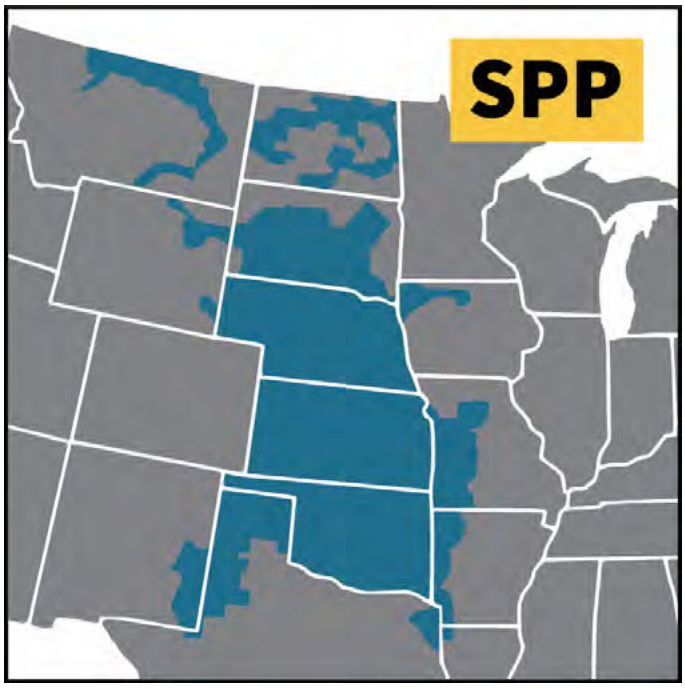
MARKET PROFILE

SPP's RTO manages transmission in fourteen states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. Founded as an 11-member tight power pool in 1941, SPP achieved RTO status in 2004, ensuring reliable power supplies, adequate transmission infrastructure, and competitive wholesale electricity prices for its members. SPP operates through its control center in Little Rock, Ar.

SPP began operating its real-time Energy Imbalance Service (EIS) market in 2007. In the same year, SPP became a FERC-approved Regional Entity. The SPP Regional Entity serves as the reliability coordinator for the NERC region, overseeing compliance with reliability standards.

SPP implemented its Integrated Marketplace in March 2014 which includes a day-ahead energy market, a real-time energy market, and an operating reserve market. SPP's Integrated Marketplace also includes a market for Transmission Congestion Rights. The SPP Integrated Marketplace co-optimizes the deployment of energy and operating reserves to dispatch resources on a least-cost basis.

Figure 2-24: Southwest Power Pool



Source: Hitachi Energy, Velocity Suite

SPP expanded its footprint in 2015, incorporating the Western Area Power Administration – Upper Great Plains region, the Basin Electric Power Cooperative, and the Heartland Consumers Power District. The expansion nearly doubled SPP's service territory by square miles, adding more the 5 GW of peak demand and over 7 GW of generating capacity.[167]

SPP also operates a real-time energy imbalance market in the Western Interconnect, which is described further below.

Peak Demand

SPP's all-time peak demand of 53 GW occurred in summer 2022.[168]

Imports and Exports

SPP has interties with MISO, TVA, and other systems. Additionally, SPP has two DC interties with ERCOT and seven DC interties to the Western Interconnection through New Mexico, Colorado, Nebraska, South Dakota and Montana. At times, SPP is both a net importer and net exporter of electricity at times.

Market Participants

SPP's market participants include investor-owned utilities, generation and transmission cooperatives, independent power producers, municipal utilities, state authorities, independent transmission companies, power marketers, financial participants, and a federal power marketing administration.

Membership and Governance

SPP is governed by a board of directors representing and elected by its members. Supporting the board is the members committee, which provides non-binding input. The members' committee is composed of representatives from each sector of SPP's membership. The SPP Regional State Committee represents retail regulatory commissions from state agencies and provides input on matters of regional importance related to the development and operation of bulk electric transmission.

Transmission Owners

SPP's largest transmission owners include:

- American Electric Power
- Oklahoma Gas and Electric
- Westar Energy
- Southwestern Public Service (Xcel Energy)
- Great Plains Energy
- Kansas City Power & Light
- Omaha Public Power District
- Nebraska Public Power District
- Tri-State Generation and Transmission
- Empire District Electric
- Western Area Power Administration – Upper Great Plains
- Western Farmers Electric Cooperative

167 Southwest Power Pool, *Western, Basin, Heartland join Southwest Power Pool,* at 1 (October 2015), https://www.spp.org/about-us/newsroom/western-basin-heartland-join-southwest-power-pool/.

168 Southwest Power Pool, *Fast Facts*, https://www.spp.org/about-us/fast-facts/.

Chronic Constraints

SPP has certain pathways that are more likely to become congested, based on the physical characteristics of the transmission grid and associated transfer capability, the geographic distribution of load, and the geographic differences in fuel costs. The eastern side of the SPP footprint has a higher concentration of load and congestion can occur when wind-powered generation from the west tries to travel across limited connections to the east. The most significant congestion has typically occurred in the Oklahoma and Texas Panhandle region.[169]

Transmission Planning

SPP conducts its transmission planning according to its Integrated Transmission Planning process,which is a three-year planning process that includes 20-year, 10-year, and near-term assessments designed to identify transmission solutions that address both near-term and long-term transmission needs. The Integrated Transmission Planning process focuses on identifying cost-effective regional transmission solutions, which are identified in an annual SPP Transmission Expansion Plan report.

Supply Resources

The total capacity in SPP is approximately 94 GW and is predominately composed of natural gas and coal-fired generators, as shown in the bar chart below. Wind is an important and growing resource in the region.

Demand Response

SPP allows demand response resources to register in its market.[170] As of December 31, 2021, 102 demand resources participated in SPP's markets, representing 176 MW of nameplate capacity. While the demand response resources can participate in SPP's markets, they are rarely dispatched.

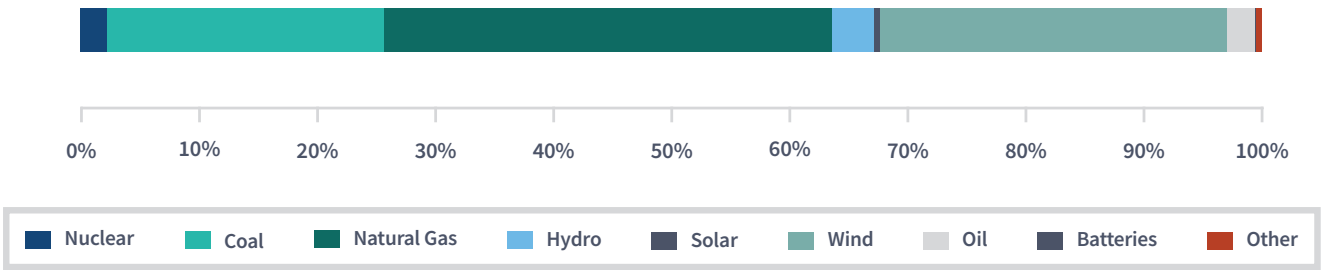
SPP allows Market Participants to register two types of demand response resources: Block Demand Response (BDR) resources and Dispatchable Demand Response (DDR) resources. BDR resources can participate in SPP's markets by providing energy and reserves in 60-minute blocks. DDR resources can participate in SPP's markets by providing energy, regulation, and reserves in 5-minute blocks.

MARKET FEATURES

Energy Markets

SPP operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. SPP's real-time market operates in 5-minute intervals.

Figure 2-25: SPP Capacity Resources



Source: EIA Form 860-M[171]

169 See Southwest Power Pool Market Monitoring Unit, *State of the Market 2022* (May 2022), at 202, https://www.spp.org/documents/67104/2021%20annual%20state%20of%20the%20market%20report.pdf.

170 SPP Market Monitor, State of the Market 2021 (May 10, 2021), at 49, https://www.spp.org/documents/67104/2021%20annual%20state%20of%20the%20market%20report.pdf.

171 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. SPP procures ancillary services via the co-optimized energy and ancillary services market. Separately, SPP has a ramping product to procure capacity that can quickly increase output to offset both anticipated and unforeseen future changes in generation or load within the hour, known as the Ramp Capability Product. SPP launched this ramp product in March 2022.

Market Power Mitigation

SPP applies a set of behavioral and market outcomes tests to determine if the local market is competitive and if generator offers should be adjusted to approximate short-run marginal costs. SPP's mitigation test includes a local market power test, a conduct test, and a market impact test. Where mitigation measures are triggered by the tests, SPP generates a mitigated resource offer that the RTO then uses for dispatch, commitment, and settlement purposes.

Capacity Markets

SPP does not offer a capacity market. However, it requires each Load Responsible Entity (LRE) to have sufficient energy supply (capacity) to cover its energy obligations. SPP develops and implements policies and processes necessary to ensure resource adequacy and determines the amount of capacity each LRE must have available to meet its energy obligations. [172]

Special Provisions for Essential Resource Retirements

A generator owner who wishes to retire a unit must request that SPP study the retirement of the resource no less than one year from the expected retirement date. SPP will then conduct studies to examine the potential effects of the resource retirement including the need for transmission network upgrades, if any.

Otherwise, SPP prepares annual reliability studies as part of its system planning responsibilities. In the event that the studies reveal a potential constraint on SPP's ability to deliver power to a local area on the transmission system, SPP works with regional stakeholders to find alternate transmission, operating procedure, or generation solutions for the constraint and thus maintain grid reliability. The SPP parties then determine an appropriate sharing of the costs, and, if unable to reach agreement, SPP will submit a proposed cost-sharing arrangement to FERC for approval.

Financial Transmission Rights

SPP refers to FTRs as Transmission Congestion Rights (TCR). A TCR is an instrument that entitles the holder to receive compensation, or requires the holder to pay a charge, for costs that arise from transmission congestion over a selected path, or source-and-sink pair of locations on the grid. A TCR provides the holder with revenue, or charges, equal to the difference in congestion prices in the day-ahead market across the selected TCR transmission path. SPP TCRs include monthly and annual products, as well as a long-term instrument called Long-Term Congestion Rights.

A related product, ARRs, provide their holders with a share of the revenue generated in the TCR auctions. In general, ARRs are allocated based on firm transmission rights. As with TCRs, ARRs provide transmission owners and eligible transmission service customers an offset or hedge against transmission congestion costs in the day-ahead market.

Virtual Transactions

SPP's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. In SPP, virtual bids are sometimes used in the day-ahead market as a placeholder or hedge for wind generation expected in the real-time market.

Credit Requirements

SPP's tariff includes credit requirements that a market participant needs to meet in order to participate in the

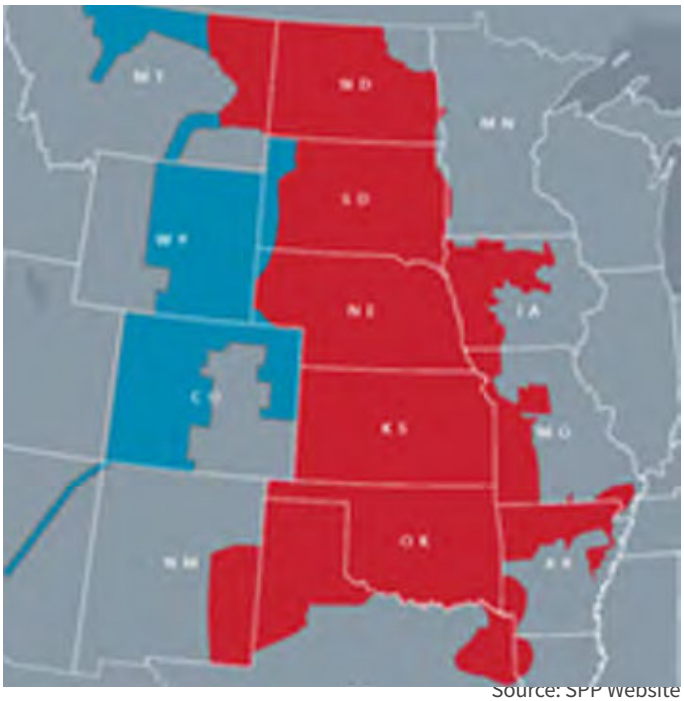
172 *Southwest Power Pool Market Monitoring Unit, State of the Market 2022 (May 2022), at 202*, https://www.spp.org/documents/67104/2021%20annual%20state%20of%20the%20market%20report.pdf

market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions. SPP must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and various financial measures.

Western Energy Imbalance Service (WEIS)

SPP launched its WEIS market in February 2021. The WEIS market balances generation and load regionally in real time for participants in the Western Interconnection. SPP's WEIS market centrally dispatches generation from participating resources every five minutes using the lowest-cost resource available to meet demand. As of August 2022, ten entities participate or plan to participate in the WEIS Market with three more anticipated to join in April 2023: Basic Electric Power Cooperative, BlackHills Energy (April 2023), Colorado Springs Utilities, Deseret Power Electric Cooperative, Guzman Energy, Municipal Energy Agency of Nebraska, Platte River Power Authority (April 2023), Tri-State Generation and Transmission Association, WAPA (Upper Great Plains West, Rocky Mountain, and Colorado River Storage Projects regions), and Xcel Energy (April 2023). The following map shows SPP's footprint in red and the WEIS in blue.

Figure 2-26: Western Energy Imbalance Service



Source: SPP Website

California Independent System Operator (CAISO)

MARKET PROFILE

CAISO operates an ISO serving most of California and part of Nevada. CAISO is a California nonprofit public benefit corporation started in 1998 when the state restructured its electric power industry. CAISO manages wholesale electricity markets, centrally dispatching electric generators. In managing the grid, CAISO provides open access to the transmission system and performs long-term transmission planning. It manages energy and ancillary markets in day-ahead and real-time markets and is responsible for regional reliability. CAISO also operates a real-time energy imbalance market, the Western Energy Imbalance Market (WEIM), which is discussed further below. CAISO operates its grid out of its main control center in Folsom, CA.

Peak Demand

CAISO's all-time peak demand was 52 GW in summer 2022.[173]

Imports and Exports

Up to about one-third of CAISO's energy is supplied by imports, principally from the Southwest (Arizona, Nevada, and New Mexico) and the Pacific Northwest (Oregon, Washington, and British Columbia). Imports from the Pacific Northwest generally increase in the

173 California ISO, *California ISO Peak Load History 1998 through 2022*, at 1 (n.d.), http://www.caiso.com/documents/californiaisopeakloadhistory.pdf.

late spring when hydroelectric production peaks from increases in winter snowmelt and runoff.

Market Participants

CAISO's market participants include load-serving investor-owned utilities, load-serving municipal utilities, generators, power marketers, utility customers, and financial entities.

Membership and Governance

The CAISO has a board of governors that consists of five members appointed by the governor and confirmed by the California Senate. The board provides corporate direction, reviews and approves management's annual strategic plans, and approves CAISO's operating and capital budgets.

CAISO uses an informal stakeholder process to propose solutions to problems that may ultimately require a filing at FERC. Unlike other RTOs, which have a formal committee structure, CAISO's stakeholder process generally consists of rounds of dialogue with stakeholders on major policy issues.

Transmission Owners

CAISO's largest transmission owners include:

- Pacific Gas and Electric
- Southern California Edison
- San Diego Gas and Electric
- Valley Electric Association
- Municipal utilities such as Vernon, Anaheim, and Riverside

Chronic Constraints

CAISO has several locally constrained areas, typically near population centers and where transmission lines have relatively low voltage (115 kV and below). The locally constrained areas that have local capacity requirements include the Greater Bay Area, Greater Fresno, Sierra, Humboldt, Los Angeles Basin, San Diego, and North Coast/North Bay.

Transmission Planning

CAISO conducts an annual transmission planning process with stakeholders that includes both short-term and long-term projects.

Figure 2-27: California Independent System Operator



Source: Hitachi Energy Velocity Suite

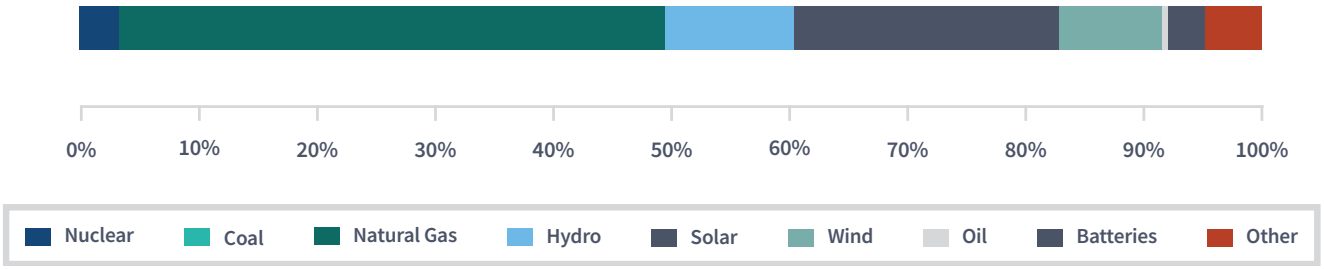
Supply Resources

The total capacity in CAISO is over 70 GW and is predominately composed of natural gas-fired and hydroelectric generators, as shown in the bar chart below. CAISO also has substantial renewable resources, including roughly half of the installed solar capacity in the U.S.

Demand Response

Demand response participation in the wholesale energy market includes programs entitled Proxy Demand Response, Reliability Demand Response Resources, and CAISO's Participating Load program. Proxy Demand Response allows for customer loads, aggregated by LSEs or third-party providers, to offer load reduction into CAISO's day-ahead, real-time, and ancillary services markets in return for compensation. Reliability Demand Response Resources allows customer loads, also aggregated by LSEs or third-party providers, to reduce load for compensation when triggered for

Figure 2-28: CAISO Capacity Mix



Source: EIA Form 860-M[175]

reliability-related events. Reliability Demand Response Resources can also offer into the day-ahead market. The Participating Load program allows the CAISO operators to directly curtail end-users' load, rather than through aggregators. This is a relatively small program that is primarily composed of the power demand from California's water pumping projects. Other demand response in California consists of programs for managing peak summer demands operated by the state's electric utilities. In general, activation of the utility demand response programs is based on criteria that are internal to the utility or when CAISO issues a Flex Alert. Flex Alerts also inform consumers of how and when to conserve electricity usage.

MARKET FEATURES

Energy Markets

CAISO operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. CAISO operates a 15-minute market to adjust schedules from those determined in the day-ahead market, then a 5-minute market to balance supply and load in real-time. Real-time bids can be submitted up to 75 minutes before the start of the operating hour.

CAISO also procures capacity in the real-time market to provide upward and downward ramping of generation in order to accommodate changes in net load with the Flexible Ramping Product.[175] This service provides compensation to the generators selected to provide the desired flexible ramping capability.[176]

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. CAISO procures ancillary services via its co-optimization of energy and ancillary services in its energy markets

In addition to ancillary services, CAISO has implemented a ramping product to procure capacity that can quickly increase output to offset changes in generation or load, known as the Flexible Ramping Product.

Market Power Mitigation

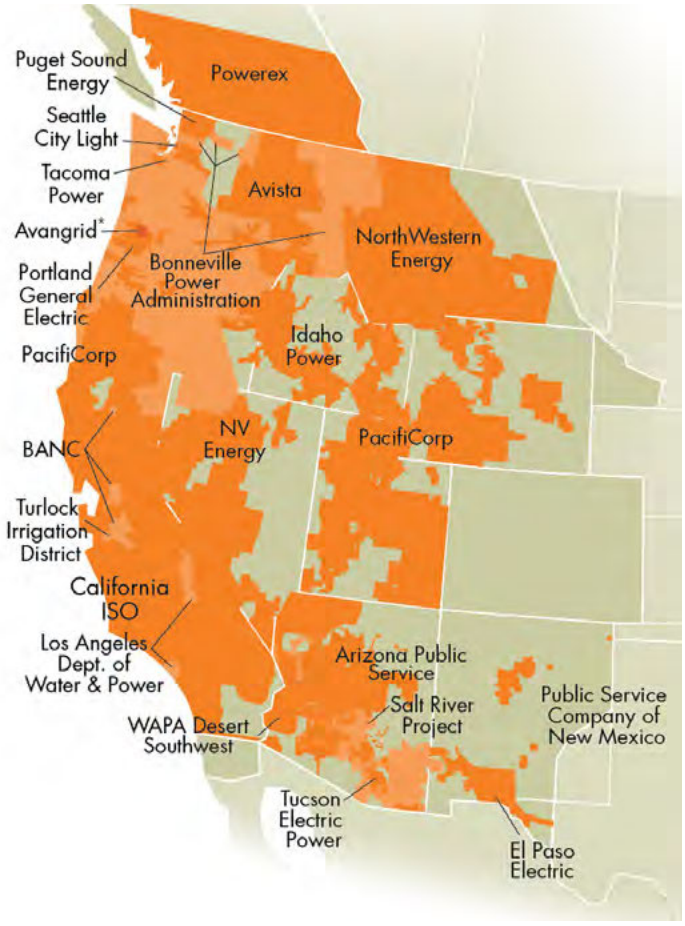
CAISO applies a set of behavioral and market outcome tests to determine if the local market is competitive and if generator offers should be adjusted to approximate price levels that would be seen in a competitive market – close to short-run marginal costs.

174 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

175 Net load in CAISO is total market demand minus generation output from solar and wind resources.

176 CAISO describes ramping capability as a resource's ability to move from one energy output to a higher (upward ramp) or lower (downward ramp) energy output; *California Independent System Operator Corp.,* 156 FERC ¶ 61,226, at P 2 (2016).

Figure 2-29: Western Energy Imbalance Market



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Capacity Markets

CAISO does not operate a formal capacity market, but it does have a mandatory resource adequacy (RA) requirement. The program requires LSEs to procure 115 percent of their aggregate system load on a monthly basis, unless a different reserve margin is mandated by the LSE's local regulatory authority. The program provides deliverability criteria that each LSE must meet, as well as system and local capacity requirements and flexibility requirements.

The CAISO market rules also include must-offer provisions pertaining to resources procured as RA resources. These resources must make themselves available to the CAISO day-ahead and real-time markets for the capacity for which they were counted.

Special Provisions for Essential Resource Retirements

CAISO employs RMR contracts to assure that it has the ability to reliably serve load in local import-constrained areas. RMR contracts also help to mitigate any local market power that one or more units may have. Over time, CAISO has been able to significantly decrease its RMR designations in much of the system. Remaining generators with RMR contracts are located primarily near the San Francisco and Los Angeles areas.

Financial Transmission Rights

In California, FTRs are referred to as Congestion Revenue Rights (CRR). A CRR is an instrument that entitles the CRR holder to a payment for costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations on the grid. The CRR also requires its holder to pay a charge for those hours when congestion occurs in the opposite direction of the selected source-and-sink pair. CRRs are monthly or quarterly products. CRRs can be bought at auction or allocated by CAISO. Allocated CRRs receive the congestion value for a specific path, similar to a converted FTR. CAISO also allocates open market CRR auction revenues to LSEs, based on their physical participation in the market, similar to an ARR in other markets.

Virtual Transactions

CAISO's market includes a virtual transactions feature, termed convergence bidding. CAISO's convergence bidding includes both virtual supply and virtual demand transactions.

Credit Requirements

CAISO's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be absorbed by all market participants. CAISO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to

certain restrictions – CAISO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth, net assets, and credit rating.

Western Energy Imbalance Market (WEIM)

On Nov. 1, 2014, CAISO began operation of an energy imbalance market (EIM) with PacifiCorp's two BAAs, PacifiCorp East and PacifiCorp West. The EIM is an extension of the CAISO's real-time market into other BAAs in the Western Interconnection. The market dispatches resources inside the participating entities' BAAs to meet intra-hour changes in their energy demand and supply. The EIM's imbalance energy helps the BAAs meet their energy demand in real-time. Overall, EIM energy represents about two to three percent of the energy used to meet load in the participating BAAs. With the balancing authorities in the Pacific Northwest, the EIM integrates low-cost hydroelectric power generation with the significant amount of solar and wind generation capacity in CAISO.

The EIM is a voluntary market where the participating balancing authorities can choose which resources to include in the market. The market participants have the flexibility to add and remove capacity from the EIM on an hourly basis. The transmission system operators for each participating BAA preserve the responsibility and flexibility to respond to events such as a sudden large imbalance between load and supply caused by a loss of a power plant or transmission line.

As of November 2022, the EIM consisted of the following LSEs and their respective BAAs: BPA, Puget Sound Energy, Portland General Electric, PacifiCorp West, PacifiCorp East, Idaho Power, NV Energy, Tucson Electric Power, Avista, NorthWestern Energy, Los Angeles Department of Water & Power, Public Service Company of New Mexico, Turlock Irrigation District, Salt River Project, Seattle City Light, Balancing Authority of Northern California, Idaho Power Company, Portland General Electric, Puget Sound, NV Energy, Arizona Public Service, and CAISO. Additionally, Powerex (the marketing arm of the Canadian utility, BC Hydro) joined the EIM, providing contributions of generation and load imbalance (the difference between generation supply and demand schedules).[177] Other balancing authorities have expressed interest in becoming EIM Entities.

The EIM provides a market mechanism for dispatching generation resources to meet imbalance energy needs along with a limited amount of power flows between the participating BAAs. The market dispatches generation based on the relative cost of the resources, resulting in cost savings for the participants. Before the EIM, a balancing authority such as PacifiCorp West or PacifiCorp East resolved imbalances between energy demand and supply in real-time by dispatching its resources and using ancillary services (mainly regulation). Under the EIM, by contrast, the market automates the dispatch of enough resource capacity within the BAAs, along with transmission flows between BAAs, to resolve energy imbalances.[178] The automated EIM sets LMPs at both 15-minute and 5-minute intervals.

Along with dispatch cost savings, the EIM also helps integrate renewable generation resources. Prior to the EIM, CAISO imported power from outside its service territory to balance load throughout most hours of the day. However, with the growth of solar and wind generation, particularly in California, there were periods when these resources were forced to curtail because there was too much energy offered into the market. Now, with the EIM, any excess power can be exported throughout the participating BAAs. In some hours, this results in power exports from CAISO to other BAAs.[179]

177 Powerex (BC Hydro) also makes transmission rights available to the EIM, providing its power to the EIM at the British Columbia-U.S. border

178 The EIM software calculates dispatch solutions for the EIM market area as a whole. Consequently, participating balancing authorities need not maintain high levels of reserves.

179 *See* Department of Market Monitoring – California ISO, *2017 Annual Report on Market Issues & Performance,* at 118 (June 2018), http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf.

As the independent system operator of the EIM, CAISO addresses local market power mitigation at 5-minute and 15-minute intervals across the EIM area, which includes the non-CAISO balancing authority areas. CAISO also procures a Flexible Ramp Product to provide upward and downward flexible capacity to meet energy ramp requirements. In these respects, CAISO's operator responsibilities have grown in the EIM as enhancements to the market design have been implemented.









Chapter 3
Gas-Electric Interdependency

GAS-ELECTRIC INTERDEPENDENCY

The significant shift in the U.S. fuel mix has heightened the importance over the past decade of the interdependence of the natural gas and electric systems. Natural gas is now the largest source of U.S. electricity generation; in 2021, about 38.3 percent of utility-scale electricity generation in the U.S. (1.576 trillon kilowatt hours, kWh) was from natural gas.[181] In the same year, the electric power sector accounted for about 37 percent of total U.S. natural gas consumption. The amount of natural gas used for electricity generation (also known as power burn) has increased approximately 49 percent over the past decade.[182] The growth of power burn has been driven by plentiful, low-cost natural gas supply, the favorable economics of gas-fired combined cycle technology, and the relatively low emissions associated with gas-fired generation compared to other fossil fuels. Given the importance of natural gas in electricity generation, integration of market operations between the natural gas and electricity industries is critical. This section provides an overview of natural gas and electric system interdependencies. In addition, it discusses key issues pertaining to gas-electric harmonization[183] that FERC has addressed to ensure the coordinated, reliable, and efficient operation of both the interstate natural gas pipeline network and electricity systems.

FERC JURISDICTION

FERC has jurisdiction over many aspects of gas-electric harmonization, particularly on the electricity side, where it has authority over wholesale electricity markets. In addition, the North American Electric Reliability Corporation (NERC), the FERC-certified electric reliability organization responsible for reliability of the Bulk Power System, has conducted assessments and event analyses that have resulted in recommendations pertaining to gas-electric coordination.[184] Further, FERC may recommend that the North American Energy Standard (NAESB)[185] develop standards pertaining to the nation's natural gas system and bulk electric system, including gas-electric coordination, for adoption by FERC, which then become mandatory. FERC may consider reforms that require the wholesale electricity markets to account for conditions on the pipeline system. In comparison, however, FERC's ability to identify and assess risks on the reliability of natural gas transportation service in real time is limited. Furthermore, FERC lacks statutory authority to respond to natural gas transportation risks.

BACKGROUND

Natural gas usage for electricity generation (power burn) will likely remain relatively flat. The natural gas share of power burn is projected to continue in a constant range despite potential gains due to projected coal and nuclear generating unit retirements, as electricity generation capacity replacements for the expected retirements are increasingly met by generation from renewable sources. Renewable electric-generating technologies are projected to account for about 60 percent of cumulative electricity generation capacity additions through 2050, and natural gas-fired capacity accounts for almost the entire amount of remaining additions. These natural gas-fired generators

181 *See* EIA, *Electricity explained* (July 15, 2022), https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php.

182 *See* EIA, *Natural gas explained* (December 6, 2022), https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php.

183 The term "harmonization" encompasses interactive dynamics between gas and electric such as communication, coordination, and alignment of economic incentives facilitating cross-system reliability.

184 *See* section 215(g) of the Federal Power Act.

185 NAESB is an American National Standards Institute (ANSI) accredited, non-profit 501(c)(6) corporation formed with the support of the U.S. Department of Energy (DOE) for the purpose of developing voluntary business practice standards designed to promote more competitive and efficient natural gas and electric markets. NAESB complies with ANSI's requirements that its procedures are open to materially affected entities and that the standards represent a reasonable consensus of the industry without domination by any single interest or interest category.

will both provide energy and help generators.[186] The U.S. interstate natural gas pipeline system has a long history of reliably serving all customers, including electricity generators. Nevertheless, extreme winter weather events and associated disruptions and constraints to certain natural gas infrastructure over
the last several years have prompted FERC to research, assess, and take action on a number of issues arising from the growing interdependence of the natural gas and electricity markets. These disruptions including the Southwest Gas Outages in 2011, the Polar Vortex in 2014, the Aliso Canyon Storage Field leak in 2015, the Bomb Cyclone during the winter of 2017-2018, Winter Storm Uri in February of 2021, and Winter Storm Elliot in December of 2022, have led to questions regarding the adequacy of market structures and regulations to support the reliance of electricity generation on natural gas. This has in turn prompted FERC to address a number of issues arising from the interdependence of the natural gas and electricity markets.

As an initial exploration of these challenges, FERC convened five regional conferences throughout the month of August 2012, to solicit input from both industries regarding the harmonization of natural gas and electricity markets.[187] The conferences were structured around three sets of issues: scheduling and market structures/rules; communications, coordination, and information-sharing; and reliability concerns. Information gathered at the conferences confirmed that gas-electric interdependence concerns are more acute in some regions than others, with the discussion at each conference focusing on the circumstances and needs of each region. Notwithstanding the regional focus of the discussions, several topics emerged that were common to multiple regions. First, participants in many regions sought confirmation that sharing information in furtherance of enhancing gas-electric coordination would not run afoul of FERC's Standards of Conduct or be construed as engaging in undue discrimination or preference.[188] The Standards of Conduct are intended to prevent undue preferences in the providing of interstate transmission services by prohibiting marketing employees from receiving non-public transmission information. Second, several concerns were expressed regarding the misalignment of natural gas and electric scheduling practices, as well as application of FERC's no bump rule and pipeline capacity release rules.[189] Third, questions were raised in several regions regarding whether generators have appropriate incentives to deliver firm energy. Finally, industry representatives in multiple regions described steps they were considering to address reliability issues in the context of gas-electric coordination.

COMMUNICATION BETWEEN THE NATURAL GAS AND ELECTRIC INDUSTRIES

With electric generation's increased reliance on natural gas, it has become more important that the electric and nature gas sectors maintain robust communication to ensure that their systems are operated reliably and effectively. Communication between interstate natural gas pipelines and electric transmission operators can be essential to help ensure that electric transmission operators provide grid reliability and that interstate natural gas pipelines can meet contractual and operational obligations to all their shippers.

During the FERC-sponsored regional conference, natural gas and electric industry stakeholders pointed out that, historically, industry officials have been reluctant to share operational information because of concerns that doing so could be a violation of current laws, regulations, or tariffs, including FERC's prohibition on undue discrimination. Accordingly, multiple industry participants requested

186 *See* EIA, *Annual Energy Outlook* (March 3, 2022), https://www.eia.gov/outlooks/aeo/narrative/electricity/sub-topic-04.php.

187 *Coordination Between Natural Gas and Electricity Markets*, 141 FERC ¶ 61,125 (2012).

188 The Standards of Conduct govern communications between interstate natural gas pipelines and their affiliates that engage in marketing functions, and public utilities that own or operate electric transmission facilities and their affiliates that engage in marketing functions. *See* 18 CFR § 358.1(a) and (b) (2012).

189 Both rules are covered later in this section.

that, to facilitate the exchange of information between transmission operators, FERC should more clearly identify the types of operational information that may be shared between transmission operators and clarify that the sharing of such information does not violate the prohibition against undue discrimination.

To address these concerns, FERC issued Order No. 787[190] on November 15, 2013, which amended FERC regulations to provide authority for interstate natural gas pipelines and public utilities to share non-public, operational information with each other for the purpose of operational planning and promoting reliable service on both systems. Specifically, the order permits information-sharing for day-to-day operations, planned outages, and scheduled maintenance when, such information is provided for the purpose of promoting reliable service or operational planning.

SCHEDULING AND DISPATCH BETWEEN THE INTERSTATE NATURAL GAS PIPELINE AND WHOLESALE ELECTRIC INDUSTRIES

Natural gas-fired generators must coordinate their operations consistent with both natural gas and electric business practice timelines. Electric transmission operators are continuously and near instantaneously balancing supply and demand to ensure that the system remains in equilibrium. In contrast, due to the physical characteristics of interstate natural gas transmission,[191] pipelines require advance nominations to ensure they have sufficient line pack and storage available to meet the scheduled daily load of all their customers, including natural gas-fired generators, which may constitute significant load for a pipeline, and which generally rely on a just-in-time natural gas supply and pipeline delivery. While pipeline linepack[192] and storage provide some operational flexibility to pipelines to accommodate load swings throughout the day, short-term swings in demand by natural gas-fired electricity generators resulting from redispatch by electric transmission operators may be difficult to manage, particularly during times of coincident peak loads on interstate natural gas pipelines and electric transmission systems, such as during unusual cold weather events when end-use customers may rely on both natural gas and electricity.

A historical, key concern for the electric industry has been that natural gas-fired generators had insufficient time to procure natural gas pipeline transportation given that the day-ahead deadline to request pipeline transportation service was after or very close to the time that the generators receive their day-ahead dispatch instructions from the electricity market operator. In addition, intraday pipeline scheduling flexibility provided natural gas-fired generators in some regions with limited opportunities to revise pipeline nominations within the operating day to accommodate changes in load throughout the electric day. Finally, a third challenge was that the lack of alignment between the industries contributed to operational problems and logistical challenges resulting from the electric operating day extending over two Gas Days.[193]

190 *Communication of Operational Information Between Natural Gas Pipelines and Transmission Operators,* Order No. 787, 78 Fed. Reg. 70,163, at P 2 (November 22, 2013), FERC Stats. & Regs. ¶ 31,350 (2013) (cross-referenced at 145 FERC ¶ 61,134), order on reh'g, Order No. 787-A, 147 FERC ¶ 61,228 (2014), *order dismissing request for clarification,* 152 FERC ¶ 61,051 (2015).

191 Natural gas transportation velocities through long-distance pipelines can rarely exceed 20 miles per hour (mph) under firm service or 50 mph under intermittent service.

192 "Linepack" refers to the volume of natural gas that can be "stored" in a natural gas pipeline.

193 The existing 24-hour operating day, or Gas Day, for interstate natural gas pipelines begins at 9:00 a.m. CCT and ends at 9:00 a.m. CCT the following day. All nominations for interstate natural gas pipeline transportation service are for a daily quantity to be transported over the 24-hour Gas Day. By contrast, with respect to electricity industry scheduling practices, most electric utilities use a 24-hour operating day that begins at 12:00 a.m. local time.

Table 3-1: Previous and Revised NAESB Natural Gas Nomination

Time Shifts -- All times CCT		Previous NAESB Standards	Revised NAESB Standards
Timely (Effective Next Day)	Nomination Deadline	11:30 AM	1:00 PM
Evening (Effective Next Day)	Nomination Deadline	6:00 PM	6:00 PM
Intraday 1 (Effective Current Day)	Nomination Deadline	10:00 AM	10:00 AM
Intraday 2 (Effective Current Day)	Nomination Deadline	5:00 PM	2:30 PM
Intraday 3 (Effective Current Day)	Nomination Deadline	None	7:00 PM

Through a multi-year effort that engaged industry stakeholders, FERC sought to facilitate the coordination of the scheduling practices of the natural gas and electric industries to accommodate the growing interdependency. To better align the scheduling of wholesale natural gas and electricity markets in light of increased reliance on natural gas for electricity generation, FERC issued Order No. 809 on April 16, 2015.[194] This order accepted NAESB's proposal to move the Timely Nomination Cycle nomination deadline for scheduling natural gas transportation from 11:30 AM CCT to 1:00 PM CCT to provide generators more time to acquire natural gas supply and pipeline transportation capacity after learning their electric dispatch obligations. The final rule also accepted NAESB's proposal to add an additional, third intraday nomination cycle at 7:00 PM CCT to provide greater flexibility for generators to obtain and schedule natural gas during the day of operation. This new "no-bump" intraday cycle[195] starts at 7:00 p.m. CCT, two hours later than the prior "no-bump" second intraday cycle, which was moved up to 2:30 p.m. CCT and which is "bumpable." Table 3-1 depicts the previous NAESB gas nomination timeline and the revised NAESB gas nomination timeline accepted in Order No. 809, effective April 1, 2016.

In related actions, on March 20, 2014, FERC instituted proceedings under section 206 of the Federal Power Act to ensure that regional transmission operator (RTO) and independent system operator (ISO) day-ahead scheduling practices conform with any revisions to the natural gas scheduling practices adopted by FERC in Order No. 809.[196] The Section 206 Order required each RTO/ISO to propose tariff revisions such that generators will receive dispatch instructions in sufficient time to be able to acquire natural gas and pipeline transportation by the start of the Timely Nomination Cycle and to complete RTO/ISO supplemental reliability dispatch in sufficient time for generators to use the Evening Cycle. Alternatively, RTOs/ISOs could show cause as to why existing scheduling practices should remain unchanged. FERC subsequently issued orders on all

194 *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities,* Order No. 809, 80 Fed. Reg. 23,198, at P 5 (April 24, 2015), FERC Stats. & Regs. ¶ 31,368 (2015) (cross-referenced at 151 FERC ¶ 61,049 (2015)), *order on clarification,* 152 FERC ¶ 61,095, *order on reh'g,* 152 FERC ¶ 61,212 (2015), *order on clarification,* 153 FERC ¶ 61,049 (2015).

195 The No-Bump Rule restricts firm shippers from bumping nominated and scheduled interruptible service during the last standard intraday nomination cycle of the Gas Day.

196 *Order Initiating Investigation into ISO and RTO Scheduling Practices and Establishing Paper Hearing Procedures,* 146 FERC ¶ 61,202, at P 1 (2014) (Section 206 Order).

RTO/ISO compliance filings in response to the Section 206 Order.[197]

FUEL ASSURANCE, ELECTRIC SYSTEM RELIABILITY, AND INCENTIVES TO DELIVER FIRM ENERGY

Natural gas-fired electricity generation is often not backed by primary firm pipeline transportation contracts. Firm pipeline contracts provide shippers of natural gas, including electricity generation operators, with an agreed-upon amount of capacity for the pipeline transportation of natural gas. Firm transportation service means that the service is not subject to a prior claim by another customer or another class of service and receives the same priority as any other class of firm service. The pipeline's delivery of natural gas cannot be curtailed below the contracted quantity under a firm contract except under unforeseeable circumstances such as pipeline and compressor outages or system maintenance.

In contrast, interruptible contracts (also called IT or non-firm contracts) are lower-priority pipeline transportation arrangements. Under these contracts, the flow of natural gas to an electricity generator may be stopped or curtailed if firm contract holders use the available capacity. On peak natural gas demand days, interruptible transportation may be unavailable because firm customers will be using their full contractual entitlements, and pipelines therefore cannot schedule interruptible transportation service. Interruptible contracts are generally set up for short periods, often for next-day delivery. Interruptible contracts are less expensive than firm contracts, reflecting the higher risk of disrupted fuel receipts. Electricity generators may also use natural gas pipeline capacity released or sold by an existing firm capacity holder that is available seasonally or for limited periods of time to other shippers. Alternatively, the electricity generators may buy natural gas from a marketer that is, in turn, using released pipeline capacity. This resale market for pipeline capacity is called Capacity Release. FERC designed the posting and bidding procedure that gives pipeline shippers the ability to auction off all or a portion of their firm capacity for a designated period.[198]

FERC has identified generator access to sufficient fuel supplies and the firmness of generator fuel arrangements as a significant issue contributing to potentially poor generator performance and inefficient market operations. Electricity generators that rely on non-firm arrangements for fuel transportation face the risk of not procuring enough fuel on high demand days. However, firm contracts require generators to pay more for pipeline capacity, and thus ultimately result in higher fuel prices. As such, specific concerns have focused on the ability of RTO/ISO markets to address firm fuel supplies and their valuation. These issues have been considered in various venues. On November 20, 2014, FERC issued an Order (Fuel Assurance Order) directing each RTO/ISO to file a report on the status of its efforts to address market and system performance associated with "fuel assurance" issues, by February 18,

197 The Commission issued six orders accepting compliance filings from the RTOs/ISOs identified in the Section 206 Order. The Commission accepted compliance filings from California Independent System Operator, ISO New England, Inc., and New York Independent System Operator, Inc. without requiring scheduling changes because the ISOs were able to show cause as to why their existing scheduling practices did not need to be modified. The Commission accepted compliance filings from Midcontinent Independent System Operator, Inc., PJM Interconnection, L.L.C., and Southwest Power Pool, Inc., finding that the proposed tariff revisions would better align the ISO's/RTO's scheduling with that of the natural gas industry as discussed in the Section 206 Order. See California Independent System Operator Corporation, 153 FERC ¶ 61,315 (2015), ISO New England, Inc., 153 FERC ¶ 61,211 (2015), Midcontinent Independent System Operator, Inc., 154 FERC ¶ 61,276 (2016), New York Independent System Operator, Inc., 153 FERC ¶ 61,210 (2015), PJM Interconnection, L.L.C., 153 FERC ¶ 61,209 (2015), and Southwest Power Pool, Inc., 153 FERC ¶ 61,316 (2015).

198 The Commission's current pipeline capacity release program is designed to permit expeditious and flexible releases, in a transparent and not unduly discriminatory manner, to the shipper placing the highest value on the capacity. The Commission generally requires that a firm shipper (releasing shipper) sell its capacity by offering it for bid on the pipeline's website, with the capacity awarded to the highest bidder. A releasing shipper may release its firm capacity in whole or in part, on a permanent or short-term basis, and with "recall" provisions that allow the releasing shipper to interrupt the replacement shipper's use of the capacity under specified circumstances.

2015.[199] FERC explained that the term "fuel assurance" describes a range of generator-specific and system-wide issues, including the overall ability of resources to access sufficient fuel and the firmness of their fuel arrangements as necessary to maintain reliability in each RTO/ISO. Many of these issues were also previously identified in FERC's September 25, 2013, centralized capacity markets technical conference concerning the ability of capacity markets and resource adequacy constructs to procure and retain the resources necessary to meet future reliability. FERC observed at the time that most capacity markets failed to properly value fuel assurance because their auctions establish capacity prices based on economic bids, without taking into account fuel supply arrangements or the operational characteristics of the generators.[200] FERC further identified fuel assurance issues in the April 1, 2014 polar vortex technical conference, which explored the impacts on system performance and market operations of cold weather events occurring in the 2013/2014 winter and the actions taken by RTOs/ISOs to respond to those impacts.

FERC has approved tariff changes proposed by ISO New England (ISO-NE), and PJM to their capacity market rules to allow market participants to recover costs associated with the provision of fuel assurance.[201] These capacity market rule changes were designed to improve the performance of capacity resources by providing payments for superior performance and establishing penalties for poor performance. While neither the Pay for Performance program in New England nor the Capacity Performance program in PJM required a specific method of securing firm fuel supplies, the payments and penalties were designed to incentivize market participants to procure backup fuels, firm pipeline transportation, alternative generating capacity, demand response, or other methods of ensuring resources can produce electricity.

NATURAL GAS PIPELINE CAPACITY RELEASE REGULATIONS

As discussed in the previous section, electricity generators may use natural gas pipeline capacity released or sold by an existing firm capacity holder. FERC, on June 19, 2008, issued Order No. 712,[202] which approved significant changes to its natural gas pipeline capacity release regulations to strengthen competition and benefit consumers by providing natural gas users, producers, and marketers more options for how they transact as well as more accurate price signals on the market value of pipeline capacity.

More specifically, FERC revised its regulations governing interstate natural gas pipelines to reflect changes in the market for short-term transportation services on pipelines and to improve the efficiency of FERC's capacity release program. FERC allowed market-based pricing for short-term capacity releases[203] and facilitated asset management arrangements (AMAs)[204] by relaxing the prohibition on tying and on bidding requirements

199 *Order on Technical Conferences*, 149 FERC ¶ 61,145 (2014) ("November 20 Order").

200 *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators*, *Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators,* 149 FERC ¶ 61,145, at P 1 (2014).

201 *PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,208 (2015); see also ISO New England Inc., 149 FERC ¶ 61,009 (2014).

202 *Promotion of a More Efficient Capacity Release Market,* Order No. 712, 123 FERC ¶ 61,286, at P 1 (2008), *order on reh'g,* Order No. 712-A, FERC Stats. & Regs. ¶ 31,284 (2008), *order on reh'g,* Order No. 712-B, 127 FERC ¶ 61,051 (2009).

203 The Commission found that the maximum rate ceiling previously applied to capacity release transactions denied releasing and replacement shippers the ability to negotiate transactions that reflect the market value of capacity at all times. Thus, providing the ability to negotiate capacity release transactions based on price differentials or at market clearing prices would help in providing short-term capacity to replacement shippers, such as natural gas-fired electricity generators.

204 AMAs provide significant benefits to many participants in the natural gas and electric marketplaces and to the secondary marketplace itself. They maximize the utilization and value of capacity by creating a mechanism for capacity holders to use third party experts to both (1) manage their natural gas supply arrangements and (2) use that capacity to make natural gas sales or re-releases of the capacity to others when the capacity is not needed to serve the releasing shipper. AMAs result in ultimate savings for end-use customers by providing for lower natural gas supply costs and more efficient use of the pipeline grid.

for certain capacity releases.[205] Finally, FERC waived its prohibition on tying and bidding requirements for capacity releases made as part of state-approved retail open-access programs.

RELIABILITY CONSIDERATIONS IN THE CONTEXT OF GAS-ELECTRIC COORDINATION

An issue related to fuel assurance, but with a broader scope, is the systemic risk to the electric system from a potential natural gas system disruption and how such risk can be mitigated. As natural gas use for power generation has grown, grid operators are beginning to consider the implications of natural gas system contingencies on the electric grid.

FERC has continued to address the systemic risk to the electric system from a potential natural gas system disruption and how these risks can be reduced. In February 2021, Winter Storm Uri, which impacted the central-United States, and particularly Texas, caused outages at electricity generating plants that resulted in millions of people being without heat or power for nearly four days and significant loss of life. Winter Storm Uri resulted in a combined 23,418 MW of manual firm load shed, the largest controlled firm load shed event in U.S. history.[206] Winter Storm Uri also caused a reduction of daily natural gas production, including the production necessary to keep many natural gas-fired power plants operational. Unplanned outages of natural gas wellheads due to freeze-related issues, loss of power, and facility shut-ins, as well as unplanned outages of natural gas gathering and processing facilities, resulted in a decline of natural gas available supply and transportation to many natural gas-fired generating units. Once natural gas supply outages began at the wellhead, they rippled throughout the natural gas and electric infrastructure, causing processing outages and reductions, pipeline declarations of Operational Flow Order (OFO)s[207] and force majeure, and outages and derates of natural gas-fired generating units. U.S. natural gas production in February 2021 experienced the largest monthly decline on record. Between February 8 and 17, 2021, the total natural gas production in the U.S. lower 48 states fell by 28 percent.[208]

Winter Storm Uri has contributed to FERC and NERC's renewed focus on critical infrastructure interdependencies. On February 16, 2021, FERC and NERC, announced a joint inquiry with the Regional Reliability Entities, to examine the root causes of the reliability events that have occurred throughout the county, in particular the regions served by the Electric Reliability Council of Texas, Inc. (ERCOT), Midcontinent Independent System Operator, Inc. ("MISO"), and Southwest Power Pool, Inc. (SPP). The inquiry's final report was issued on November 16, 2021, and included 28 formal recommendations that seek to prevent a recurrence of the failures experienced during the February 2021 cold weather event.[209] One of the key recommendations, pertaining to gas-electric coordination, was that FERC consider establishing a forum to identify actions to improve the reliability of the natural gas infrastructure system as necessary to support the bulk power system, and to address recurring challenges stemming from natural gas-electric infrastructure interdependency. Accordingly, FERC and NERC encouraged NAESB to convene a forum to identify solutions to the reliability issues facing the nation's natural gas system and bulk electric system. In response,

205 Tying refers to attempts by the releasing shipper to add additional terms or conditions to the release of pipeline capacity by tying the release of pipeline capacity to any extraneous conditions.

206 *See* FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* at *9* (November 16, 2022), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

207 OFOs are notices issued by natural gas pipelines to protect the operational integrity of the facility. Pipelines typically invoke OFOs during high or peak-demand periods to maintain system pressure and reliable operations. The orders may either restrict service or require affirmative action by shippers.

208 *See* FERC, NERC and Regional Entity Staff Report*, The February 2021 Cold Weather Outages in Texas and the South Central United States* at 13 (November 16, 2022), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

209 *Id*.

NAESB convened a multi-meeting forum, beginning on October 21, 2022, to identify actions that would improve the reliability of the natural gas infrastructure system to support the bulk power system and to address ongoing challenges from the interdependency of natural gas-electric infrastructure in categories including:

1. Measures to improve gas-electric information sharing for improved system performance during extreme cold weather emergencies;
2. Measures to improve reliability of natural gas facilities during cold weather (freeze protection, electric supply); and
3. Measures to improve the ability of generators to obtain fuel during extreme cold weather events, when natural gas heating load and natural gas-fired generators both demand high amounts of natural gas while natural gas production may have decreased.

In a similar vein, on September 8, 2022, and on June 20, 2023, FERC convened forums to discuss the electricity and natural gas challenges facing the New England region.[210] Topics discussed included the historical context of New England winter gas-electric challenges and concerns and considerations for upcoming winters, such as reliability of gas and electric systems and fuel procurement issues. The forum also explored whether additional information or modeling of the electric and/or gas systems are needed to inform the development of solutions to these challenges.

Discussion centered around ISO-NE's significant reliability dependence on natural gas, along with natural gas pipeline constraints that shift peak fuel supply reliance to liquified natural gas (LNG) procurement. Participants observed that New England had thus far avoided a severe energy outage through actions such as incentives for stored fuels and winterization of facilities, along with timely coordination among ISO-NE, pipelines, and natural gas pipeline shippers that have been able to release their capacity or resell their natural gas supplies.

As another example of a severe weather event, Winter Storm Elliott, which occurred from December 23 -26, 2022, stressed regional electric grids across the U.S. in different ways. It contributed to power outages affecting millions of electricity customers. Although most of these outages were due to weather impacts on electric distribution facilities operated by local utilities, utilities in parts of the southeast were nevertheless forced to engage in rolling blackouts, and the bulk-power system in other regions was significantly stressed. FERC, NERC, and NERC's Regional Entities announced on December 28, 2022 that they would open a joint inquiry into the operations of the bulk-power system during the extreme winter weather conditions that occurred during Winter Storm Elliott. On November 7, 2023, FERC and NERC released the Winter Storm Elliott report which recommends the completion of cold weather reliability standard revisions and suggests improvements to reliability for U.S. natural gas infrastructure.[211]

210 *New England Winter Gas-Electric Forum,* Docket No. AD22-9-000, (September 8, 2022 and June 20, 2023).

211 *See* Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott (October 2023), https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott.







Chapter 4

U.S. Crude Oil and Petroleum Products Markets

U.S. CRUDE OIL AND PETROLEUM PRODUCTS MARKETS

Petroleum, or crude oil, and its derived products play a key role in the U.S. economy, accounting for approximately 24 percent of primary energy consumption in the U.S. in 2021.[180] Petroleum is not directly consumed in its natural form, but is distilled and refined into an array of products that can be used for various applications. These include fuels for transportation, power generation, and heating. Other applications include petrochemical feedstocks used to manufacture various products, such as plastics, pharmaceuticals, fertilizers, and construction materials. Petroleum is especially important in the transportation sector, where it accounted for 90 percent of all transportation fuels used in 2021.[181]

Petroleum and petroleum products, such as gasoline, diesel fuel, and jet fuel, are domestically produced and imported. The percent of imported petroleum and petroleum products has been decreasing in recent years as U.S. crude oil production from shale has increased. Approximately 79 percent of the domestic U.S. crude oil production comes from three states-- Texas, New Mexico, and North Dakota--and federal offshore fields located in the Gulf Coast (PADD 3).[182] U.S. refineries, which separate crude oil into usable products, are found throughout the country but are most heavily concentrated on the Gulf Coast. Total U.S. refining capacity peaked in 2020 but has since fallen for two consecutive years.[183]

FERC Jurisdiction

FERC's jurisdiction over the oil markets is limited to the setting of interstate oil pipeline transportation rates and ensuring open access to the interstate oil pipeline system.

FERC JURISDICTION

Under the Interstate Commerce Act (ICA), FERC regulates the transportation of oil in interstate commerce. The ICA requires that all charges made for the transportation of oil or oil products be just and reasonable, and not unduly discriminatory.[184] In this regard, FERC does not regulate the oversight of oil pipeline construction or oil pipeline safety.

FERC's jurisdictional responsibilities regarding crude oil and petroleum product pipelines include:

- Regulating rates and practices of oil pipeline companies engaged in interstate transportation;
- Ensuring the provision of pipeline transportation to shippers on a non-discriminatory and non-preferential basis; and
- Establishing just and reasonable rates for transporting crude oil and petroleum products by pipeline.

Outside of FERC's jurisdictional responsibilities, the regulation of crude oil and petroleum product pipelines falls under a number of different government entities. The Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) is

180 Derived from EIA, *Monthly Energy Review*, *1. Energy Overview*, *Table 1.2 Primary Energy Production by Source*, *Annual* (accessed October 2022), https://www.eia.gov/totalenergy/data/browser/index.php?tbl=T01.02#/f=A&start=2017&end=2017&charted=1-2-3-4-6-13.

181 *Id., 2. Energy Consumption by Sector, Table 2.5 Transportation Sector Energy Consumption, Annual* (accessed October 2022), https://www.eia.gov/totalenergy/data/browser/index.php?tbl=T02.05#/?f=A .

182 Derived from EIA, *Crude Oil Production, Annual-Thousand Barrels per Day* (accessed October 2022), https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm.

183 *See* EIA, *Today in Energy, U.S. refinery capacity decreased during 2021 for second consecutive year* (June 29, 2022), https://www.eia.gov/todayinenergy/detail.php?id=52939.

184 *See* 49 App. U.S.C. §§ 1(5)(a) and 3(1).

responsible for regulating and ensuring the safe and secure movement of hazardous materials to industry and consumers by all modes of transportation, including pipelines. PHMSA's Office of Pipeline Safety ensures safety in the design, construction, operation and maintenance, and spill response of oil and natural gas pipelines and other hazardous liquid transportation pipelines. Federal regulatory approval is not ordinarily required for siting of new crude oil and petroleum product pipelines, unless the pipelines cross federal lands. Generally, state and local laws are the primary regulatory factors for siting crude oil and petroleum product pipelines.

Petroleum Characteristics

Petroleum is a mixture of hydrocarbons that were primarily formed from plants and organisms that lived millions of years ago. It is found in tiny spaces within sedimentary rocks, in underground reservoirs, or near the surface in tar (or oil) sands. Crude oil is highly heterogeneous, and naturally ranges in density and consistency, depending on the geological setting. Its color can vary from a light golden yellow to a deep black.

Different countries, regions, and geological formations produce different types of crude, which are generally described as light or heavy, depending on their density, and sweet or sour, depending on their sulfur content. In general, heavy crude oil is sour, as it contains more sulfur. West Texas Intermediate (WTI), the U.S. pricing benchmark, is a light, sweet oil that is delivered to Cushing, Oklahoma. The European benchmark oil, Brent, is also a light, sweet oil and is based on a basket of North Sea oils that are used to set petroleum prices around the world. By contrast, Mexico's Maya crude is both heavy and high in sulfur content (sour).

Crude oil that is light and sweet usually commands higher prices than heavy, sour crude oil. This is partly because gasoline and diesel fuel, which typically sell at a significant premium to the heavier products produced in the refining process, are more readily and cheaply produced from light, sweet crude oil. However, individual refineries are optimized to process crude oil with specific properties, and deviations from any given refinery's optimal crude oil can significantly impact profitability. Thus, the value of a given crude oil can often be refinery specific.

Density of an oil (API Gravity)

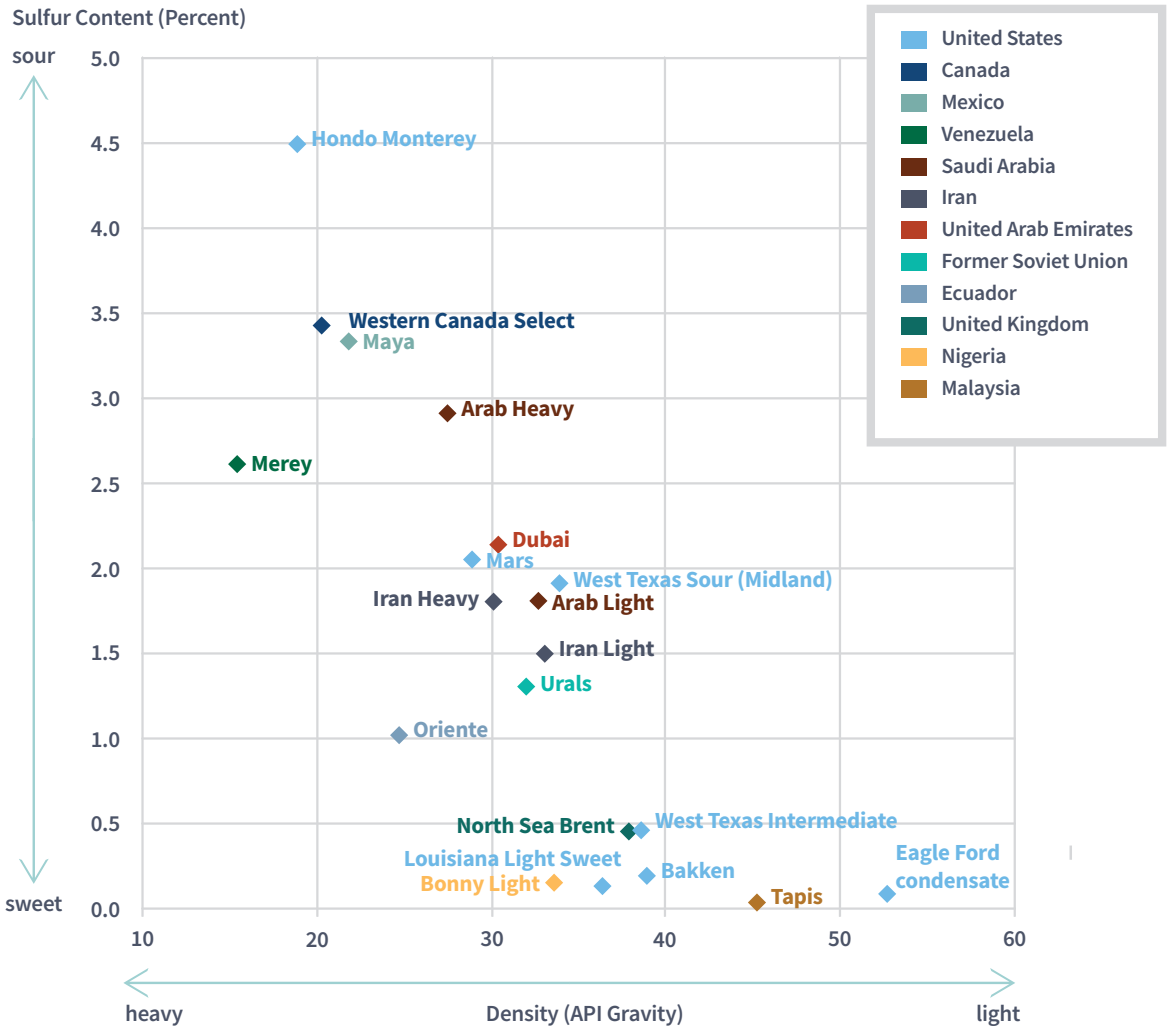
The density, or "weight," of an oil is one of the largest determinants of its market value (another key characteristic is sulfur content – see text box, "Sweet or Sour?"). The density of crude oil is often referred to as "light" or "heavy" and is measured using the American Petroleum Institute's (API) density index also known as API gravity. API gravity is determined using the specific gravity of crude oil, which is the ratio of its density to that of water (density of the oil/density of water) at 60 degrees Fahrenheit. Oils are generally classified as:

Light – API > 31.1	Medium – API between 22.3 and 31.1
Heavy – API between 10 and 22.2	Extra Heavy – API < 10.0

However, crude oil may be categorized differently depending on the region where it is produced and how the crude oil is referred to by commodity traders.

Though specific gravity is a unitless number, API gravity values in practice are often referred to as degrees. The API gravity of West Texas Intermediate is said to be 39.6 degrees. API gravity moves inversely to the density of crude oil, which means the denser an oil the lower its API gravity. An API of 10 is equivalent to water, which means crude oil with an API above 10 will float on water while crude oil with an API below 10 will sink. Crude oil that is light and sweet usually commands higher prices than heavy, sour crude oil.

Figure 4-1: Density and Sulfur Content of Selected Crude Oils



Source: EIA[185]

Benchmark Crude Oil

A benchmark crude oil is a specific product that is widely bought and sold at well-traded locations, with commonly posted prices. Other quality crude oils are traded with reference to benchmark crude oils and the pricing is typically adjusted using agreed-upon price differentials that take into account such factors as API gravity, sulfur content, and transportation costs. WTI and Brent are two major benchmark crude oils. WTI is a U.S. benchmark crude and Brent is the most commonly used benchmark in global trade. A third major benchmark, Dubai, is mostly used in Asian trade

185 *See* EIA, *Today in Energy, Changing quality mix is affecting crude oil price differentials and refining decisions* (September 21, 2017), https://www.eia.gov/todayinenergy/detail.php?id=33012.

Sweet or Sour?

The terms sweet and sour refer to the sulfur content of crude oil. Early prospectors would taste oil to determine its quality, with low sulfur oil tasting relatively sweet. Crude is considered sweet if it contains less than 0.5 percent sulfur.

Sweet crude is easier to refine and safer to extract and transport than sour crude. Because sulfur is corrosive, sweet crude also causes less equipment damage to refineries and results in lower maintenance costs over time. Due to these factors, sweet crude commands a price premium over sour crude.

Major sources of sweet crude include the Appalachian Basin in Eastern North America, West Texas, the Bakken Formation of North Dakota and Saskatchewan, Saudi Arabia, the North Sea of Europe, North Africa, Australia, and parts of Asia, including Indonesia.

Sour crude oil has greater than 0.5 percent sulfur, with some of the sulfur in the form of hydrogen sulfide, known for its "rotten egg" smell. Hydrogen sulfide is considered an industrial hazard and, thus, sour crude must be stabilized by removing hydrogen sulfide before it can be transported by oil tankers.

Sour crude is more common in the Gulf of Mexico, Mexico, South America, and Canada. Crude produced by Organization of Petroleum Exporting Countries (OPEC) member nations also tends to be relatively sour, with an average sulfur content of 1.77 percent.

U.S. Crude Oil Supply

PETROLEUM RESERVES

Crude oil resource estimates are categorized in several ways. The most certain is the category "proved reserves," which takes into account the potential to extract crude oil based on current technology and economic feasibility.

At the end of 2020, there were an estimated 38 billion barrels of proved crude oil and condensate reserves in the U.S.[186] While the measure can fluctuate from year to year, from 2009[187] to 2020, proved reserves increased by more than 40 percent. This growth was substantially driven by exploration and drilling in shale formations and technological advances, such as horizontal drilling and hydraulic fracturing (horizontal drilling and hydraulic fracturing were discussed in Chapter 1, Wholesale Natural Gas Markets).

Proved Oil Reserves

Estimated quantities of oil that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions.

Shale and tight oil formations accounted for 48 percent of all U.S. crude oil proved reserves by the end of 2020.[188] The top areas in the country for proved crude oil reserves are in New Mexico and Texas (home to the Permian and Eagle Ford basins)

186 *See* EIA, *U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2020,* at 1 (January 2022), https://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf.

187 Derived from EIA, *U.S. Crude Oil, Natural Gas, Natural Gas Liquids Proved Reserves*, 2009 (November 30, 2010), https://www.eia.gov/naturalgas/crudeoilreserves/archive/2009/cr2009.html.

188 Derived from EIA, *U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2020*, at 13 (January 2022), https://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf.

and North and South Dakota (home to much of the Bakken and Three Forks formations).[189]

Outside the U.S., other top countries by proved reserves include Venezuela and Canada. As a region, most of the world's proved reserves are in the Middle East, including Saudi Arabia, Iran, Iraq, Kuwait, and the United Arab Emirates.[190]

DOMESTIC PRODUCTION AND IMPORTS

From the 1970s to the early 2000s, the U.S. imported a growing proportion of its crude oil supply and petroleum products, which peaked at 13.7 million barrels per day (MMbd), or 67 percent of total U.S. supply in 2005. However, improvements in domestic production that started in the late 2000s began a reversal of that trend. In 2021, imports of crude oil and petroleum products fell to 8.5 MMbd, or 34 percent of the total U.S. supply.

Crude oil imports to the U.S. came from over 65 countries in 2021. Canada was the largest foreign supplier to the U.S. supplying more than 51 percent of U.S. total imports, which included the robust output from the oil sands region in Alberta.[191] The second-largest supplier to the U.S. was Mexico, followed by Russia and Saudi Arabia.[192]

Just as the case with proved reserves, the increase in domestic oil production followed the successful commercialization of horizontal drilling and hydraulic fracturing. Texas has historically been the largest producer among the states and has also substantially increased its production output with shale oil from its Eagle Ford (South Texas) and Permian Basin (West Texas) formations. The overall production in Texas reached 4.8 MMbd in 2021, up from an average of 1.1 MMbd from 2000 through 2010.[193]

New Mexico, also home to the Permian Basin, produced 1.25 MMbd in 2021, the second most from an individual state, up from an average of only 0.17 MMbd between 2000 and 2010.[194] Finally, North Dakota, with its Bakken Shale, produced 1.1 MMbd in 2021, the third most from an individual state, up from an average of only 0.132 MMbd between 2000 and 2010.[195]

Because increases in shale production have driven nearly all U.S. oil production growth since 2008, most of the new supply is light, sweet oil, which has also affected refinery investments and operations. These refinery changes, likewise, tend to influence future changes in the types of crude oil imported and processed in U.S.

Crude Oil and Petroleum Products Demand

The largest demand sector for petroleum products in the U.S. is transportation, which accounted for approximately 90 percent of total domestic consumption in 2021. Among the specific product categories, motor gasoline alone made up 57 percent of petroleum products sold by prime suppliers into the U.S. market. The second largest was No. 2 distillate, accounting for 28 percent of sales, which includes diesel fuel, fuel

189 *Id*.

190 *See* BP, *Statistical Review of World Energy 2021*, at 16, https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2021-full-report.pdf.

191 Derived from EIA, *U.S. Imports by Country of Origin, Total Crude Oil and Products, Monthly-Thousand Barrels, U.S.* (accessed October 2022), https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_ep00_im0_mbbl_m.htm.

192 *Id.*

193 Derived from EIA, *Texas Field Production of Crude Oil, Total Crude Oil and Products, Monthly-Thousand Barrels, U.S.* (accessed October 2022), https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPTX2&f=A.

194 Derived from EIA, *New Mexico Field Production of Crude Oil, Annual* (accessed October 2022), https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mcrfpnm1&f=a.

195 Derived from EIA, *North Dakota Field Production of Crude Oil, Annual* (accessed October 2022), https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPND2&f=A.

oil for space heating, and, in a lesser capacity, oil for electric generation. The third-largest demand category was jet fuel, with nine percent of sales.[196]

Prime Suppliers

Companies that produce, import, or transport petroleum products across state boundaries, to sell to local distributors, retailers, or end users. Prime supplier sales are a good proxy for demand.

Other petroleum products include propane used for space heating and in agricultural and petrochemical processes; kerosene used in heating and lighting; No. 1 fuel oil, which can be blended into heating fuel or diesel fuel; No. 4 fuel oil used for commercial heating and power generation; residual fuels (includes No. 5 and No. 6 fuel oils) used in power generation and ship boilers; and asphalt used to build roads.

Crude Oil Refining

In 2021, the U.S. had over 17 MMbd of operating refinery capacity.[197] For historical reasons dating back to gasoline rationing during World War II, the country is divided into five geographical regions called Petroleum Administration for Defense Districts (PADDs).[198] The majority of U.S. refining capacity is located in the Gulf Coast, in PADD 3. In 2021, approximately 53 percent, or 9.3 MMbd of refining capacity was located in PADD 3.

Most of the larger and more modern refineries are situated along the Gulf Coast in Texas, Louisiana, Mississippi, and Alabama. Many refineries are located close to the traditional crude oil production areas, near import centers in the Gulf Coast or proximate to major population centers where demand for refined products is greatest, including California and the metropolitan areas of New York City and Chicago. However, shutdowns have reduced U.S. refinery capacity across the U.S. Six refineries closed or were converted to renewable diesel facilities between 2020 and 2021, totaling 750,000 barrels per day of lost capacity.[199] These closures or conversions were mainly due to reduced demand for crude oil distillation.

In general, crude oil refining involves processing crude oil through distillation facilities where the crude oil is heated and separated into its lighter and heavier components. Distillation occurs in a fractionating column, which uses a temperature differential across the column to separate the liquid mixture into its component parts. The heat causes the lighter, more volatile hydrocarbon molecules to vaporize and rise. As they cool, the heavier components with higher boiling points, such as heavy fuels and residual fuels, liquefy and settle into trays where they are carried out of the unit into their own processing streams. The lighter molecules rise higher in the unit and are processed into light products, such as gasoline and naphtha (a byproduct used in solvents). Depending on the refinery configuration, heavier components may be further processed to yield additional amounts of the more valuable light products. Breaking down the heavier products into lighter ones requires more specialized and expensive equipment and processes such as catalytic crackers[200] and cokers[201].

196 Derived from EIA, *Prime Supplier Sales Volume*, *U.S.*, *Annual* (accessed October 2022), http://www.eia.gov/dnav/pet/pet_cons_prim_dcu_nus_a.htm.

197 Derived from EIA, *Refinery Utilization and Capacity*, *U.S.*, *Annual* (accessed October 2022), https://www.eia.gov/dnav/pet/pet_pnp_unc_dcu_nus_a.htm.

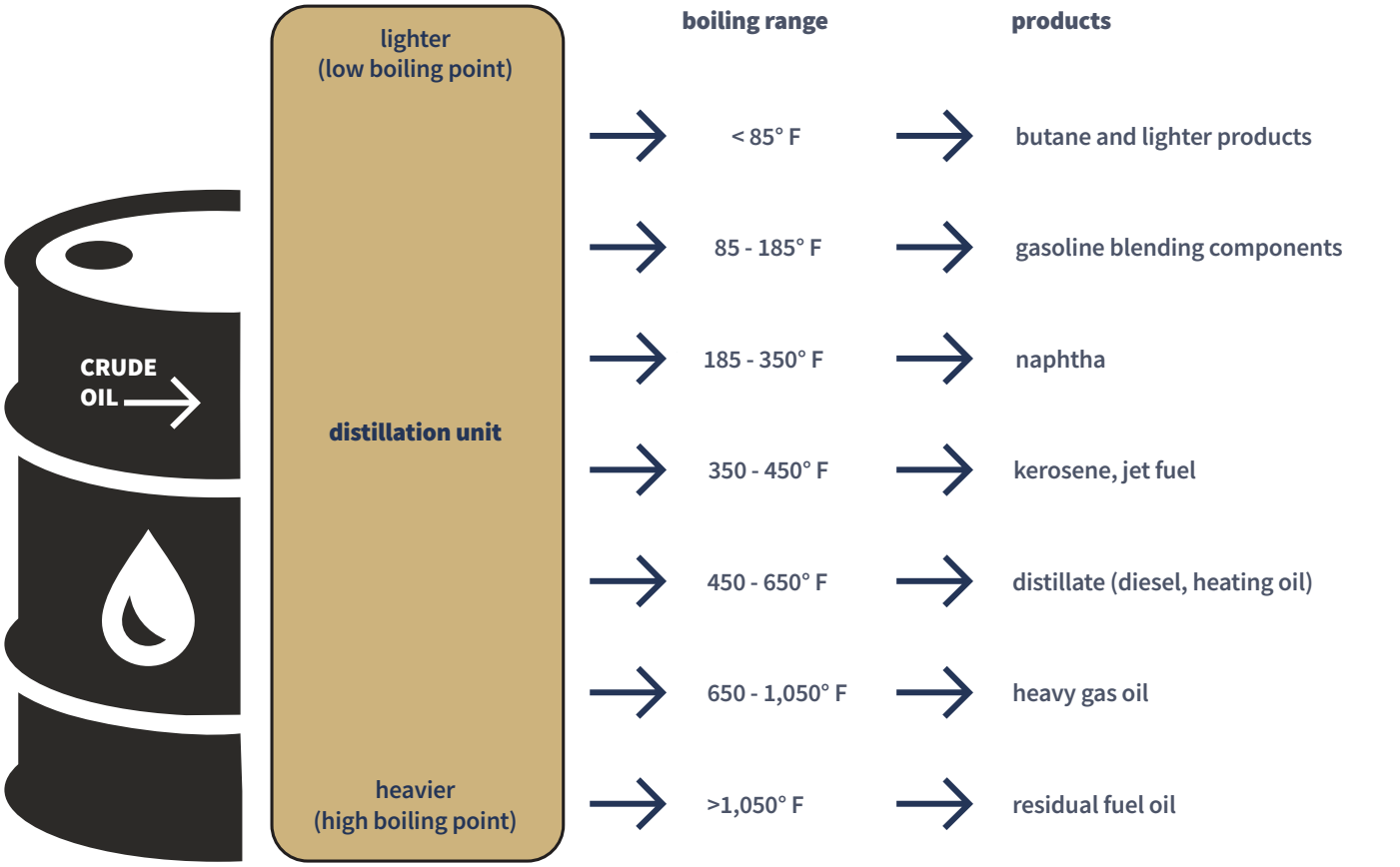
198 *See* https://www.eia.gov/petroleum/marketing/monthly/pdf/paddmap.pdf for a map of PADD locations.

199 Derived from EIA, *Annual Energy Outlook*, *Production* (accessed March 3, 2022), https://www.eia.gov/outlooks/aeo/narrative/production/sub-topic-03.php.

200 Catalytic cracking is the process used to convert high molecular weight hydrocarbon fractions of crude oil into gasoline, olefinic gases, and other petroleum products.

201 A coker is a machine that converts residual oil into low molecular weight hydrocarbon gases, naphtha, light and heavy gas oils, and petroleum coke.

Figure 4-2: Diagram of a Basic Distillation Unit



Source: EIA[202]

Crude Oil and Petroleum Products Transportation

There are nearly 150,000 miles of crude oil and petroleum product pipelines in the U.S.[203] Crude oil pipeline mileage grew by nearly 28,000 miles, or 23 percent, between 2012 and 2020, and was driven by increased shale production.[204] Crude pipelines move oil from the production fields and import terminals to refineries for processing. Pipelines then distribute the refined fuels to consumers across the country.

The operators of the three largest crude oil and liquids pipelines in North America are Enbridge Energy, Colonial Pipeline Company and Transcanada. Enbridge Energy operates one of the longest crude oil and liquids transportation systems in the world. Enbridge Energy's pipelines transported 1.1 trillion barrel-miles in 2021,

202 *See* EIA, *Oil: Crude and Petroleum Products Explained, The Refining Process* (August 14, 2018), https://www.eia.gov/energyexplained/oil-and-petroleum-products/refining-crude-oil.php#tab2.

203 Derived from API-AOPL, *Annual Liquids Pipeline Report*, at 45 (2021), https://liquidenergypipelines.org/Documents/en-us/1e14ec3b-9b98-46f3-aa54-808792b8a13a/1.

204 *Id*. and Derived from API-AOPL, *Annual Liquids Pipeline Report*, at 45 (2018), https://www.pipelaws.com/wp-content/uploads/sites/451/2018/05/2018-Annual-Liquids-Pipeline-Report-API-AOPL.pdf.

the most among crude oil pipelines.[205] Enbridge Energy's vast network of oil and liquids pipelines travel from Canada and North Dakota to the Midwest and Gulf Coast.[206] The second largest pipeline is Colonial Pipeline Company, with 722 billion barrel-miles transported in 2021.[207] It carries supply from the refining centers in Texas and Louisiana to the major demand centers along the U.S. East Coast. It also transports gasoline, diesel fuel, jet fuel, and other products from Houston, Texas to Linden, N.J. on a 5,500-mile network, crossing 13 states. A distant third-largest pipeline is the TransCanada Keystone Pipeline, which transported 239 billion barrel-miles of crude oil in 2021 from Canada to the U.S. Mid-Continent and the Gulf Coast.[208]

MOVEMENT OF CRUDE OIL WITHIN AND EXPORTS FROM THE U.S.

Two federal statutes have played a role in shaping the movement of crude oil and crude oil products. First, the Jones Act[209] generally prohibits any foreign-built or foreign-flagged vessel from engaging in trade that begins at any point within the U.S. and delivers commercial cargo to any other point within the U.S.[210] Because of the limited numbers of oil and petroleum products vessels that meet the Jones Act requirements, the ability to move crude oil and refined products between domestic marine ports is periodically constrained. That means, for example, that producers can be limited in their ability to move crude oil to the Gulf Coast via pipeline and then ship it to East Coast refiners. Likewise, Gulf Coast refiners can be limited in their ability to move refined products up the East Coast via waterborne vessels.

The second was a ban on most exports of crude oil in a policy stemming from the 1970s oil crisis. While the ban was highly restrictive, certain licensed exports were allowed, including slightly refined crude oil condensate, shipments of crude oil owned by a company to an affiliate refinery in Canada, and heavy-for-light crude oil swaps with Mexico. The export ban was repealed in late 2015 as part of the Consolidated Appropriations Act of 2016.[211] Following the repeal, the U.S. exported 1.1 million barrels per day of crude oil to various countries in 2017, up from approximately 100 thousand barrels per day from 1975 through 2015, with Canada as the largest recipient of the exports.[212] In 2021, the U.S. exported nearly 3 million barrels per day of crude oil.

Crude Oil and Petroleum Products Markets and Trading

As a global commodity, crude oil's price on the world markets is set by the traders who buy and sell the commodity at various locations around the world. However, most trades are based on, or derivative to, a handful of benchmark crude prices, such as WTI, Brent, and Dubai. There are also benchmark locations for petroleum products, including New York Harbor in the

205 Derived from FERC, *2021/Q4 FERC Form 6*, at 600 (October 2022), Enbridge Energy Limited Partnership, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=94740646-9F0A-C0FE-9363-803547600000, Enbridge Pipelines (FSP) L.L.C., https://elibrary.ferc.gov/eLibrary/filedownload?fileid=4D1DAA66-FF9C-CE65-9097-80298B700000, Enbridge Pipelines (Southern Lights) LLC, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=1E0DC7DE-8645-C597-86FC-803DE5D00000, Enbridge Pipelines (Toledo) Inc., https://elibrary.ferc.gov/eLibrary/filedownload?fileid=A4795E1D-B912-CC17-91BF-802966E00000, Enbridge Transportation (IL-OK) L.L.C, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=655EE23C-DC4D-C0A7-93AB-802959200000, Enbridge Storage (Patoka) LLC, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=4F6065E6-3AF8-C503-9950-803DB3B00000.

206 *See* Enbridge Energy, *Infrastructure Map*, https://www.enbridge.com/Map.aspx#map:infrastructure,crudeInfrastructure.

207 Derived from FERC, 2021/Q4 FERC Form 6, at 600 (October 2022), Colonial Pipeline Company, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=9DDCCC5F-E2E1-C84F-9260-803E93F00000.

208 Derived from FERC, *2021/Q4 FERC Form 6*, at 600 (October 2022), TransCanada Keystone Pipeline, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=4A0CEFEC-C81F-C8E8-9161-801F47F00000.

209 The term "Jones Act" refers to section 27 of the Merchant Marine Act of 1920, 46 U.S.C. § 50101, *et seq.* (2012).

210 46 U.S.C. at § 55102.

211 Consolidated Appropriations Act, 2016, Division O – Other Matters, Title I, Sec. 101 (a – b).

212 *See* EIA, *This Week in Petroleum* (March 7, 2018), www.eia.gov/petroleum/weekly/archive/2018/180307/includes/analysis_print.php.

U.S., Amsterdam-Rotterdam-Antwerp (ARA) in Europe, and Singapore in Asia.

Domestic crude oil markets are more closely tied to global trends than U.S. natural gas markets because of the tremendous worldwide production of crude oil which enjoys relatively low shipping costs.[213] In comparison, natural gas faces additional costs to ship overseas because of the need for liquefaction and regasification facilities, which require multi-billion dollar investments.

World crude oil prices have historically experienced periods of great volatility, often driven by supply and demand fundamentals and external shocks, such as production disruptions related to geopolitical events and speculative trading. Crude oil prices rose following supply disruptions that occurred during international events such as the Arab Oil Embargo in 1973 and 1974, the Iranian Revolution, the Iran-Iraq War in the 1980s, and the Persian Gulf War in 1990 and 1991. For example, WTI spot prices were $4.31 per barrel (bbl) in June 1973, but by December 1974, crude oil prices reached $11.16/bbl, a 159 percent increase. Global economic events can also affect crude markets. For instance, during the recession of 2008 and 2009, the WTI benchmark reached $145.31/bbl on July 3, 2008 and, by December 23, 2008, the price had fallen to $30.28/bbl, a decline of nearly 80 percent due to falling earning projections and credit contractions that, a result of decreased demand. Similarly in a more dramatic fashion, the WTI benchmark seemingly collapsed overnight into negative territory from $18.31/bbl on April 17, 2020 to negative $36.98/bbl on April 20, 2020 due to the COVID-19 pandemic triggering an unprecedented demand shock for oil. The culmination of stay-at-home mandates, restricted travel, and closed economies created an oversupply that left producers scrambling to find space to store the crude oil. The reopening of the economy lifted prices from pandemic lows, eventually peaking at $123.64/bbl on March 8, 2022, due to heightened geopolitical tensions and speculation in Europe before coming back down to a steady $82.59/bbl on September 7, 2022.[214]

From 1987 through 2010, WTI and Brent benchmarks traded within a few cents of each other, with WTI benchmark generally commanding a small price premium. However, the sharp increase in production of shale oil in the U.S. resulted in a surge in supply at Cushing, causing WTI benchmark prices to drop below the Brent benchmark. Between 2011 and 2014, the Brent benchmark price reached a premium of $29/bbl in September 2011, but the spread narrowed to about $6/bbl by December 2017.[215] Crude oil became oversupplied at Cushing because of large increases in oil production that outpaced the development of transportation and storage infrastructure. The then-current ban on exports of crude oil further limited the options for addressing the supply pressures. Since 2011, the construction of additional infrastructure combined with the repeal of export restrictions has reduced the oversupply at Cushing and, in turn, narrowed the price differential between the WTI and Brent benchmarks, to an average of $2.72/bbl in 2021.

213 *See* EIA, *Low Tanker Rates Are Enabling More Long Distance Crude Oil and Petroleum Product Trade* (October 27, 2016), https://www.eia.gov/todayinenergy/detail.php?id=28532.

214 Derived from Federal Reserve Bank of St. Louis, *Crude Oil Prices: West Texas Intermediate (WTI) – Cushing, Oklahoma* (accessed October 2022), https://fred.stlouisfed.org/series/DCOILWTICO.

215 Derived from EIA, *Spot Prices (Crude Oil)* (September 6, 2018), https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.





Chapter 5
Trading and Capital Markets

TRADING AND CAPITAL MARKETS

Restructuring of the energy markets and changes in the industry during the 1980s and 1990s resulted in the expansion of the commodity markets associated with natural gas and electricity. In particular, restructuring resulted in the growth of financial products that derive their value from the underlying energy products. Expansion in physical and financial market trading for natural gas and electricity has tightened the traditional relationship between these markets. As a result, activities in the physical markets affect values in financial markets. Likewise, activities in the financial markets can also affect values in the physical markets.

This chapter explores the trading of physical and financial contracts for natural gas and electricity. It also provides an overview of capital markets and their importance to investments in industry infrastructure.

Trading Physical and Financial Natural Gas and Electricity

Natural gas and electricity are often bought and sold using standardized contracts. The standard terms and conditions and standard product definitions of such contracts appeal to a wide variety of market participants because they need only negotiate on terms such as price, term, quantity and delivery point. Contracts can also be customized to meet the needs of individual buyers and sellers through a vast array of differing pricing and delivery mechanisms, as well as customized terms and conditions. Contracts in the physical and financial natural gas and electricity markets can also be referred to as instruments or securities.

In general, a physical contract provides an obligation to physically deliver natural gas or electricity in exchange for payment.[216] As discussed in Chapters 1 and 2 (Wholesale Natural Gas Markets and Wholesale Electricity Markets), producers and consumers of natural gas and electricity sell and buy energy products to manage price and volatility risk in a variety of their enterprise operations that include production, marketing, and meeting customer demand.

When a contract does not require the delivery of natural gas or electricity but instead provides a right to a financial payout in exchange for a payment, the contract is referred to as a financial contract or swap.[217] The payment is typically based on the underlying value of the physical commodity or index[218] of asset values or financial products specified by the contract. Under such a contract, the commodity or index is called the underlying or underlier. Because the value of the financial contract is derived from the value of the underlier, the contract is also called a derivative, which is a general term for a contract whose value is derived from some other physical or financial product.

Market participants buy and sell energy-based financial contracts for a number of reasons. As mentioned above, physical market participants, such as producers and consumers, typically use financial contracts to manage price risk and protect against price volatility. That is, financial contracts can serve as a tool for managing risk akin to insurance. Other market participants use the energy markets to speculate, or to assume a market risk in the hope of profiting from market fluctuations.

216 As discussed below, a buyer of a commodity under a physical contract may in many instances elect not to take delivery. The buyer may do so by reselling the commodity, where the reselling is referred to as obtaining an offsetting contract.

217 Many financial contracts are standardized, regulated products called cash-settled energy futures.

218 Indices are weighted average prices for a group of transactions over a given time frame at a specified location.

CONTRACT CHARACTERISTICS

Every contract, whether physical or financial, is identified by a number of characteristics, such as the product conveyed, location, timeframe, size or quantity, and the price or mechanism for determining the settlement. Additionally, there are different types of contracts based on uses and obligations of the participants, which are further described in the section below on Contract Types.

Product conveyed: Each contract specifies what is being bought and sold. For physical contracts, the product bought or sold would be natural gas or electricity. For derivatives, a payout may be derived from natural gas or electricity prices.

Location: Standardized contracts trade on exchanges and on Over the Counter (OTC) electronic brokerage platforms. For example, the InterContinental Exchange (ICE) offers trading of standardized physical contracts and cash-settled energy futures at predetermined locations or pricing points (exchanges and OTC transactions are discussed further below). Natural gas and electricity are traded at different locations throughout the country. Natural gas trading locations are usually located at the intersections of major pipeline systems, pipeline zones, near storage facilities, locations where local distribution companies (LDCs) receive natural gas from pipelines, and pooling points. Standard trading locations are referred to as market hubs. The Henry Hub is the U.S. natural gas benchmark hub and is also the delivery point for the New York Mercantile Exchange (NYMEX) natural gas futures contract. For electricity, contracts are often based on locations known as nodes, zones, or hubs. Examples of frequently traded electricity locations are the PJM Western Hub and the Mid-Columbia Hub. For physical contracts, the location must be physically viable – a location where natural gas or electricity can actually be delivered. Because financial contracts do not result in actual physical delivery, the contract may reference a location that is not physically viable – the location is only used in determining the price that will be paid for a specific quantity. Off-exchange bilateral OTC transactions can use any location desired by the counterparties. This allows traders to negotiate complex pricing mechanisms based on a number of locations.

Timeframe: Each contract has a number of time elements. The trade date is the date on which the contract is executed. The termination date is the last day of the contract term. The settlement date establishes when payment is due under the contract. Also, physical contracts specify the delivery day(s) or month – the day(s) or month during which the product is to be delivered. Physical and financial electricity contracts may also specify peak or off-peak delivery, with the peak or off-peak hours defined by the contract and reflecting the North American Energy Standards Board (NAESB) contract definitions.

For physical contracts, begin and end dates are the timeframe during which a physical product (natural gas or electricity) is to be delivered. Next-day physical natural gas contracts often have the same begin and end flow dates; however, on weekends and holidays, flow days can span multiple days for delivery. For example, a next-day physical natural gas contract may have a trade date of Thursday, August 25, a begin flow date of Friday, August 26, and an end flow date of Friday, August 26. The weekend strip may have a trade date of Friday, August 26, a begin flow date of Saturday, August 27, and an end flow date of Monday, August 29. A monthly physical natural gas contract may have a trade date of Thursday, August 25, a begin flow date of Thursday, September 1, and an end flow date of Friday, September 30. Monthly physical contracts are generally for delivery in equal parts per gas day over a month for natural gas and equal parts per hour for electricity. For financial contracts, the begin and end dates indicate the underlying natural gas or power days' index and settlement prices to be used in setting the payout for a specific quantity of natural gas or power.

Quantity: All physical contracts specify the amount of natural gas or electricity to be delivered. For standardized products traded on a futures exchange or on an OTC electronic brokerage platform, the quantity

is predetermined and specified in the contract. For off-exchange contracts traded in OTC markets, the contract quantity can be any amount agreed upon by the parties.

Price: All physical contracts specify a price that will be exchanged for physical delivery. All financial contracts specify a price, or prices, which will determine a cash exchange between the two parties.

Fixed prices are known at the time a transaction is entered into. The fixed price is a set price at which the seller agrees to sell, and the buyer agrees to buy. A fixed price would be represented, for example, as $3 per million British thermal units (MMBtu) for natural gas or $30 per megawatt-hour (MWh) for electricity.

Floating prices are not known at the time a transaction is entered into but will be known at the time of settlement. For example, a price may be tied to the average of all the daily prices at a location over the course of a month, typically published as an index. Indices referenced in contracts in the natural gas market are published using a known methodology by a variety of index developers, such as S&P Global Commodity Insights (also known as Platts) or Natural Gas Intelligence (NGI).[219] NYMEX and other exchanges also post prices for standardized contracts that can be referenced in contracts. Electricity contracts often reference the Locational Marginal Prices (LMPs) set by the regional transmission organizations (RTOs) and independent system operators (ISOs) (see Chapter 2) or indices calculated by exchanges such as ICE.

Options contracts also include prices, such as a strike price and a premium. Options contracts are discussed in more detail in the following section.

CONTRACT TYPES

The most common contract types are forwards, futures, swaps, and options.

Physical Forward Contract: A forward contract is an agreement between two parties to receive or deliver a commodity at a specified time in the future. A forward contract is often used for physical delivery. The buyer pays an agreed-upon forward purchase price and the seller delivers the natural gas or electricity on the designated date. The product is physically settled with delivery.

Financial Forward Contract: Forward contracts may also be financially settled when no delivery of a commodity takes place, also known as a swap contract. A financially settled contract, also referred to as cash settled, has the parties paying and receiving in cash the loss or gain based on the price of the underlying product. A forward contract may also be traded off-exchange.

Cash Settled Energy Futures: After passage of the Dodd-Frank Act,[220] many financially settled energy contracts traded on electronic brokerage platforms are cleared cash, settled energy futures contracts.[221]

Physical Futures Contract: A futures contract is a standardized forward contract that is traded on an exchange, such as CME's NYMEX[222]. Each contract represents the same quantity and quality of the underlying physical commodity, valued in the same pricing format, to be delivered and received at the same delivery location. In addition, the specific time period of delivery and receipt is the same for all contracts traded for a particular calendar month. Because futures are interchangeable with one another

219 Data used for developing price indices is collected from market participants who voluntarily report the quantities and prices of their trades to the index developers. Some index developers incorporate trades from ICE in their indices.

220 The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 reformed the regulation of swaps. *See* https://www.cftc.gov/LawRegulation/DoddFrankAct/index.htm for more information.

221 *See* https://www.cmegroup.com/market-data/browse-data/cash-settled-futures.html for examples of cash-settled futures products.

222 The Group owns NYMEX. The CME Group offers a marketplace for derivatives composed of its exchanges: Chicago Mercantile Exchange (CME), New York Mercantile Exchange (NYMEX), Chicago Board of Trade (CBOT), and COMEX (formerly known as the Commodity Exchange, Inc.). See CME Group, Driving Global Growth and Commerce (n.d.), https://www.cmegroup.com/company/history/.

and are traded on centralized exchanges, futures markets generally are more liquid than forward markets.

Option Contract: An option is an instrument that gives its holder the right, but not the obligation, to buy or sell an underlying physical or financial contract at a set price for a set time period. The right to buy the underlying contract is called a call option, and the right to sell is called a put option. The price paid to buy or sell the option is known simply as the option's price or premium. The price at which the underlying contract may be bought or sold is the strike price. Electing to buy or sell the underlying commodity or security at the future date is known as exercising the option. An option's expiration date is the last date at which an option may be exercised. The options themselves may be bought or sold and are frequently standardized and traded on an exchange. Options traded on an exchange or an electronic trading platform may be traded up to the contract's expiration. The owner of an option may sell the option rather than exercise the option or may let it expire if it is not profitable to exercise it. Traders may use options to boost profits through more complex trading strategies or to reduce the volatility of their returns.

EXAMPLES OF CONTRACTS

Electricity Forward Contract

In the electric industry, the Edison Electric Institute (EEI) Master Power Purchase and Sale Agreement is a commonly used contract that can be employed for forward sales of power. Transacting parties may make a bilateral sale by agreeing to transaction-specific values for price, quantity, delivery location, and period of delivery, among other details pertinent to the negotiated transaction. The terms of the transaction are documented on a transaction-specific confirmation.

NYMEX Natural Gas Futures Contract

For the natural gas industry, the dominant physical futures contract is the NYMEX Henry Hub Natural Gas (NG) Futures contract. For NYMEX's NG contract, the standard contract specifications are the delivery location – Sabine Pipeline Hub at the Henry Hub in Louisiana; the term – monthly; and the quantity – 10,000 MMBtu delivered equally over the course of the flow month.

LD1 Future or Natural Gas (Henry Hub) Financial Future

The physically deliverable NYMEX NG contract has its prompt-month[223] strip expire on the third to last business day of the month. The NG contract's Last Day 1 (LD1) settlement price is set during a 30-minute settlement window on its expiration day from 2pm to 2:30pm Eastern Prevailing Time. The settlement price is used to settle the legs of many financial and physical contracts. The simplest contract is the cash settled LD1 future, also known as NYMEX lookalike contracts or Natural Gas Financial Futures product. These are simple fixed-for-float swap futures in which the buyer pays a price and receives the LD1 settlement price if taken to settlement. Such contracts allow a market participant to maintain or hedge a price exposure without having to make or take physical delivery of the natural gas commodity.

Natural Gas Basis Future

A basis swap contract or basis future is a financial instrument that provides payments calculated on the price difference between a month-ahead index at a given location and the Henry Hub LD1 settlement price. An example is the ICE Michcon Basis Futures contract, in which traders buy and sell the contract, which derives its price from the subtraction of the NYMEX Henry Hub Futures contract price from the Mich Con city-gate Inside FERC monthly price. Basis futures can trade strips of a single month or multiple months, the settlement is determined each month until the contract expires, and the standard contract size is 2,500 MMBtu per flow day. Traders can use natural gas financial basis contracts for either hedging or speculative trades.

Natural Gas Index Future

An index swap contract or index future is a financial

223 The prompt month is the futures contract that is closest to expiration, typically prompt-month refers to the next contract month.

instrument that provides payments calculated on the price difference between a given location's averaged day-ahead index for a month and that month's first-of-month index set in the bidweek just before the start of the month. The ICE Michcon Index Futures contract allows traders to buy and sell a contract that derives its price from the subtraction of the Mich Con city-gate Inside FERC monthly price from the average of the Mich Con city-gate Platts Gas Daily prices over the flow days of a given month.

Natural Gas Swing Future

A swing swap contract or swing future is a financial instrument that provides payments based on the location's day-ahead index. ICE's Michcon Swing Future contract allows traders to buy and sell a contract that derives its price from the average of the Mich Con city-gate Platts Gas Daily prices over specific flow days. In addition to trading as full month strips, swing futures can trade during the flow month, providing a balance-of-month strip for the remaining flow days in the month.

Natural Gas Fixed Price Future

A fixed price future is a financial instrument that provides payments based on the location's month ahead index. ICE's Michcon Fixed Price Future contract allows traders to buy and sell a contract which derives its price from the Mich Con city-gate Inside FERC monthly price.

Natural Gas Options Contract

A natural gas options contract, such as ICE's Option on SoCal Fixed Price Futures (the futures price for the Southern California Border trading hub published by the Natural Gas Intelligence index), gives the purchaser the right, but not the obligation, to buy a specified number of fixed price futures contracts at a predetermined price, at a future date. The put option gives the option buyer the right, but not the obligation, to sell the fixed price futures at a minimum selected floor (strike) price. A natural gas consumer, such as a gas-fired power plant, might buy a call option to protect against having to pay more for natural gas than the selected strike price. Similarly, a natural gas producer or marketer could use a put option to protect against price drops below the strike price as a means of ensuring the profitability of future natural gas production. Traders also use options to speculate on the price of the underlying commodity, in anticipation of future market prices or as part of more complex financial trades.

Forward and Futures Curves

Standardized forwards, futures, and swaps are traded for every month, years into the future. The NYMEX natural gas futures contract, for example, is traded more than eight years into the future although only the first few years are actively traded. Each of the monthly contracts for which trading occurs has a price. Together, the prices for future contract months create a trajectory of prices known as the forward or futures curve.

Markets for Trading Physical and Financial Natural Gas and Electricity

As mentioned above, contracts in both physical and financial markets are transacted through exchanges, OTC electronic brokerage platforms, or off-exchange. With exceptions for cleared physical futures or trading, physical trading on electronic brokerage platforms is generally bilateral and OTC. Off-exchange trading inherently occurs bilaterally OTC. In the case of electricity, transactions also take place in RTOs and ISOs (see Chapter 2 for more information on RTO/ISOs).

EXCHANGES

An exchange is a central marketplace where buyers and sellers trade commodities, derivatives, and other financial instruments. A market participant (e.g., a buyer or seller) does not interact directly with its counterparty on an exchange. Instead, the

counterparties place their orders with the exchange, which then matches the buyer and seller anonymously. Exchange-traded contracts are standardized and the specifications for the contract, such as quantity and location, are established in advance by the exchange.

Historically, exchange trading occurred in trading pits where traders actively called out orders to buy and sell, known as open outcry. However, with the advent of electronic trading, open outcry has largely become obsolete, and most trading is now done electronically. Physical OTC trades on electronic brokerage platforms inherently require communication and coordination with a counterparty, which becomes known after a transaction. Electronic brokerage platforms trading in OTC markets provide an anonymized trading screen where buyers and sellers do not know their counterparty, and some platforms allow traders to communicate with bidding and offering counterparties in OTC products.

Natural gas and electricity are traded on exchanges and electronic brokerage platforms such as the NYMEX and ICE. In addition to energy contracts for natural gas and power, NYMEX facilitates the sale and purchase of financial and physical contracts for other commodities, including metals and agricultural products. ICE also offers natural gas and electricity contracts (both in cash-settled energy futures and physical OTC contracts), as well as emissions allowances. Nodal Exchange offers locational (nodal) futures contracts to market participants in the organized electricity markets, as well as electricity contracts for forward months at RTO hubs, zones, and nodes.

Margin is collateral contributed as a percentage of the current market value of a commodity contract. Margin allows market participants to trade without having to pay cash for the full value of the trade. Effectively, someone who trades on margin borrows much of the money used to buy or sell from the exchange or another entity. The trader posts collateral by putting down a certain amount of money or percentage of the trade value in cash or other security acceptable to the exchange.

OVER-THE-COUNTER MARKETS

An OTC market is a market where buyers and sellers interact with one another, usually via electronic or telephone communications, and without the supervision of an exchange. In OTC markets, contracts are bilateral, meaning two market participants directly negotiate and complete a purchase or sale. OTC transactions are not required to be standardized; they range from complicated negotiations for one-off structured contracts to standardized contracts traded through an electronic brokerage platform. The ability to tailor a contract to the exact needs of the counterparties is one of the chief benefits of OTC markets. Nonetheless, standardized contracts can also be transacted OTC. Many negotiations begin with a standardized contract, such as the natural gas contract developed by the North American Energy Standards Board (NAESB), and are then modified.

OTC transactions may be conducted via brokers that include voice brokers (brokers who conduct most business by phone or instant messaging) and electronic brokerage platforms. Unlike an exchange, the broker performs the function of matching specific buyers and sellers. In OTC trades, buyers and sellers are not anonymous to one another.

RTO/ISO MARKETS

Electricity is also bought and sold through RTO/ISOs. In general, RTO/ISO markets are operated to support the physical operation of the electric grid, dispatching generation to meet customer demand. RTO/ISO markets are multilateral; buyers and sellers are not matched individually against each other. The overall level of buying, or demand, is matched to the overall level of selling, or generation. In matching generation and demand, RTOs/ISOs are considered to clear the market but the word clearing has a different meaning than other markets or exchanges. For RTOs/ISOs, clearing refers to the matching of supply and demand, or, put it another way, to clear the market means the RTO/ISO accepts sufficient generation offers to meet demand needs. In general, if a generator's offer in the day-ahead market clears, the generator's output was offered at or below the day-ahead locational marginal price, and the

generator is expected to deliver power. RTO/ISOs also allow for bilateral physical transactions, although each RTO/ISO handles bilateral trades differently.

RTO/ISO markets have products that have some similarities to financial contracts. RTO/ISOs allow virtual transactions, such as virtual supply offers or virtual demand bids, which allow a market participant to trade financially on the expected price difference between an RTO/ISO's day-ahead and real-time markets. Virtual transactions (virtuals) are directly integrated into the operation of the physical market and affect physical supply and demand, and prices. However, virtual trades do not result in physical delivery. Chapter 2 provides additional information on virtuals.

Additionally, RTO/ISOs offer financial transmission rights (FTRs). FTRs and similar instruments are designed to provide financial compensation to offset transmission congestion costs over specific transmission paths. FTRs are allocated to transmission owners and auctioned to market participants by the RTO/ISOs on a periodic basis. The amount of available FTRs is linked to the physical operation of the transmission system and the amount of expected transmission capacity. FTRs are also discussed further in Chapter 2.

RTO/ISOs maintain credit policies to prevent default and, in the event of default, allocate the costs of defaults or other performance failures across market participants. RTO/ISO credit policies are discussed in Chapter 2 as well.

Trading Concepts and Terminology

Trading

Trading is the act of buying and selling a contract or contracts. A trade is a single consummated transaction.

Trading Volumes and Transactions

Trading volume refers to the total amount of a commodity traded or the number of related contracts that have changed hands in a given energy market for a given time period, such as a single trading day. Trading volumes give an indication of the nature of the market activity and traders may track increases or decreases in trading volumes over time to gauge the tendency for a price trend to continue.[224]

Market Prices, Bids, and Offers

The market price of a contract is the average price (or volume-weighted average price) of all individual trades for that contract. Trading requires a buyer and a seller, each willing to transact for a price. The price a buyer is willing to pay to purchase a contract is the bid price. The price at which the seller offers is the offer price. The prices at which buyers want to buy and sellers want to sell may not be the same. When the bid and offer prices differ, the difference between the prices is the bid-offer spread or bid-ask spread. This spread is the difference between the highest price at which buyers are currently willing to buy (the highest bid) versus the lowest price at which sellers are currently willing to sell (the lowest offer). For example, if a buyer bids $7 and the seller offers at $10, the bid-ask spread is $3.

Spot Prices

The spot price is a cash market price for a physical commodity that is available for immediate delivery (generally next-day or intra-day for natural gas and day-ahead or real-time for electricity).

Settlement

Settlement is the exchange of physical commodities or currency to close out a physical or financial contract. For settlement, a contract will indicate if delivery is to be made for a physical contract (physically settled) or a financial payout made for a financial contract (financially settled). Settlement occurs both on

224 Note that, with transactions involving standardized financial contracts such as an ICE natural gas swap futures contract, one can also readily determine a notional amount of energy volume represented by the number of trades because each contract trades a standardized amount of energy -- e.g., 2,500 MMBtu per contract.

Settlement Example

As mentioned above, the final settlement for the NYMEX natural gas (NG) futures contract for a given month occurs three business days prior to the start of the month of delivery (the prompt month). The contract expires and the last-day settlement (LD1 settlement) price is based upon the trading in the last half-hour of the settlement day. LD1 settlement is the final price for that particular futures contract term. For the NYMEX natural gas futures contract, most market participants either liquidate or "roll" their positions well before the settlement period. Rolling is the process of (1) liquidating the current month's contract before the contract expires and (2) purchasing a comparable position in the upcoming contract month. The trader holds the same number of contracts, but the contract month changes as time passes and contracts expire. Rolling and liquidating NG contracts is necessary for market participants to avoid making or taking physical delivery of the commodity for the contract month. It is far more common for a market participant to roll or liquidate than physically settle an NG futures contract.

exchanges and for OTC transactions. On exchanges, futures settlements occur according to a documented process and timeframe established by the exchange, while OTC transaction settlement occurs under the terms agreed upon by the parties.

Most market participants liquidate or roll contracts prior to expiration day and avoid trading during the settlement period of a contract. As the time to contract expiration approaches, price risk and volatility may increase significantly, while market liquidity and the remaining open positions (open interest) may decrease. Market participants seeking to maintain price exposure or hedges through expiration frequently use cash-settled lookalike contracts.[225]

Daily settlement prices are used to revalue traders' positions to the current market price for accounting and for margin calculations. Daily and LD1 settlement prices are also reported in publications and indexes and are used for price discovery.

Mark-to-Market

Mark-to-Market is an accounting methodology that provides a daily update of the value of a portfolio of market positions, all revalued to current market prices. Mark-to-Market results in near real-time updates to financial and accounting gains and losses, even though a trader might not actually transact to cash out of the positions.

Position

A position is the accumulated unexpired contracts held at a given point in time. Traders may have positions in each contract, as well as an overall position reflecting the balance of all their contracts.

Long and Short Positions

Traders are always aware of their positions and are constantly evaluating how market changes will affect the value of their positions, for example, by knowing whether a position benefits or loses when prices go up or down. A trader would establish a long position when he or she purchases an asset. In other words, a long position generally benefits from price increases.[226] A trader would establish a short position when he or she sells an asset. A short position generally benefits

225 A lookalike contract is based on a futures contract traded on the New York Mercantile Exchange (NYMEX). It may be traded on other platforms such as ICE.

226 Note that a trader taking a long position by purchasing index gas benefits from declining index prices. A long position in physical or financial products where the buyer pays an index price benefits from declines in that index price.

from falling prices.[227] If a position is neutral, the trader benefits from neither a rise nor a fall in prices and the position is considered "flat."

Position Limits

Position limits are imposed on exchanges, such as ICE and NYMEX, in accordance with the rules of the Commodity Futures Trading Commission. The position limits restrict the number of contracts a trader may hold at any point in time, during the month that the contract expires, or during some period closer to settlement. For example, NYMEX imposes position limits, which it refers to as accountability levels,[228] for any one month, for all months, and for expiration-month positions. Accountability levels for the NYMEX Henry Hub natural gas futures contract are 12,000 contracts for all months, 6,000 contracts for one month and 2,000 contracts in the expiration month.[229] Trading entities can petition to have accountability levels waived or modified.

Clearing

Clearing is a process in which financial or physical transactions are brought to a single entity to manage counterparty risk. The entity (referred to as a clearinghouse) steps into the middle of the transaction and becomes the counterparty to each buyer and seller. The clearinghouse assumes the risk that either the buyer or seller will fail to perform its contractual obligations, and thus maintains rules about the creditworthiness of traders, collateral that must be posted and fees that must be paid for the service. NYMEX and ICE act as clearinghouses for transactions occurring on their platforms.

Liquidating

Liquidating a position is the process of making a position neutral or flat. This can be done by selling that position for cash, or by undertaking an opposite and equal transaction.[230] After liquidation of a futures position, the trader has no net position in a contract.

Liquidity

Liquidity refers to the market for a contract having sufficient trade volume so that traders can transact with substantial volume (e.g., to liquidate his or her position) at any time and to do so without, or with limited, effect on market price. A market would be considered to be thin, or less liquid, if the market experiences few transactions or little volume. In low liquidity instances, significantly large trades may result in a noticeable movement in the market price.

Open Interest

Open interest is the aggregation of all traders' existing, or open, positions. For example, in futures and options markets, open interest is the total number of futures or options contracts transacted in a given period (e.g., in the delivery month) or market that have not yet been liquidated by an offsetting transaction or fulfilled by delivery. As the number of existing contracts generally changes from day to day, open interest is often tracked by traders and analysts to assess trends in market activity pertaining to beginning (or opening) positions or ending (or closing) positions in the market. In physical futures markets, open interest (both in terms of the total number of contracts and the number of counterparties) rapidly decreases as contracts near expiration and are settled.

Trading Analysis and Strategy

In deciding whether to trade, both hedgers and speculators pay attention to what is going on in the

227 A trader taking a short position by selling index gas benefits from increasing index prices. A short position in physical or financial products where the seller receives an index price benefits from increases in that index price.

228 Accountability levels are trading limits related to the total number of futures contracts held. These levels are set by exchanges and cannot be exceeded without a request for modification or a waiver.

229 *See* CME Group, *Position Limits*, *NYMEX & COMEX Position Limits* (n.d.), http://www.cmegroup.com/market-regulation/position-limits.html for up to date information.

230 CME Group, *Understanding Futures Expiration & Contract Roll*, (accessed June 23, 2023), https://www.cmegroup.com/education/courses/introduction-to-futures/understanding-futures-expiration-contract-roll.html.

market and develop their own view of where the market is likely to go. Traders may develop complicated forecasts as the basis for decisions on a number of transactions: whether, when, and where to build a merchant power plant; how to hedge natural gas production; and of course, when to buy and sell in the markets.

FUNDAMENTAL ANALYSIS

Two general schools of thought influence traders' thinking when analyzing markets for trading opportunities. The first is fundamental analysis, which considers physical demand and supply fundamentals including: production, pipeline and transmission capacity, planned and unplanned outages, as well as weather, economic, and demographic changes. Changes in information about fundamentals (or changes in perceptions of fundamentals) alter traders' views of the supply-demand balance, and therefore, of prices. Fundamental analysis is used often to determine the impacts of longer-term trends in the physical market – the development of shale gas supplies, for example.

TECHNICAL ANALYSIS

The second school of thought is technical analysis, which forecasts price movements based on patterns of price changes, rates of change, and changes in trading volumes and open interest, without regard to the underlying fundamental conditions. Instead of looking at the market for a physical good, technical analysis primarily looks at trading and price changes. Technical analysis is used most often to determine short-term movements and trends, helping traders time their buys and sells.

TRADERS' STRATEGY

A trader's strategy consists of a defined plan that includes decisions such as what contracts to trade and how to trade them. A trader's strategy will depend on the objectives of his or her company. Trading strategies in natural gas and electricity markets include activities such as buying or selling the physical product, managing the risk of physical and financial positions – also known as hedging--and attempting to make money through speculation.

Hedging

Hedging is the act of establishing an offsetting position with the intent of minimizing substantial losses should an original position lose its value. More specifically, market participants and traders with physical positions are exposed to potential gains or losses as market prices change over time. To manage this risk, market participants and traders may use any of a variety of transactions with opposing risk exposures to reduce or eliminate the original market risk. Traders frequently unwind hedges to lock in profits should a position gain in value.

A local distribution company (LDC) provides natural gas to end-use (retail) customers and is concerned with obtaining sufficient volumes of natural gas to serve variable customer demand at the lowest possible price. To ensure sufficient quantities and diversify the risk associated with price swings, an LDC trader may create a portfolio of supplies, with a block of firm supply to meet minimum daily needs. An LDC trader may also decide to buy in the next-day market to meet demand peaks. Additionally, an LDC trader may diversify the sources of natural gas, both to improve the reliability of supply and to diversify its price. Physical market participants can also manage risk by trading financial contracts. Physical market participants may also hedge for other reasons, such as establishing a predictable cash flow to support financing or to show state regulators that purchasing practices are prudent.

Speculating

Speculators, or traders seeking to profit from financial or physical markets without any other underlying energy production or consumption requirements, may employ different strategies to profit from the market. Some traders may take a passive approach, seeking to benefit from long-term price movements or to diversify a broader portfolio. Others may buy and sell relative to short-or medium-term movements in prices or price spreads. Some market participants may use High Frequency Trading (HFT), a trading activity guided by computer algorithms that process many buy and sell orders in extremely short timeframes. HFT trades are

executed in milliseconds and HFT trading programs can execute thousands and thousands of trades per day.

Capital Markets

Capital markets refer to the markets for ownership capital and debt. Capital markets provide the money needed to make investments in infrastructure such as power plants or natural gas pipelines, to operate plants and companies and to trade or conduct transactions. Most corporate financing is funded through a mixture of equity and debt capital.

Equity capital is most commonly raised through a direct sale of shares in a company to the public, after which shares may be traded on one or more stock exchanges. Note that, in recent years, a substantial amount of private equity has invested in the energy markets as well.

Debt capital may take the form of bonds, which are debt obligations sold directly to investors, and which typically specify a particular interest rate and a fixed time period. Companies may also borrow funds by employing a bank loan. Bank loans are frequently sold onward to investors through a process known as syndication.

EQUITY DEBT AND FINANCING

Equity financing is money provided in exchange for a share in the ownership, or shares of stock, of the business. A company does not have to repay the capital received, and shareholders are entitled to benefit from the company's operations through dividends and potential gains from appreciation in the original investment.

Characteristics of equity include:

- Equity capital can be kept by the company indefinitely.
- A company can issue shares in the company – stock – through financial markets. Companies may also use private equity – money from venture capital firms or private investment entities.
- The most common form of stock is common stock, which does not require regular dividend payments. Investor-owned utilities often issue preferred stock that entitles the holder to a fixed dividend, whose payment takes priority over that of common stock dividends.
- Stockholders and private equity investors get a say in how the company is operated and may impose restrictions.
- Equity investors may be more willing to assume higher risks in return for higher potential returns. Electric utilities are typically considered fairly conservative investments. Natural gas producers generally attract more risk-inclined investors.
- The return required to attract equity is generally higher than the interest paid to debt holders.
- Equity capital does not require collateral; equity constitutes a share in the company.
- Additional equity capital infusions may dilute, or reduce, the value of existing shares.

Debt financing involves borrowing money to be repaid over time, along with interest at a fixed or variable interest rate. With debt, the investor does not become an owner of the company. Some common types of debt include bonds – securities that companies issue in financial markets with maturities (when the loan must be repaid) of more than a year; shorter-term debt issued by companies through financial markets; and bank loans, such as lines of credit. A revolving line of credit is an assurance from a bank or other institution that a company may borrow and repay funds up to some limit at any time. Municipal and cooperative utilities typically use debt, since municipals and cooperatives have no ownership to sell.

Characteristics of debt include:

- Capital obtained through debt must be repaid or refinanced.
- Debt may be short-term, such as lines of credit from banks or corporate paper, or debt may be long-term.
- Companies must make their interest payments and repayment on schedule or the debt holders can take action, including forcing the company into bankruptcy. A company must generate sufficient cash through its operations or through other financing to make debt payments.
- Interest gets paid before equity dividends. In the

event of bankruptcy, all debtholders are generally paid back in full before shareholders are compensated.
- Debt gives lenders little or no control of the company (unless the company gets into financial trouble).
- Debt can leverage company profits; similarly, debt can magnify losses.
- Lenders are typically conservative, wanting to minimize downside risks.
- Borrowers may be required to provide collateral to secure debt. Debt without collateral is known as unsecured debt.

Companies often try to match the type of financing with the investment that they are making. Pipelines, power plants, and transmission facilities are long-lived assets and are typically financed using long-term capital, such as stock and long-term bonds, which can have 30-year maturities.

Other capital is also needed to conduct day-to-day operations. Some of the cash needed to fund operations comes from a company's revenues. However, revenues do not always come in when payments are due. Consequently, companies also rely on working capital, including some long-term capital from stocks and medium- and long-term bonds. Short-term investments and day-to-day operations also rely on commercial paper and bank loans to cover day-to-day cash needs. If a company faces significant problems, the company may have to issue higher-priced debt to obtain financing, which is a form of compensation to the lender in return for the added risk of lending. High-yield or junk bonds are issued by entities lacking investment grade credit ratings (see Credit Ratings, below).

CAPITAL EXPENDITURES

The overall stability of the capital markets – or the desire and ability of investors and lenders to provide capital – is an important issue for the overall health of the capital-intensive energy industry. The recession of 2008 and 2009 took a toll on capital spending as financial commitments to infrastructure fell for the first time in years, but spending has been rising since 2010 (see bar chart below).

The electricity industry makes the bulk of the capital expenditures in the utilities sector, specifically on electric transmission, distribution, and generation.

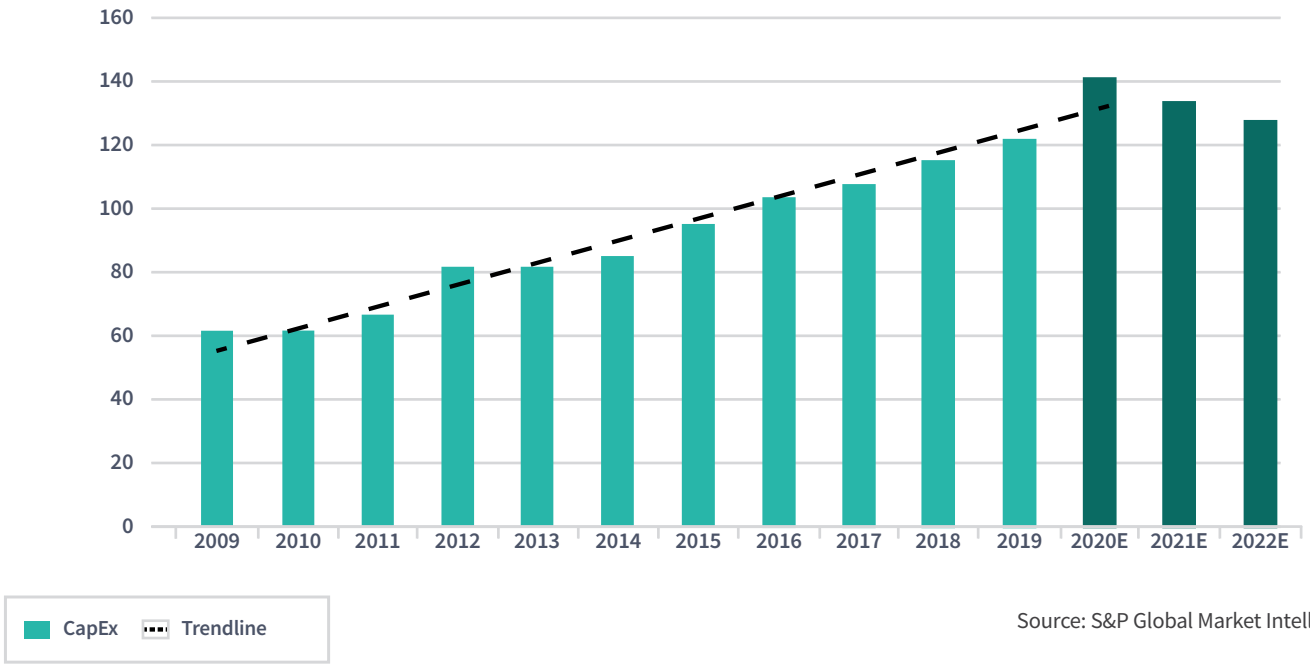
CREDIT RATINGS

Access to capital markets depends on the perceived riskiness of the entity seeking the capital.[231] To measure relative riskiness, many providers of capital look at different measures, including company financial reports, third-party analysis, and credit ratings assigned by the three major credit rating agencies -- Standard and Poor's (S&P), Moody's, and Fitch Ratings.

Not all market participants present the same level of riskiness. Market participants, such as investors and traders, consider the risks their counterparty may present, including the risk of default. One standardized tool used to assess relative risk is the credit rating. The credit rating agencies usually assess a company's Energy utility actual and estimated capital expenditures ($B) riskiness every time the company issues debt. A credit rating represents the rating agency's estimation of the likelihood that an issuer will be unable to repay its debt, as well as the capacity and willingness of the borrower to meet its financial obligations. Many organizations, including RTO/ISOs, consider credit ratings, among other things, when setting their credit policies, which determine with whom companies may transact and

231 In general, the risker a company is perceived to be, the higher rate of return an investor will require to invest in the equity or debt security of the company. Returns for an equity investor can come in the form of the return of capital through a dividend or stock buyback, or through an expectation of higher future profitability on which the investor will have a claim. Debt securities provide a return through the interest rate which accrues to the purchaser, known as the yield.

Figure 5-1: Actual and Estimated Capital Expenditures of Energy Utilities ($B)

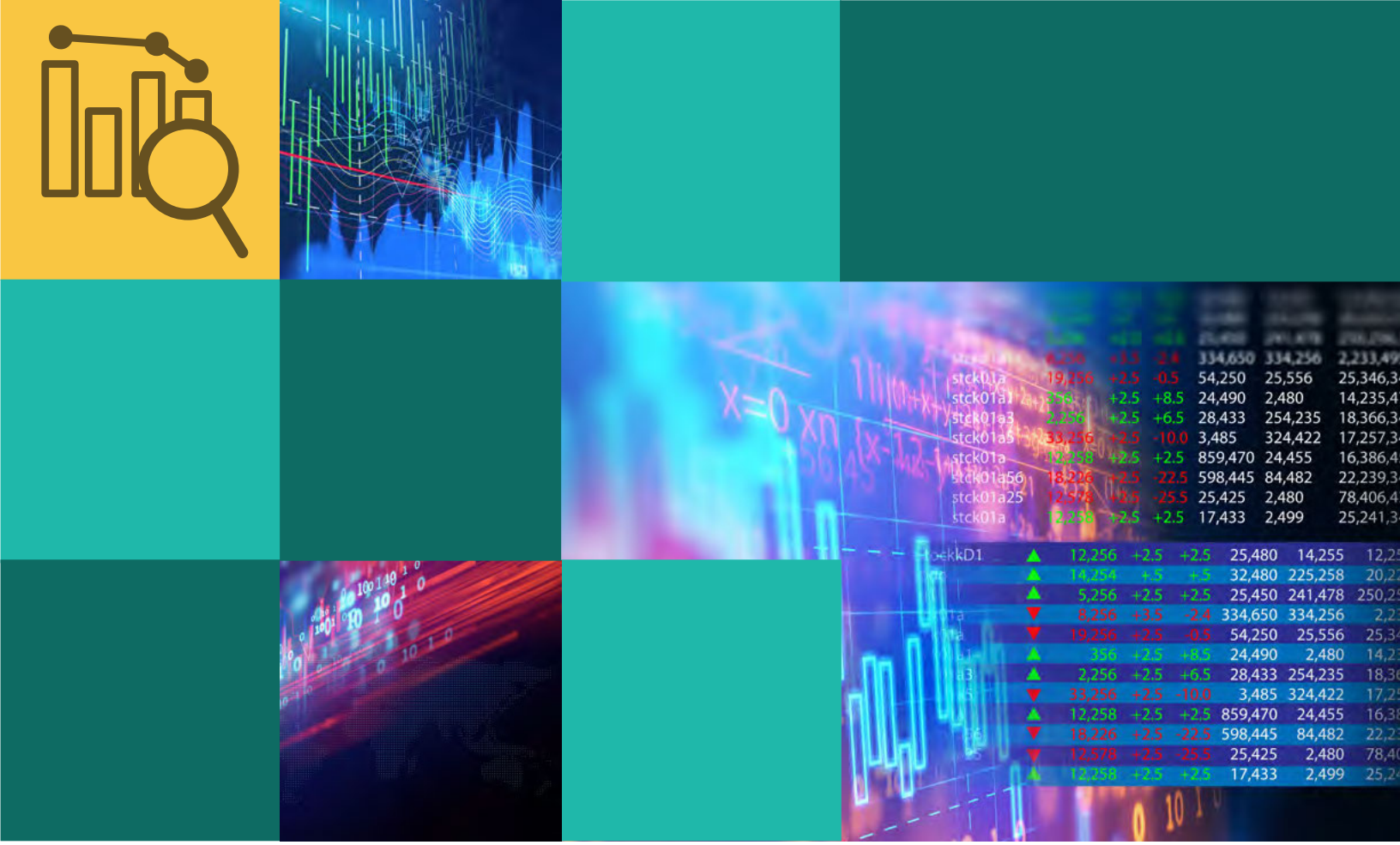


Source: S&P Global Market Intelligence[232]

whether the counterparty will need to post collateral. Each credit rating agency has its own way of assessing risk, reflected in the rating system the agency uses.

Credit quality tends to vary across industry sectors, may fluctuate over time, and is dependent both on the amount of debt issued by a company as well as the stability of a company's cash flow. As a result, companies with predictable income and capital expenditures, such as regulated electric utilities and natural gas LDCs, tend to have higher credit quality than companies subject to more variable cash flows. In contrast, merchant generators (known as independent power producers or IPPs) have experienced challenges with matching volatile cash flows against their capital and debt burdens. As a result, IPPs have experienced several credit rating downgrades and even bankruptcies over the past decade.

232 S&P Global Market Intelligence, *z*, at 1 (June 8, 2020).



Chapter 6
Market Manipulation

MARKET MANIPULATION

Following the Western Energy Crisis in the early 2000s,[233] Congress enacted the Energy Policy Act of 2005 (EPAct 2005), which added anti-manipulation provisions to the Federal Power Act, 16 U.S.C. § 824v (2012), and the Natural Gas Act, 15 U.S.C. § 717c-1 (2012). To implement these provisions, the Commission issued Order No. 670 in 2006,[234] adopting the Commission's Anti-Manipulation Rule, codified as 18 C.F.R. § 1c (2022). Recognizing that Congress and other federal regulators have long prohibited manipulation of other markets, such as securities and commodities markets, the Commission draws from the experience of sister federal agencies in implementing its anti-manipulation authority.

The Anti-Manipulation Rule applies to any "entity," which the Commission and courts have interpreted to cover both companies and individual people.[235] The Anti-Manipulation Rule prohibits (1) using a fraudulent device, scheme or artifice, or making any untrue statement of a material fact or omitting to state a material fact necessary to make a statement that was made not misleading, or engaging in any act, practice or course of business that operates or would operate as a fraud or deceit upon any entity; (2) with the requisite scienter (intent, knowledge, or recklessness); (3) in connection with a transaction subject to Federal Energy Regulatory Commission (FERC) jurisdiction. Unlike in private lawsuits, the Commission need not show reliance, loss causation, or damages to prove a violation.[236]

To the extent that an allegation of manipulation depends on the actor's purpose, both the Commission and courts have found that a violation can occur even if the wrongful objective is not the actor's sole purpose. For example, the Commission and courts have found that a party can engage in market manipulation if its primary purpose was wrongful, even if that was not its only goal.[237]

The prohibition on market manipulation is intended to deter or punish fraud in wholesale energy markets. The Commission defines fraud in general terms, meaning that fraud includes any action, transaction, or conspiracy for the purpose of impairing, obstructing, or defeating a well-functioning market. Fraud is a question of fact to be determined by all the circumstances of a case. In Order No. 670, the Commission modeled its Anti-Manipulation Rule on Securities and Exchange Commission (SEC) Rule 10b-5 in an effort to prevent and deter fraud and manipulation affecting the markets the Commission is entrusted to protect. Like SEC Rule 10b-5, FERC's Anti-Manipulation Rule is intended to be a broad anti-fraud catch-all clause.

Manipulation comes in many forms. As a federal court of appeals explained in a commodities manipulation case, "We think the test of manipulation must largely be a practical one . . . . The methods and techniques of manipulation are limited only by the ingenuity of man."[238] The Commission recognized this reality by framing its Anti-Manipulation Rule broadly, rather than articulating specific conduct that would violate the Rule. While not an exhaustive list, the most

233 The Western Energy Crisis of 2000-2001 was a series of market conditions and events in the Western U.S. that included diminished power supplies due to drought, inadequate infrastructure, a flawed power market design, and market manipulation. *See* FERC, *Addressing the 2000-2001 Western Energy Crisis* (2010), www.ferc.gov/industries/electric/indus-act/wec.asp. *See also, e.g., Puget Sound Energy, Inc.,* 146 FERC ¶ 63,028, PP 5-16 (2014).

234 *Prohibition of Energy Market Manipulation*, Order No. 670, 114 FERC ¶ 61,047, at P 38, *reh'g denied*, 114 FERC ¶ 61,300 (2006).

235 *FERC v. Vitol Inc.,* 2021 WL 6004339, at *8 (E.D. Cal. December 20, 2021); *FERC v. Coaltrain Energy, L.P.,* 2018 WL 7892222, at **9–10 (S.D. Ohio March 30, 2018) (reviewing rationale and collecting prior cases).

236 Order No. 670, 114 FERC ¶ 61,047 at P 48 n.102 (2006) ("reliance, loss causation and damages are not necessary for a violation of the [Anti-Manipulation] Rule"); *ETRACOM LLC & Michael Rosenberg,* 155 FERC ¶ 61,284 (2016) (no requirement to prove causation).

237 *FERC v. Coaltrain Energy, L.P., et al.,* 501 F. Supp.3d 503, 531-35 (S.D. Ohio 2020); *FERC v. Coaltrain Energy, L.P., et al.,* 2018 WL 7892222, at **13-14 (S.D. Ohio March 30, 2018).

238 *Cargill, Inc. v. Hardin,* 452 F.2d 1154, 1163 (8th Cir. 1971).

common types of fraud in energy, other commodities, and securities markets in recent years are discussed below. The borders of these categories are flexible and a single scheme may include elements of multiple types of fraud.

In addition to the information provided here, the Commission's Office of Enforcement (Enforcement) staff has published a white paper providing additional background on the types of manipulative schemes discussed here.[239]

Manipulative Trading Techniques and Cross-Product Manipulation

Traders sometimes place trades not to profit from market forces but to achieve a different, improper goal. For example, a trader may engage in high-volume wash trading to create a false impression of strong market interest in the instrument.[240] In another unlawful strategy, a trader may buy or sell at uneconomic prices to move a price to trigger an option that will profit the trader.

Another common manipulative technique is "marking the close," in which a trader places transactions near the close of a trading period not to profit based on market forces but to affect the closing or settlement price. This may be done to drive up (or down) mark-to-market marks for valuation, to avoid margin calls, or to benefit positions in related instruments. "Banging the open" is a similar practice in which a trader buys or sells in large quantities at the opening of trading to induce others to trade at that price level and to create a false impression about how the market views fundamentals that day.

Manipulators have grown more sophisticated with the expanded use of derivative products, whose value is set by the price of transactions in a related product. Many of the manipulative schemes that Enforcement staff has investigated and prosecuted are cross-product schemes in which an entity places trades in one market (e.g., the physical market), often at a loss, with the intent to affect the settlement price of derivative instruments (e.g., the financial market). Such trading can violate the Anti-Manipulation Rule because the trading is not undertaken in response to supply-and-demand fundamentals but rather to benefit another position. Trading for that purpose can undermine the functioning of jurisdictional markets.

Key to understanding cross-product manipulation is that financial and physical energy markets are interrelated: physical natural gas or electric transactions can help set energy prices on which financial products are based, so that a manipulator can use physical trades (or other energy transactions that affect physical prices) to move prices in a way that benefits their overall financial position. One useful way of looking at this type of manipulation is that the transaction is a "trigger" that is used to "target" a price. Commonly, the trigger is a physical product, but cases have also arisen where the trigger was a financial product. For example, the trigger could be a physical power flow scheduled in a day-ahead electricity market at a particular node, and the target could be the day-ahead price established by the market operator for that node. Or the trigger could be a purchase of natural gas at a trading point located near a pipeline, and the target could be a published index price corresponding to that trading point. The purpose of using the trigger to target a price is to raise or lower that

239 *FERC Staff White Paper on Anti-Market Manipulation Enforcement Efforts Ten Years after EPAct 2005* (2016) (Enforcement Staff White Paper on Manipulation), *available at* https://www.ferc.gov/legal/staff-reports/2016/marketmanipulationwhitepaper.pdf.

240 Wash trading refers to offsetting trades that, as an economic matter, cancel one another out. *See Houlian Chen, Powhatan Energy Fund, LLC, HEEP Fund, LLC, CU Fund, Inc.,* 151 FERC ¶ 61,179 P 104 (2015) (Order Assessing Civil Penalties).

price in a way that will increase the value of a "benefiting position" (e.g., a Financial Transmission Right (FTR) product in power markets, a swap, a futures contract, or other derivative).

Usually, increasing the value of the benefiting position (i.e., increase profits or mitigate losses) is the goal or motive of the manipulative scheme. Understanding the nature and scope of a manipulator's benefiting financial positions—and how they relate to the triggering transactions—can be a key focus of manipulation cases. The Commission's Anti-Manipulation Rule is an intent-based rule: a finding of manipulation requires proving that the manipulator acted intentionally, knowingly, or recklessly to impair, obstruct, or defeat the proper functioning of the energy markets the Commission regulates.[241]

The mere fact that a trade may move market prices does not by itself make the trade illegal. If a market-moving trade is placed for a legitimate purpose—such as to hedge risk or try to profit based on market fundamentals—the conduct, without more, would not violate the Commission's Anti-Manipulation Rule.

Information-Based Manipulation

Many manipulative schemes rely on spreading false information, which involves knowingly disseminating untrue information about an asset's value to move its price. A well-known scheme in the securities markets is the "pump and dump," in which a participant spreads a false, misleading, or exaggerated statement that drives the price up and then sells the shares after the price rises. In the energy markets, a common way to misrepresent a commodity's value is to misrepresent the price of the commodity or its level of trading activity. False reporting and wash-trading schemes were well-documented forms of manipulation in the early 2000s and contributed to the Western Energy Crisis.[242] False reporting occurs when a market participant submits fictitious transactions or information to a price-index publisher to affect the index-settlement price. Another form of information-based manipulation involves providing misinformation through conduct that is intended to misrepresent a market participant's characteristics, circumstances, or intentions, to receive a benefit, payment, or award for which it would not be eligible but for the misleading conduct. This includes engaging in trading strategies that are intended to create market results inconsistent with the purpose of the transactions.

Similarly, wash trading may involve actual but offsetting trades for the same (possibly nonmarket) price and volume between the same market participants such that no real economic exchange takes place; however, it may falsely inflate trading volumes at a price level and give the impression of greater trading activity. False reporting and wash trading have resulted in a number of criminal prosecutions by the Department of Justice.

Gaming

Many of the cases investigated and prosecuted by Enforcement staff concern gaming of tariff provisions or market rules. The Commission has made clear that gaming includes behavior that circumvents or takes unfair advantage of market rules or conditions in a deceptive manner that harms the proper functioning of the market and potentially other market participants or consumers. The prohibition on gaming is longstanding and applied to a number of pre-EPAct 2005 schemes including those that arose during the Western Energy Crisis.[243] More recently, the Commission has pursued numerous cases involving gaming, including,

241 Order No. 670, 114 FERC ¶ 61,047 at PP 49, 52-53 (2006).

242 The Commission's Report on the Western Energy Crisis is available here: Addressing the 2000-2001 Western Energy Crisis | Federal Energy Regulatory Commission (ferc.gov) (2003).

243 *See* Enforcement Staff White Paper on Manipulation 23-25.

as discussed below, *GDF Suez Energy Marketing NA, Inc.*, *JPMorgan Ventures Energy Corp.*, the *PJM Interconnection, L.L.C.* (*PJM) Up-To Congestion Cases*, *Golden Spread Electric Cooperative, Inc.*, and *GreenHat Energy, LLC*. In considering these cases, the Commission has found gaming to include effectively riskless transactions executed for the purpose of receiving a collateral benefit; conduct that is inconsistent or interferes with a market design function; and conduct that takes unfair advantage of market rules to the detriment of other market participants and market efficiency. In these cases, entities typically submit offers or bids that falsely appear to be based on normal market forces (i.e., supply and demand fundamentals) but are in fact aimed at different, improper objectives.

Withholding

Withholding is the removal of supply from the market and is one of the oldest forms of commodities manipulation. The classic manipulative scheme referred to as a "market corner" involves taking a long contract position in a deliverable commodity and stockpiling physical supply to force those who have taken a short position to buy back those positions at an inflated price.

Withholding played an important role in the Western Energy Crisis in the early 2000s. Market participants, particularly Enron, exploited supply-demand imbalances and poor market design. Generation operators scheduled maintenance outages during peak demand periods, which is an example of physical withholding. In addition, transmission lines were overscheduled to create the appearance of congestion in an effort to reduce the supply of electricity. These efforts, in combination with economic withholding (discussed below) and information-based schemes (discussed above), resulted in a dramatic rise in wholesale electricity prices. Utilities such as Pacific Gas & Electric (PG&E) and Southern California Edison were unable to pass on these high prices to their retail customers because of state price caps. The crisis precipitated widespread blackouts, impaired the state's economy, and led to PG&E's bankruptcy filing in April 2001.

Economic withholding, which also contributed to the Western Energy Crisis, is similar to physical withholding, but rather than turning off a generator or stockpiling a physical commodity, the manipulator sets an offer price for a needed resource that is so high that the resource will not be selected in the market. For example, a generator in a constrained market such as New York City could purposely set its offer price high enough that it would not be called on to run. This scheme would create a shortage of generation and, thus, raise prices for the benefit of the rest of its generation fleet or its financial positions.

Representative Matters

The following representative matters involve at least one of the types of manipulative schemes previously described. Each of these matters has either been resolved through settlement or is currently pending before a district court or on remand from a Court of Appeals.

BARCLAYS BANK, PLC (BARCLAYS) AND DANIEL BRIN, SCOTT CONNELLY, KAREN LEVINE, AND RYAN SMITH (TRADERS)

On July 16, 2013, the Commission determined that Barclays and the Traders violated the Commission's Anti-Manipulation Rule.[244] The Commission found that Barclays and the Traders engaged in loss-generating trading of day-ahead, fixed-price physical electricity on the InterContinental Exchange (ICE) with the intent to benefit financial swap positions at primary electricity trading points in the western United States. In sum, Barclays undertook fixed-price, day-ahead physical trades at various western trading points to change the ICE daily index for the benefit of its financial swap positions whose price was based on that index.

244 *Barclays Bank PLC, Daniel Brin, Scott Connelly, Karen Levine, and Ryan Smith,* 144 FERC ¶ 61,041 (2013) (Order Assessing Civil Penalties).

Barclays and the Traders failed to pay the penalties assessed by the Commission. Enforcement staff filed an action to affirm the Commission's assessment in the United States District Court for the Eastern District of California on October 9, 2013. In May 2015, the court rejected defendants' motion to dismiss and ruled that the conduct alleged was actionable as manipulation, that the Commission had jurisdiction over the manipulative trading at issue, and that the Commission had authority to pursue individuals. Following a mediation under the court's supervision, Enforcement staff and defendants reached a settlement for $105 million. Barclays agreed to pay a $70 million civil penalty and $35 million in disgorgement.[245] The Commission approved the settlement on November 7, 2017.[246]

BP AMERICA, INC. AND AFFILIATES (BP)

On August 5, 2013, the Commission issued an order to show cause and notice of proposed penalty to BP.[247] In that proceeding, Enforcement staff alleged that BP made uneconomic natural gas sales at Houston Ship Channel and took steps to increase its market share at Houston Ship Channel as part of a manipulative scheme to suppress the Houston Ship Channel Gas Daily index. Enforcement contended that this was a cross-product manipulation scheme, motivated by a desire to benefit certain physical and financial positions held by BP whose price was set by the same index.

On August 13, 2015, Administrative Law Judge (ALJ) Carmen Cintron issued her Initial Decision finding that BP violated the Anti-Manipulation Rule and Section 4A of the NGA.[248] On July 11, 2016, the Commission issued an order affirming the ALJ's Initial Decision and directed BP to pay $20,160,000 in civil penalties and to disgorge unjust profits in the amount of $207,169 to the Low Income Home Energy Assistance Program of Texas for the benefit of its energy consumers.[249]

On August 10, 2016, BP sought rehearing of the Commission's July 16, 2016 order, and on December 11, 2017, filed a motion seeking to dismiss the action based on the five-year statute of limitations in 28 U.S.C. § 2462. On December 17, 2020, the Commission denied rehearing, provided a modified discussion reaching the same result, and denied the motion to dismiss based on the statute of limitations.[250]

BP appealed the Commission's orders to the Fifth Circuit Court of Appeals. On October 20, 2022, the Court of Appeals upheld the orders in most respects. The Court of Appeals held that the Commission could not base its market manipulation claims on BP's intrastate (entirely within Texas) transactions, but that the Commission properly rested, as an alternative basis for jurisdiction, on particular interstate transactions by BP. On market manipulation, the court affirmed the Commission's findings of manipulative conduct and intent, based on BP's changed trading behavior during the investigative period and the "suspicious nature" of BP's trading patterns. As for the Commission's penalty assessment, the court found that its jurisdictional ruling, resting on a smaller set of BP transactions, requires a new calculation. The court did not otherwise limit the agency's discretion on remand to revisit its calculation.

On July 7, 2023, the Commission approved a Stipulation and Consent Agreement resolving the Commission's case against BP.[251] In)the settlement, BP agreed to pay a civil penalty of $10,750,000 and agreed not to seek return of the $250,295 of disgorgement it already paid.

245 *FERC v. Barclays Bank PLC,* 105 F. Supp. 3d 1121 (2015).
246 *Barclays Bank PLC, Daniel Brin, Scott Connelly, and Karen Levine,* 161 FERC ¶ 61,147 (Order Approving Stipulation and Consent Agreement) (2017).
247 *BP America Inc.,* 144 FERC ¶ 61,100 (2013).
248 *BP America Inc.,* 152 FERC ¶ 63,016 (2015).
249 *BP America Inc.,* 156 FERC ¶ 61,031 (2016).
250 *BP America Inc.,* 173 FERC ¶ 61,239 (2020) (Order Addressing Arguments Raised On Rehearing).
251 *BP America Inc.,* 184 FERC ¶ 61,016.

CONSTELLATION ENERGY COMMODITIES GROUP (CCG)

On March 9, 2012, the Commission approved a settlement with CCG in which CCG agreed to disgorge $110 million in unjust profits and pay a civil penalty of $135 million.[252] Enforcement staff determined that CCG had employed a scheme of virtual and physical trading in the New York ISO (NYISO) market to move day-ahead prices in a direction that would benefit CCG's financial swap positions.[253] Although CCG's virtual and physical transactions were routinely unprofitable, they enabled CCG to make a $110 million profit on its swap positions. Enforcement determined that this manipulation of the physical and virtual markets caused widespread economic losses to market participants in the Day Ahead markets of ISO New England (ISO-NE) and NYISO.[254] Enforcement staff also determined that CCG violated 18 C.F.R. § 35.41(b) by providing inaccurate and misleading information to the NYISO. Specifically, Enforcement determined that CCG denied that its virtual transactions were related to its swap positions and instead told the NYISO that the transactions were independent of the swap positions and were based on market fundamentals. In addition to $245 million in monetary relief, CCG agreed to a variety of compliance measures, including (a) monitoring of profit and loss concentrations in virtual and physical trading and (b) advance documentation of the purpose of virtual transactions.

ETRACOM LLC (ETRACOM) AND MICHAEL ROSENBERG

On June 17, 2016, the Commission found that ETRACOM and Rosenberg violated the Commission's Anti-Manipulation Rule by implementing a scheme to submit virtual transactions for the purpose of economically benefitting ETRACOM's Congestion Revenue Rights (CRR) positions, which are similar to Financial Transmissions Rights in other ISOs.[255] Specifically, in May 2011, the Commission found that ETRACOM submitted continuous and uneconomic virtual supply offers at New Melones, a node near the eastern border of California Independent System Operator (CAISO), during every hour over an 18-day period with the intent to artificially lower prices there. Many of ETRACOM's virtual supply offers were placed near the offer floor of negative $30, and ETRACOM accumulated $42,000 in losses related to its virtual supply offers over that period. At the same time, the artificially-lowered prices increased the profit on ETRACOM's CRR positions at New Melones by over $315,000 during that period. The Commission assessed civil penalties against ETRACOM and Rosenberg of $2.4 million and $100,000, respectively. The Commission further directed ETRACOM to disgorge the $315,000 of unjust profits, with interest. ETRACOM and Rosenberg failed to pay the penalties assessed by the Commission. Therefore, on August 17, 2016, the Commission filed an action to affirm the Commission's assessment of penalties in the United States District Court for the Eastern District of California. On April 10, 2018, the Commission approved a settlement in which ETRACOM agreed to pay the full disgorgement amount (with interest)and a penalty of $1,500,508.[256]

GDF SUEZ ENERGY MARKETING NA, INC. (GDF SUEZ)

On February 1, 2017, the Commission approved a settlement with GDF Suez resolving an investigation relating to lost opportunity cost credits (LOCs) in the PJM market.[257] Under the terms of the settlement, GDF Suez agreed to pay a civil penalty of $41 million and to disgorge to PJM $40.8 million in unjust profits.

Enforcement staff concluded that GDF Suez violated the Commission's Anti-Manipulation Rule by targeting and

252 *Constellation Energy Commodities Group, Inc.,* 138 FERC ¶ 61,168 (2012).

253 For background about NYISO, *see* https://www.ferc.gov/power-sales-and-markets/rtos-and-isos/nyiso.

254 For background about ISO-NE, *see* https://www.ferc.gov/industries-data/electric/electric-power-markets/iso-ne.

255 *ETRACOM LLC and Michael Rosenberg,* 155 FERC ¶ 61,284 (2016) (Order Assessing Civil Penalties).

256 *ETRACOM LLC and Michael Rosenberg,* 163 FERC ¶ 61,022 (2018) (Order Approving Stipulation and Consent Agreement). For more information about PJM, *see* https://www.ferc.gov/industries-data/electric/electric-power-markets/pjm.

257 *GDF SUEZ Energy Marketing NA, Inc.,* 158 FERC ¶ 61,102 (2017) (Order Approving Stipulation and Consent Agreement).

inflating its receipt of LOCs. PJM pays LOCs to combustion turbine units that clear the day-ahead market but are not subsequently dispatched in the real-time market. During the period of GDF Suez's conduct (2011-2013), PJM calculated LOCs for combustion turbine units based on the difference between the real-time locational marginal price and the higher of a unit's price-based and cost-based offers in the day-ahead market. GDF Suez targeted and inflated its receipt of LOCs by discounting its offers below-cost to clear the day-ahead market at times when the units likely would not have cleared based on undiscounted offers and when GDF Suez expected that PJM would not dispatch the units in the real-time. This resulted in profits from LOCs when PJM did not dispatch the units and when they would have operated at a loss if dispatched. GDF Suez's discounted offers did not reflect the price at which it could economically generate power, but rather the price at which it could obtain a day-ahead award and then receive LOCs when the units could not have operated profitably.

ISO-NE DAY-AHEAD LOAD RESPONSE PROGRAM (DALRP)

Based on an Enforcement staff investigation of Rumford Paper Company (Rumford), Lincoln Paper and Tissue LLC (Lincoln), Competitive Energy Services, LLC (CES), and Richard Silkman (Silkman), the Commission, in July 2012, issued each subject an order to show cause alleging that their conduct related to the DALRP in the ISONE market violated the Commission's Anti-Manipulation Rule. Enforcement staff and Rumford reached a settlement of the allegations against the company, which the Commission approved in March 2013.[258] On August 29, 2013, the Commission issued Orders Assessing Civil Penalties to Lincoln, CES, and Silkman, finding that the subjects fraudulently inflated load baselines and repeatedly offered load reductions at the minimum offer price to maintain the inflated baseline.[259] The Commission found that the scheme involved uneconomic energy purchases that served no legitimate purpose and were designed to increase DALRP payments that would not have otherwise been obtained. The Commission determined that this scheme misled ISO-NE, inducing payments to these entities based on the inflated baselines for load reductions that never occurred.

The Commission ordered Lincoln to pay $5 million in civil penalties and approximately $379,000 in disgorgement; CES to pay $7.5 million in civil penalties and approximately $167,000 in disgorgement; and Silkman to pay $1.25 million in civil penalties. When none of the respondents paid the amounts assessed by the Commission, Enforcement staff filed two petitions in the United States District Court for the District of Massachusetts on December 2, 2013 to affirm the Commission's orders. On April 11, 2016, the Court denied Lincoln's, Silkman's, and CES's motions to dismiss the Commission's petitions for failure to state a claim, but transferred the cases to the United States District Court for the District of Maine.[260] The Commission subsequently approved a settlement in which Lincoln agreed to a $5 million penalty, subject to certain conditions on account of its bankruptcy, and disgorgement of $379,016.[261] In 2020, the Commission settled its claims against Silkman and CES with a civil penalty of $708,159 against CES, a civil penalty of $600,000 against Silkman, and disgorgement of $166,841 from CES.[262]

JP MORGAN VENTURES ENERGY CORPORATION (JPMVEC)

On July 30, 2013, the Commission approved a settlement between Enforcement staff and JPMVEC resolving

258 *Rumford Paper Co.,* 142 FERC ¶ 61,218 (2013) (Order Approving Stipulation and Consent Agreement).

259 *Lincoln Paper and Tissue, LLC,* 144 FERC ¶ 61,162 (2013) (Order Assessing Civil Penalty); *Competitive Energy Services, LLC,* 144 FERC ¶ 61,163 (2013) (Order Assessing Civil Penalty); *Richard Silkman,* 144 FERC ¶ 61,164 (2013) (Order Assessing Civil Penalty).

260 *FERC v. Silkman,* 177 F. Supp.3d 683 (D. Mass. 2016) (order regarding motions to dismiss); *FERC v. Silkman,* 2016 WL 1444604 (D. Mass. April 11, 2016) (order regarding transfer).

261 *Lincoln Paper and Tissue, LLC,* 155 FERC ¶ 61,228 (2016) (Order Approving Stipulation and Consent Agreement).

262 *Competitive Energy Services, LLC,* 173 FERC 61,176 (2020) (Order Approving Stipulation and Consent Agreement).

an investigation of JPMVEC's bidding practices.[263] Pursuant to the settlement, JPMVEC agreed to pay $285 million in civil penalties, $124 million in disgorgement to CAISO ratepayers, and $1 million in disgorgement to Midcontinent Independent System Operator (MISO) ratepayers. In addition, the company agreed to waive its claims that CAISO owed it money from two of the strategies that Enforcement staff had investigated, and agreed to conduct a comprehensive external assessment of its policies and practices in the power business.

Enforcement staff determined that JPMVEC violated the Commission's Anti-Manipulation Rule by engaging in twelve manipulative bidding schemes in CAISO and MISO. These schemes distorted a well-functioning market in several ways, including but not limited to, misleading CAISO and MISO into paying JPMVEC at rates far above market prices; submitting bids that were expected to, and did, lose money at market rates, as they were not driven by the market forces of supply and demand; defrauding the RTOs/ISOs by obtaining payments for benefits that JPMVEC did not deliver; and displacing other generation and influencing energy and congestion prices.[264]

MAXIM POWER CORP. (MAXIM)

On May 1, 2015, the Commission assessed $5 million in civil penalties against Maxim and its affiliates and $50,000 against the individual employee principally responsible for the conduct, finding that Maxim's offers to ISO-NE for its Pittsfield, Mass., power plant were manipulative.[265] Although the Pittsfield plant could burn either natural gas or fuel oil, Maxim almost always burned natural gas because it was usually much cheaper to do so. In the summer of 2010, on hot days when it expected the Pittsfield plant to receive day-ahead awards for reliability, Maxim submitted offers to ISO-NE based on oil prices even though the unit actually burned natural gas. Because the unit was needed for reliability, Maxim received make-whole payments for costly oil that Maxim did not in fact burn, generating substantial profits for the firm.[266] Maxim also sent emails to ISO-NE's market monitor that, the Commission found, had falsely communicated that the unit was actually burning oil.

After Maxim failed to pay the assessed penalties, the Commission filed an action to affirm the Commission's assessment of penalties in the United States District Court for the District of Massachusetts. After the court denied Maxim's motion to dismiss,[267] the Commission, on September 26, 2016, approved a settlement negotiated by Enforcement staff and Maxim in which Maxim agreed to pay $4 million in disgorgement to ISO-NE and $4 million in civil penalties.[268] The settlement covered both the conduct at issue in the district court case and a separate strategy that Enforcement determined to be manipulative.

PJM UP-TO CONGESTION (UTC) CASES

In August 2010, the Commission opened an investigation into whether certain market participants were manipulating the PJM UTC market. Following three separate show-cause proceedings that commenced between May 2015 and May 2016, the Commission found certain trading by five entities and eight

263 *In Re Make-Whole Payments and Related Bidding Strategies,* 144 FERC ¶ 61,068 (2013) (Order Approving Stipulation and Consent Agreement). For more information about CAISO, see https://www.ferc.gov/industries-data/electric/electric-power-markets/cais o. For more information about MISO, see https://www.ferc.gov/industries-data/electric/electric-power-markets/miso.

264 For background about RTOs and ISOs, *see* https://www.ferc.gov/power-sales-and-markets/rtos-and-isos.

265 *Maxim Power Corporation, Maxim Power (USA), Inc., Maxim Power (USA) Holding Company Inc., Pawtucket Power Holding Co., LLC, Pittsfield Generating Company, LP, and Kyle Mitton,* 151 FERC ¶ 61,094 (2015) (Order Assessing Civil Penalties).

266 Make-whole payments are designed to compensate units that are dispatched by ISO-NE even though the unit's offer prices are higher than market prices.

267 *FERC v. Maxim Power Corp.*, 196 F. Supp. 3d 181 (D. Mass. 2016).

268 *Maxim Power Corp., Maxim Power (USA), Inc., Maxim Power (USA) Holding Company Inc., Pawtucket Power Holding Company, LLC, and Pittsfield Generating Company, LP,* 156 FERC ¶ 61,223 (2016) (Order Approving Stipulation and Consent Agreement).

individuals to violate the Anti-Manipulation Rule and assessed civil penalties.[269] The manipulative trading involved the reservation of large volumes of transmission in connection with spread trades that were effectively wash trades or trades between points with de minimis or zero price spreads. The lack of price spreads allowed the traders to reserve exceptionally large volumes of transmission which, in turn, enabled the traders to claim certain credits that PJM was allocating to paid-for transmission.

When the respondents failed to pay the assessed penalties, the Commission filed three actions to affirm the Commission's penalty assessments: in the U.S. District Court for the Eastern District of Virginia seeking $28.8 million in penalties and $3.47 million in disgorgement against Powhatan Energy Fund, LLC (Powhatan) and other funds and $1 million against Houlian Chen; in the U.S. District Court for the District of Columbia seeking $14 million in penalties and $1.28 million in disgorgement against City Power Marketing, LLC (City Power) and $1 million in penalties from K. Stephen Tsingas (Tsingas); and in the U.S. District Court for the Southern District of Ohio seeking $26 million in penalties and $4.12 million in disgorgement against Coaltrain Energy, L.P (Coaltrain) and $12 million in total penalties from four individuals.

In *City Power*, the Court denied defendants' motion to dismiss, holding that the alleged conduct was actionable as manipulation and that the Commission could penalize individuals.[270] Subsequently, in February 2017, defendants settled for a $9 million penalty against City Power, a $1.42 million penalty against Tsingas, and $1.3 million in disgorgement.[271]

In *Coaltrain*, as in *City Power*, the court denied defendants' motions to dismiss, holding, among other things, that the Commission had alleged actionable manipulation, pled fraud with specificity, has jurisdiction over financially-settled transactions, and can penalize individuals.[272] After discovery, the court denied defendants' motions for summary judgment, while granting the Commission's motion for summary judgment on its claim that Coaltrain violated 18 C.F.R. § 35.41(b) by falsely denying the existence of key company documents.[273] The Commission settled the *Coaltrain* case in 2022 with an agreement by the defendants to pay back virtually all of the $4.1 million in unjust profits.[274]

The Commission settled its case against Houlian Chen for a $600,000 disgorgement payment to PJM, based on documentation of Chen's limited ability to pay.[275] After the other defendant, Powhatan, declared bankruptcy, the U.S. District Court for the Eastern District of Pennsylvania issued a default judgment against it for $3,465,108 in disgorgement and $16,800,00 in civil penalties.[276] The Court's order includes detailed findings based on the record evidence.[277]

GOLDEN SPREAD ELECTRIC COOPERATIVE, INC. (GOLDEN SPREAD)

In November 2021, the Commission approved a settlement agreement between Enforcement staff and Golden Spread, in which Golden Spread agreed to disgorge $375,000 and pay a civil penalty of $550,000

269 *Houlian Chen, Powhatan Energy Fund, LLC, HEEP Fund, LLC, CU Fund, Inc.,* 151 FERC ¶ 61,179 (2015) (Order Assessing Civil Penalties); *City Power Marketing, LLC and K. Stephen Tsingas,* 152 FERC ¶ 61,012 (2015) (Order Assessing Civil Penalties); and *Coaltrain Energy, L.P., Peter Jones, Shawn Sheehan, Robert Jones, Jeff Miller, Jack Wells, and Adam Hughes 155* FERC ¶ 61,204 (2016) (Order Assessing Civil Penalties).

270 *FERC v. City Power Marketing, LLC,* 199 F. Supp. 3d 218 (D.D.C. 2016).

271 *City Power Marketing, LLC and K. Stephen Tsingas,* 160 FERC ¶ 61,013 (2017) (Order Approving Stipulation and Consent Agreement).

272 *FERC v. Coaltrain Energy, L.P., et al.,* 2018 WL 7892222 (S.D. Ohio March 30, 2018).

273 *FERC v. Coaltrain Energy, L.P., et al.,* 501 F. Supp.3d 503 (S.D. Ohio 2020).

274 *Coaltrain Energy, L.P.,* 181 FERC ¶ 61,031 (2022) (Order Approving Stipulation and Consent Agreement).

275 *Houlian Chen,* 177 FERC ¶ 61,076 (2021) (Order Approving Stipulation and Consent Agreement).

276 *FERC v. Powhatan Energy Fund, LLC,* 2023 WL 2603381 (E.D. Va. March 22, 2023).

277 *Id.*

to resolve Enforcement staff's allegations of market manipulation in the Southwest Power Pool (SPP).[278] Through its investigation, Enforcement staff determined that Golden Spread engaged in a scheme to wrongfully obtain make-whole payments from SPP. Make-whole payments in SPP are designed to ensure that a market participant's costs are met when market revenues are insufficient to cover the resource's short-run variable costs across an entire day. Golden Spread inflated its make-whole payments by choosing "self-commit" status (i.e., being a price taker) when Golden Spread expected the unit to be profitable, while offering in at market prices when it expected the unit to be unprofitable. By doing so, Golden Spread was able to obtain make-whole payments from SPP for the unprofitable hours, even though the unit was profitable across the day as a whole.

Enforcement staff concluded that Golden Spread's strategy signaled to the market that it was trading based on market fundamentals when, in fact, it was trading for the improper purpose of targeting and inflating make-whole payments.

GREENHAT ENERGY, LLP (GREENHAT), JOHN BARTHOLOMEW, KEVIN ZIEGENHORN, AND THE ESTATE OF ANDREW KITTELL

On November 5, 2021, the Commission issued an Order Assessing Civil Penalties against GreenHat, John Bartholomew (Bartholomew), Kevin Ziegenhorn (Ziegenhorn), and the Estate of Andrew Kittell (Kittell Estate).[279] The Commission found that GreenHat and the individual respondents violated section 222(a) of the FPA and the Commission's Anti-Manipulation Rule by: (1) engaging in a manipulative scheme in PJM by purchasing FTRs with virtually no upfront cash, planning not to pay for losses at settlement, and obtaining cash for the individual respondents by selling profitable FTRs to third parties; (2) purchasing FTRs based not on market considerations but to amass as many FTRs as possible with minimal collateral; (3) making false statements to PJM about money purportedly owed by a third party firm to try to convince PJM not to proceed with a planned margin call; and (4) submitting inflated bids into a PJM long-term FTR auction with the intent to artificially raise the clearing price of FTRs that the third party firm had purchased from GreenHat and offered for sale in the auction.[280] The Commission assessed civil penalties in the following amounts: $179,600,573 against GreenHat, $25 million against Bartholomew, and $25 million against Ziegenhorn. The Commission also directed GreenHat, Bartholomew, Ziegenhorn, and the Kittell Estate, jointly and severally, to disgorge unjust profits of $13,072,428, plus applicable interest.

The Commission filed suit against GreenHat, Bartholomew, Ziegenhorn, and the Kittell Estate in the U.S. District Court for the Eastern District of Pennsylvania on January 6, 2021. On August 19, 2022, the Commission approved two settlements that wholly resolved the matter: one with GreenHat and the Kittell Estate, and one with Bartholomew and Ziegenhorn.[281] GreenHat and the Kittell Estate agreed to pay $600,000 in disgorgement (based on ability to pay); Bartholomew and Ziegenhorn agreed to pay a total of $775,000 in disgorgement (also based on ability to pay); Bartholomew and Ziegenhorn agreed not to trade in Commission-jurisdictional markets for ten years, and never to trade in PJM; GreenHat agreed to entry of judgment of $179,600,573 in favor of PJM in a Texas state court lawsuit; and GreenHat agreed to dismiss its $62 million lawsuit against a third party firm, which was based on factual claims that the Commission determined to be false. All of the Defendants have paid the agreed amounts to PJM and the federal court lawsuit was dismissed in April 2023.

278 *Golden Spread Electric Cooperative, Inc.,* 177 FERC ¶ 61,109 (2021). (Order Approving Stipulation and Consent Agreement). For background about SPP, *see* https://www.ferc.gov/industries-data/electric/electric-power-markets/spp.

279 *GreenHat Energy, LLC,* 177 FERC ¶ 61,073, at P 2 (2021) (Penalty Order).

280 *Id.* P 30.

281 *GreenHat Energy, LLC,* 180 FERC ¶ 61,109 (2022) (GreenHat and Kittell Estate) (Order Approving Stipulation and Settlement Agreement); *GreenHat Energy, LLC,,* 180 FERC ¶ 61,108 (2022) (Bartholomew and Ziegenhorn) (same).



FEDERAL ENERGY REGULATORY COMMISSION

Office of Energy Policy and Innovation

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-20:
DOE Order No. 202-08-1

The Secretary of Energy
Washington, DC 20585

Order No. 202-08-1

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Texas due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will serve to alleviate the emergency and serve the public interest.

As a result of the massive devastation caused by Hurricane Ike, large portions of the areas affected by the hurricane are without electricity, posing a threat to human life and health. It is my judgment that in these circumstances, the order I am issuing today will meet the emergency and serve the public interest because it will alleviate electricity shortages and protect the life and health of the people in the affected areas.

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

Effective immediately, CenterPoint Energy is authorized and directed to temporarily connect at distribution and transmission level voltages such as 12.5kV, 13.2kV, 25kV, 69kV, 138kV, and 230kV to restore power to Entergy Gulf States, Inc. as well as electric cooperatives and municipal customers within the State of Texas. Pursuant to section 202(d) of the FPA, 16 U.S.C. 824a(d), during the continuance of this order, any person engaged in the transmission and sale of electric energy and not otherwise subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) may, pursuant to this order, make such temporary connections with any public utility subject to the jurisdiction of FERC and shall not become subject to FERC jurisdiction as a result of that temporary connection.

This order shall be effective upon its issuance and shall expire at 12:01 a.m., November 1, 2008.

Issued in Washington, D.C. at 1600 this 14th day of September, 2008.

Samuel W. Bodman
Secretary of Energy

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