BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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 2-91:
NERC Winter Assessments 2022-24 (Compiled)

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2022–2023 Winter Reliability Assessment

November 2022



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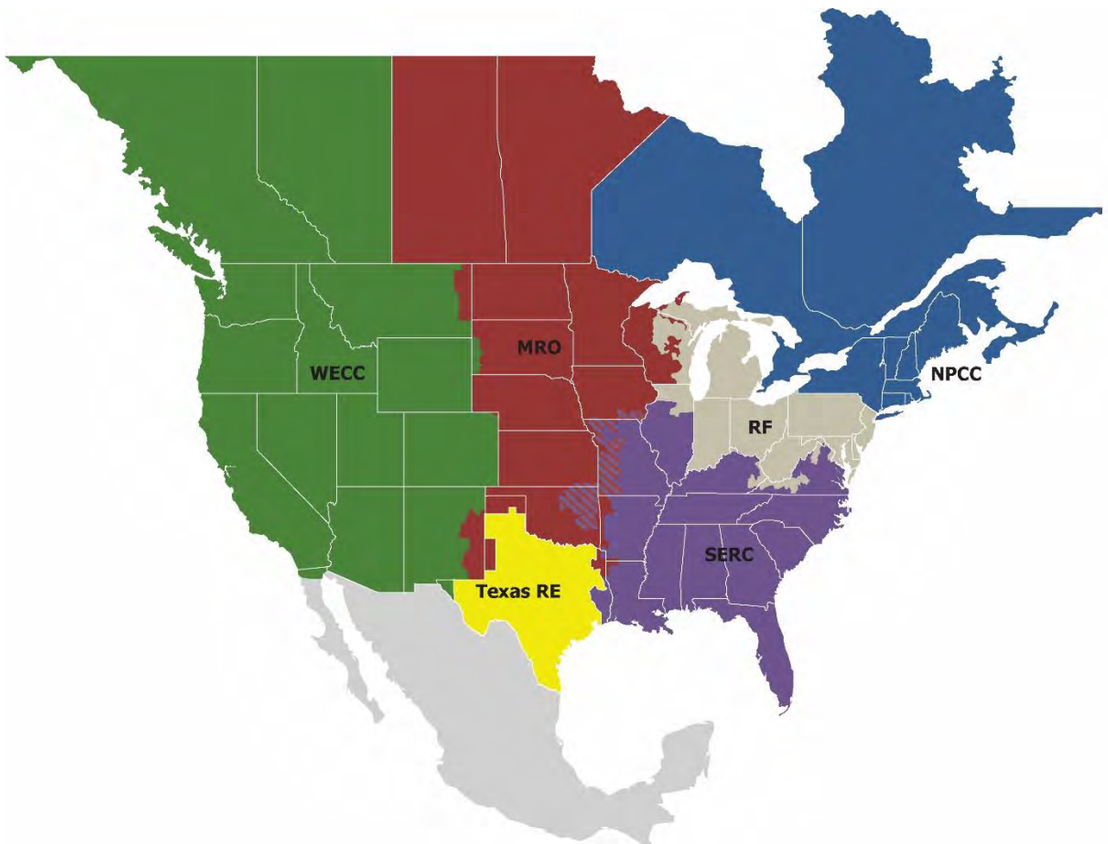
Preface

The vision for the Electric Reliability Organization Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

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

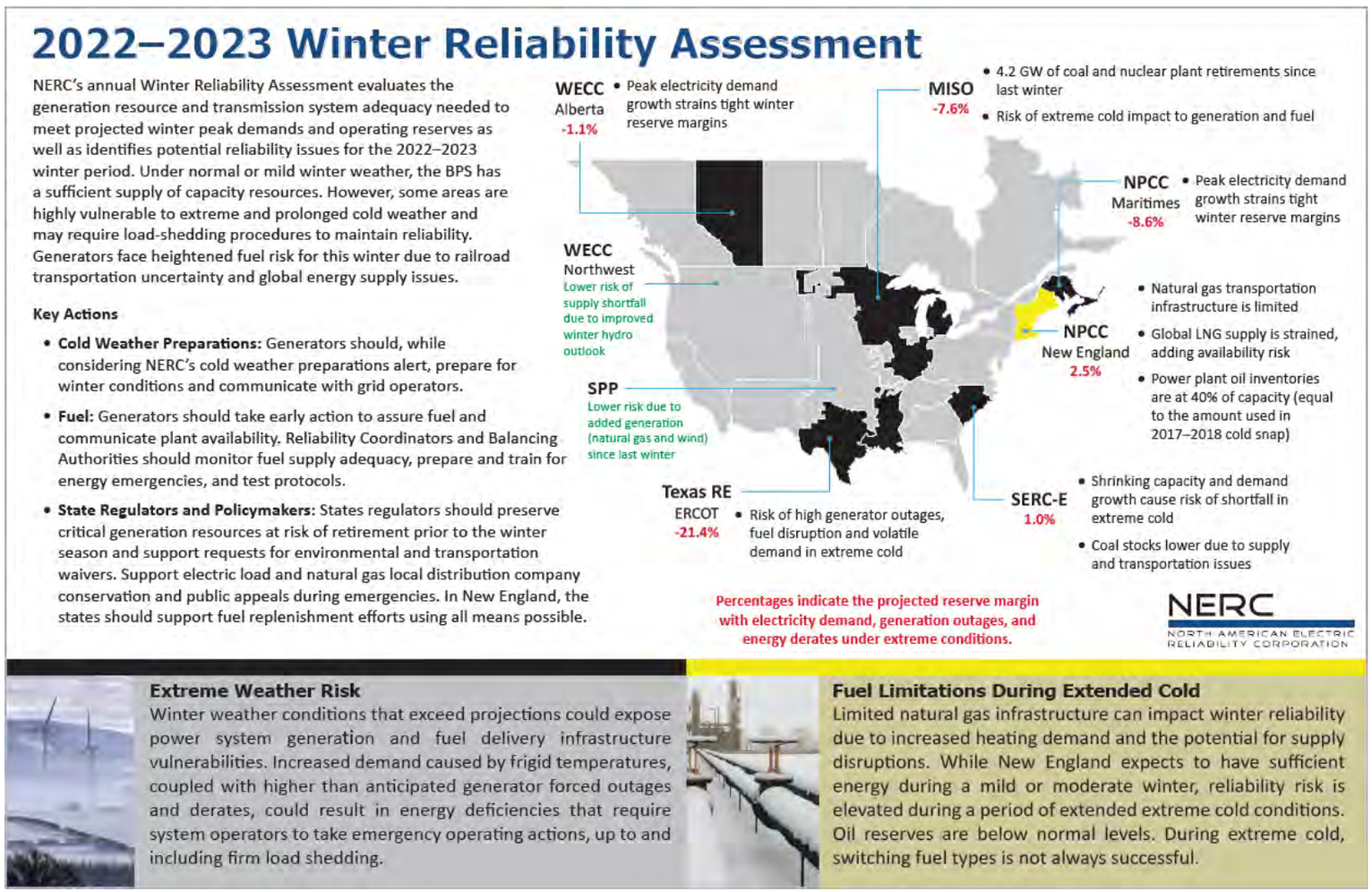
The North American BPS is made up of six Regional Entity boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another. Refer to the **Data Concepts and Assumptions** section for more information. A map and list of the assessment areas can be found in the **Regional Assessments Dashboards** section.



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

About this Assessment

NERC's *2022–2023 Winter Reliability Assessment* (*WRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the *WRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might impact the BPS. The reliability assessment process is a coordinated reliability evaluation between the Reliability Assessment Subcommittee (RAS), the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects NERC's independent assessment and is intended to inform industry leaders, planners, operators, policy makers, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming winter period. Below is a summary of this *WRA*.



Key Findings

This *WRA* covers the upcoming three-month (December–February) winter period. This assessment provides an evaluation of generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional topics of concern. The following findings are NERC and the Regional Entities' (the ERO Enterprise's) independent evaluation of electricity generation and transmission capacity and potential operational concerns that may need to be addressed for the upcoming winter:

A large portion of the North American BPS is at risk of insufficient electricity supplies during peak winter conditions (Figure 1). Higher peak-demand projections, inadequate generator weatherization, fuel supply risks, and natural gas infrastructure are contributing to risks seen in the following areas:

- **Texas RE-ERCOT:** The risk of a significant number of generator forced outages in extreme and prolonged cold temperatures continues to threaten reliability where generators and fuel supply infrastructure are not designed or retrofitted for such conditions. Furthermore, a U.S. Environmental Protection Agency (EPA) decision regarding compliance with hazardous coal ash disposal regulations is expected before the end of 2022 that could impact the availability of two coal-fired generation units (combined total of 1,477 MW) in the last weeks of winter. These units could be important resources during extreme conditions, and an EPA decision can provide flexibility in scheduling outages for plant improvements. Demand volatility in Texas from extreme cold temperatures also contributes to energy shortfall risks.
- **Midcontinent ISO (MISO):** Since the 2021/2022 winter, reserve margins in MISO have fallen by over 5%. Nuclear and coal-fired generation retirements total over 4.2 GW since the prior winter. Declining reserves are the result of few resource additions. An extreme cold-weather event that extends deep into MISO's area could lead to high generator outages from inadequate weatherization in southern units and unavailability of fuel for natural-gas-fired generators.
- **SERC-East:** Like Texas RE-ERCOT and the southern parts of MISO, extreme cold could result in high generator outages and demand volatility. A rare cold weather event in the South could result in an energy emergency in this area.
- **WECC-Alberta and NPCC-Maritimes:** Peak electricity demand is projected to grow in both of these winter-peaking systems. In Maritimes, this could strain capacity for normal winter peak conditions. Alberta has sufficient capacity for normal winter peak demand; however, extreme conditions that cause high generator forced outages are likely to cause energy emergencies.
- **NPCC-New England:** The capacity of the natural gas transportation infrastructure could be constrained when cold temperatures cause peak demand for both electricity generation and consumer space-heating needs. Potential constraints on the fuel delivery systems and limited inventory of liquid fuels may exacerbate the risks for fuel-based generator outages and output reductions that result in energy emergencies during extreme weather.



Figure 1: Winter Reliability Risk Area Summary

- **Generator Owners (GO) face additional fuel and supply risk.** Reliable operation of the thermal generating fleet is critical to winter reliability, and assured fuel supplies is an ongoing winter reliability concern. Current domestic and global affairs warrant even greater attention to generator fuel supplies, including natural gas, fuel oil, and coal for the upcoming winter. Inventories of coal and fuel oil in most areas are lower than usual due to a summer of high electricity demand and high natural gas prices that made other fuels more economically advantageous for electricity generation. Low fuel storage levels coupled with a range of potential fuel resupply challenges are creating additional risks for winter regional BPS reliability. Careful attention should be paid to periodic fuel surveys that provide early indication of fuel supply risks.

- **Steps have been taken since 2021's Winter Storm Uri to improve generator performance during extreme cold weather events.** The three areas hardest hit by the 2021 Winter Storm Uri[1]—Texas RE-ERCOT, SPP, and MISO—have implemented several improvements based on their operating experience. Texas weatherization standards for both generators and natural gas facilities designated as critical infrastructure aim to improve generator availability during extreme weather this winter. In SPP and MISO, where Winter Storm Uri impacts were less severe, a focus on operational coordination and situational awareness is intended to help operators ensure that sufficient resources are available for extreme conditions. While the risk of energy emergencies for the upcoming winter has not been eliminated, improvements—due to lessons learned from Winter Storm Uri—are expected to reduce the likelihood and lessen the severity of a future Winter Storm Uri scale event.
- **NERC's 2022 Level 2 Alert, *Cold Weather Preparations for Extreme Weather Events.*** In September 2022, the ERO issued a Level 2 NERC alert to Reliability Coordinators (RC), Balancing Authorities (BA), Transmission Operators (TOP), and GOs.[2] The alert includes recommendations as well as a series of questions to help evaluate the Bulk Electric System's winter readiness. The responses indicate the importance of grid operators being prepared to implement their operating plans to manage potential supply shortfalls in extreme weather.
- **Inadequate supply of distribution transformers could slow restoration efforts following winter storms.** The electricity industry is facing a shortage of distribution transformers as a result of production not keeping pace with demand. A survey by the American Public Power Association revealed that many utilities have low levels of emergency stocks that are used for responding to natural disasters and catastrophic events.[3] Severe winter storms often include high winds, icing, and precipitation that damage distribution power lines and transformers. Asset sharing programs used by utilities provide visibility and voluntary equipment sharing to maximize resources; however, electricity customers may experience delayed restoration of power following storms as crews must work to obtain new equipment.

Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

- BAs and RCs should work with GOs to ensure fuel supplies are adequate for normal and extreme conditions prior to winter. Fill storage capacity, prepare fuel delivery systems, and coordinate with fuel providers to secure needed fuel as applicable. While short-term solutions are limited, firm supply arrangements should be pursued when feasible. Long-term solutions are needed to secure energy and maintain fuel assurance to support reliability and resilience. In addition, GOs should routinely and periodically keep BAs and RCs informed on fuel levels and readiness.
- RCs and BAs should implement fuel surveys early to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- State and province policy makers have the authority and jurisdiction to implement actions that preserve critical generation resources. State and provincial regulators should consider energy risks for the upcoming winter season and take steps to delay imminent generation retirements if essential to reliability. Additionally, state regulators can assist grid operators in advance of and during extreme cold weather by supporting requested environmental and transportation waivers as well as public appeals for electric load and natural gas conservation.
- Grid operators, GOs, and Generator Operators (GOP) should implement the mitigations identified in the NERC Level 2 alert*, Cold Weather Preparations for Extreme Weather Events–II*, and they should take recommended weatherization steps prior to winter.

[1] The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report | Federal Energy Regulatory Commission

[2] https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20R-2022-09-12-01%20Cold%20Weather%20Events%20II.pdf

[3] https://www.publicpower.org/periodical/article/appa-survey-members-shows-distribution-transformer-production-not-meeting-demand

Risk Highlights

Additional Generator Fuel and Supply Risk

Reliable operation of the thermal generating fleet is critical to winter operations, and assured fuel supplies is an ongoing winter reliability concern. The current state of domestic and global affairs warrants even greater attention on generator fuel supplies, including natural gas, fuel oil, and coal. Low fuel storage levels coupled with a range of potential fuel resupply challenges are creating additional risks for winter regional BPS reliability.

Generator Fuel Supplies

Owners of coal, fuel oil, and dual-fueled generators in North America typically replenish stored fuels following the peak summer season in preparation for winter. Energy suppliers also increase inventories of natural gas, coal, and distillate fuels in preparation for high-demand winter periods. Several fuel supply challenges have emerged in the lead-up to the 2022–2023 winter that are being monitored by grid operators and GOs, including potential rail strikes, constrained and delayed rail deliveries, reduced stored natural gas and fuel oil inventories, and uncertainty from global markets in New England potentially impacting liquefied natural gas (LNG) deliveries. The following are two areas of concern:

Coal Inventories

Grid operators in the U.S. Southeast, MISO, and PJM are monitoring coal inventories (fuel and consumables) as GOs face limited stocks and resupply uncertainty. Across the United States, resupply by rail has been hampered throughout 2022 as staffing shortages and other issues have affected the rail industry. Some GOs in the Midwest and Southeast are experiencing delivery issues for coal and certain emissions-control chemicals. A small number of units currently have low coal inventory. Inventories in some areas are lower than typical following a summer of high electricity demand and high natural gas prices that made coal more economically advantageous. A milder fall in the Central and Eastern parts of North America has helped some coal stocks rebound. Monitoring performed by PJM, where coal-fired generation can be expected to contribute over 25% of peak demand needs, indicates that pre-winter coal supplies in November now exceed 85% of the levels reached at their peak in the prior winter (**Figure 2**).

Based on coal stock data from the Energy Information Administration,[4] fuel inventories have reached 96 days of bituminous supply and 81 days subbituminous across the coal generation fleet on average (**Figure 3**). Some plants reported as low as 15 days of supply during the past summer.

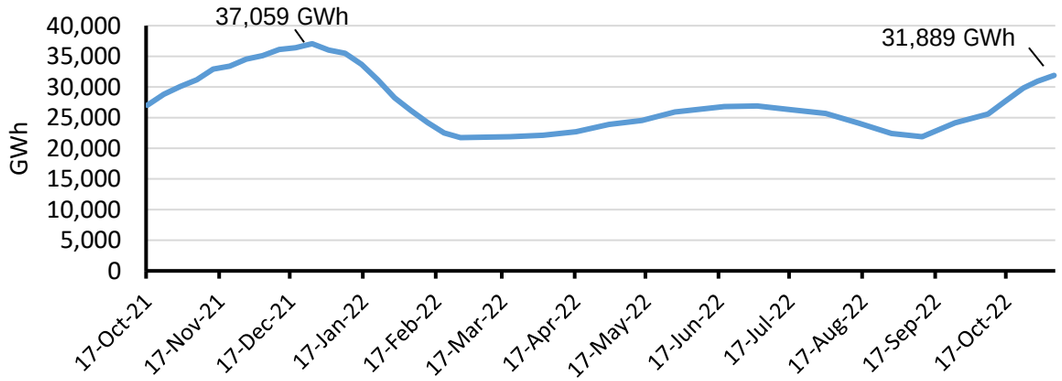


Figure 2: PJM Bi-weekly Fuel Inventory for October 10, 2022[5]

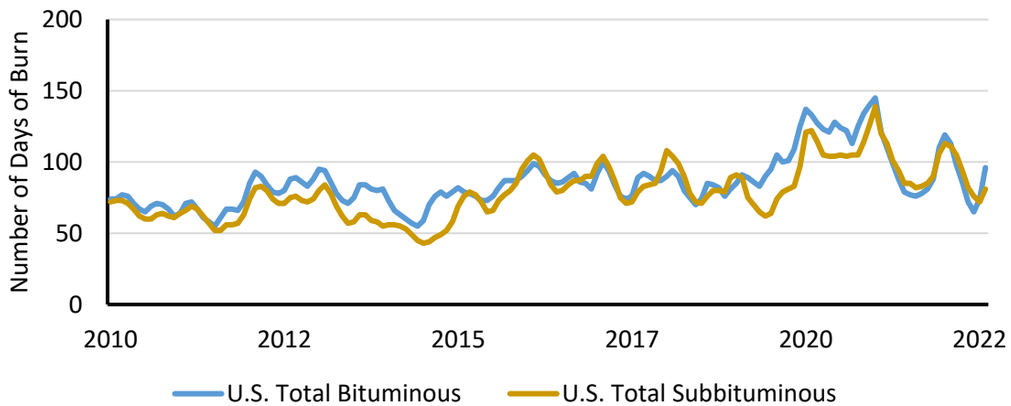


Figure 3: Days of Burn by Non-lignite Coal, January 2010–August 2022

[4] EIA Electric Power Sector Coal Stocks: Electricity Monthly Update - U.S. Energy Information Administration (EIA)

[5] Displays the fuel inventory in GWh calculated by PJM based on data provided through PJM's Fuel Inventory and Supply Data Request. Information is available on PJM's Operating Committee page: https://www.pjm.com/committees-and-groups/committees/oc

Shipping availability by rail this winter is uncertain, reinforcing the need to monitor generator coal stockpiles and act early to reach peak winter levels. RCs in affected areas are continuing to mitigate the coal supply issues by working with their BAs to limit run time of low-inventory plants, using economics, de-rating units, reducing loading at night, and monitoring coal supply.

LNG and Fuel Oil Availability

Low fuel availability elevates winter reliability risk. LNG is critical to meeting energy needs in New England during cold weather, and the continuing disturbance to global energy markets creates supply uncertainty. LNG terminals in New England help alleviate pipeline constraints by providing access points for LNG shipped in tankers to be vaporized and injected into pipelines that serve many natural-gas-fired generators.

As a global energy commodity, LNG is experiencing record high demand that is straining supplies and transportation as well as increasing the risk of disruption. Fuel oil stores are also an important generator fuel in New England as well as in neighboring New York and the Maritimes Provinces of Canada.

Fuel oil is used as either a primary fuel or as a backup to natural gas. Replenishment of on-site generator fuel oil stores since last winter is lagging, and levels remain below historical norms. In New England, the Independent System Operator (ISO) survey of generators in October indicates that on-site stored fuel oil used for electricity generation is just over 92 million gallons, or 40% of available storage capacity (**Figure 4**). Most oil-fired generating capacity (70%) in New England uses lighter distillate fuel oil (DFO). The remaining 30% of the oil-fired fleet capacity uses residual fuel oil (RFO). The current level of combined fuel oil in storage is far lower than the 54% peak level of the prior winter. It is also close to being insufficient for the kind of extreme winter events that could occur in the area. For instance, during a 13-day cold snap over the 2017–2018 winter, over 80 million gallons of fuel oil was used for electricity generation in the New England area. [6]

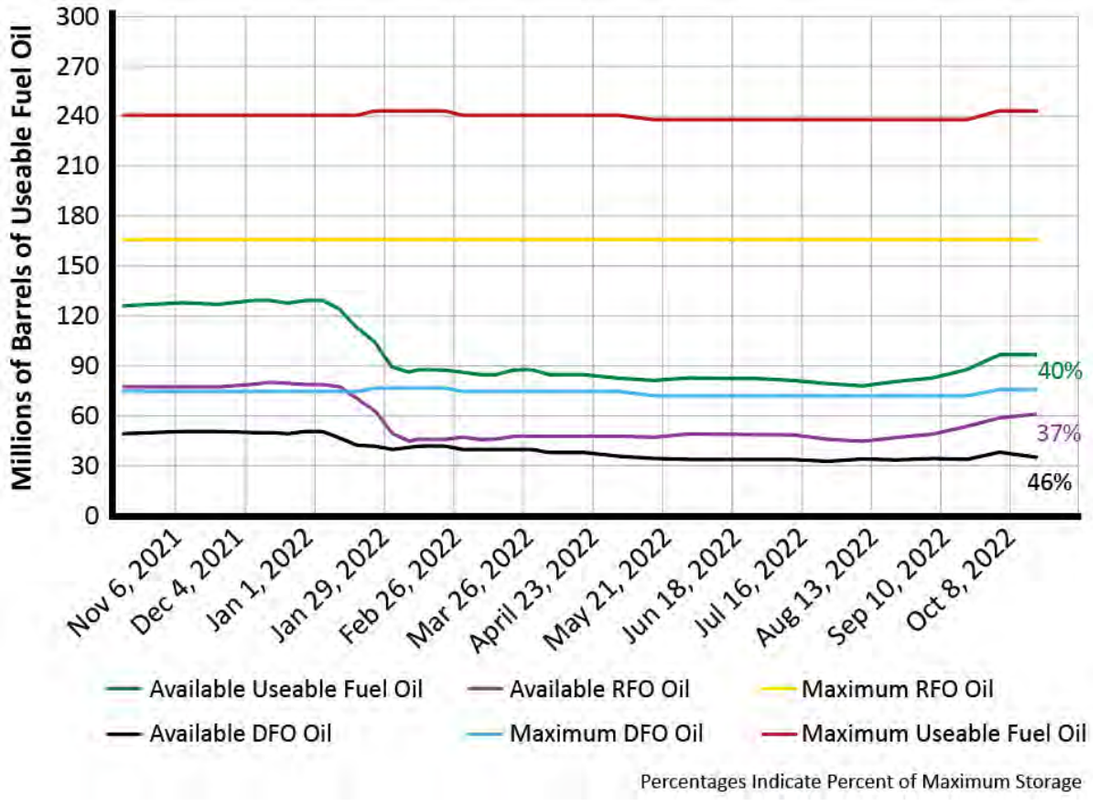


Figure 4: ISO New England 21-day Energy Assessment, Total Usable New England Fuel Oil Inventory Through October 8, 2022[7]

Assessment of Stored Fuel Risk

No specific issues have been identified that would prevent reaching the necessary fuel levels. However, weather, staffing, and general issues affecting transportation have the potential to either directly impact fuel delivery to generator storage sites or affect fuel production through disrupted chemical shipments. Careful attention to ISO's pre-winter and periodic fuel surveys is needed to provide early indication of fuel supply risks. Tools like ISO-New England's (ISO-NE) 21-day energy assessments can reduce these risks to operations.

[6] ISO-NE *Winter 2017/2018 Recap: Historic cold snap reinforces findings in Operational Fuel-Security Analysis*: https://isonewswire.com/2018/04/25/winter-2017-2018-recap-historic-cold-snap-reinforces-findings-in-operational-fuel-security-analysis/

[7] https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/21-Day-Energy-Assessment-Forecast-and-Report-Results

Seasonal Risk Scenario Margins

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

The seasonal risk scenario charts can be expressed in terms of reserve margins. In **Table 1**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario. The typical outages reserve margin is comprised of anticipated resources, less the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the anticipated reserve margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

Table 1: Seasonal Risk Scenario Margins

Assessment Area	Anticipated Reserve Margin	Typical Outages	Extreme Conditions
MISO	43.1%	14.0%	-7.6%
MRO-Manitoba	18.1%	16.2%	9.2%
MRO-SaskPower	28.7%	22.0%	12.6%
NPCC-Maritimes	17.5%	11.3%	-8.6%
NPCC-New England	72.0%	54.7%	2.5%
NPCC-New York	83.2%	58.9%	23.9%
NPCC-Ontario	24.3%	24.3%	9.5%
NPCC-Quebec	12.7%	12.7%	2.3%
PJM	45.9%	33.2%	16.0%
SERC-C	25.1%	18.4%	2.7%
SERC-E	23.9%	17.3%	1.0%
SERC-FP	36.7%	33.2%	0.0%
SERC-SE	31.7%	22.8%	8.4%
SPP	70.0%	44.5%	9.3%
TRE-ERCOT	36.4%	20.4%	-21.4%
WECC-AB	20.8%	18.3%	-1.1%
WECC-BC	16.2%	16.1%	6.4%
WECC-CAMX	49.7%	41.7%	18.6%
WECC-WPP	33.8%	31.3%	10.1%
WECC-SRSG	93.5%	84.7%	55.7%

Reliability Enhancements in Storm-Affected Assessment Areas

Industry, regulators, and the ERO Enterprise have taken significant actions to improve winter readiness following the devastating effects of the February 2021 Winter Storm Uri cold weather event. The first cold weather Reliability Standards, adopted by the NERC Board in June 2021, advance BPS reliability by requiring generators to implement plans for cold weather preparedness as well as to provide cold weather operating parameters to their RCs, TOPs, and BAs for use in operating plans. Though these requirements take effect in the United States in April 2023, just after the upcoming winter season, some reliability benefits of the new requirements may be realized sooner through cold weather planning and preparations that improve generator performance and operator coordination. Across industry, the recommendations of the FERC-NERC-Regional Entity staff report—*The February 2021 Cold Weather Outages in Texas and South Central United States.*—are shaping direction at ISO/RTOs, in technical committees and industry forums, and among industry planners and operators.

The three hardest-hit areas by the 2021 Winter Storm Uri—Texas RE-ERCOT, SPP, and MISO—have implemented several improvements based on their operating experience. Texas weatherization standards, applicable to generators and natural gas facilities designated as critical infrastructure, aim to improve generator availability during extreme weather this winter. In SPP and MISO, where Winter Storm Uri impacts were less severe, a focus on operational coordination and situational awareness should help operators prepare to have sufficient resources for extreme conditions.

Texas RE-ERCOT, SPP, and MISO continue to be at-risk for energy emergencies during the upcoming winter based on their expected resources, normal and extreme demand, and historical generator outage information. However, the enhancements described in the following Texas RE-ERCOT, SPP, and MISO sub-sections are expected to reduce the likelihood of emergencies and lessen the severity that an extreme winter cold weather event on the scale of Winter Storm Uri could cause.

Texas RE-ERCOT

Since February 2021, Texas regulators, ERCOT, and GOs have implemented winter preparedness programs and other reforms aimed at improving generator performance in extreme winter weather. These actions are expected to reduce generator outages in extreme conditions to reduce the likelihood of energy emergencies as well as to mitigate impacts to firm load should an energy emergency occur:

- Regulations in Texas require generator and transmission owners to winterize equipment and facilities. ERCOT conducts weather preparedness inspections of generation and transmission as well as tracks exceptions to requirements until completed.
- In August 2022 the Railroad Commission of Texas (RRC), which regulates the Texas fuel oil and natural gas industry, approved its Final Rule[8] on weather emergency preparedness standards for designated "critical [natural] gas facilities" in the state's new Electricity Supply Chain Map.[9] TRRC inspectors will begin inspecting facilities to determine compliance beginning December 1, 2022, based on submitted compliance attestations. Inspections will focus on infrastructure that produces, stores, processes, and/or transports large volumes of natural gas, and this TRRC effort will be prioritized by facility size.
- ERCOT procured over 2,900 MW of firm fuel supply resources for the upcoming winter. Under the new market product, the procured natural-gas-fired generators must have back-up fuel that would support operations for 48 hours in the event that natural gas supply is interrupted.
- ERCOT has reviewed load-shedding plans with area TOPs and conducts periodic training exercises. Additionally, they coordinate with TOPs to prepare enhanced manual load-shedding and rotating outage plans designed to minimize disruption to firm load.

SPP

SPP is implementing a set of actions—policy changes and assessments approved by the SPP Board of Directors—to address issues related to fuel assurance, resource planning and availability, emergency response, communications, and other critical areas. For the upcoming winter, these actions will improve generator preparedness and operator response:

- SPP held the Winter Preparedness Workshop to help inform members of forecasted conditions for the upcoming season and review SPP's seasonal preparedness steps outlined in its operating procedures.
- RC and BA staff have implemented a high risk scenario alerting system for managing risk periods. This system will identify and alert staff on potential upcoming records, such as load, wind, and wind penetration, to allow time for extra studies to be executed and analyzed as well as to be addressed by the SPP response team.

SPP established an Improved Resource Availability Task Force, which will take primary responsibility for addressing recommendations related to fuel assurance and resource planning as well as

[8] https://www.rrc.texas.gov/media/c5hdc4ga/rule-3-66.pdf
[9] https://www.puc.texas.gov/agency/resources/reports/mapping/2021_Mapping_Agency_Report.pdf

availability that is identified in SPP's *Comprehensive Review of SPP's Response to the February 2021 Winter Storm* report.[10]

MISO

MISO has implemented actions to provide situational awareness and early coordination for reducing risks from extreme winter weather:

- MISO continues to survey GOs and GOPs about unit preparedness and winter fuel sufficiency.
- Processes are in place for coordination with neighboring RCs and BAs on needs for firm or non-firm transfers to address extreme system conditions. Pre-season transfer studies for normal and extreme scenarios are underway.

For future years, MISO's new resource adequacy construct (filed with FERC for approval) is expected to deliver additional winter resource capacity by using a winter reserve margin and resource capacity accreditations that account for winter peak conditions.

MISO Neighboring Area Studies

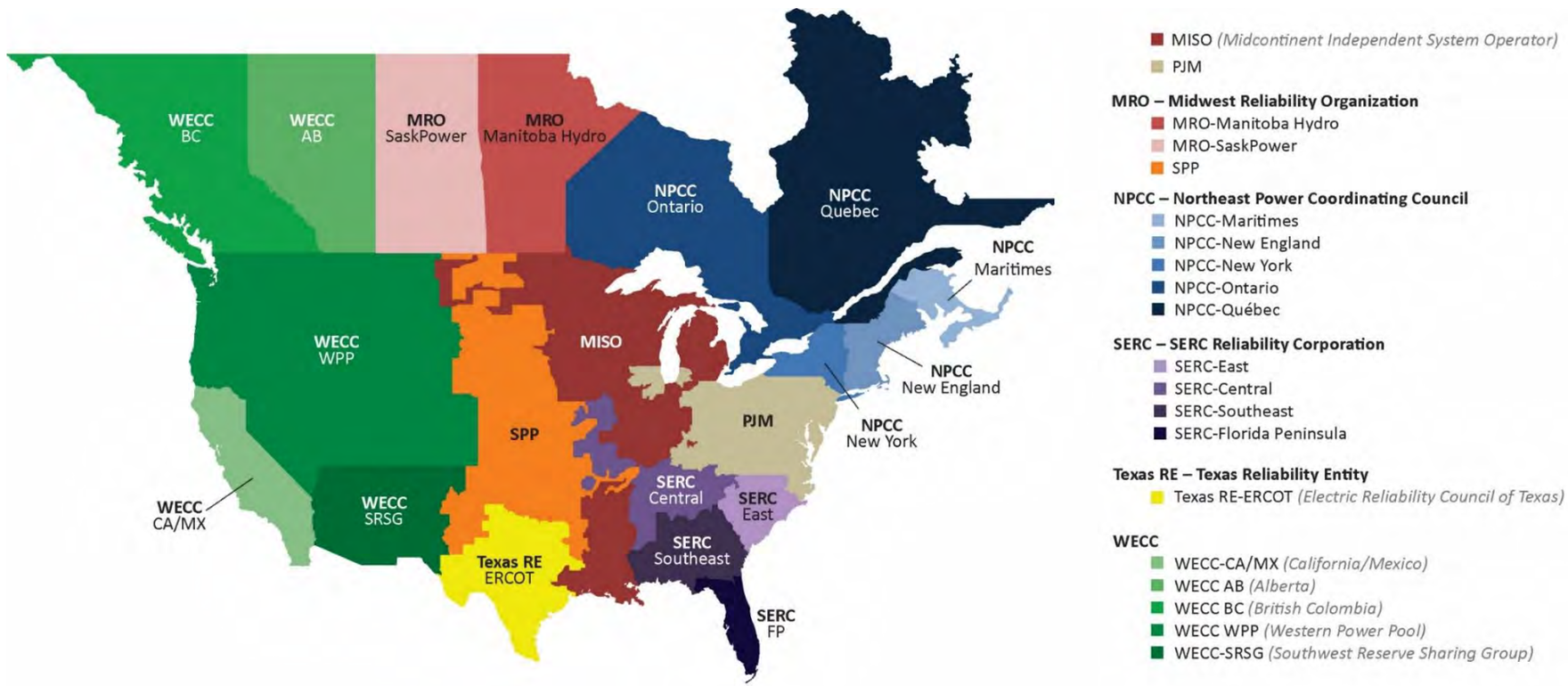
During Winter Storm URI, other areas in the Eastern Interconnection experienced localized transmission emergencies resulting from the large transfers flowing across the transmission system from generators in PJM to the affected areas in MISO and SPP. Accordingly, the *FERC-NERC-Regional Entity staff Joint Report* recommended planners and operators study large power transfers during stressed conditions. Transfer studies have been conducted in SERC to help prepare for the upcoming winter. During extreme cold temperatures, there is the potential for significant transfers through the area as excess power is shipped to meet power demands in affected areas outside of SERC.

A SERC technical working group performed a 2022–2023 winter reliability study to determine the adequacy and reliability of the SERC transmission system using a 2022–2023 winter peak power flow model, which included 12 GW power transfer from PJM to MISO. The study also simulated the impacts of higher load demands due to colder than normal temperatures in each SERC sub-area by increasing generation throughout them all while simultaneously increasing load in a particular sub-area. SERC concluded that the transmission system was adequate for normal and extreme conditions and that localized transmission constraints, when observed, could be mitigated through system reconfiguration.

[10] https://www.spp.org/markets-operations/current-grid-conditions/2021-winter-storm-review/

Regional Assessments Dashboards

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



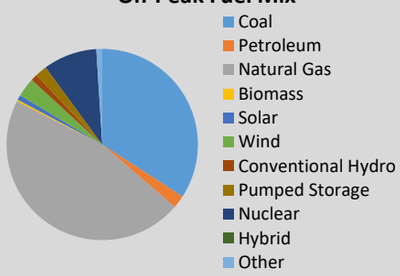


MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authority and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

On-Peak Fuel Mix



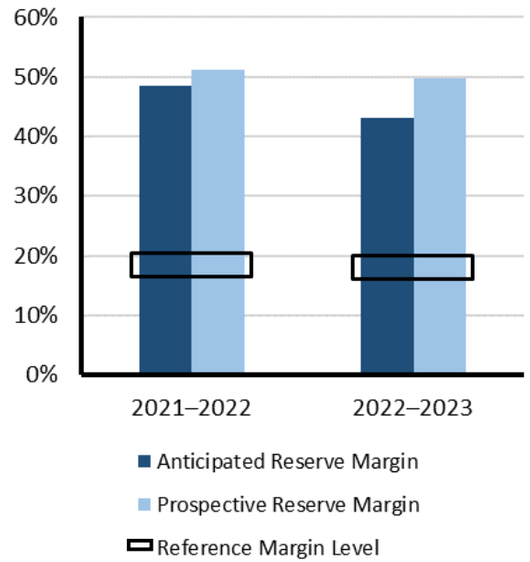
Highlights

- Since 2021–2022 winter, reserve margins in MISO have fallen by over 5%. Nuclear and coal-fired generation retirements total over 4.2 GW since the prior winter. Declining reserves are the result of few resource additions. Since last winter, more demand response (2,250 MW) and new wind generation (500 MW on-peak/3,200 MW nameplate) was added.
- MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency. In addition, MISO is acknowledging that resource adequacy risk is not limited to the summer system peak season, MISO is filing changes to the resource adequacy construct to implement a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons.
- Though risk has been identified for this upcoming winter season in a high generation outage and high winter load scenario, MISO expects to maintain reliability through the use of measures that include load modifying resources (LMR) (MISO's demand response), non-firm transfers into the system, energy only interconnection service resources not receiving capacity credit, and/or internal transfers that exceed the sub-area import/export constraint between the MISO North/Central and South areas. MISO continues to coordinate extensively with neighboring RCs and BAs to improve situational awareness and vet needs for firm or non-firm transfers to address extreme system conditions.

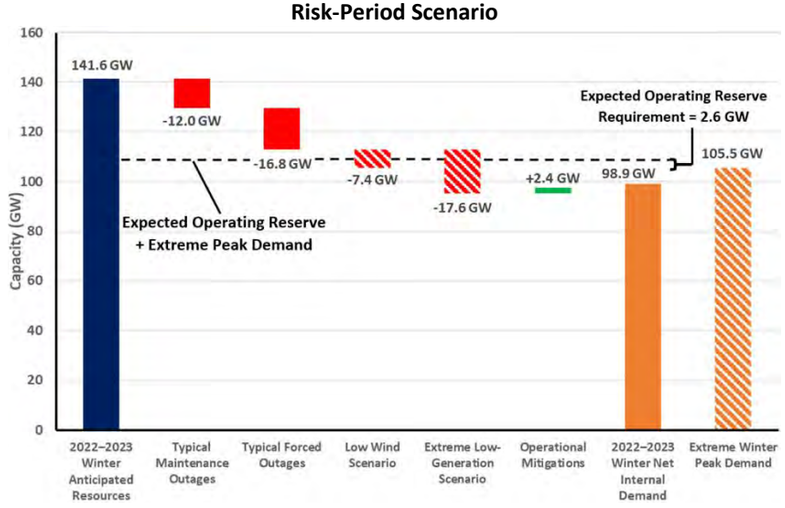
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and energy emergency alerts (EEAs). Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

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

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

Low Wind Scenario: Below average wind contributions

Extreme Low-Generation: Maximum historical generation outages

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

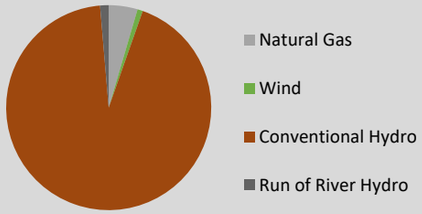


MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba which is 251,000 square miles.

Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

On-Peak Fuel Mix



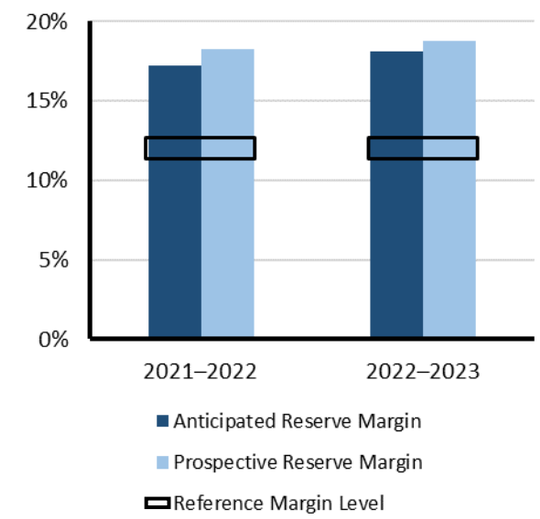
Highlights

- The Anticipated Reserve Margin for the 2022–2023 winter exceeds the 12% Reference Margin Level.
- There are no emerging reliability/resource adequacy issues anticipated for the upcoming winter season.
- All seven units at the Keeyask Hydroelectric Generating Station (630 MW net addition) are anticipated to be in commercial operation for the 2022–2023 winter.

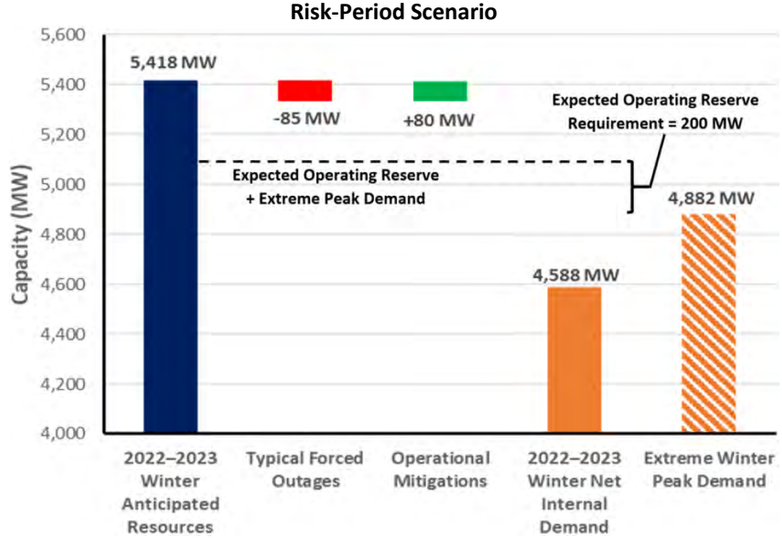
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand scales additional load experienced during all-time peak actual versus forecasted load (January 2019)

Forced Outages: Accounts for average forced outages

Operational Mitigations: Recall 80 MW of additional curtailable load



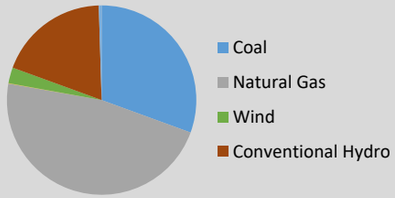
MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and approximately 1.1 million customers. Peak demand is experienced in the winter.

The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province.

SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System and its interconnections.

On-Peak Fuel Mix



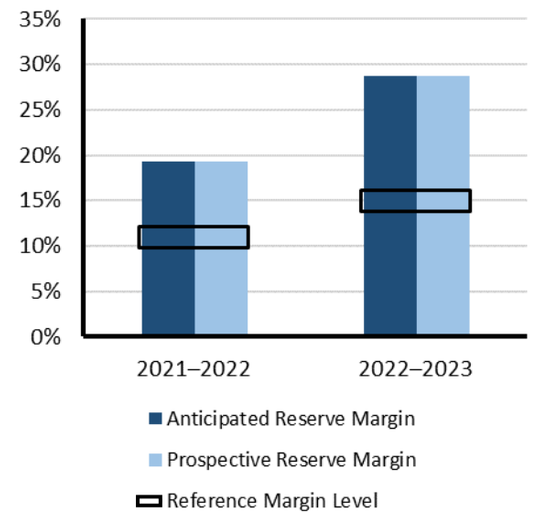
Highlights

- SaskPower experiences peak load in winter because of extreme cold weather. Reserve margins have increased since the 2021–2022 winter with the addition of new wind generators and increased firm capacity imports from Manitoba.
- SaskPower conducts an annual winter joint operating study with Manitoba Hydro with inputs from Basin Electric Power Cooperative (North Dakota) and prepares operating guidelines for any identified issues.
- The risk of operating reserve shortage or EEA during peak load times exists if large generation forced outage occurs during peak load times combined with transmission tie-line maintenance work or generation maintenance work scheduled during winter months.
- In case of extreme winter conditions combined with large generation forced outages, SaskPower would use available demand response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions.

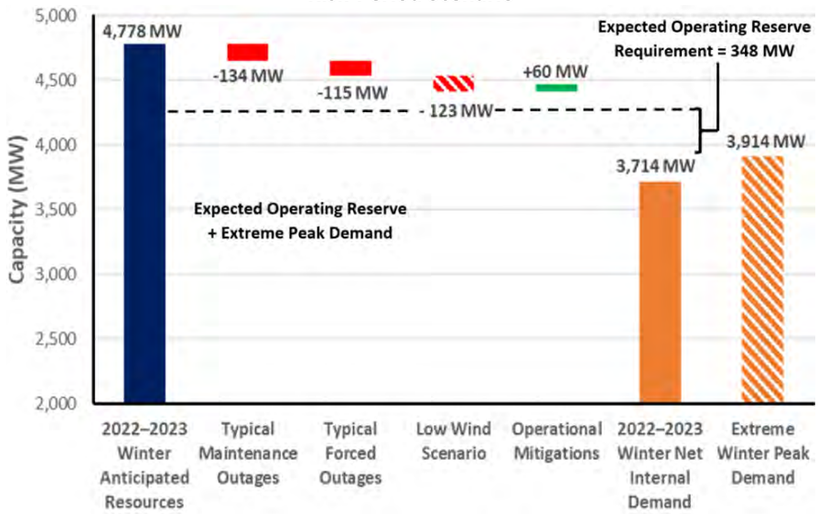
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Maintenance Outages: Average of planned maintenance outages for the winter months, December–February, over the past three years

Forced Outages: Estimated using SaskPower forced outage model

Low Wind Scenario: Estimated using SaskPower forced outage model

Operational Mitigations: Estimated average value based on short term transfer capability from neighboring utilities for the upcoming 2022–2023 winter



NPCC-Maritimes

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

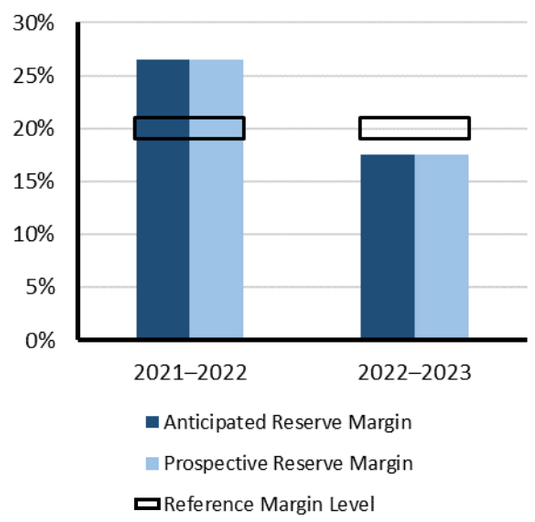
Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations and planning procedures in place.
- The Maritimes area is a winter-peaking system. All of the area's declared firm capacity is expected to be operational for the winter operating period.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil on-site to enable sustained operation in the event of natural gas supply interruptions.
- The results (preliminary) of NPCC's probabilistic assessment indicate that established operating procedures are sufficient to maintain a balance between electricity supply and demand.[11] Only the low likelihood reduced resource case, highest peak load scenario, resulted in an estimated cumulative loss of load expectation (LOLE) risk of ~0.2 days/period with associated loss of load hours (LOLH) (<1 hours/period) and expected unsupplied energy (EUE) (3.4 MWh) over the winter period. The Maritimes area's low likelihood resource case assumed that wind capacity was de-rated by half (1,100 to 550 MW) for every hour in the winter period, coupled with an assumed 50% reduction in natural-gas-fired generation and reduced transfer capabilities.

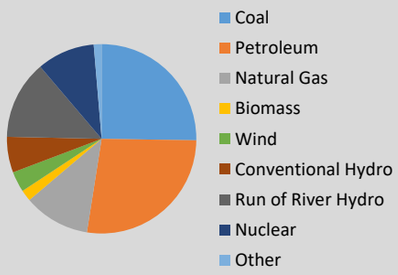
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. As noted above, the risk of load shedding is low.

On-Peak Reserve Margins



On-Peak Fuel Mix



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Outages: Based on historical operating experience

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

[11] Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: https://www.npcc.org/library/reports/seasonal-assessment

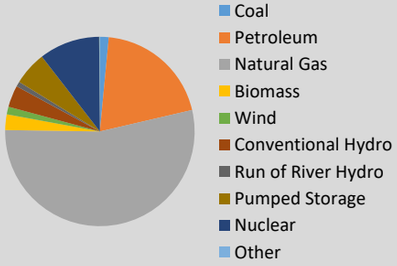


NPCC-New England

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

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

On-Peak Fuel Mix



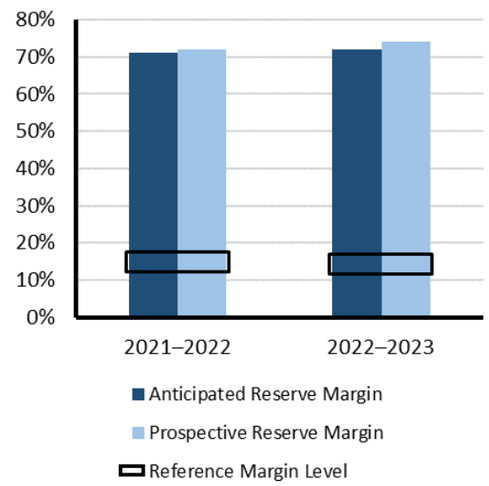
Highlights

- ISO-NE expects to meet its regional resource adequacy requirements this 2022–2023 winter operating period for a mild or moderate winter similar to 2021–2022 or 2017–2018. A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold spell given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and LNG).
- ISO-NE expects to have sufficient capacity resources to meet the 2022–2023 90/10 winter peak demand forecast of 20,695 MW for the weeks beginning January 8, January 15, and January 22, 2023.
- ISO-NE evaluates an above 90/10 scenario that captures the area's coldest day in the last 25 years while using both our current and future load models. The above 90/10 winter peak demand forecast is 21,238 MW for the three previously identified peak weeks. ISO-NE currently has sufficient resources to meet this demand; however, if a cold snap were to occur, the area may have to rely on its external ties and emergency procedures to operate reliably.[12]

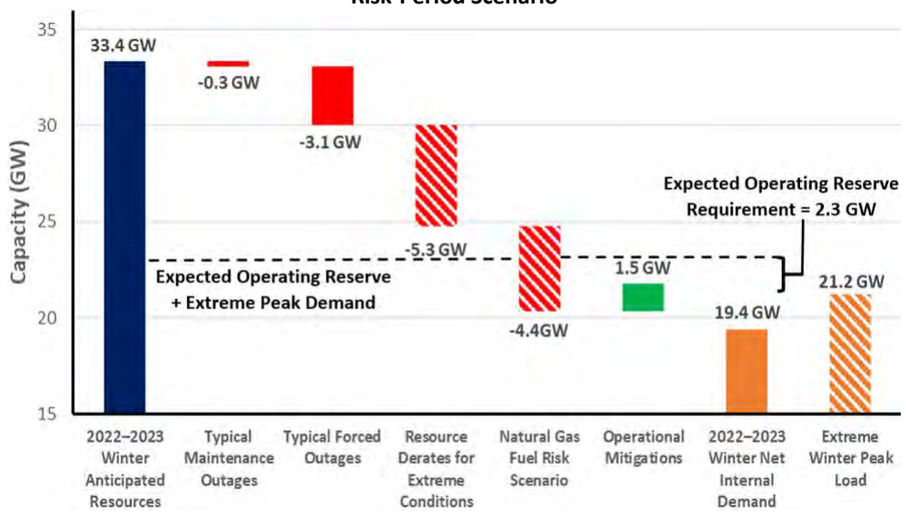
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and demand forecast for coldest day from the last 25 years

Maintenance and Forced Outages: Based on weekly averages

Extreme Derates and Natural Gas Scenario: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather related outages reported by generators

Operational Mitigations: Based on ISO-NE operating procedures

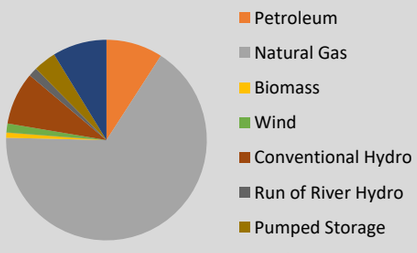
[12] Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: https://www.npcc.org/library/reports/seasonal-assessment



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only Balancing Authority within the state of New York. The BPS encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves 20.2 million customers. The established Reference Margin Level is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2022–2023 IRM at 19.6%.

On-Peak Fuel Mix



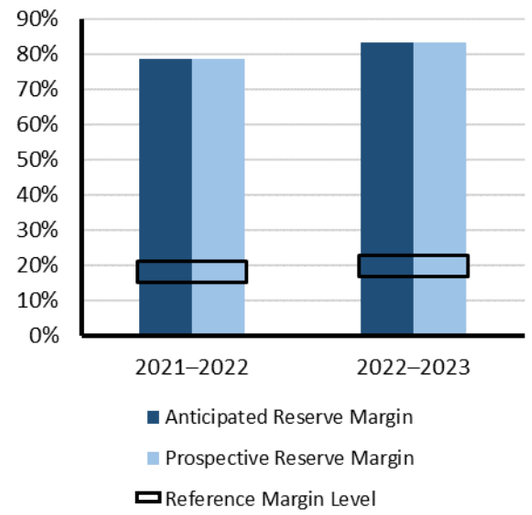
Highlights

- New York is a summer peaking area and no emerging reliability issues are anticipated during the 2022–2023 winter assessment period. Surplus capacity margins above the NYISO's operating reserve requirements are projected.
- The results (preliminary) of NPCC's probabilistic assessment for the area indicate that emergency operating procedures to maintain a balance between electricity supply and demand are not anticipated for the upcoming winter. No cumulative LOLE, LOLH, or EUE risks were found for the winter period for all modeled scenarios.[13]

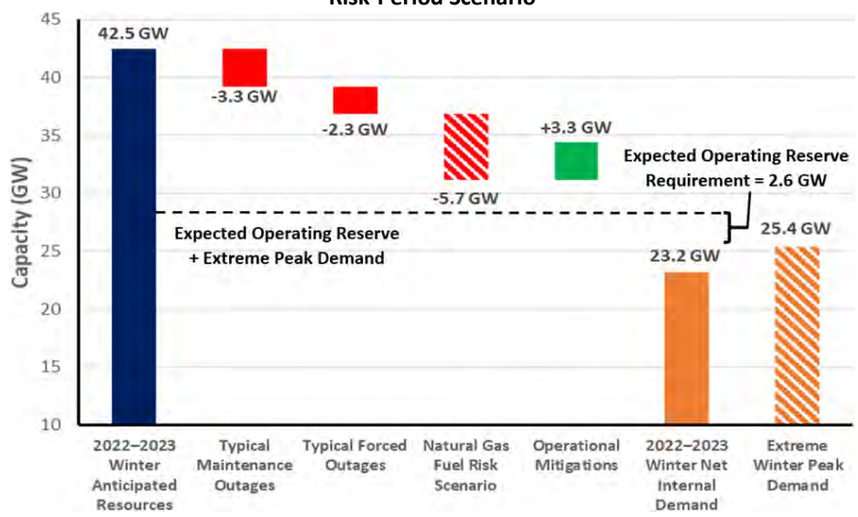
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and (99/1) demand forecast with demand response adjustments

Maintenance Outages: Based on planned scheduled maintenance

Forced Outages: Based on historical 5-year averages

Natural Gas Fuel Scenario: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather

Operational Mitigations: Based on NYISO operating procedures

[13] Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: https://www.npcc.org/library/reports/seasonal-assessment



NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the Balancing Authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 14 million.

Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

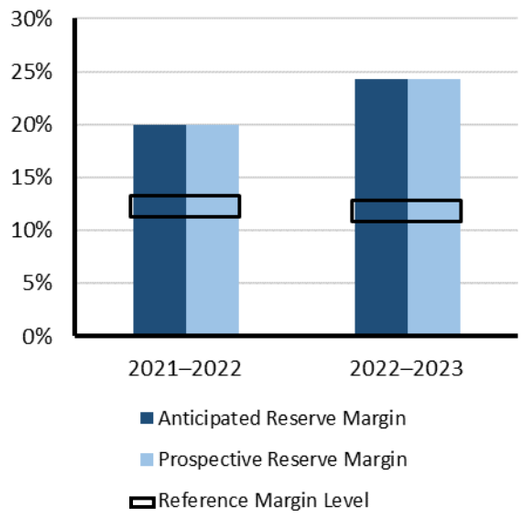
Highlights

- IESO anticipates that it will maintain reliability on its system through the 2022–2023 winter
- In spite of Ontario's ongoing nuclear refurbishment program, the IESO expects to have comfortable reserve margins throughout the winter season
- The results (preliminary) of NPCC's probabilistic assessment for the area indicate that emergency operating procedures to maintain a balance between electricity supply and demand are not anticipated for the upcoming winter. No cumulative LOLE, LOLH or EUE risks were found for the winter period for all modeled scenarios.[14]

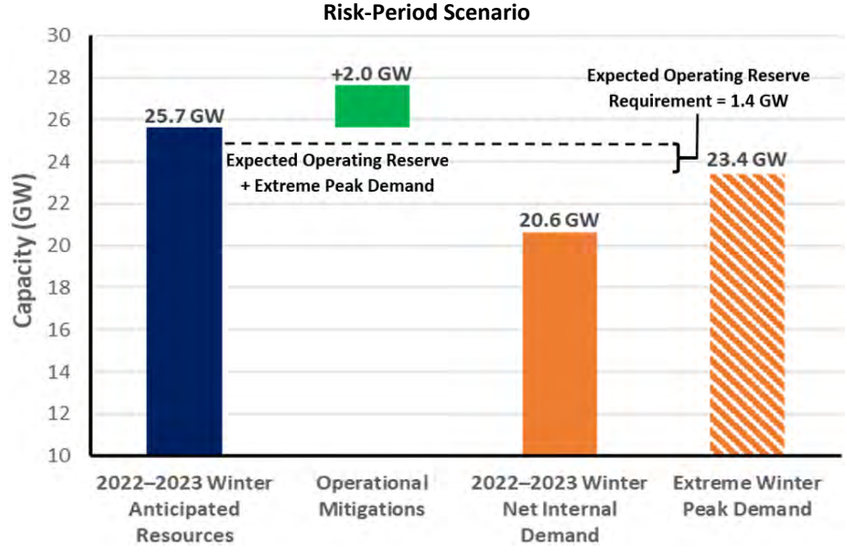
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



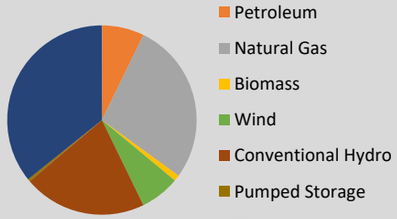
Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand from 31 years of winter demand history

Operational Mitigations: Imports anticipated from neighbors during emergencies

On-Peak Fuel Mix



[14] Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: https://www.npcc.org/library/reports/seasonal-assessment

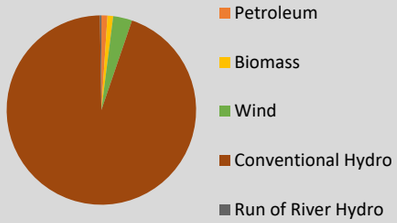


NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million.

Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes; consisting of either HVDC ties, radial generation, or load to and from neighboring systems.

On-Peak Fuel Mix



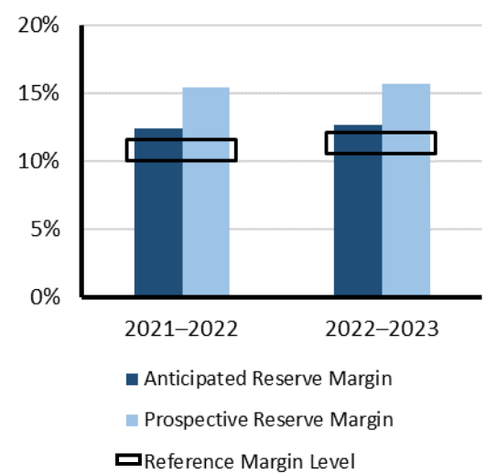
Highlights

- Québec is expecting to maintain system resource adequacy this winter.
- The Québec area is a winter-peaking system with predominately hydroelectric generation resources. Adequate capacity margins above its reference reserve requirements are projected for the 2022–2023 winter assessment period.
- No changes have been made to the assessment area's winter preparedness programs since the previous winter season.
- The results (preliminary) of NPCC's probabilistic assessment for the area indicate that emergency operating procedures to maintain a balance between electricity supply and demand are not anticipated for the upcoming winter. No cumulative LOLE, LOLH, or EUE risks were found for the winter period for all modeled scenarios.[15]

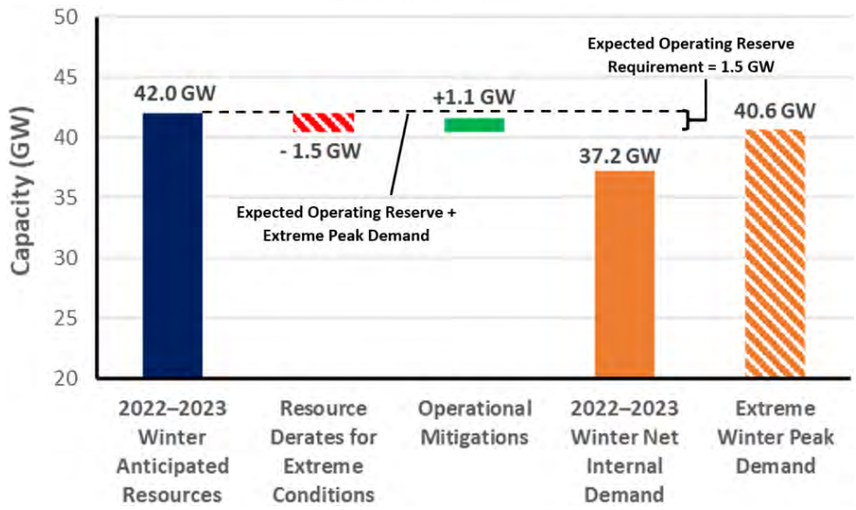
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Québec plans to use short-term capacity purchases in order to meet capacity requirements when needed. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. As noted above, risk of load shedding is low.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand represents two standard deviations higher than the mean demand forecast

Extreme Derates: Rare scenario of 1,500 MW in unplanned outages

Operational Mitigations: Imports anticipated from neighbors during emergencies

[15] Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: https://www.npcc.org/library/reports/seasonal-assessment

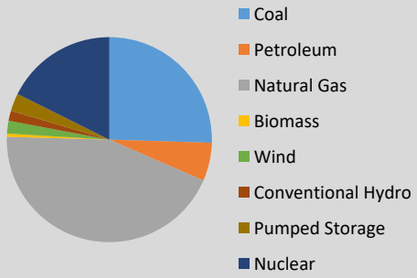


PJM

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

PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

On-Peak Fuel Mix



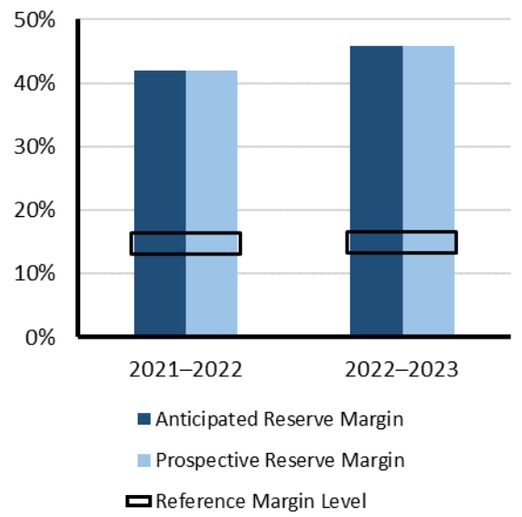
Highlights

- PJM expects no resource problems over the entire 2022–2023 winter peak season because installed capacity is almost three times the reserve requirement.
- No other reliability concerns are expected.

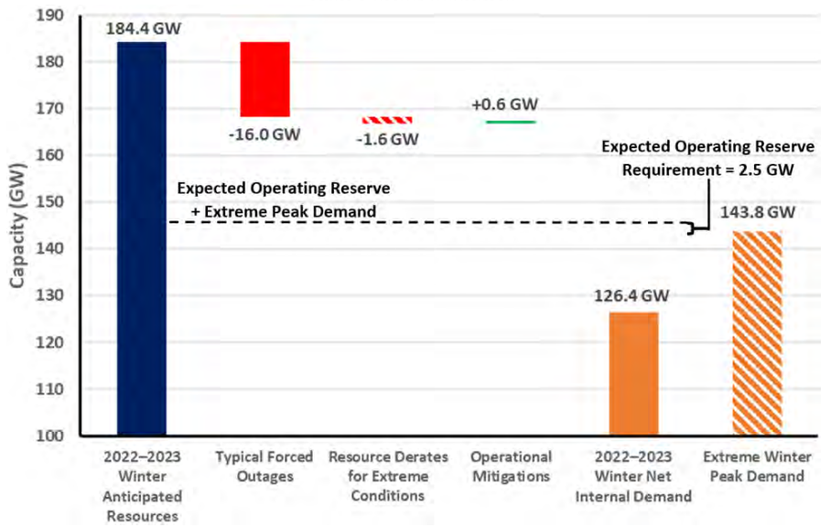
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Outages: Based on historical data and trending

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

Operational Mitigations: A total of 0.6 GW based on operational/emergency procedures



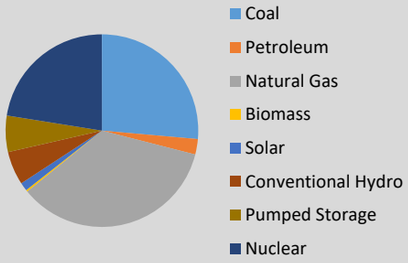
SERC-East

SERC-East is a winter-peaking assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



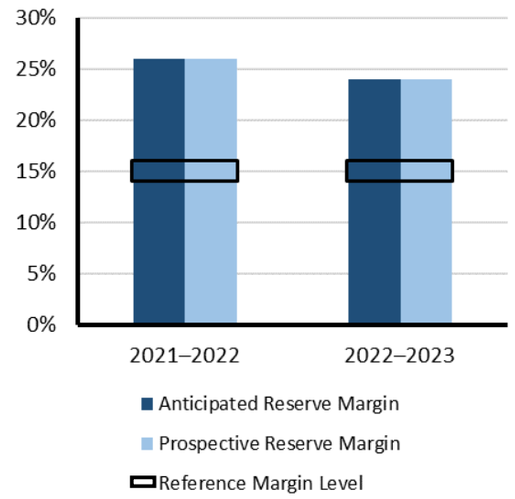
Highlights

- SERC-East has not identified any emerging or potential reliability issues for the upcoming winter season.
- Currently, there are issues with fuel supply and transportation in the SERC-East assessment area. Transportation providers and coal suppliers continue to struggle with post pandemic personnel shortages, volume increases, and inflationary cost increases. SERC-East does not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- SERC-East has extensive weatherization processes that include procedures specific to freezing events. SERC-East is prepared to respond to unexpected day-to-day events and coordinate with neighboring entities to promote overall system reliability.

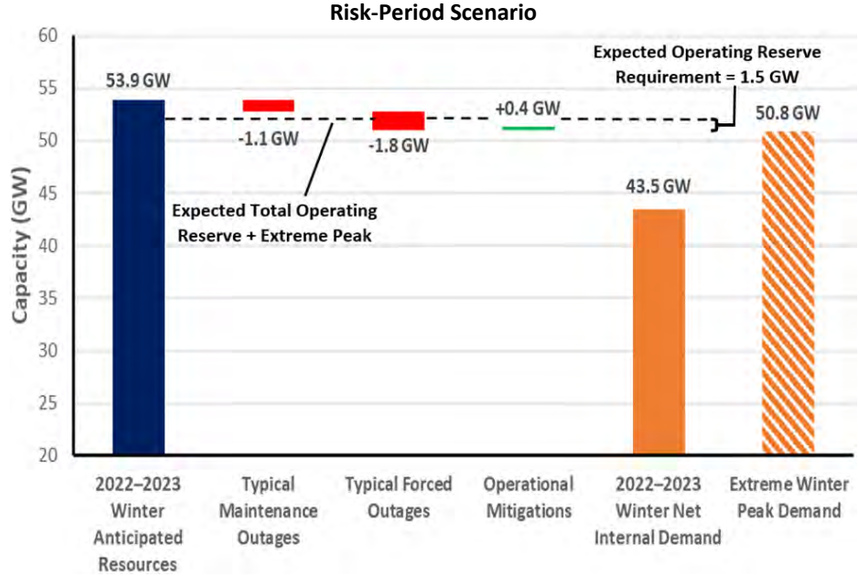
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need for non-firm transfers, operating mitigations and EEAs. Risk of load shedding is low.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

Operational Mitigations: A total of 0.4 GW based on operational/emergency procedures



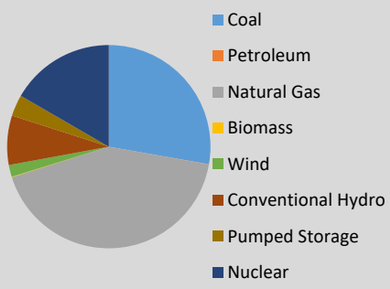
SERC-Central

SERC-Central is a winter-peaking assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

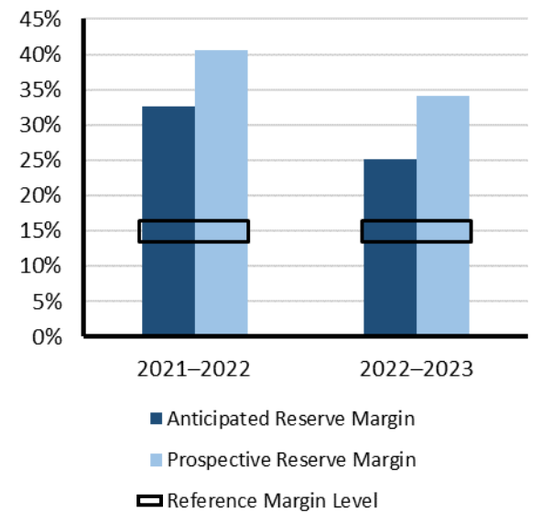
On-Peak Fuel Mix



Highlights

- SERC-Central has not identified any emerging or potential reliability issues for the upcoming winter season.
- SERC-Central does not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- SERC-Central has extensive weatherization processes that include procedures specific to freezing events and is prepared to respond to unexpected day-to day-events and coordinate with neighboring entities to promote overall system reliability.

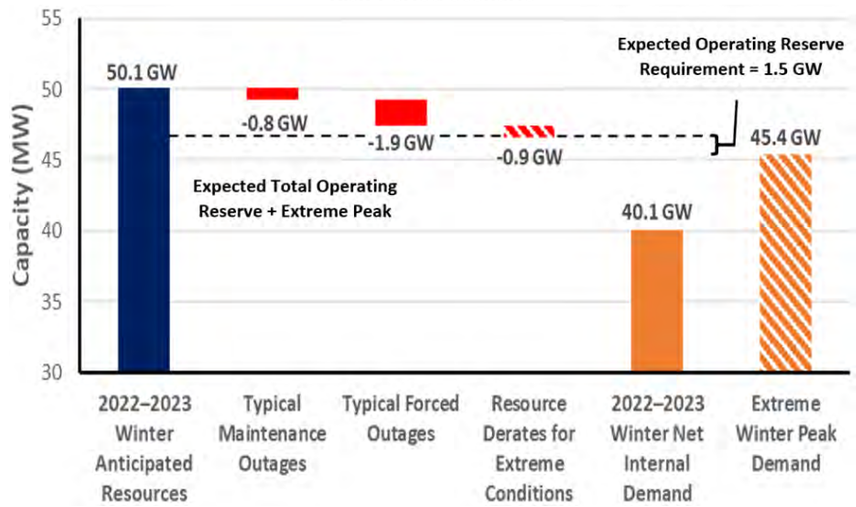
On-Peak Reserve Margins



Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

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



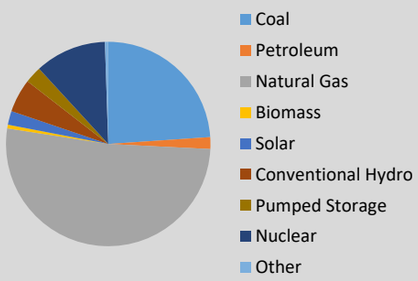
SERC-Southeast

SERC-Southeast is a winter-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



Highlights

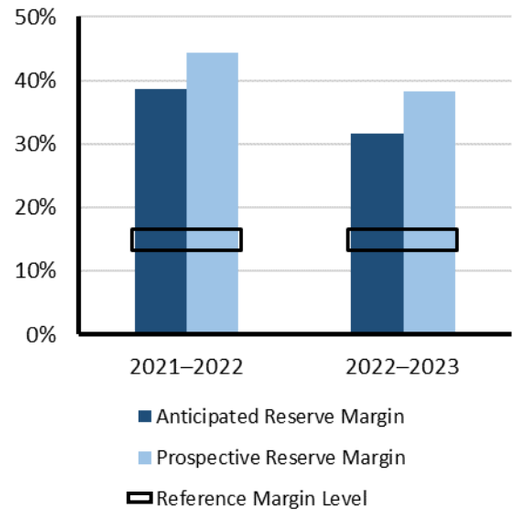
Aside from fuel availability concerns shared across the industry, SERC-Southeast have not identified any additional or emerging potential reliability related risks.

SERC-Southeast has extensive weatherization processes that include procedures specific to freezing events and is prepared to respond to unexpected day-to-day events and coordinate with neighboring entities to promote overall system reliability.

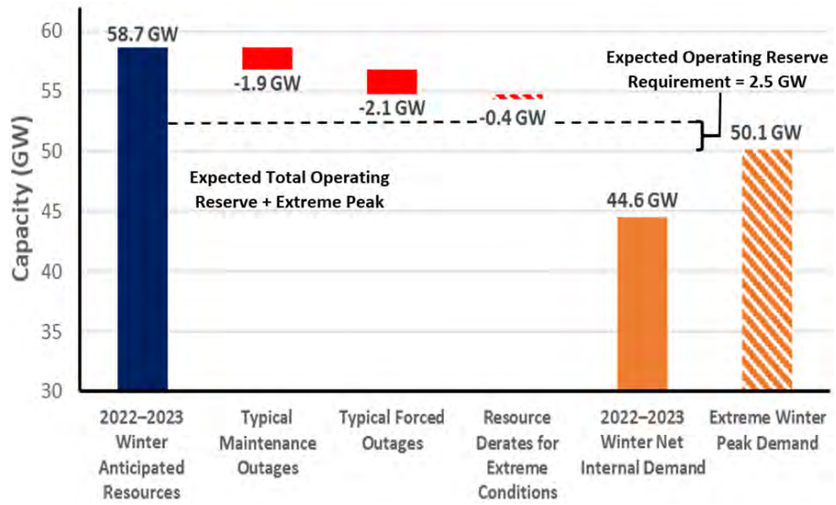
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

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



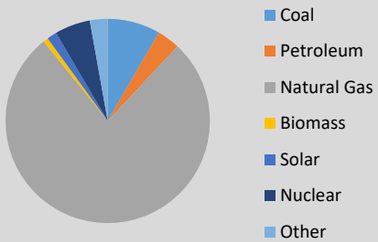
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



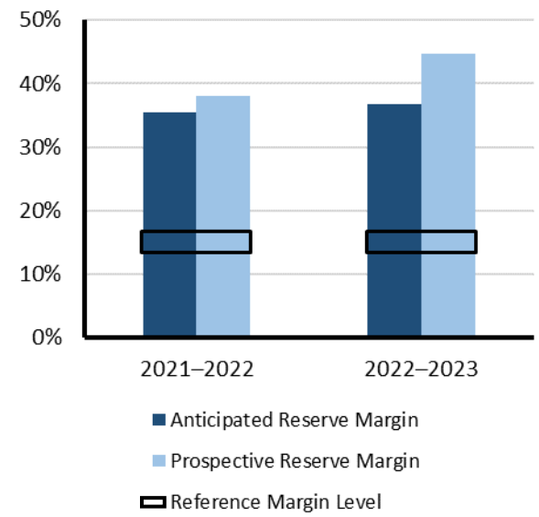
Highlights

- SERC-Florida Peninsula have not identified any emerging or potential reliability issues for the upcoming winter season.
- SERC-Florida Peninsula do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- SERC-Florida Peninsula have extensive weatherization processes that include developing procedures specific to freezing events.

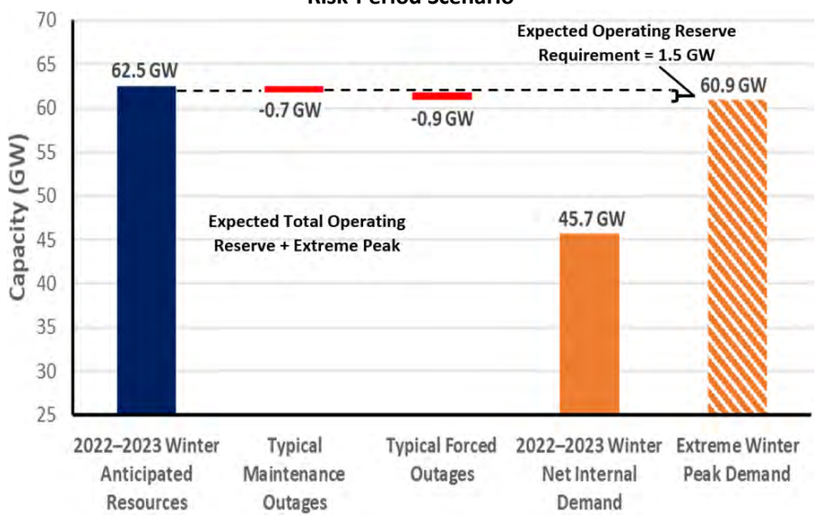
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and (95/5) demand forecast

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

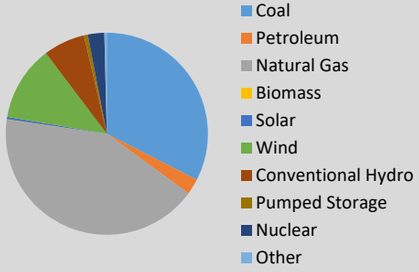


SPP

Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming.

The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

On-Peak Fuel Mix



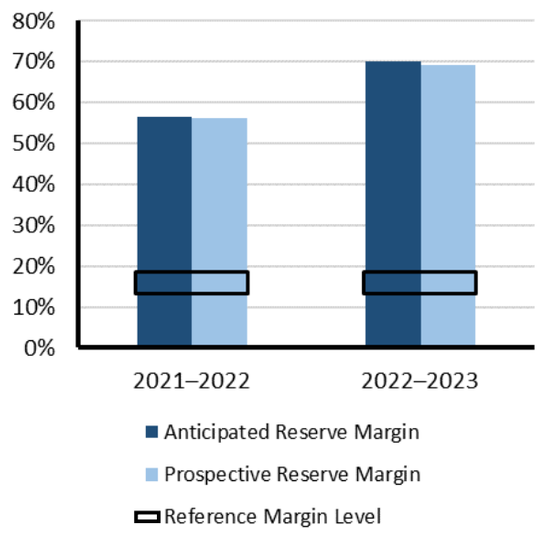
Highlights

- SPP's planning reserves are adequate for the upcoming winter season. Since the 2021–2022 winter, SPP has added 3,700 MW of natural-gas-fired generation.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2022–2023 winter season but realizes that interruptions to fuel supply could create unique operation challenges.
- SPP continues to work with neighboring areas to address potential electric deliverability issues associated with extreme weather events. Efforts focus on enhancing communications and operator preparedness.
- In an effort to minimize the need for conservative operations, EEAs, and the responses to mid-range forecast error uncertainty in wind forecasts, SPP created some new mitigation processes to deal with high impact areas of concern. SPP has developed operational mitigation teams, processes, and procedures that have been put in place to maintain real time reliability needs.
- SPP created the Improved Resource Availability Task Force , which will take primary responsibility for addressing Tier 1 recommendations related to fuel assurance and resource planning and availability identified in the ***Comprehensive Review of SPP's Response to the February 2021 Winter Storm*** report.
- SPP hosts its winter preparedness workshop in October 2022.

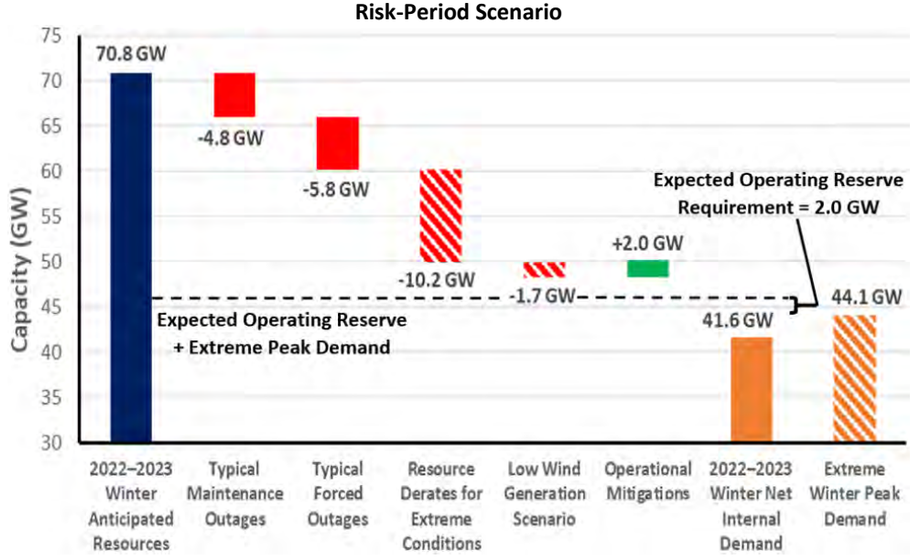
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Maintenance and Forced Outages: A capacity derate for maintenance outages, forced outages, and performance in extreme weather based on historical data

Extreme Derates: A capacity derate for generator performance in extreme weather based on historical data

Low Wind Scenario: 1.7 GW of wind potentially off-line when temperatures fall below their cold weather performance packages

Operational Mitigations: A total of 2 GW based on operational/emergency procedures (External Assistance)

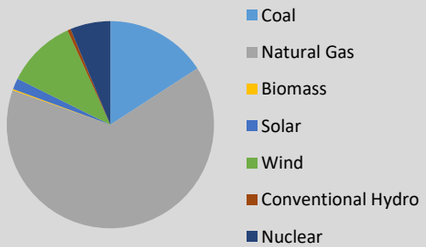


Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature.

ERCOT is summer-peaking. It covers approximately 200,000 square miles, connects over 46,500 miles of transmission lines, has over 710 generation units, and serves more than 25 million people. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas Regional Entity is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

On-Peak Fuel Mix



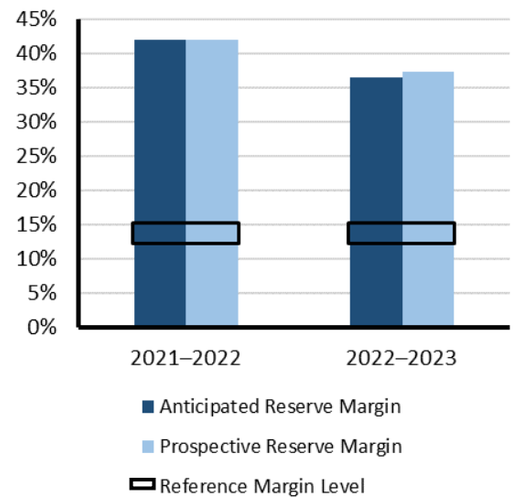
Highlights

- With an Anticipated Reserve Margin of 36.4%, capacity reserves are sufficient to meet forecasted peak demand to cover the types of weather events regularly experienced.
- Probabilistic risk assessment for the upcoming winter season confirms a low probability of energy emergency events occurring during the expected peak load hour (hour-ending 8:00 a.m.) and other higher-risk hours. The assessment accounts for the risk of another weather event like Winter Storm Uri as well as the impacts of winter preparedness standards implemented by the Public Utility Commission of Texas and the TRRC, which regulates the Texas fuel oil and natural gas industries.
- ERCOT conducted 324 weather preparedness inspections during 2021, covering 302 generation sites and 22 transmission service providers. These inspections focused on whether each reporting entity performed the weatherization activities described in their winter weather readiness reports required by the PUCT. ERCOT has been working with the PUCT on development of Phase II of the preparedness standards, which addresses both winter and summer preparedness compliance.
- The U.S. EPA is proposing a "conditional acceptance" of CPS Energy's plan to address two ponds at the coal-fired Calaveras Spruce station that are not in compliance with EPA regulations for coal combustion residuals. If the generation units at the site (J.K. Spruce 1 and 2: 1,477 MW) are found to be needed for grid reliability, then the EPA would allow ERCOT and CPS Energy to plan the outages to best minimize reliability issues during the outage period. If the EPA denies the conditional acceptance, then the Spruce units would cease operations 135 days after the EPA denial decision is made.

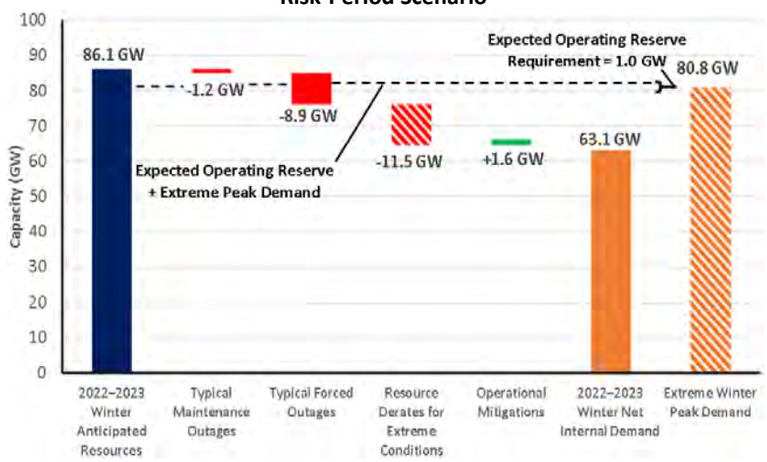
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs, including load shedding that may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme winter peak demand based on 2020–2021 winter storm Uri peak demand

Maintenance and Forced Outages: Based on the historical averages of maintenance or forced outages respectively for December through February weekdays, hours ending 7:00–10:00 a.m. local time for the last three (2019/2020, 2020/2021, and 2021/2022) winter seasons (Winter Storm Uri-related forced outages between February 15–18, 2021, were excluded from this calculation.)

Extreme Derates: Accounts for reduced thermal, wind, and solar PV capacity contributions due to performance in extreme conditions. Uses averages from Winter Storm URI with adjustments to account for implemented weatherization improvements.

Operational Mitigations: Additional capacity from switchable generation, additional imports, and voltage reduction



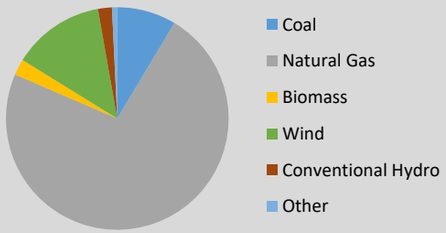
WECC-AB

WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



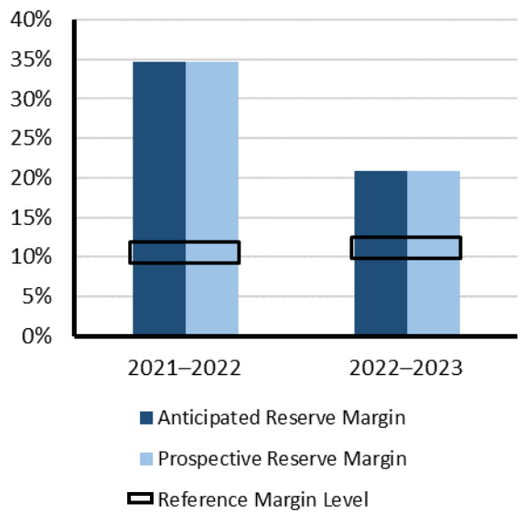
Highlights

- Alberta is a winter peaking area. Winter temperatures are forecast to be below normal. Alberta's operating reserve margins are met before imports in all scenarios except the Low Wind, which leaves a gap of 0.1 GW, and the extreme combined scenario, which leaves a gap of 0.6 GW under extreme peak demand conditions. Both are anticipated to be able to be covered through imports.
- The drop in on-peak reserve margins between last winter and the upcoming winter is a reflection of a slight demand increase of 330 MW combined with roughly 1,500 MW less Tier 1 resources than in the last plan.

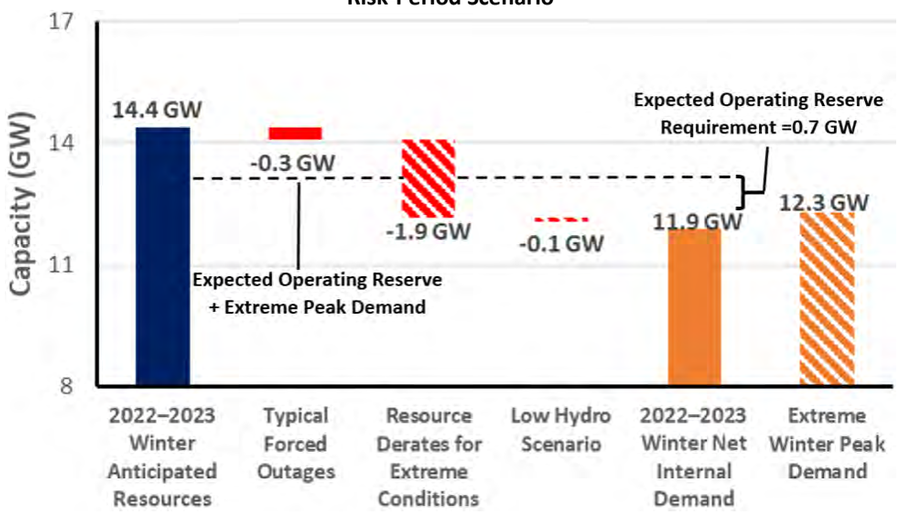
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Risk of load shedding is low due to the expected availability of transfers from neighboring areas.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro output due to drought conditions



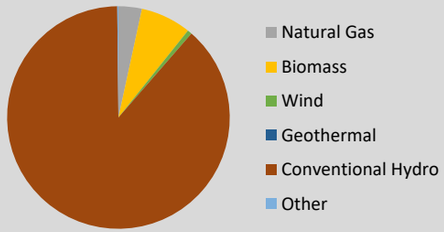
WECC-BC

WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



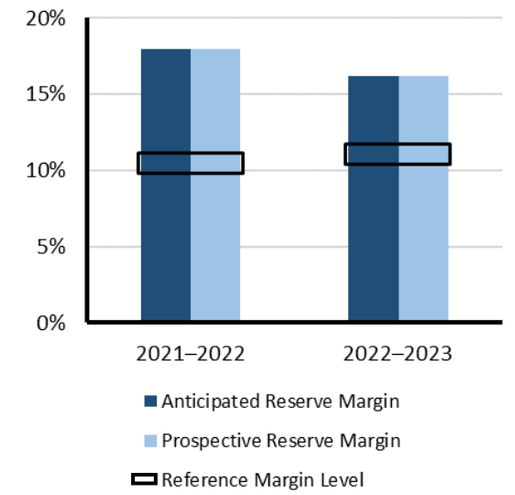
Highlight

- British Columbia is winter peaking with below normal temperatures forecast. In British Columbia before imports, operating reserve margins are not met by at least 0.4 GW in the occurrence of an extreme peak demand. However, the net internal demand is met before imports in all winter resource availability scenarios except under Low Hydro, which leaves an approximate gap of 1 GW, and Extreme Combined, which leaves a gap of 1.1 GW. Both of these are expected to be able to be covered through imports.

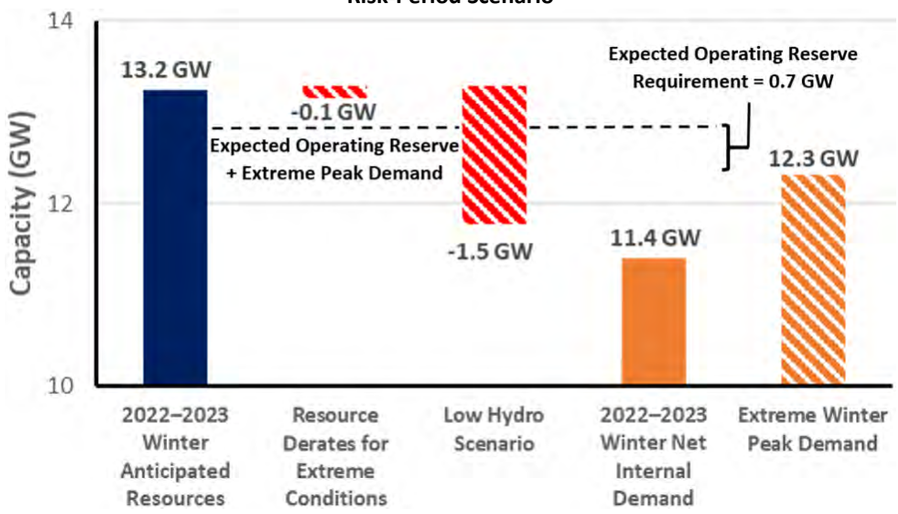
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions combined with an unlikely low-hydro scenario could result in the need to employ operating mitigations (e.g., demand response, transfers, short-term load interruption) and EEAs.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro output due to drought conditions



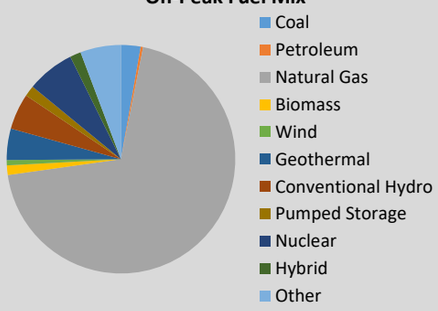
WECC-CA/MX

WECC-CA/MX (California/Mexico) is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorizes, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

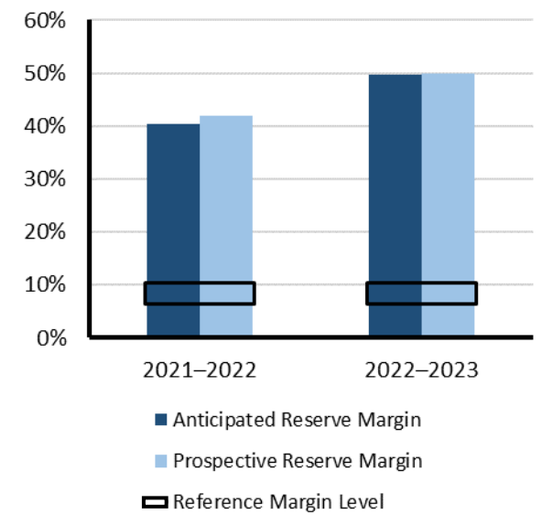
On-Peak Fuel Mix



Highlight

- CA/MX is a summer-peaking area. Above average temperatures are forecasted for the upcoming winter. Operating reserve margins are met before imports in all winter resource availability scenarios.

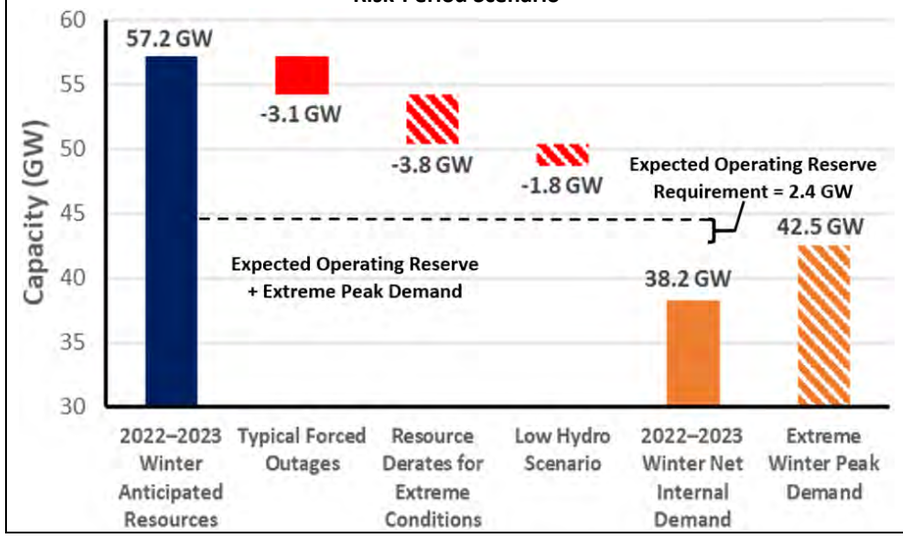
On-Peak Reserve Margins



Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Estimated using market forced outage model

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

Low Hydro Scenario: Reduced hydro output due to drought conditions



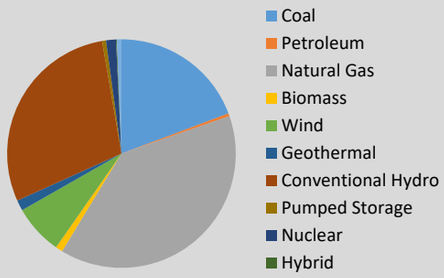
WECC-WPP

WECC-WPP (Western Power Pool) is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



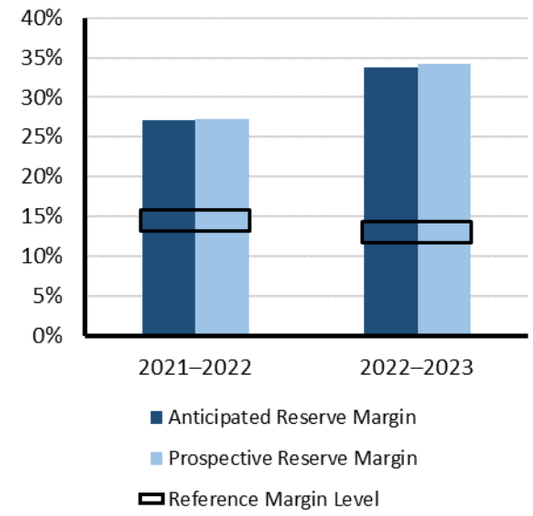
Highlight

- WPP has historically been a mixed season peaking area but is moving towards summer peaking. Operating reserve margins are met at the expected peak demand hour under all but the Extreme Combined scenario, where 1.6 GW of imports would be needed to meet operating reserve margins at an extreme peak demand.

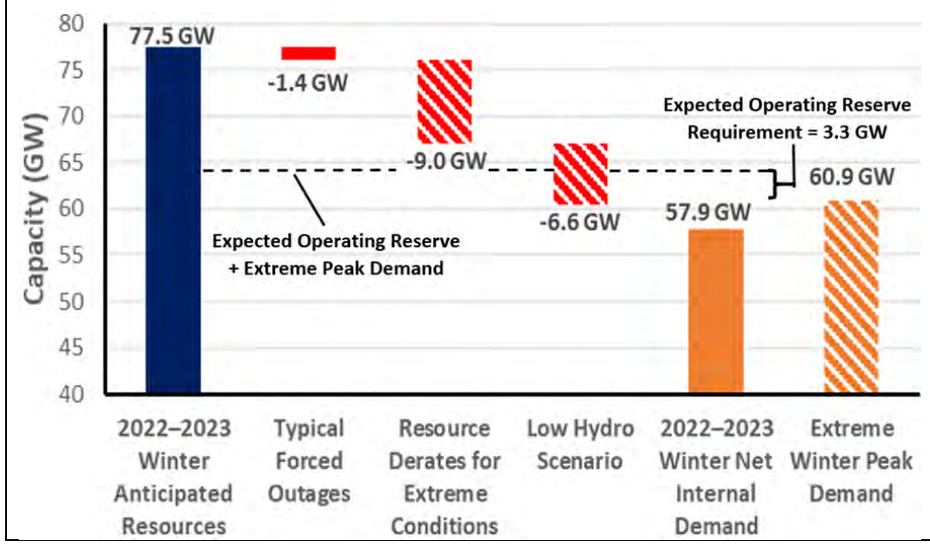
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme peak-demand scenarios. Low hydro output is unlikely, but could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. The risk of load shedding is low due to the expected availability of transfers from neighboring areas.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro output due to drought conditions



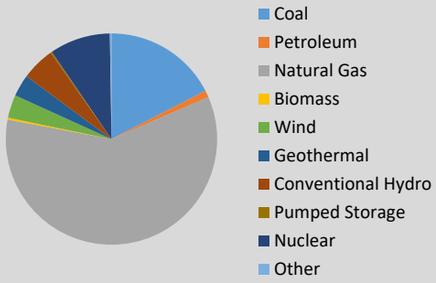
WECC-SRSG

WECC-SRSG (Southwest Reserve Sharing Group) is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



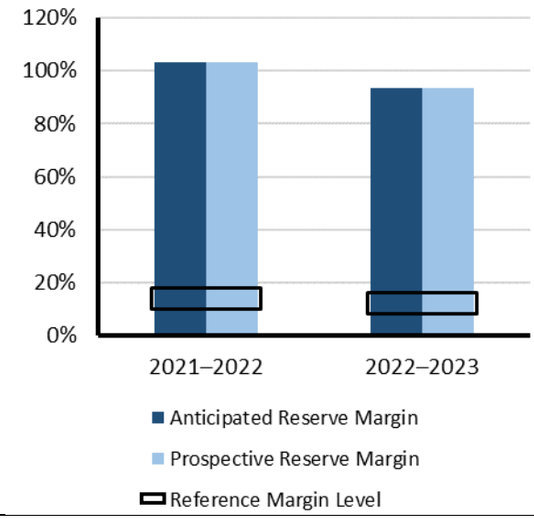
Highlight

- The summer peaking SRSG is expecting above average temperatures this winter. It is anticipated to be resource adequate under all winter extreme availability and demand scenarios. The higher margins compared to the summer season are due to a demand peak of 14 GW in the winter versus a peak of 26 GW in the summer.

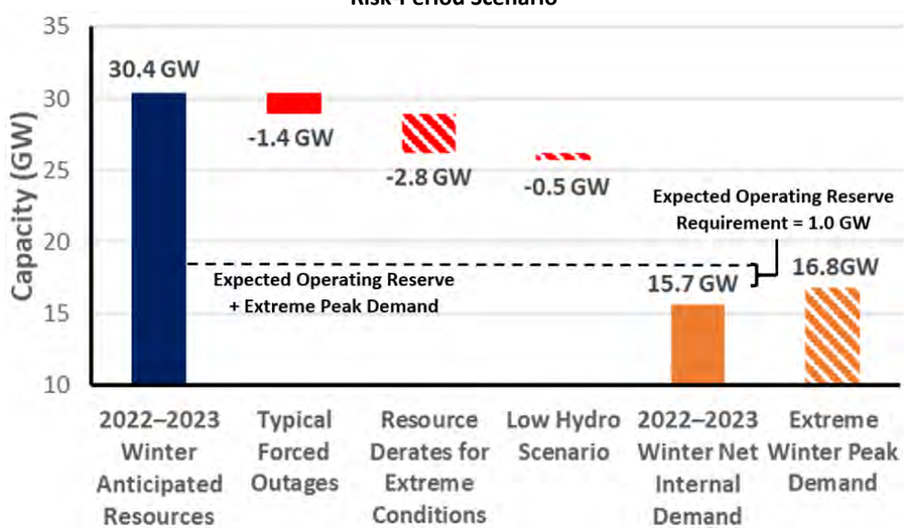
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro output due to drought conditions

Data Concepts and Assumptions

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

General Assumptions
• The reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electricity system to withstand sudden disturbances such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• *2022 Long-Term Reliability Assessment* data has been used for most of this 2022–2023 assessment period augmented by updated load and capacity data.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[16] or total internal demand for the summer and winter of each year.[17]
• Total internal demand projections are based on normal weather (50/50 distribution[18]) and are provided on a coincident[19] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

[16] *Glossary of Terms* used in NERC Reliability Standards

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

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

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

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the winter season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

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

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

Seasonal Risk Scenario Chart Description

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

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

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

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

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[20] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. Other than in NPCC-Maritimes, all assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for the 2022–2023 winter as shown in **Figure 5**. The Canadian winter-peaking systems of NPCC-Maritimes and NPCC-Québec have reserve margins that are near Reference Margin Levels but are unlikely to experience high outage rates from their winterized generators. The potential limited availability of locally stored fuel supplies could result in additional generator outages due to depleted fuel inventories. Variable energy resources, such as wind and solar, often contribute significantly less of their installed capability at the period of peak demand in winter. Winter peaks in many areas occur in early morning hours or other times of darkness, resulting in little or no electrical resource output. Consequently the capacity contribution of variable energy resources to an area's anticipated resources may be a fraction of installed capability in winter.

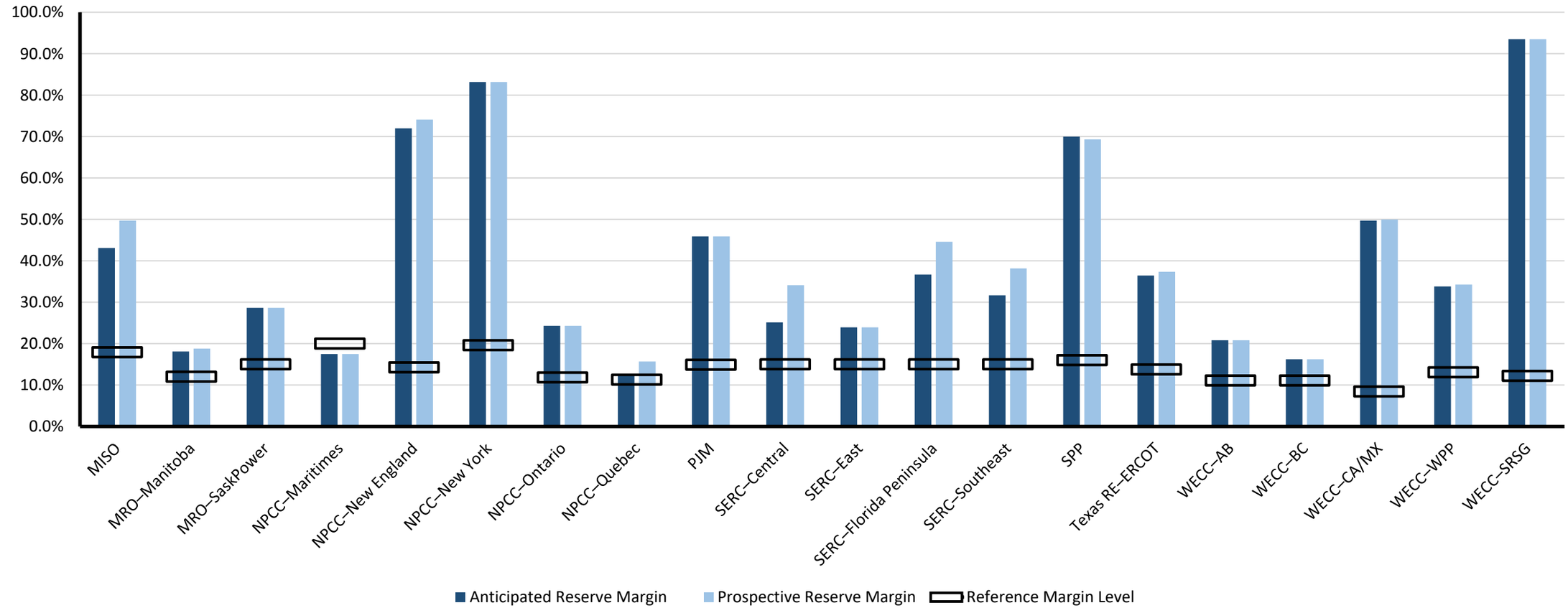


Figure 5: Winter 2022–2023 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

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

Changes from Year-to-Year

Figure 6 provides the relative change in the forecast Anticipated Reserve Margins from the 2021–2022 winter to the 2022–2023 winter. Note that the Reference Margin Level is unchanged for areas that don't have a 2021–2022 Reference Margin Level shown. A significant decline can indicate potential operational issues that emerge between reporting years. MISO, NPCC-Maritimes, SERC-Central, SERC-Southeast, Texas RE-ERCOT, and WECC-AB have noticeable reductions in anticipated resources between the 2021–2022 winter and the 2022–2023 winter. All areas except NPCC-Maritimes remain above their Reference Margin Levels for 2022–2023 winter. The lower Anticipated Reserve Margins for MISO, SERC-Central, SERC-Southeast, Texas RE-ERCOT, and WECC-AB do not result in reliability concerns on peak for this upcoming winter. The Canadian winter peaking systems of NPCC-Maritimes and NPCC-Québec have reserve margins that are near Reference Margin Levels but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the **Data Concepts and Assumptions** section.

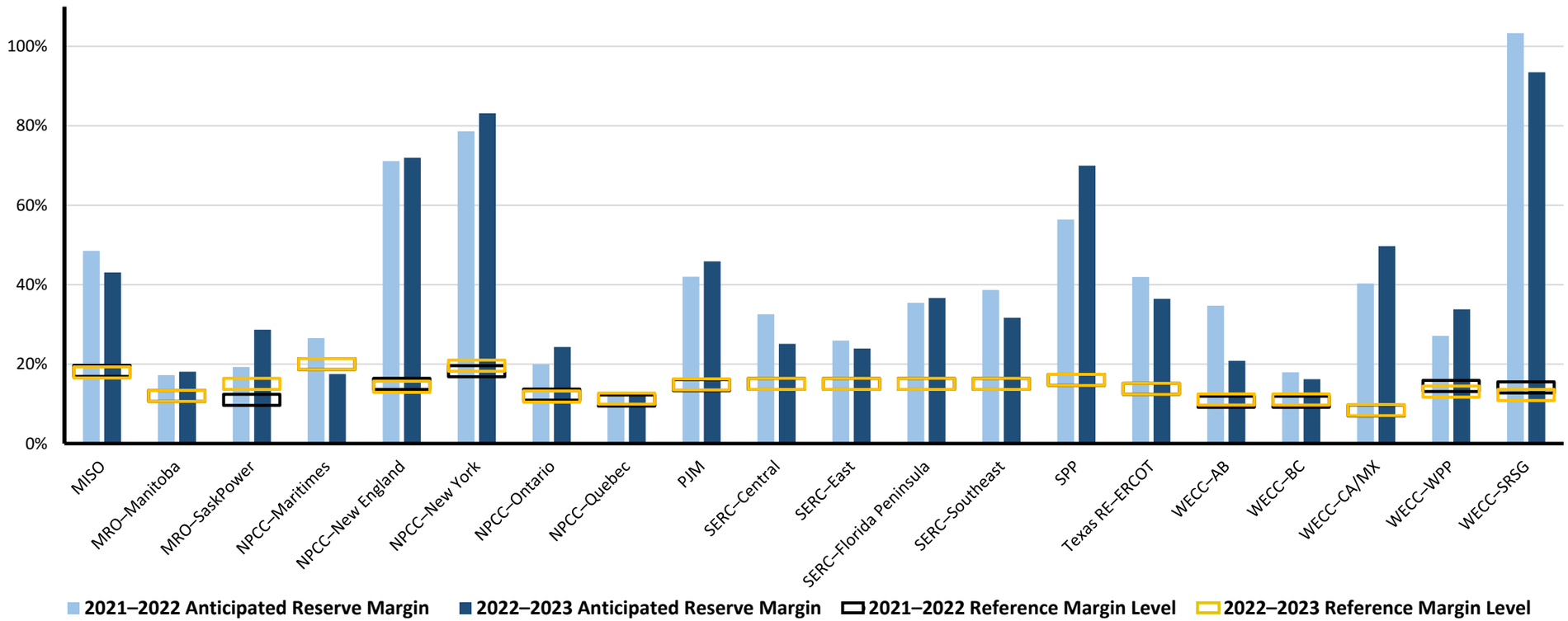


Figure 6: Winter 2021–2022 and Winter 2022–2023 Anticipated Reserve Margins Year-to-Year Change

Internal Demand

Winter peak demand forecasts in many assessment areas are increasing (see **Figure 7)**. The aggregate of winter peak demand forecasts for all areas in the North American BPS has increased by 4,381 MW (0.6%) since the 2021–2022 winter. Since the 2019–2020 winter projections (made prior to the COVID-19 pandemic), the aggregate of demand forecasts for all of North America has increased by 2,766 MW, a 0.4% increase.

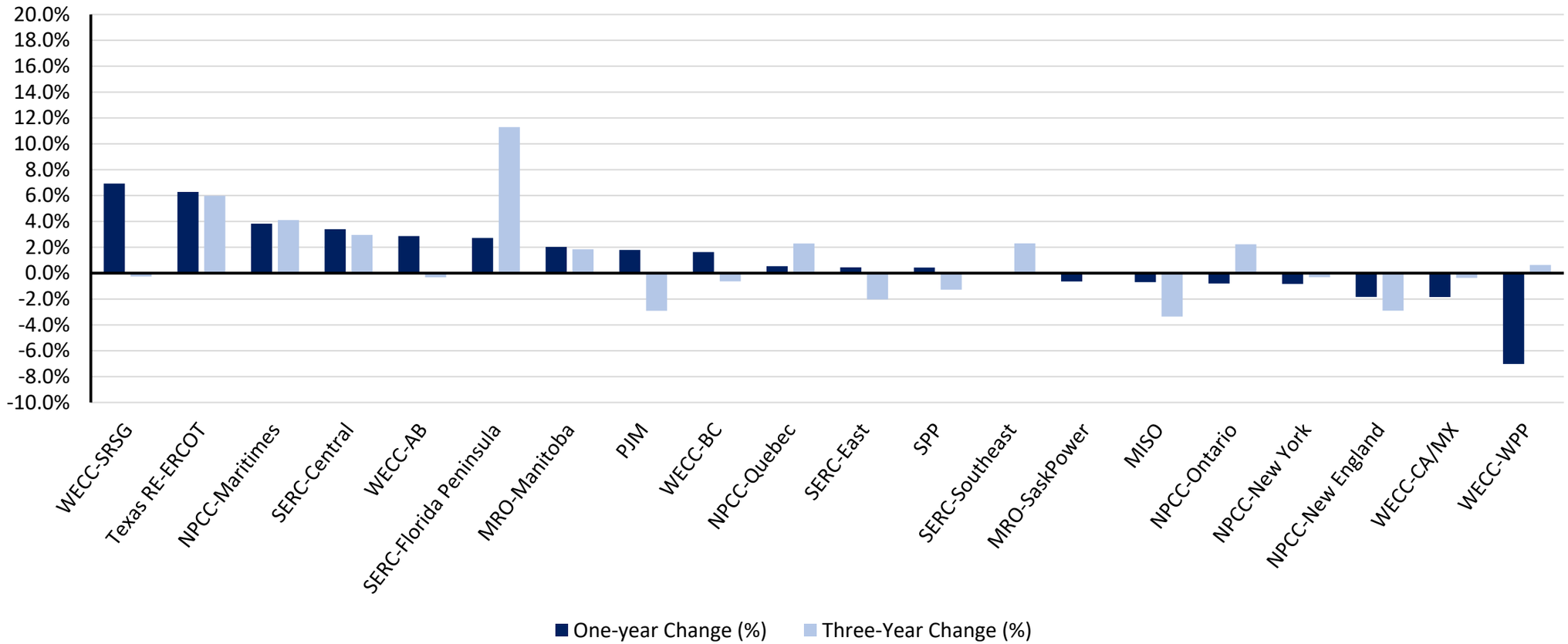


Figure 7: Change in Net Internal Demand: 2022–2023 Winter Forecast Compared To Prior Year Winter Forecasts

Demand and Resource Tables

Peak demand and supply capacity data for each assessment area are provided below (in alphabetical order).

MISO Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	100,812	102,611	1.8%
Demand Response: Available	3,480	3,672	5.5%
Net Internal Demand	97,332	98,939	1.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	138,535	137,926	-0.4%
Tier 1 Planned Capacity	3,738	0	-100.0%
Net Firm Capacity Transfers	2,283	1,352	-40.8%
Anticipated Resources	144,556	141,565	-2.1%
Existing-Other Capacity	0	669	-
Prospective Resources	147,182	148,125	0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	48.5%	43.1%	-5.4
Prospective Reserve Margin	51.2%	49.7%	-1.5
Reference Margin Level	18.3%	17.9%	-0.4

MRO-SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,798	3,781	-0.4%
Demand Response: Available	60	67	11.7%
Net Internal Demand	3,738	3,714	-0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,321	4,488	3.9%
Tier 1 Planned Capacity	13	0	-100.0%
Net Firm Capacity Transfers	125	290	132.0%
Anticipated Resources	4,459	4,778	7.2%
Existing-Other Capacity	0	0	-
Prospective Resources	4,459	4,778	7.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.3%	28.7%	9.4
Prospective Reserve Margin	19.3%	28.7%	9.4
Reference Margin Level	11.0%	15.0%	4.0

MRO-Manitoba Hydro Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,497	4,588	2.0%
Demand Response: Available	0	0	-
Net Internal Demand	4,497	4,588	2.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,438	5,705	4.9%
Tier 1 Planned Capacity	279	279	0.1%
Net Firm Capacity Transfers	-446	-566	26.9%
Anticipated Resources	5,271	5,418	2.8%
Existing-Other Capacity	46	33	-29.4%
Prospective Resources	5,318	5,451	2.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.2%	18.1%	0.9
Prospective Reserve Margin	18.3%	18.8%	0.5
Reference Margin Level	12.0%	12.0%	0.0

NPCC-Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	5,616	5,784	3.0%
Demand Response: Available	317	282	-11.0%
Net Internal Demand	5,299	5,502	3.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,584	6,461	-1.9%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	121	4	-96.7%
Anticipated Resources	6,705	6,465	-3.6%
Existing-Other Capacity	0	0	-
Prospective Resources	6,705	6,465	-3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.5%	17.5%	-9.0
Prospective Reserve Margin	26.5%	17.5%	-9.0
Reference Margin Level	20.0%	20.0%	0.0%

NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,349	20,009	-1.7%
Demand Response: Available	587	610	4.0%
Net Internal Demand	19,762	19,399	-1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	32,668	32,129	-1.6%
Tier 1 Planned Capacity	14	162	1057.0%
Net Firm Capacity Transfers	1,134	1,070	-5.6%
Anticipated Resources	33,816	33,361	-1.3%
Existing-Other Capacity	184	142	-23.0%
Prospective Resources	34,000	33,769	-0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	71.1%	72.0%	0.9
Prospective Reserve Margin	72.0%	74.1%	2.1
Reference Margin Level	15.0%	14.3%	-0.7

NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,940	21,255	1.5%
Demand Response: Available	132	614	364.1%
Net Internal Demand	20,808	20,641	-0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	25,403	26,051	2.6%
Tier 1 Planned Capacity	63	112	77.0%
Net Firm Capacity Transfers	-500	-500	0.0%
Anticipated Resources	24,966	25,662	2.8%
Existing-Other Capacity	0	0	-
Prospective Resources	24,966	25,662	2.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.0%	24.3%	4.3
Prospective Reserve Margin	20.0%	24.3%	4.3
Reference Margin Level	12.3%	11.8%	-0.5

NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	24,025	23,893	-0.5%
Demand Response: Available	631	695	10.1%
Net Internal Demand	23,394	23,198	-0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,239	40,393	0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,547	2,097	35.6%
Anticipated Resources	41,786	42,490	1.7%
Existing-Other Capacity	0	0	-
Prospective Resources	41,786	42,490	1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	78.6%	83.2%	4.6
Prospective Reserve Margin	78.6%	83.2%	4.6
Reference Margin Level	18.2%	19.6%	1.4

NPCC-Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	39,386	39,699	0.8%
Demand Response: Available	2,368	2,759	16.5%
Net Internal Demand	37,017	37,217	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	42,072	42,113	0.1%
Tier 1 Planned Capacity	27	255	838.2%
Net Firm Capacity Transfers	-499	-417	-16.4%
Anticipated Resources	41,600	41,951	0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	42,700	43,051	0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.4%	12.7%	0.3%
Prospective Reserve Margin	15.4%	15.7%	0.3%
Reference Margin Level	10.8%	11.3%	0.5%

PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	132,632	132,980	0.3%
Demand Response: Available	8,466	6,583	-22.2%
Net Internal Demand	124,166	126,397	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	179,247	185,102	3.3%
Tier 1 Planned Capacity	19	0	-100.0%
Net Firm Capacity Transfers	-2,937	-726	-75.3%
Anticipated Resources	176,329	184,376	4.6%
Existing-Other Capacity	0	0	-
Prospective Resources	176,329	184,376	4.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.0%	45.9%	-3.9
Prospective Reserve Margin	42.0%	45.9%	-3.9
Reference Margin Level	14.7%	14.9%	-0.2

SERC-East Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	44,175	44,648	1.1%
Demand Response: Available	903	1,180	30.7%
Net Internal Demand	43,272	43,468	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	53,933	53,287	-1.2%
Tier 1 Planned Capacity	0	75	-
Net Firm Capacity Transfers	562	513	-8.7%
Anticipated Resources	54,495	53,875	-1.1%
Existing-Other Capacity	0	3	-
Prospective Resources	54,495	53,877	-1.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.9%	23.9%	-2.0
Prospective Reserve Margin	25.9%	23.9%	-2.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,320	41,745	3.5%
Demand Response: Available	1,564	1,671	6.8%
Net Internal Demand	38,756	40,074	3.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,271	51,008	-0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	99	-868	-
Anticipated Resources	51,370	50,140	-2.4%
Existing-Other Capacity	3,135	3,601	14.9%
Prospective Resources	54,505	53,741	-1.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	32.5%	25.1%	-7.4
Prospective Reserve Margin	40.6%	34.1%	-6.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,074	48,582	5.4%
Demand Response: Available	1,571	2,870	82.7%
Net Internal Demand	44,503	45,712	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	57,694	61,987	7.4%
Tier 1 Planned Capacity	1,169	237	-79.7%
Net Firm Capacity Transfers	1,414	250	-82.3%
Anticipated Resources	60,277	62,474	3.6%
Existing-Other Capacity	1,147	3,618	215.5%
Prospective Resources	61,424	66,092	7.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	35.4%	36.7%	1.3
Prospective Reserve Margin	38.0%	44.6%	6.6
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,232	46,513	0.6%
Demand Response: Available	1,682	1,954	16.2%
Net Internal Demand	44,550	44,559	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	61,899	60,097	-2.9%
Tier 1 Planned Capacity	1,102	1,102	0.0%
Net Firm Capacity Transfers	-1,218	-2,524	107.2%
Anticipated Resources	61,782	58,674	-5.0%
Existing-Other Capacity	2,516	2,895	15.1%
Prospective Resources	64,298	61,569	-4.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	38.7%	31.7%	-7.0
Prospective Reserve Margin	44.3%	38.2%	-6.1
Reference Margin Level	15.0%	15.0%	0.0

SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	41,669	41,650	0.0%
Demand Response: Available	211	13	-93.7%
Net Internal Demand	41,458	41,637	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	65,197	71,131	9.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-348	-359	3.3%
Anticipated Resources	64,850	70,772	9.1%
Existing-Other Capacity	0	0	-
Prospective Resources	64,820	70,496	8.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	56.4%	70.0%	13.6%
Prospective Reserve Margin	56.4%	69.3%	13.0%
Reference Margin Level	16.0%	16.0%	0.0

Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	62,001	66,436	7.2%
Demand Response: Available	2,598	3,302	27.1%
Net Internal Demand	59,403	63,134	6.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	81,443	85,478	5.0%
Tier 1 Planned Capacity	2,665	644	-75.8%
Net Firm Capacity Transfers	210	20	-90.5%
Anticipated Resources	84,318	86,142	2.2%
Existing-Other Capacity	0	0	-
Prospective Resources	84,382	86,710	2.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	41.9%	36.4%	-5.5
Prospective Reserve Margin	42.1%	37.3%	-4.8
Reference Margin Level	13.75%	13.75%	0.0

WECC-AB Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,569	11,901	2.9%
Demand Response: Available	0	0	-
Net Internal Demand	11,569	11,901	2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	12,842	13,144	2.3%
Tier 1 Planned Capacity	2,743	1,234	-55.0%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	15,585	14,378	-7.7%
Existing-Other Capacity	0	0	-
Prospective Resources	15,585	14,378	-7.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	34.7%	20.8%	-13.9
Prospective Reserve Margin	34.7%	20.8%	-13.9
Reference Margin Level	10.5%	11.1%	0.6

WECC-BC Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,213	11,395	1.6%
Demand Response: Available	0	0	-
Net Internal Demand	11,213	11,395	1.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,077	13,223	1.1%
Tier 1 Planned Capacity	146	20	-86.4%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	13,223	13,243	0.1%
Existing-Other Capacity	0	0	-
Prospective Resources	13,223	13,243	0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.9%	16.2%	-1.7
Prospective Reserve Margin	17.9%	16.2%	-1.7
Reference Margin Level	10.5%	11.1%	0.6

WECC-CA/MX Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	39,779	38,978	-2.0%
Demand Response: Available	829	749	-9.7%
Net Internal Demand	38,950	38,230	-1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,996	55,287	6.3%
Tier 1 Planned Capacity	2,205	1,943	-11.9%
Net Firm Capacity Transfers	449	0	-100.0%
Anticipated Resources	54,650	57,231	4.7%
Existing-Other Capacity	0	0	-
Prospective Resources	55,312	57,326	3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	40.3%	49.7%	9.4
Prospective Reserve Margin	42.0%	50.0%	8.0
Reference Margin Level	8.3%	8.4%	0.1

WECC-SRSG Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	14,910	16,004	7.3%
Demand Response: Available	241	318	32.3%
Net Internal Demand	14,669	15,686	6.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	29,446	29,799	1.2%
Tier 1 Planned Capacity	381	553	45.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	29,827	30,352	1.8%
Existing-Other Capacity	0	0	-
Prospective Resources	29,836	30,352	1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	103.3%	93.5%	-9.8
Prospective Reserve Margin	103.4%	93.5%	-9.9
Reference Margin Level	14.1%	12.2%	-1.9

WECC-WPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	62,822	58,605	-6.7%
Demand Response: Available	551	707	28.4%
Net Internal Demand	62,271	57,898	-7.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	74,865	76,477	2.2%
Tier 1 Planned Capacity	424	988	133.1%
Net Firm Capacity Transfers	3,877	0	-100.0%
Anticipated Resources	79,166	77,465	-2.1%
Existing-Other Capacity	0	0	-
Prospective Resources	79,205	77,730	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.1%	33.8%	6.7
Prospective Reserve Margin	27.2%	34.3%	7.1
Reference Margin Level	14.5%	13.1%	-1.4

Errata

November 2022

- The Extreme Conditions reserve margin for SERC-FP in Table 1 was corrected (page 8)
- The Scenario Description language in Texas RE-ERCOT's dashboard was corrected (page 26)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2023–2024 Winter Reliability Assessment

November 2023



WRA Infographic | WRA Video

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Preface

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

Reliability | Resilience | Security

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

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



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

About this Assessment

NERC's *2023–2024 Winter Reliability Assessment (WRA)* identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the *WRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS.

This reliability assessment process is a coordinated evaluation between the Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas.

This report reflects an independent assessment by the ERO Enterprise (i.e., NERC and the six Regional Entities) and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

This *WRA* covers the upcoming three-month (December–February) winter period. This assessment provides an evaluation of the generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional risks. The following findings are the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as the potential operational concerns that may need to be addressed for the upcoming winter:

1. **A large portion of the North American BPS is at risk of insufficient electricity supplies during peak winter conditions** (Figure 1). Prolonged, wide-area cold snaps threaten the reliable performance of BPS generation and the availability of fuel supplies for natural-gas-fired generation. As observed in recent winter reliability events, over 20% of generating capacity has been forced off-line when freezing temperatures extend over parts of North America that are not typically exposed to such conditions. When electricity supplies become constrained, BPS system operators can face a simultaneous sharp increase in demand as electric heating systems consume more power in cold temperatures. These areas (see **Figure 1)** are at greatest risk for electricity supply shortfalls this winter:

   - **Midcontinent ISO (MISO):** New wind and natural-gas-fired generation and the extension of some older fossil-fired plants have increased available resources this winter by over 9 GW from 2022. Recently, MISO implemented a seasonal resource adequacy construct that more effectively values risks and resource contributions that vary by time of year. Like prior years, an extreme cold-weather event that extends into MISO's southern areas can cause high generator outages from inadequate weatherization or insufficient natural gas fuel supplies.

   - **MRO-SaskPower:** Reserve margins have fallen this winter by eight percentage points when compared to the previous winter due to increased peak demand projections, the retirement of a natural-gas-fired unit (95 MW), and planned generator maintenance. High numbers of forced generator outages or wind turbine cold temperature cutouts can lead to operating reserves shortfalls at peak winter demand levels.

   - **NPCC-Maritimes:** Peak demand growth has been offset by additional resource capacity and import agreements for the upcoming winter, causing reserve margins to rise by over two percentage points compared to 2022. Demand levels at the forecasted peak can still strain the area's firm supplies and lead to operating mitigations or energy emergencies.

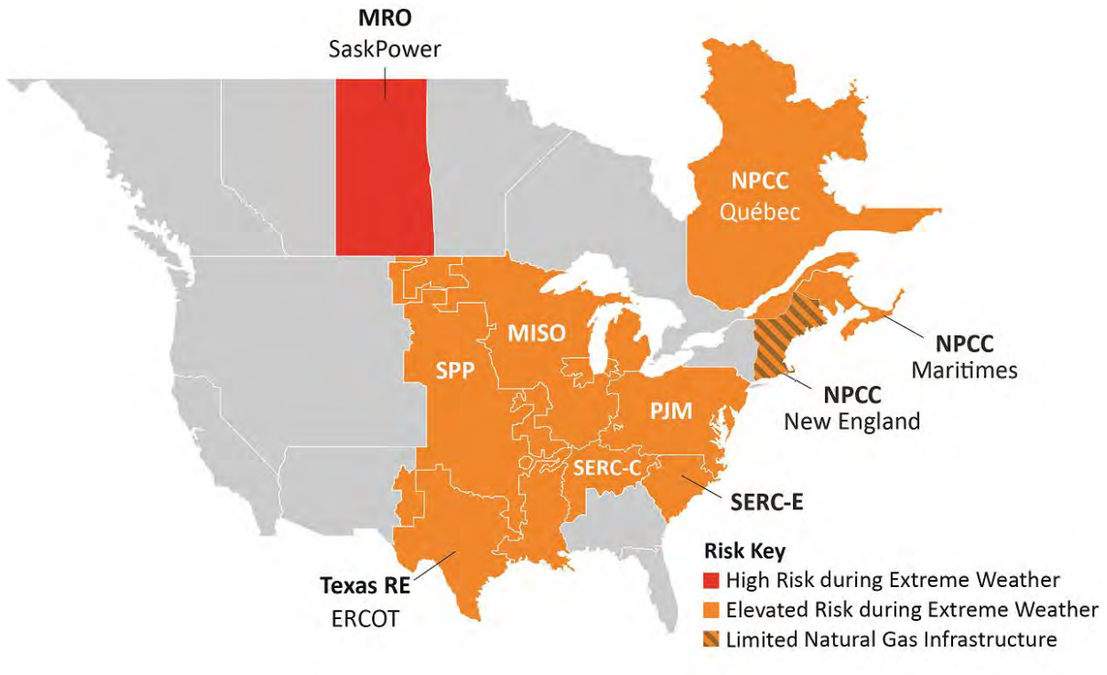


Figure 1: Winter Reliability Risk Area Summary

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

- **NPCC-New England:** The capacity of natural gas transportation infrastructure could be constrained when cold temperatures cause peak demand for both electricity generation and consumer space-heating needs. Potential constraints on the fuel delivery systems and the limited inventory of liquid fuels may exacerbate the risks for fuel-based generator outages and output reductions that result in energy emergencies during extreme weather. ISO-New England (ISO-NE) introduced the Inventoried Energy Program this year as an interim measure to address energy security concerns. The program provides compensation for generators that maintain inventoried energy for their assets during extreme cold periods. The program is also planned for 2024–2025 winter while ISO-NE develops more comprehensive energy security measures for regulatory approval.

- **NPCC-Québec:** An increase in forecasted peak demand and additional firm export commitments have resulted in lower reserve margins for the upcoming winter. Despite having reliable performance from hydroelectric generation in winter, non-firm imports may be needed to meet operating reserve requirements if demand levels exceed the forecasted peak.
- **PJM, SERC-East, and SERC-Central:** A severe cold weather event that extends to the Southern United States can lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Forecasted peak demand has risen while resources have changed little in these areas since Winter Storm Elliot caused energy emergencies across the area in 2022. PJM and SERC have adequate resources for normal winter conditions; however, their generators are vulnerable to derates and outages in extreme conditions.
- **Southwest Power Pool (SPP):** The Anticipated Reserve Margin (ARM) of 38.8% is over 30 percentage points lower than last winter; this is driven by higher forecasted peak demand and less resource capacity. While the reserve margin is adequate for normal forecasted peak demand and expected generator outages, higher demand levels and outages that have occurred during extreme cold weather result in shortfalls that can trigger energy emergencies. The vast wind resources in the area can alleviate firm capacity shortages under the right conditions; however, energy risks emerge during periods of low wind or forecast uncertainty and high electricity demand.
- **Texas RE-ERCOT:** Like other assessment areas in the Southern United States, the risk of a significant number of generator forced outages in extreme and prolonged cold temperatures continues to threaten reliability where generators and fuel supply infrastructure are not designed or retrofitted for such conditions. The risk of reserve shortage is greater than last winter due primarily to robust load growth that is not being met by corresponding growth in dispatchable resources. ERCOT is taking steps to procure additional capacity ahead of winter that can reduce the likelihood of energy emergencies. Additionally, ERCOT implemented a new firm fuel supply service in its market that is expected to partially offset the lost generation capacity that can occur when natural gas supplies are limited. Electricity demand in Texas rises sharply as extreme cold temperatures add to winter operating challenges and energy shortfall risks.

2. **Generator fuel supplies remain at risk during extreme, long-duration cold weather events.** Fuel assurance is vitally important to meeting winter electricity demand across North America. Natural-gas-fired generator availability and output can be threatened when natural gas supplies are insufficient or when the flow of fuel cannot be maintained. During Winter Storm Elliott, natural gas production rapidly declined with the onset of extreme cold temperatures, contributing to wide-area electricity and natural gas shortages.

   Currently, natural gas production, transportation, storage, and a significant portion of the BPS link together to form a single interconnected energy delivery system that extends from the natural gas wellhead to end-use electricity and natural gas customers. The operation of this interconnected energy system can be disrupted when natural gas fuel supplies are not available for electricity generation as well as when electricity is not available to operate electricity-driven compressors and other critical infrastructure components in the natural gas supply chain. Recent extreme cold weather events have shown that energy delivery disruptions can have devasting consequences for electric and natural gas consumers in impacted areas.

   Winter Storm Elliott demonstrated the wide-area consequences for BPS reliability that can result from reduced natural gas production during periods of extreme cold weather. In addition to wellhead impacts on production, natural-gas-fired generating units that lacked firm supply or transportation contracts to meet their winter peak electrical output faced challenging and often insurmountable fuel procurement issues when natural gas supply and available pipeline capacity became scarce. During Winter Storm Elliott, natural-gas-related fuel outages occurred alongside generator outages, derates, and failures to start that resulted from freezing issues and mechanical/electrical issues that are closely correlated with falling temperatures.

   The joint *FERC-NERC-Regional* Entity *Joint Inquiry into Winter Storm Elliott* made the following recommendations related to adequate fuel supply assurance and other matters:[1]

   - Establishing reliability rules for natural gas infrastructure
   - Improving communication and business practices between industries
   - Assessing Balancing Authority (BA) reliability commitment processes for addressing potential capacity shortages during forecasted cold weather events

   To enhance situational awareness across impacted interconnected energy delivery systems, the FERC-NERC report also included a more immediate recommendation that BPS operators and natural gas industry controllers convene to establish control room to control room operational communications protocols that can be invoked when extreme cold weather approaches and that these protocols remain in place over the duration of the event.

[1] FERC Winter Storm Elliott Report

Coal is also an important fuel for electricity generation in winter. Generator owners report fewer coal supply issues compared to last winter. Normal rail transportation services are available and coal stocks are at a high level compared to historical averages. Some coal fired generation that relies on barge shipments in inland waterways could be impacted by drought restrictions that limit barge loading.

3. **Load forecasting in winter is growing in complexity. Underestimating demand is a risk to reliability in extreme cold temperatures.** Extreme cold temperatures and irregular weather patterns characterized by strong cold fronts, wind, and precipitation can cause demand for electricity to deviate significantly from historical forecasts. Electrification of the heating sector is increasing temperature-sensitive load components while increasing levels of variable-output solar photovoltaic (PV) distributed energy resources (DER) add to the load forecast uncertainty. Underestimating electricity demand prior to the arrival of cold temperatures can lead to ineffective operations planning and insufficient resources being scheduled. Generator performance and fuel issues are more likely to occur when generators are called upon with short notice; this can expose BAs to potential resource shortfalls. Load serving entities and BAs should apply lessons from prior winter operating experience to operational load forecasts and pay particular attention to the risk of demand underestimation ahead of extreme winter conditions.

4. **Curtailment of electricity transfers to areas in need during periods of high regional demand is a growing reliability concern.** During energy emergencies and periods of transmission system congestion, Reliability Coordinators (RC) and BAs may curtail transfers for various reasons with established procedures and protocols. While the curtailments alleviate an issue in one part of the system, curtailments can contribute to supply shortages or affect local transmission system operations in another area. During Winter Storm Elliott, firm exports were curtailed from PJM during a period of widespread energy emergencies in the U.S. Eastern Interconnection. For winter 2023–2024, several areas identified as having capacity or energy risks are relying on imports of electricity supplies. These areas include MRO-SaskPower, NPCC-Maritimes, NPCC-New England, SERC-Central, and SERC-East. A wide-area cold snap that severely affects regional demand or generator availability presents an added concern in areas that are dependent on imports for managing high electricity demand.

5. **New cold weather Reliability Standards in place at the start of the 2023–2024 winter are aimed at improving coordination between Generator Owners/Operators and BPS Operators.** New cold weather Reliability Standards adopted by the NERC Board of Trustees (Board) in June 2021 went into effect in the United States earlier this year. Generator Owners (GO) and Generator Operators (GOP) are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their RCs, Transmission Operators (TOP), and BAs for use in operating plans. Additional Reliability Standard requirements have been developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity staff report—The February 2021 Cold Weather Outages in Texas and Southcentral United States.* The NERC Board adopted these requirements in October 2023 and directed NERC to file them with regulatory authorities for approval and industry implementation.

6. **Industry responses to NERC's Level 3 Alert - Cold Weather Preparations for Extreme Weather Events–III indicate that generator winter preparations are on a positive trend, but freezing temperatures remain a concern for some generators.** In May, NERC issued a Level 3 essential actions alert to BAs, TOPs, and GOs. The alert highlighted actions to increase readiness and enhance plans to reduce risk for the upcoming winter and beyond. Additionally, recipients of the alert were required to respond to questions that support NERC's review of progress toward mitigating winter reliability risks. The responses indicate GOs have determined cold weather temperature limits for their generators and taken steps to assess and prepare critical components to operate at these temperatures. Many GOs, however, noted that generator unit and auxiliary component mechanical failures from past cold weather events remain a concern for the upcoming winter. Problem areas include improper heat tracing, frozen instrumentation and control equipment, generator circuit breaker tripping in low temperatures or low air pressures, and wind turbine blade icing.

Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

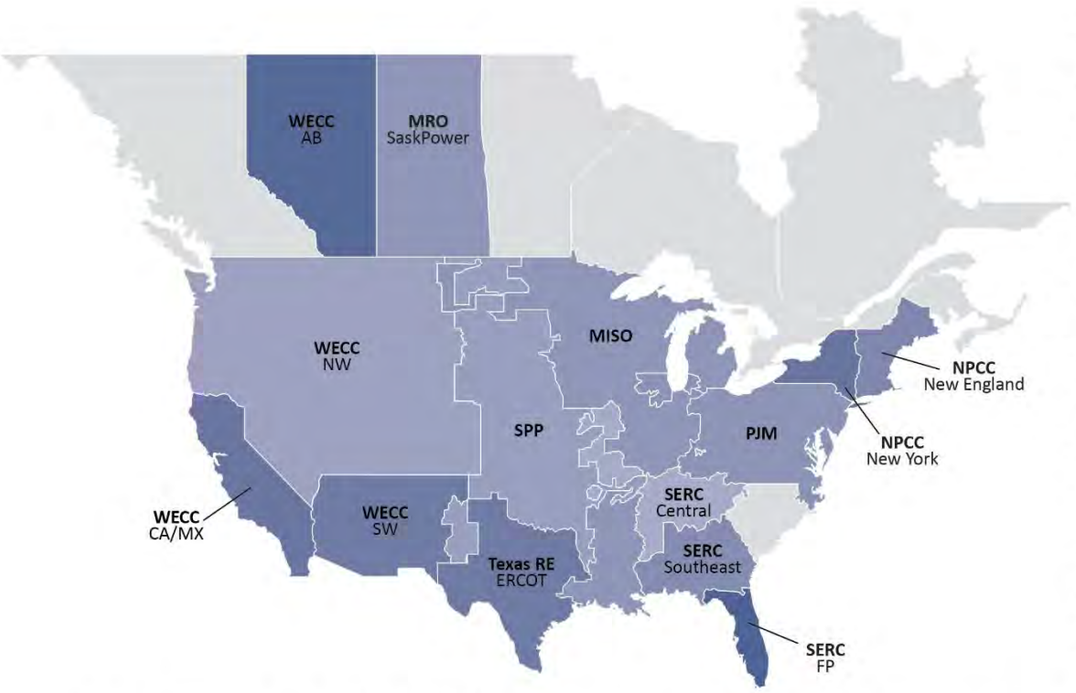
- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially high generator outages and extreme demand levels. Operators should be trained and familiar with manual load shedding plans prior to winter and review procedures in advance of severe winter weather.
- TOPs, BAs, and GOs should implement the essential actions identified in the NERC Level 3 alert, Cold Weather Preparations for Extreme Weather Events–III, and should take recommended weatherization steps prior to winter.
- BAs should be cognizant of the potential for short-term load forecasts to underestimate load in extreme cold weather events and be prepared to take early action to implement protocols and procedures for managing potential reserve deficiencies.
- RCs and BAs should implement generator fuel surveys to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- State and provincial regulators can assist grid owners and operators in advance of and during extreme cold weather by supporting requested environmental and transportation waivers as well as public appeals for electricity and natural gas conservation.

Risk Highlights

Over the past 11 years, five cold weather events have jeopardized Bulk Electric System (BES) reliability by triggering unplanned cold weather-related generation outages. To maintain BES reliability during Winter Storm Uri in February 2021 and Winter Storm Elliott in December 2022, BES operators were required to shed firm load. During both winter storms, numerous electrical and mechanical issues rendered significant portions of the impacted areas' thermal generation fleet unavailable while natural gas supply and transportation issues prevented numerous otherwise available natural-gas-fired generators from supplying much needed electrical energy. Moreover, a significant portion of generating units failed to perform at temperatures above their own documented minimum operating temperatures.

Generator Fuel Supply Risk

As noted in past winter reliability assessments, the performance of the thermal generating fleet is critical to winter operations. The electric and natural gas industries continue to work through the recommendations contained in the *FERC-NERC-Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South-Central United States.*[2] The final report on Winter Storm Elliott—the 2022 storm that contributed to power outages for millions of electricity customers in the Eastern half of the United States—recommends completion of cold weather reliability standard revisions stemming from 2021's Winter Storm Uri and improvements to reliability for the U.S. natural gas infrastructure.[3] What has become clear is that the natural-gas-electric system has now become fully interconnected, each requiring the other to remain reliable (i.e., impacts on one system can impact the other). These considerations should drive higher levels of coordination to ensure sustained reliable operation of this interconnected system.



All other assessment areas have less than 35% natural gas fired generation contribution to winter resource mix.

	Natural-Gas-Fired Generation	
	Peak Winter Capacity	Contribution to Total Winter Resource Mix
MISO	67.5 GW	46%
MRO-SaskPower	2.1 GW	46%
NPCC-New England	17.3 GW	54%
NPCC-New York	24.5 GW	66%
PJM	84.9 GW	47%
SERC-Central	22.7 GW	44%
SERC-Florida Peninsula	50.6 GW	79%
SERC-Southeast	31.5 GW	51%
SPP	27.4 GW	41%
Texas RE-ERCOT	54.2 GW	62%
WECC-AB	11.4 GW	75%
WECC-CA/MX	39.9 GW	65%
WECC-NW	31.0 GW	39%
WECC-SW	18.2 GW	62%

Figure 2: Natural-Gas-Fired Generation Capacity Contributions to 2023–2024 Winter Generation Mix

Natural Gas Supply to Generators

Natural-gas-fired generation is vitally important to meeting winter electricity demand across much of North America (**Figure 2**). Furthermore, the natural gas industry relies on electricity to power some of its critical components. For instance, some compressors run on electricity while others are fueled by natural gas. This means that the natural gas industry depends on the delivery of electricity to run as intended, and as stated in many other places, the electric industry depends on the delivery of natural gas. This can exacerbate the scale of impacts when either industry is threatened.

[2] The February 2021 Cold Weather Outages in Texas and the South-Central United States | FERC, NERC and Regional Entity Staff Report | Federal Energy Regulatory Commission

[3] FERC Winter Storm Elliott Report

Generator availability and output can be threatened when natural gas supplies are insufficient or when natural gas infrastructure is unable to maintain the flow of fuel. The BES's ability to deliver electricity was put at risk by past natural gas production declines during periods of extreme cold weather. As Winter Storm Elliott demonstrated, this is the case even in areas of North America where cold weather is common. Wide-area extreme cold events increase the likelihood of natural gas production declines and result in increased demand for natural gas by local distribution company (LDC) customers and natural-gas-fired electric generators. Wide-area events can also concurrently render multiple grid BA areas energy deficient and thus preclude an impacted BA from importing the electricity it requires to meet BA load even when transmission to support such transfers is available. Longer duration events increase the risk that the imbalances resulting from declining natural gas production and increased natural gas demand approach unsustainable levels. For areas that are pipeline constrained, high natural gas demand during extreme cold weather presents risks for generators that lack firm natural gas transportation arrangements.

Coal Transportation

While many factors that contributed to uncertain rail shipment of coal to electric generators prior to the 2022–2023 winter assessment have subsided, other transport issues could emerge for this winter. Drought conditions that impact the Missouri River and other major navigable waterways could restrict coal availability and cause units to run at a derated level to conserve coal inventory. Low water levels can also affect generators that rely on once-through cooling processes and limit the generator's capacity output.

Extreme Cold Temperatures and Demand Forecasting

Accurate load forecasting is essential for reliable operations. BAs and load-serving entities frequently update the load forecasts that serve as key inputs for long-range resource planning, seasonal outage coordination, and operational plans from day-ahead to real-time. Cold weather patterns and the temperature-correlated behavior of some end-use loads present some of the most challenging issues and complex load forecasting, adding to winter reliability risk.

Most assessment areas can experience a wide range of winter peak demand from one year to the next, largely depending upon the severity of winter conditions. Load forecasts for normal winter peak (referred to as 50/50 peak demand or net internal demand elsewhere in this report) reflect the highest expected system load for an average winter. A higher level of demand used throughout this report is the load forecast for extreme 90/10 peak demand, which generally represents the highest 10% of the winter peak demand forecast distribution.[4] Actual winter peak demand in each area is expected to be below this level most (but not all) years. **Figure 3** shows these two demand levels for assessment areas where the extreme peak demand forecast is 9% or greater than the normal peak demand forecast. Year-to-year differences in winter weather conditions are key drivers of the large variation in normal and extreme demand forecasts, but changing load characteristics also contribute in many areas. ARMs, which measure resource levels above the normal 50/50 peak demand, have limited ability to identify resource adequacy risk when peak demand is highly variable from year to year.

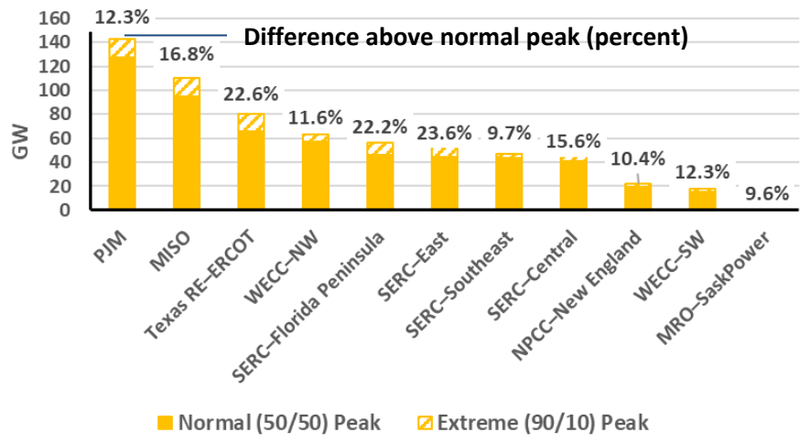


Figure 3: Normal and Extreme Peak Demand Forecasts for 2023–2024 Winter

The growing complexity in load forecasting and increasing load forecast uncertainty adds to winter reliability risks. Extreme cold temperatures and unfamiliar weather patterns characterized by strong cold fronts, wind, and precipitation can cause demand for electricity to deviate significantly from historical forecasts. Electrification of the heating sector is increasing temperature-sensitive load components while increasing levels of variable-output solar PV DERs add to load forecast uncertainty. Underestimating electricity demand prior to the arrival of cold temperatures can lead to ineffective operations planning and insufficient resources being scheduled. Generator performance and fuel issues are more likely to occur when generators are called upon with short notice, exposing BAs to potential resource shortfalls. Load serving entities and BAs should apply lessons from prior winter operating experience to operational load forecasts and pay particular attention to the risk of demand underestimation ahead of extreme cold temperatures.

[4] Anticipated Reserve Margins (ARM) are calculated from this demand level. NERC assesses winter reliability risk using this extreme 90/10 peak demand level (see the risk scenario summary for each assessment area in the **Regional Assessments Dashboards** section).

Seasonal Risk Scenario Margins

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

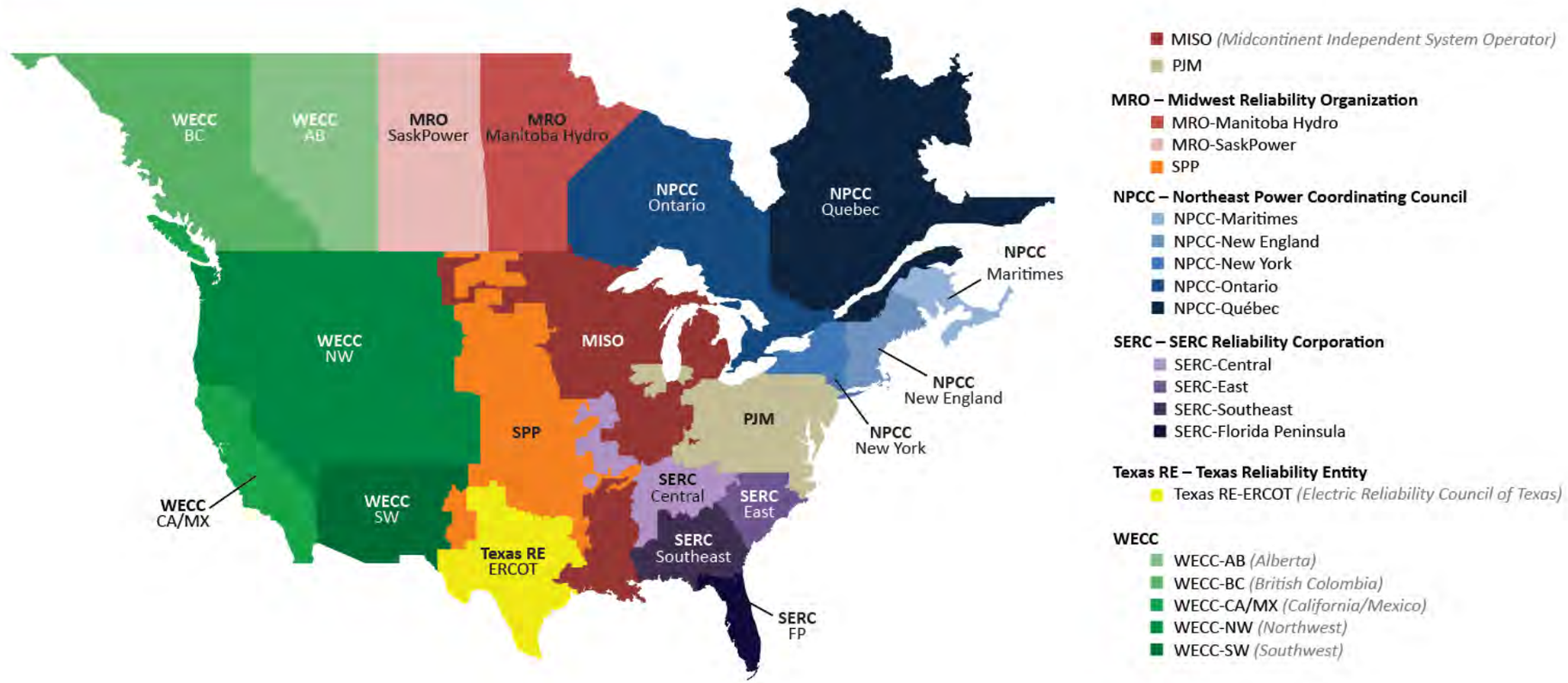
The seasonal risk scenario charts can be expressed in terms of reserve margins. In **Table 1**, each assessment area's ARM is shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario. The typical outages reserve margin is comprised of anticipated resources less the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the ARM, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

Table 1: Seasonal Risk Scenario Margins

Assessment Area	Anticipated Reserve Margin	Typical Outages	Extreme Conditions
MISO	55.8%	26.5%	-5.9%
MRO-Manitoba	15.3%	13.2%	6.6%
MRO-SaskPower	20.6%	6.9%	7.7%
NPCC-Maritimes	19.7%	13.5%	-0.5%
NPCC-New England	67.2%	47.3%	6.3%
NPCC-New York	76.3%	49.9%	12.4%
NPCC-Ontario	28.2%	28.2%	20.3%
NPCC-Quebec	10.5%	6.5%	-2.2%
PJM	39.8%	26.4%	4.2%
SERC-C	30.1%	22.6%	5.2%
SERC-E	24.4%	19.6%	9.3%
SERC-FP	41.0%	37.8%	12.7%
SERC-SE	41.6%	35.7%	13.7%
SPP	38.8%	14.5%	-14.1%
TRE-ERCOT	41.2%	27.3%	-6.6%
WECC-AB	27.1%	24.3%	5.5%
WECC-BC	15.1%	15.0%	-8.6%
WECC-CA/MX	65.3%	57.4%	32.2%
WECC-NW	43.5%	37.5%	-4.1%
WECC-SW	90.4%	85.1%	43.4%

Regional Assessments Dashboards

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





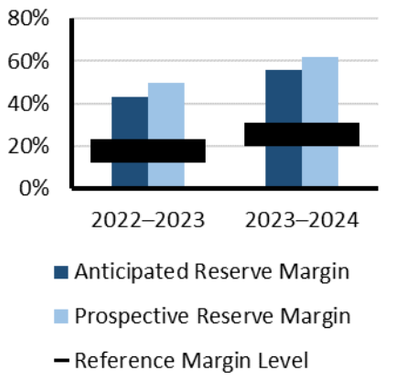
MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 39 local BAs and over 500 market participants, serving approximately 45 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Highlights

- Though some risk has been identified for this upcoming winter season in a high generation outage and high winter load scenario, reliability is expected to be maintained by the use of any number of measures, including load modifying resources, non-firm energy transfers into the system, energy-only resources that do not have a must-offer requirement for the winter but may still offer into the energy markets, or internal transfers that exceed the sub-regional import/export constraint between MISO North/Central and MISO South. MISO continues to coordinate extensively with neighboring RCs and BAs to improve situational awareness and vet any needs for firm or non-firm transfers to address extreme system conditions.
- The extreme cold weather of last winter is a reminder of just how critical resource adequacy and proper planning are for all seasons of the year, not just for a systems summer peak. Acknowledging this, MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency. In addition, MISO has filed and implemented a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons. As a result, MISO has raised Reference Margin Levels for the 2023–2024 winter season. The 2023–2024 Planning Resource Auction conducted in April 2023 was the first implemented under the seasonal construct.

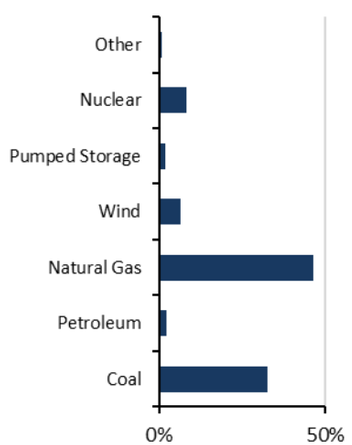
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and energy emergency alerts (EEA). Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

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

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

Low Wind Scenario: Below average wind contributions

Extreme Low-Generation: Maximum historical generation outages

Operational Mitigations: A total of 2.6 GW capacity resources available during extreme operating conditions



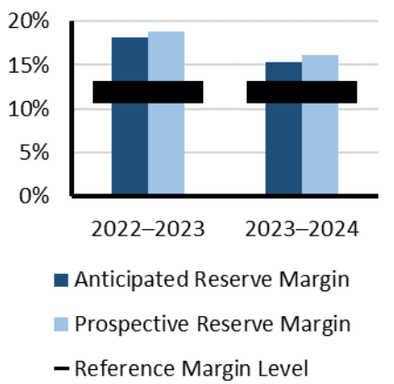
MRO-Manitoba Hydro

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

Highlights

- The ARM for winter 2023–2024 exceeds the 12% Reference Margin Level.
- No emerging reliability issues are anticipated for the upcoming winter season that are pertinent to Manitoba Hydro.
- Manitoba Hydro continues to monitor a number of issues, including extreme weather events like drought, decarbonization-driven changes to supply and demand, and asset health.
- All seven units at the Keeyask hydro station (630 MW net addition) are anticipated to be in commercial operation for winter 2023–2024.

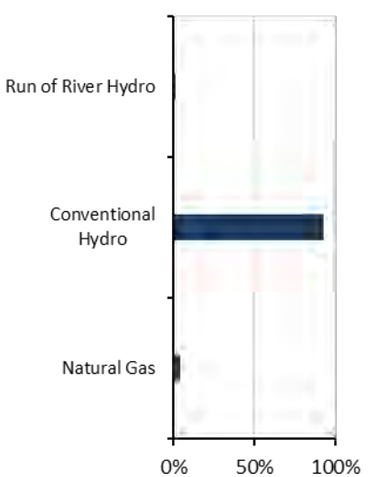
On-Peak Reserve Margin



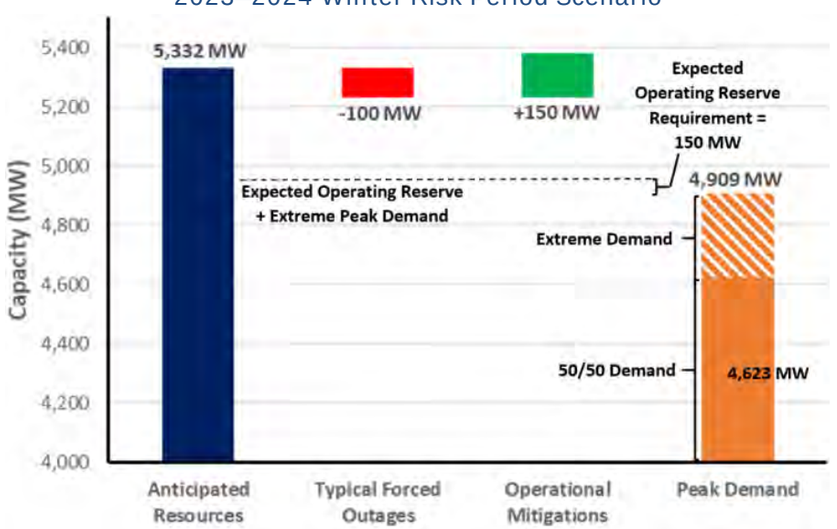
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand scales additional load experienced during all-time peak actual versus forecasted load (January 2019)

Forced Outages: Accounts for average forced outages

Operational Mitigations: Emergency Operating Procedures



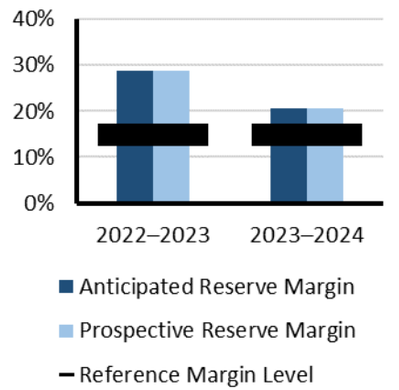
MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.2 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

Highlights

- Saskatchewan experiences peak load in winter because of extreme cold weather. Reserve margins have fallen this winter by about 8% when compared to the previous winter due to increased peak demand projections, the retirement of a natural gas unit (95 MW), and an increase of planned maintenance.
- The risk of operating reserve shortage or EEA during peak load times exists if a large generation forced outage occurs during peak load times combined with transmission tie-line maintenance work or generation maintenance work scheduled during winter months.
- In case of extreme winter conditions combined with large generation forced outages, SaskPower would utilize available demand response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions.

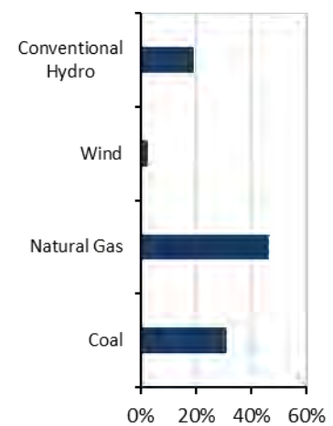
On-Peak Reserve Margin



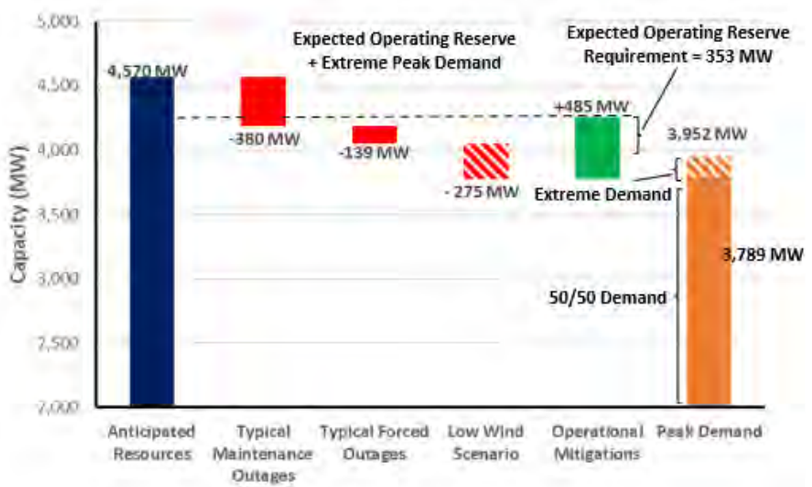
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. The risk of load shedding is low.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on potential system peak load increased by average forecast error of previous five years

Maintenance Outages: Average of planned maintenance outages for the winter months, December–February, over the past three years

Forced Outages: Estimated using SaskPower forced outage model

Low Wind Scenario: Estimated using SaskPower forced outage model

Operational Mitigations: Estimated average value based on short term transfer capability from neighboring utilities (150 MW) and reserved generating units (135 MW) for the upcoming 2023–2024 winter. This also includes 200 MW in demand-side resources and non-firm loads that require 15 minutes to 2 hours of advanced notification.



NPCC-Maritimes

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

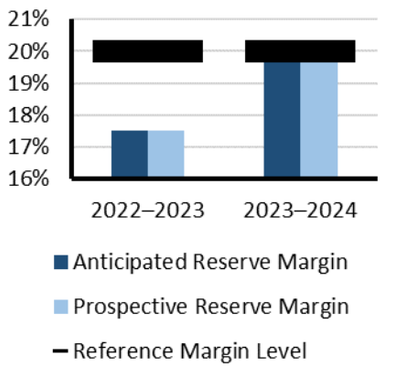
Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations and planning procedures in place. All of the area's declared firm capacity is expected to be operational for the winter operating period.
- The Maritimes area is a winter-peaking system.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil on-site to enable sustained operation in the event of natural gas supply interruptions.

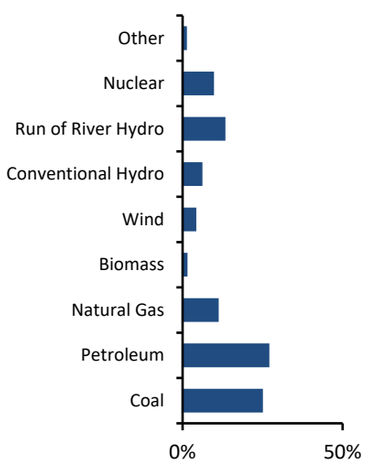
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates that the risk of load shedding is low. See **Probabilistic Assessment** section.

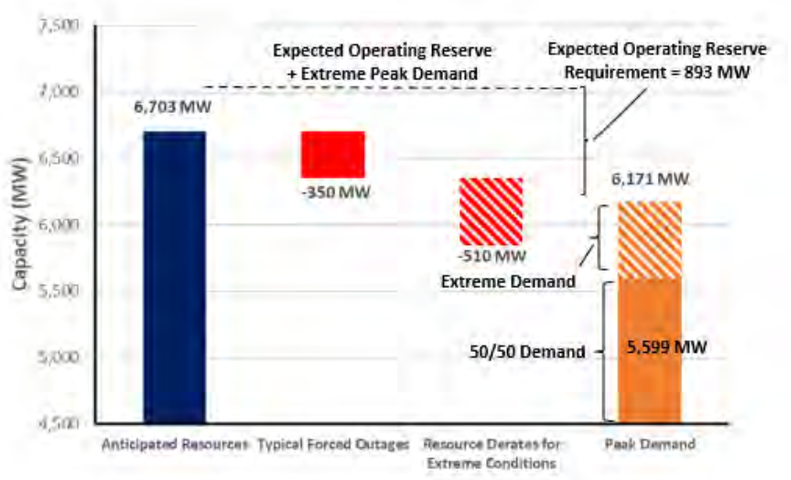
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 20 years of historical data

Forced Outages: Based on historical operating experience

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



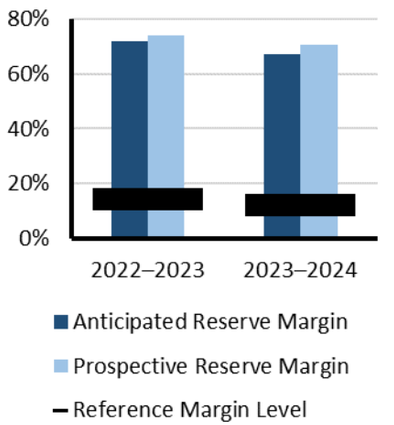
NPCC-New England

NPCC-New England is an assessment area that is served by ISO-NE, and it consists of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS. The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- ISO-NE expects to meet its regional resource adequacy requirements this 2023–2024 winter operating period for a mild or moderate winter similar to 2021–2022 or 2017–2018. A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold period given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and liquified natural gas).
- ISO-NE is offering an interim program to compensate certain resources that provide fuel security. The Inventoried Energy Program is a voluntary, interim program designed to provide incremental compensation for participants that maintain inventoried energy for their assets during extreme cold periods when winter energy security is most stressed.
- ISO-NE expects to have sufficient capacity resources to meet the 2023–2024 90/10 winter peak demand forecast of 21,032 MW for the weeks beginning January 7, January 14, and January 21, 2024.
- ISO-NE evaluates an above 90/10 scenario, which captures the area's coldest day in the last 25 years while using both their current and future load models. The above 90/10 winter peak demand forecast is 21,746 MW for the three previously identified peak weeks. ISO-NE currently has sufficient resources to meet this demand however if a cold snap were to occur the area may have to rely on its external ties and emergency procedures to operate reliably.

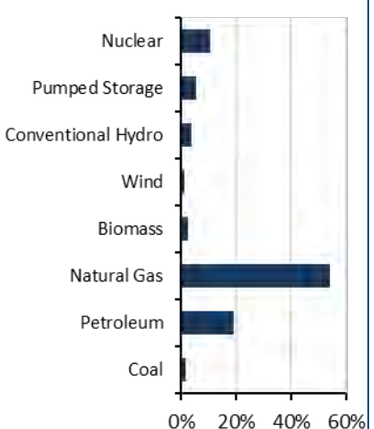
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area prolonged cold weather events. See **Probabilistic Assessment** section.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast for coldest day from the last 25 years

Maintenance and Forced Outages: Based on weekly averages

Extreme Derates and Natural Gas Scenario: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather-related outages reported by generators

Operational Mitigations: Based on ISO-NE operating procedures



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves 20.2 million customers. For this WRA, the established Reference Margin Level is 15%; wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. New York State Reliability Council approved the 2023–2024 IRM at 20.0%.

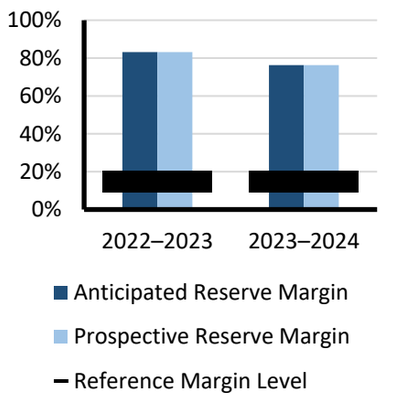
Highlights

- New York is a summer-peaking area, and no emerging reliability issues are anticipated during the 2023–2024 winter assessment period. Surplus capacity margins above the NYISO's operating reserve requirements are projected.

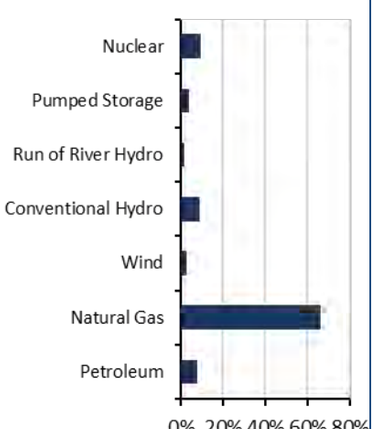
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

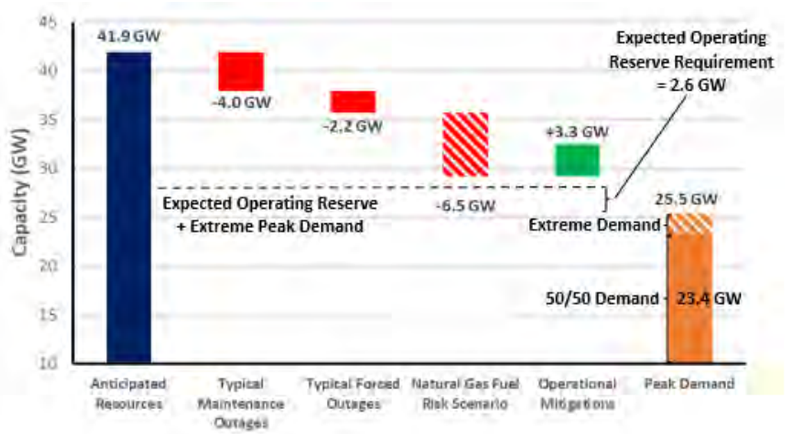
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Maintenance Outages: Based on planned scheduled maintenance

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

Natural Gas Fuel Scenario: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather

Operational Mitigations: Based on NYISO operating procedures



NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 15 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

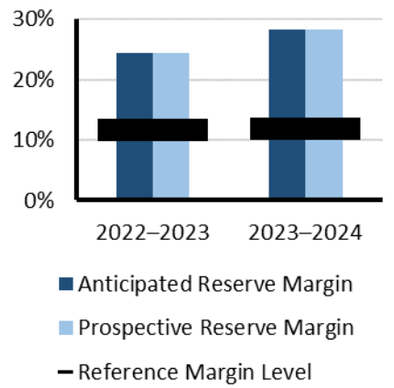
Highlights

- IESO anticipates that it will maintain reliability on its system through the winter of 2023–2024.
- Reference margins are forecast to remain at adequate levels in both normal and extreme weather scenarios.
- Ontario regularly experiences extreme cold weather; its generation fleet, transmission system, and fuel delivery infrastructure are well prepared for and adapted to such conditions.
- Unit 3 at the Darlington Nuclear Generating Station was reconnected to the provincial grid following refurbishment in July 2023, nearly six months ahead of schedule. Bruce Nuclear Generating Station's Unit 6 was returned to service following a successful refurbishment that began in January 2020.
- The IESO's December 2022 Annual Capacity Auction secured 1,160 MW of capacity for winter 2023–2024.

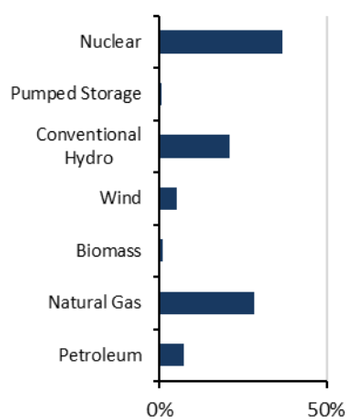
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

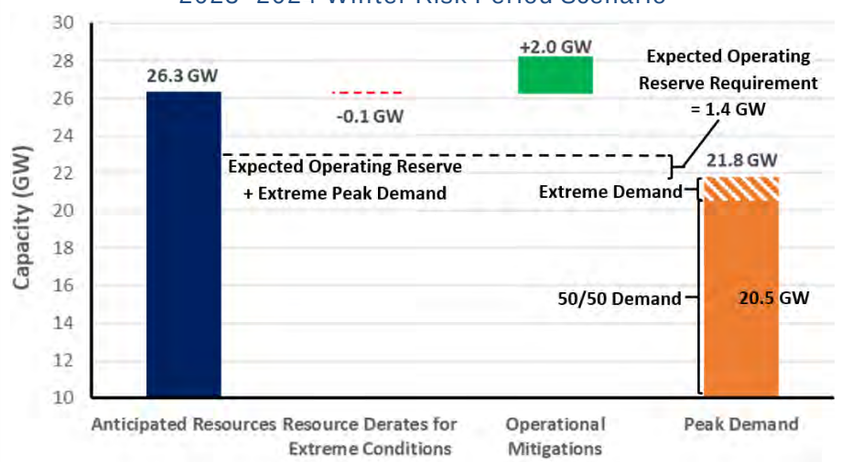
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand from 31 years of winter demand history

Extreme Derates: Generation unavailability in an extreme event using temperature derates

Operational Mitigations: Imports anticipated from neighbors during emergencies



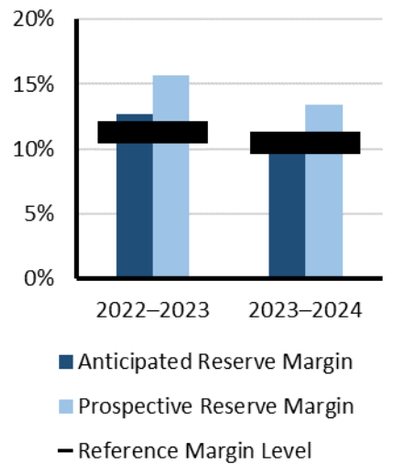
NPCC-Québec

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

Highlights

- Québec predicts that it will maintain system resource adequacy this winter.
- Forecasted demand increase and additional firm export commitments have resulted in shrinking reserve margins.
- The Québec area is a winter-peaking system with predominately hydroelectric generation resources. Adequate capacity margins above its reference reserve requirements are projected for the 2023–2024 winter assessment period.
- No changes have been made to the assessment area's winter preparedness programs.

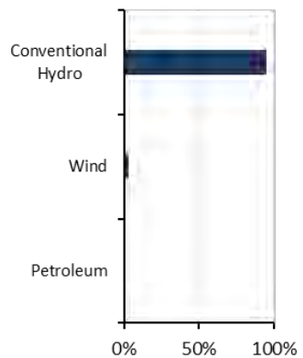
On-Peak Reserve Margin



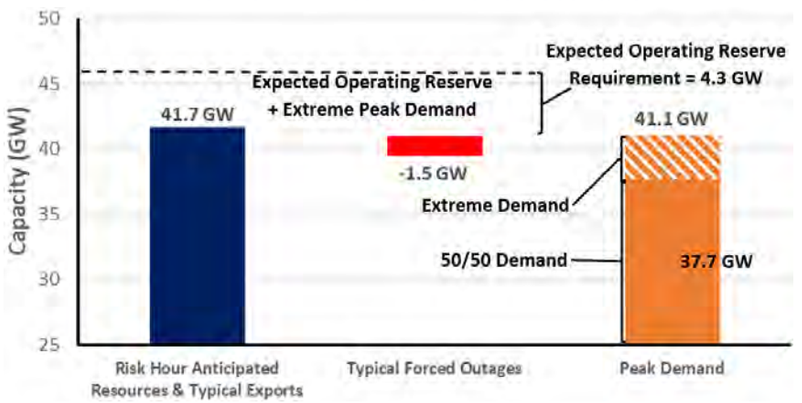
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates that the risk of load shedding is low. See the **Probabilistic Assessment** section.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 8:00 a.m.

Demand Scenarios: Net internal demand (50/50) and (95/5) demand forecast

Forced Outages: Rare scenario of 1,500 MW in unplanned outages



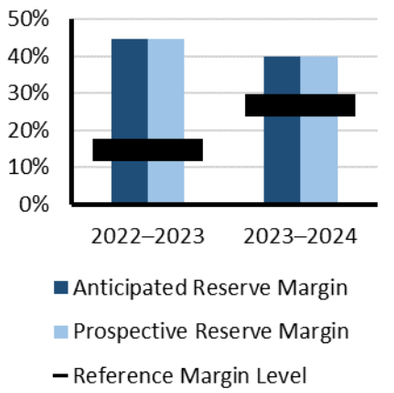
PJM

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

Highlights

- Installed capacity is significantly higher (13 percentage points) than PJM's Reserve Requirements. PJM does not expect to encounter resource problems for anticipated conditions over the 2023–2024 winter Peak season.
- A severe cold weather event that extends to the South can lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Forecasted peak demand has risen while resources have decreased since 2022 when Winter Storm Elliot caused energy emergencies in PJM and surrounding areas.

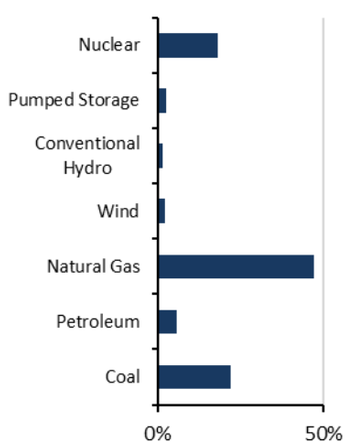
On-Peak Reserve Margin



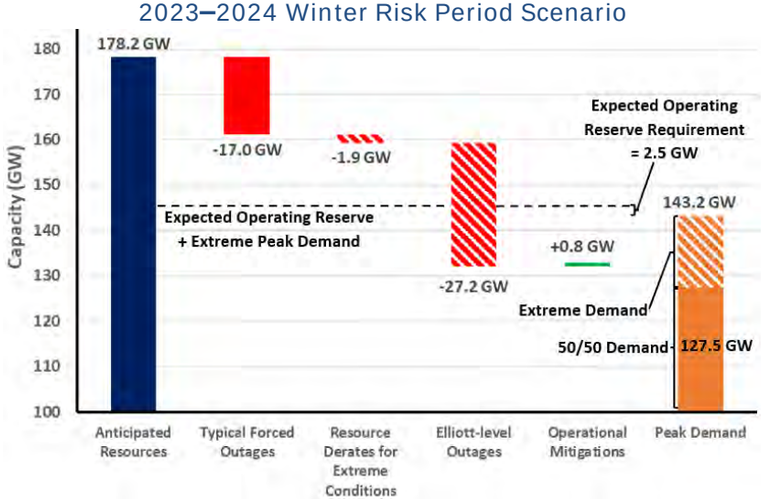
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed normal and extreme scenarios. Generator outages on a level of those experienced during Winter Storm Elliot would lead to energy emergencies.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Based on historical data and trending

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

Elliott-level Outages: Additional forced outages equal to the total MW capacity on outage due to freezing and fuel issues during winter storm Elliott in 2022.

Operational Mitigations: A total of 0.8 GW based on operational/emergency procedures

* See PJM Report *Winter Storm Elliott Event Analysis and Recommendations Report*, July 17, 2023, available here.



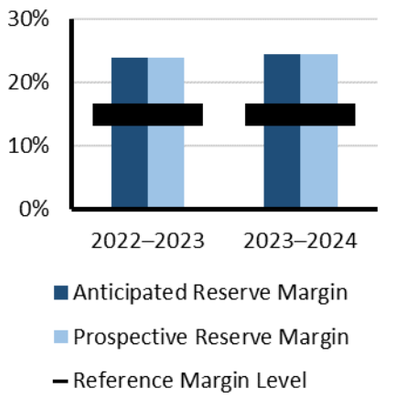
SERC-East

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

Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC East assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- The entities do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- Many entities have extensive weatherization processes that include developed procedures specific to freezing events. The entities are prepared to respond to unanticipated operational events and coordinate with neighboring entities to promote overall system reliability.

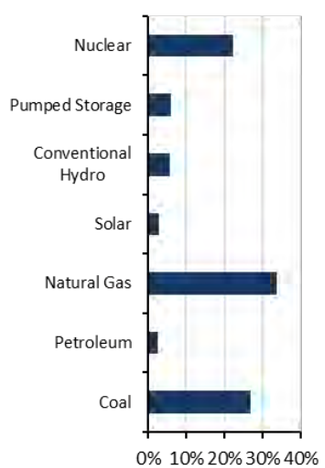
On-Peak Reserve Margin



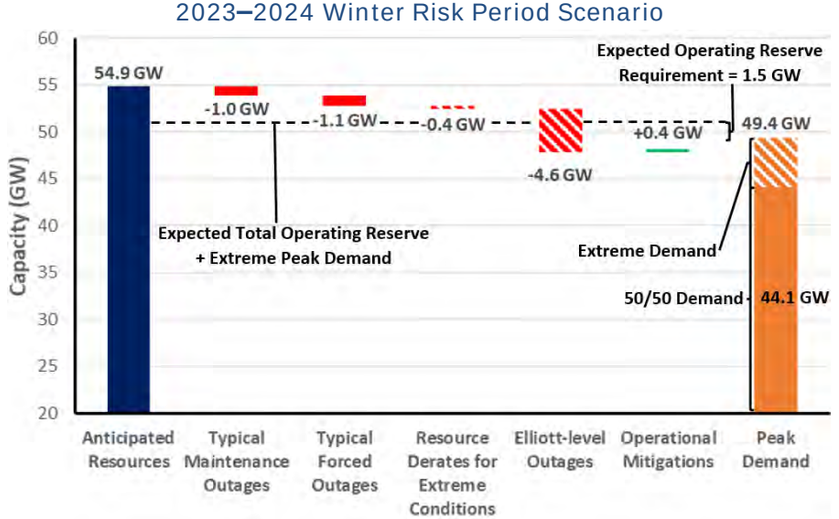
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. A severe cold weather event extending to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

Extreme Derates: Maximum historical generation outages (excluding 2022-2023)

Elliott-level Outages: Additional forced outages that, when added to the typical outage scenario, equal the total MW capacity on outage due to freezing and fuel issues during Winter Storm Elliott in 2022

Operational Mitigations: A total of 0.4 GW based on operational/emergency procedures



SERC-Central

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

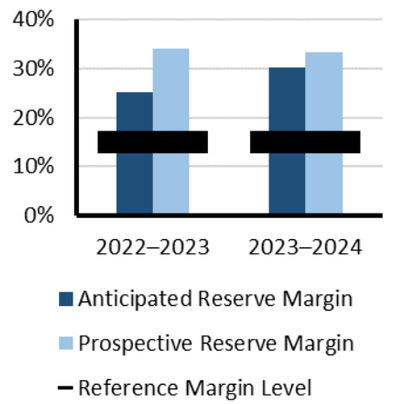
Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC-Central assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- While short-term issues (e.g., forced outages, colder than normal temperatures, or supply issues) around neighboring systems or natural gas pipelines are possibilities, the SERC-Central assessment area expects to maintain real-time operating reserves at all times. Therefore, SERC-Central does not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- SERC-Central has extensive weatherization processes that include developed procedures specific to freezing events. SERC-Central is prepared to respond to unanticipated operational events and coordinate with neighboring entities to promote overall system reliability.

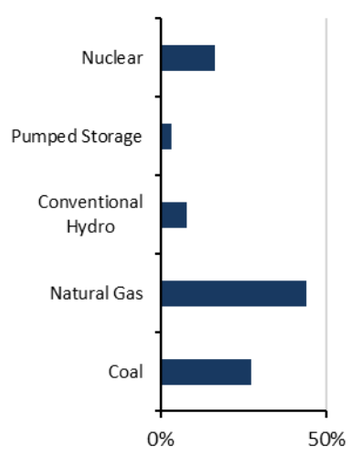
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. A severe cold weather event that extends to the South could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

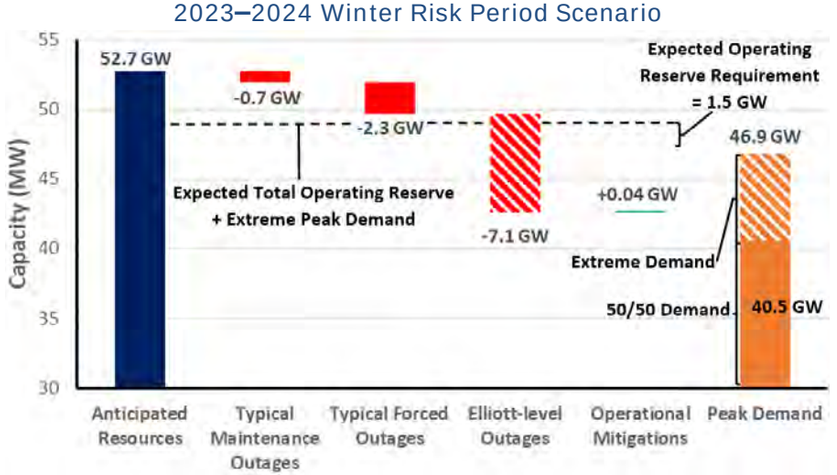
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Includes any weighted average forced outage rates on-peak that are not factored into the anticipated resources calculation

Elliott-level Outages: Additional forced outages that, when added to the typical outage scenario, equal the total MW capacity on outage due to freezing and fuel issues during Winter Storm Elliott in 2022

Operational Mitigations: A total of 0.04 GW based on operational/emergency procedures



SERC-Southeast

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

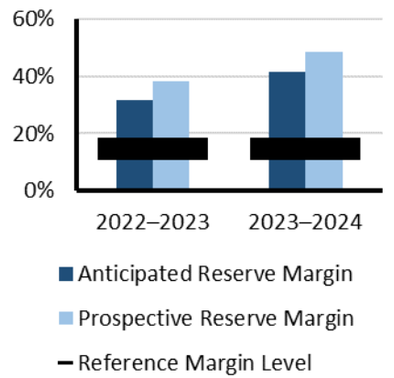
Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC-Southeast assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- The entities do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- Many entities have extensive weatherization processes that include developed procedures specific to freezing events. The entities are prepared to respond to unexpected, day-to-day events and coordinate with neighboring entities to promote overall system reliability.

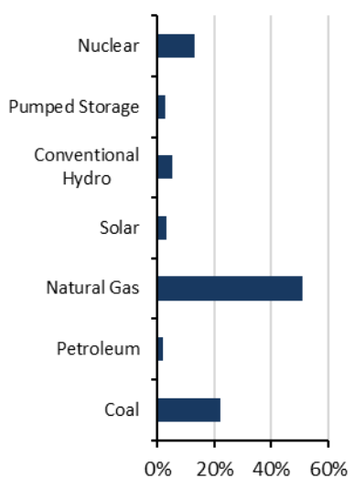
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

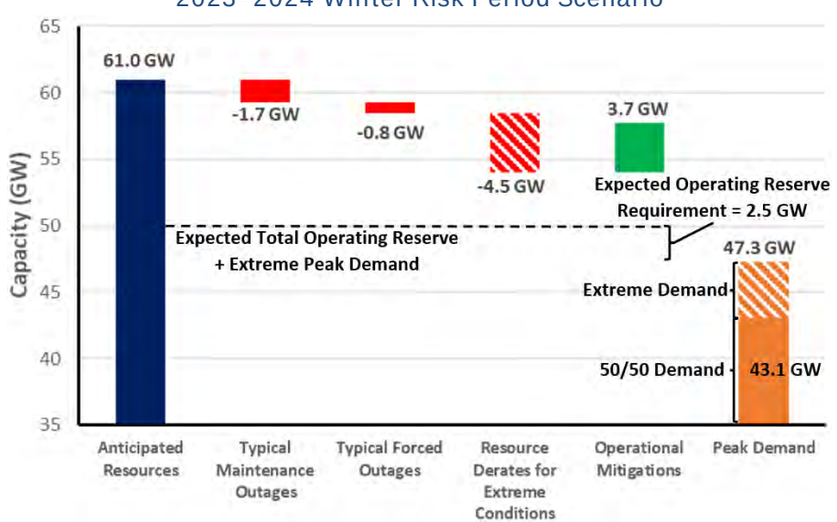
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 3.7 GW based on operational/emergency procedures



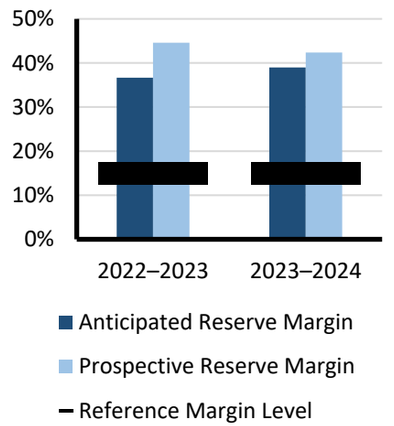
SERC-Florida Peninsula

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

Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC Florida-Peninsula assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- Although the entities do not currently anticipate reliability impacts in the upcoming winter season, some entities have expressed concerns about the difficulty of scheduling and receiving coal deliveries on a consistent basis, which would affect unit availability.
- The entities have performed a summary review of their winterization plans as well as the coordination of generation and transmission outages through the Florida Reliability Coordinating Council (FRCC) Operations PC and RC functions.

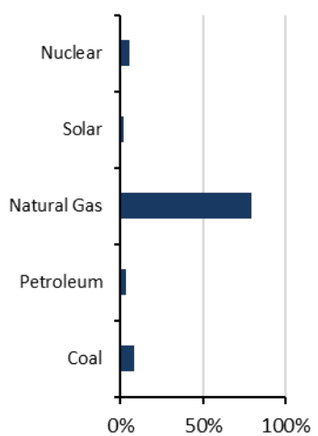
On-Peak Reserve Margin



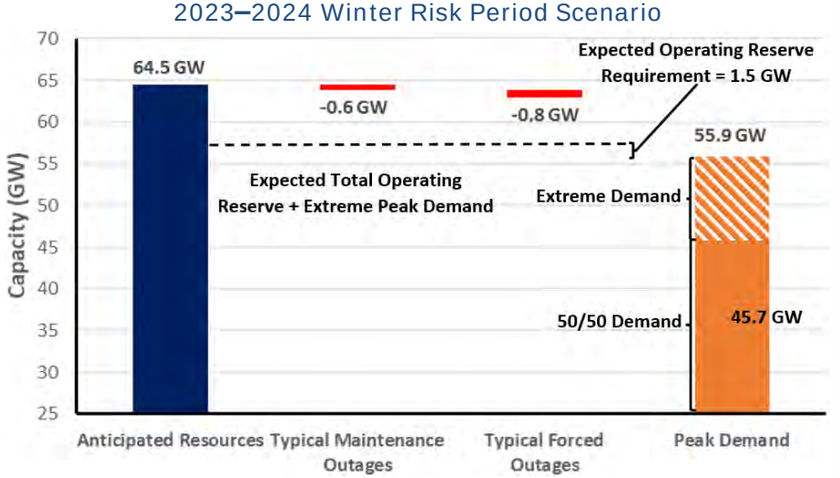
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation



SPP

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

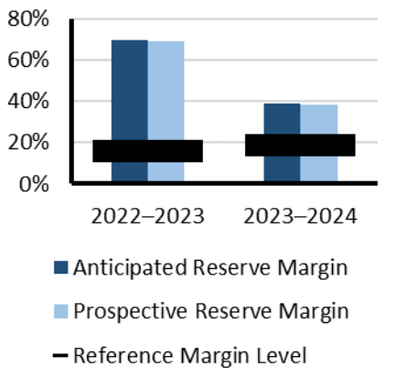
Highlights

- SPP anticipates that planning reserves are adequate for the upcoming winter season. Reserve margins have fallen this winter because of increased peak demand projections and declining anticipated resources.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2023–2024 winter season but realizes that interruptions to fuel supply could create unique operation challenges.
- SPP continues to work with neighboring areas to address potential electricity deliverability issues associated with extreme weather events. Efforts are aimed at enhancing communications and operator preparedness.
- To minimize conservative operations, EEAs, and the response to mid-range forecast error uncertainty in wind forecasts, SPP created some new mitigation processes to deal with high-impact areas of concern. SPP has developed operational mitigation teams, processes, and procedures that have been put in place to maintain real-time reliability needs.
- SPP created a Resource and Energy Adequacy Leadership Team that is addressing numerous resource adequacy initiatives that are addressing an expected unserved energy (EUE) standard, fuel assurance, winter requirements, winter PRM, outage policies, demand response, accreditation, and other areas of impact.
- SPP hosted its winter preparedness workshop in October 2023.

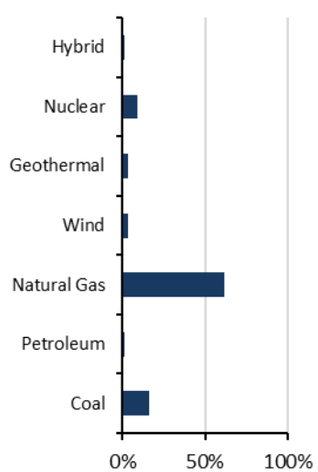
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

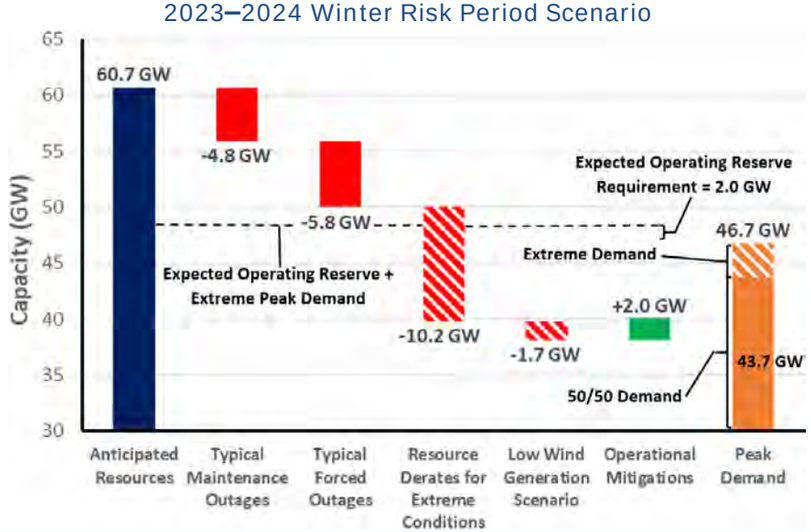
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast using historical data

Maintenance and Forced Outages: A capacity derate for maintenance outages, forced outages, and performance in extreme weather based on historical data

Extreme Derates: A capacity derate for generator performance in extreme weather based on historical data

Low Wind Scenario: 1.7 GW of wind potentially off-line when temperatures fall below their cold weather performance packages

Operational Mitigations: A total of 2 GW based on operational/emergency procedures (External Assistance)



Texas RE-ERCOT

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

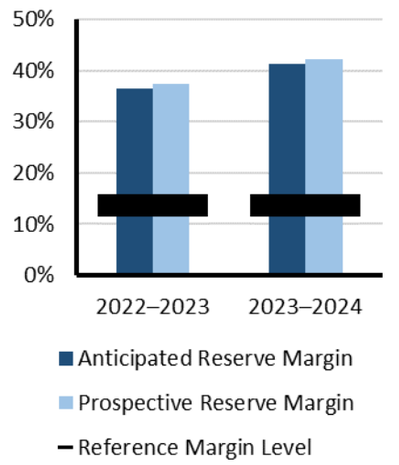
Highlights

- For the upcoming winter season, Texas RE-ERCOT will face reserve shortage risks during high net load hours. In winter, solar generation is not available to serve peak demand, making the system dependent on wind generation and dispatchable resource availability to serve load.
- Reserve scarcity risks are greater than last winter due primarily to robust load growth along with insufficient new dispatchable resources to serve the higher net peak loads.
- The area has also experienced a large increase in thermal units planned to be indefinitely mothballed to operate under a summer-only availability schedule; a loss of 1,283 MW of winter-rated capacity is expected.
- The risk of reserve shortages leading to EEA declarations has increased from “low” to “elevated” for hour-ending 8:00 a.m. based on ERCOT’s probabilistic risk assessment. ERCOT is investigating the option to procure additional capacity to reduce this reserve shortage risk on a competitive basis.
- ERCOT does not expect any significant fuel supply issues for the winter. However, fuel-related outages during Winter Storm Elliott (December 22–25, 2023) indicated that natural gas-fired generators that normally experience fuel restrictions during cold weather are expected to continue to face such restrictions. ERCOT’s new Firm Fuel Supply Service was deployed during this storm and is expected to partially offset the lost generation capacity due to these natural gas restrictions.
- ERCOT has observed increasing transmission congestion from South Texas to South-Central Texas (including the San Antonio area) that will limit transfers during the winter. A transmission project that includes a new 345 kV double circuit transmission line was recommended with an expected in-service date of June 2027 to address this congestion.

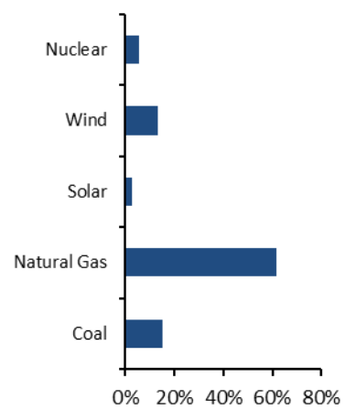
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

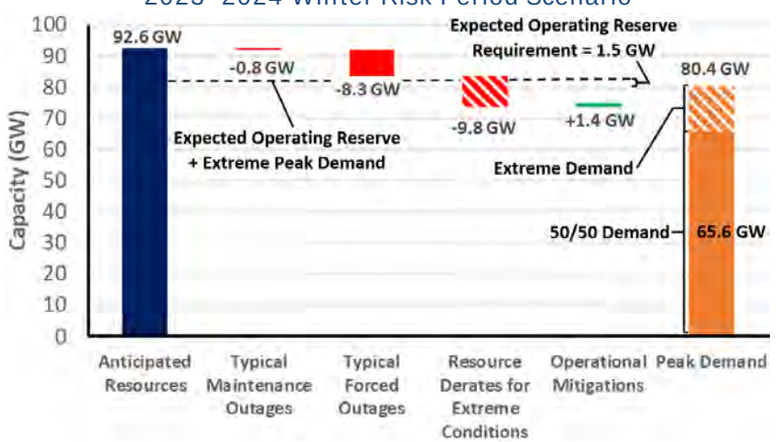
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme winter peak demand based on 2020–2021 Winter Storm Uri peak demand

Maintenance Outages: Based on historical winter data and consideration of ERCOT’s allowed maximum system daily planned outage capacity

Forced Outages: Based on the historical averages of maintenance or forced outages respectively for December through February weekdays, hours ending 7:00–10:00 a.m. local time for the last three (2020/2021, 2021/2022, and 2022/2023) winter seasons (Winter Storm Uri-related forced outages between February 15–18, 2021, were excluded from this calculation.)

Extreme Derates: Accounts for reduced thermal, wind, and solar PV capacity contributions due to performance in extreme conditions (uses averages from Winter Storm URI with adjustments to account for implemented weatherization improvements)

Operational Mitigations: Additional potential capacity from switchable generation and imports



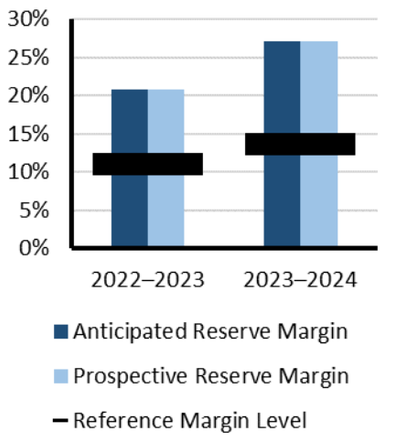
WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western U.S. states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

Highlights

- WECC-Alberta shows some risk highlighted by the risk period scenario; however, the area is expected to be able to be covered through imports if not islanded.
- WECC- Alberta's operating reserve margins are met before imports in all scenarios except the Low Wind Scenario, which leaves a gap of 0.5 GW, and the Extreme Combined Scenario, which leaves a gap of 1.0 GW under extreme peak demand conditions. Both of these scenarios are anticipated to be able to be covered through imports. WECC-Alberta is a winter-peaking area and did see a few EEA-3s last season due to a combination of extreme demand peaks from cold temperatures, low wind, and the loss of a baseload unit.

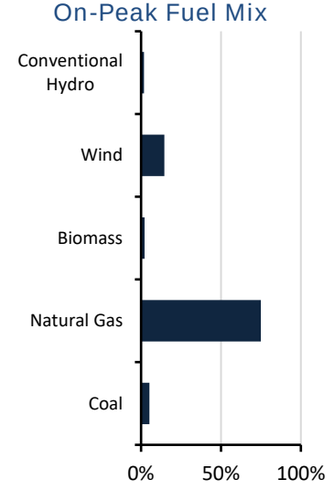
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output



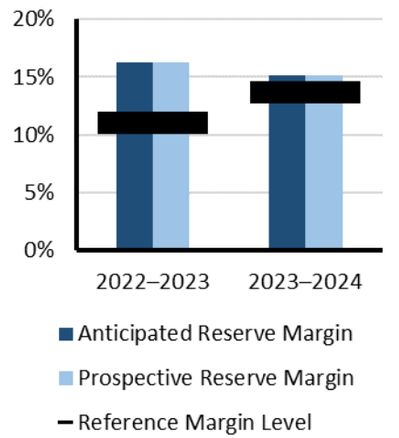
WECC-British Columbia

WECC-British Columbia is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

Highlights

- WECC-British Columbia has adequate resources for anticipated winter conditions. If peak demand exceeds normal forecasts or hydroelectric generation is lower than normal, non-firm imports may be needed to meet required operating reserves.
- WECC-British Columbia could require a range of import levels for extreme demand or low-resource scenarios. For expected demand, the area falls short of its operating reserve requirements if hydro output is abnormally low (low likelihood scenario). During the Extreme Peak Demand Scenario (90th percentile), operating reserve margins fall short by 0.6 GW with anticipated resources and could increase for more extreme outages or low-hydro scenarios. Sufficient imports from neighbors in the Western Interconnection are expected to be available, provided that BC does not become electrically islanded.

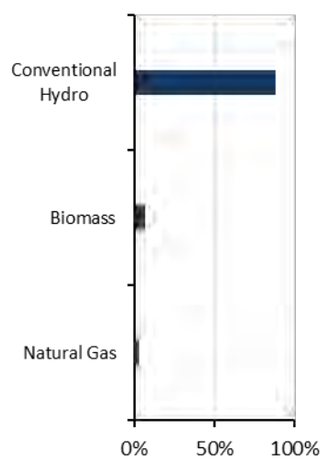
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output



WECC-California/Mexico

WECC-Californica/Mexico is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

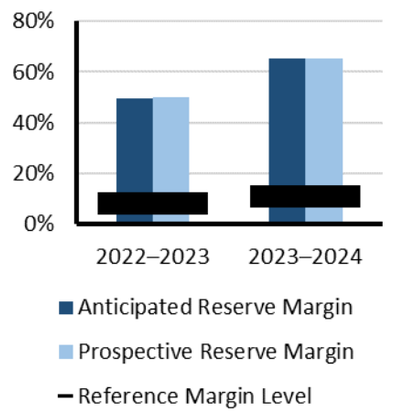
Highlights

- WECC-Californica/Mexico shows adequate energy availability under both expected and extreme scenarios.

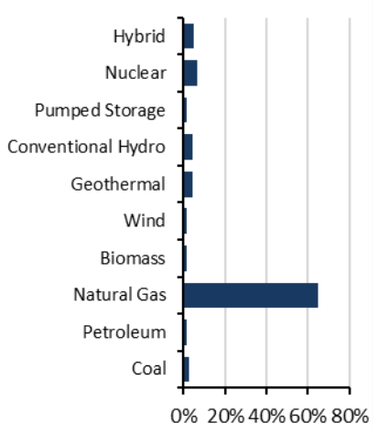
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

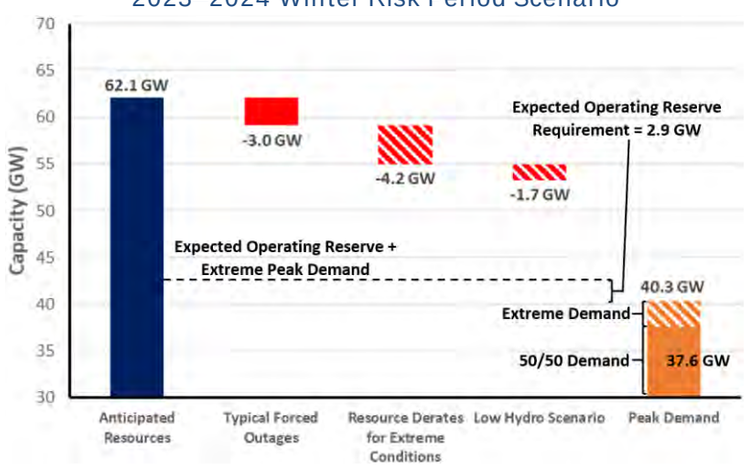
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output



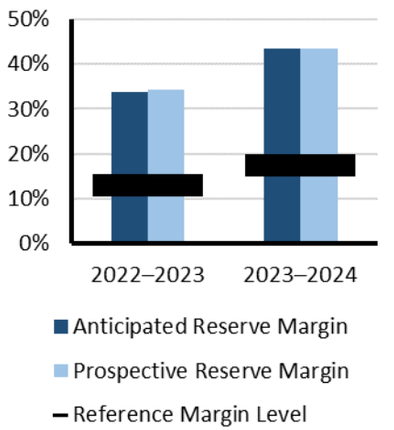
WECC-Northwest

WECC-Northwest is a summer-peaking assessment area in the WECC Regional Entity that includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

Highlights

- WECC-Northwest shows some risk highlighted by the risk period scenario; however, the area is expected to be able to be covered through imports.
- WECC-Northwest has historically been a mixed-season peaking area. Operating reserve margins are met at the expected peak demand hour under all but the Extreme Combined Scenario, where 5.3 GW of imports would be needed to meet operating reserve margins at an expected peak demand (50th percentile) and 10 GW for an extreme peak load level (90th percentile). Depending on the situation in neighboring areas, imports are expected to be available to fill the gap.

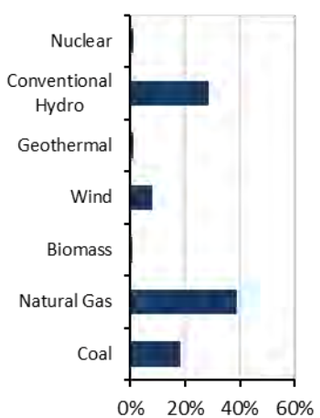
On-Peak Reserve Margin



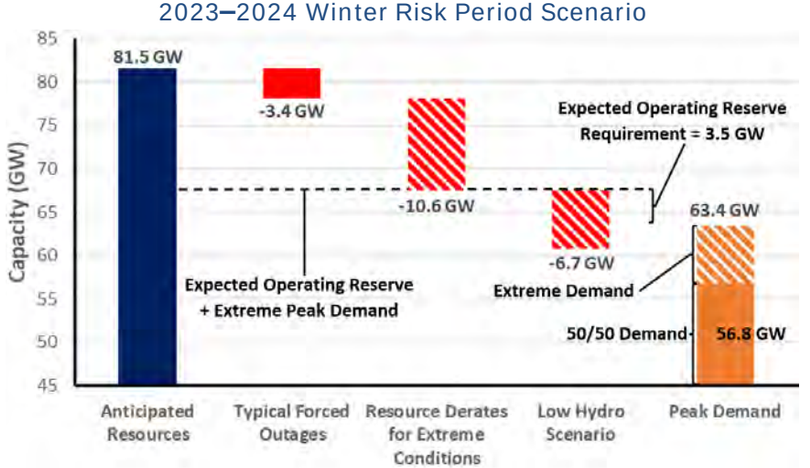
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output



WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the WECC Regional Entity that includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

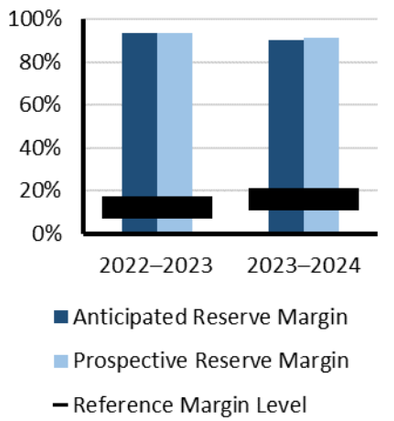
Highlights

- WECC-Southwest shows adequate energy availability under both expected and extreme scenarios.

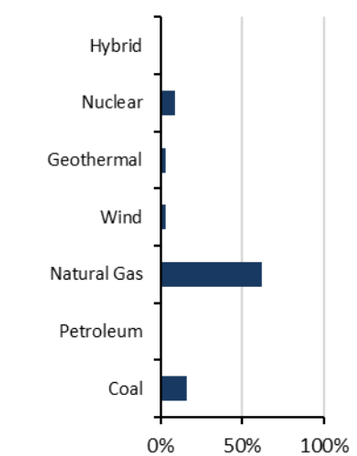
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

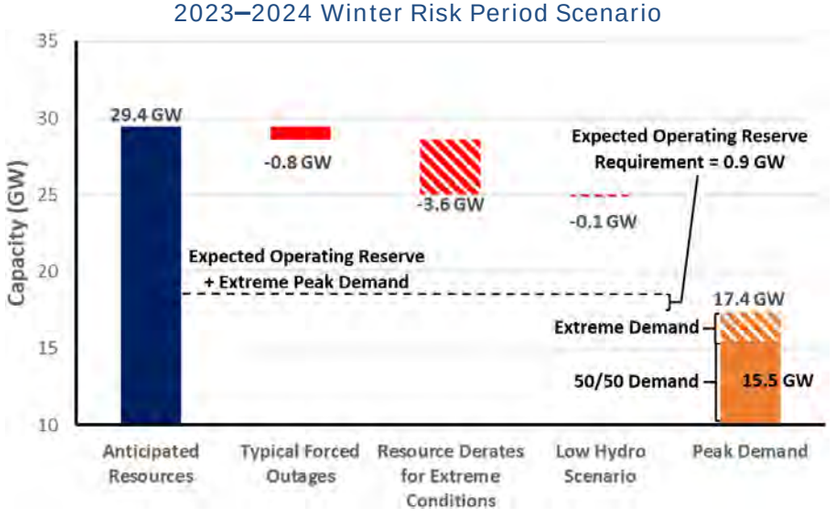
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output

Data Concepts and Assumptions

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

General Assumptions
• The reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electricity system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• *2023 Long-Term Reliability Assessment* data has been used for most of this 2023–2024 assessment period augmented by updated load and capacity data provided by Regional Entities and assessment areas.
• A positive net transfer capability would indicate a net-importing assessment area, a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[5] or total internal demand for the summer and winter of each year.[6]
• Total internal demand projections are based on normal weather (50/50 distribution[7]) and are provided on a coincident[8] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

[5] *Glossary of Terms* used in NERC Reliability Standards

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

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

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

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the winter season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

Prospective Resources: This includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

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

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

Seasonal Risk Scenario Chart Description

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

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

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

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

Resource Adequacy

The ARM, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[9] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. NPCC-Maritimes marginally does not meet their RML for the upcoming winter. Other than NPCC-Maritimes, all assessment areas have sufficient ARMs to meet or exceed their Reference Margin Level for the 2023 winter as shown in **Figure 4**.

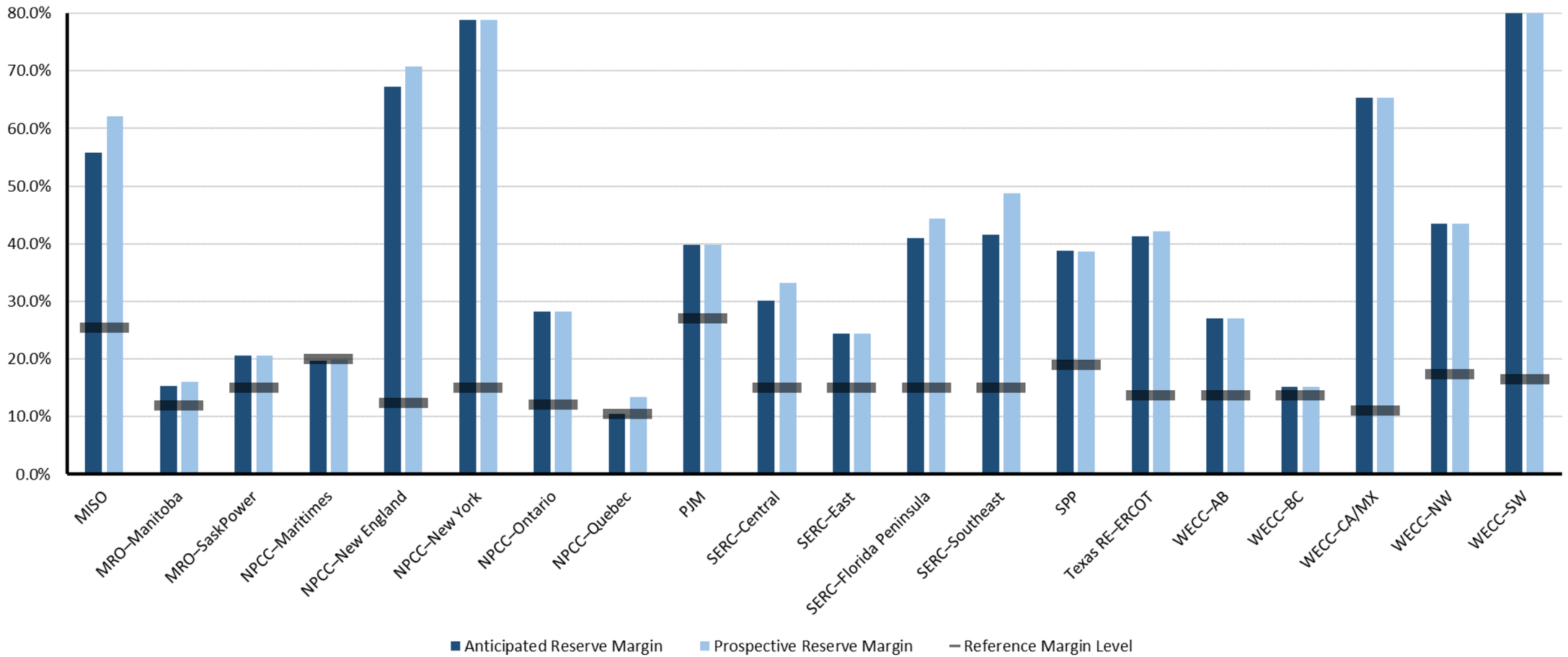


Figure 4: Winter 2023–2024 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

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

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast Anticipated Reserve Margins (ARM) from the 2022–2023 winter to the 2023–2024 winter. Note that the Reference Margin Level is unchanged for areas that don't have a 2022–2023 Reference Margin Level shown. A significant decline can indicate potential operational issues that emerge between reporting years. MRO-Manitoba, MRO-SaskPower, NPCC-Québec, and WECC-BC have noticeable reductions in anticipated resources between the 2022–2023 winter and the 2023–2024 winter. All areas except NPCC-Maritimes remain above their Reference Margin Levels for 2023–2024 winter. NPCC-Québec is marginally above its Reference Margin Level. The lower ARMs for MRO-Manitoba, MRO-SaskPower, NPCC-Québec, and WECC-BC do not result in reliability concerns during expected conditions for this upcoming winter. The Canadian winter-peaking systems of MRO-Manitoba, MRO-SaskPower, NPCC-Maritimes and NPCC-Québec have reserve margins that are near Reference Margin Levels but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the **Data Concepts and Assumptions** section.

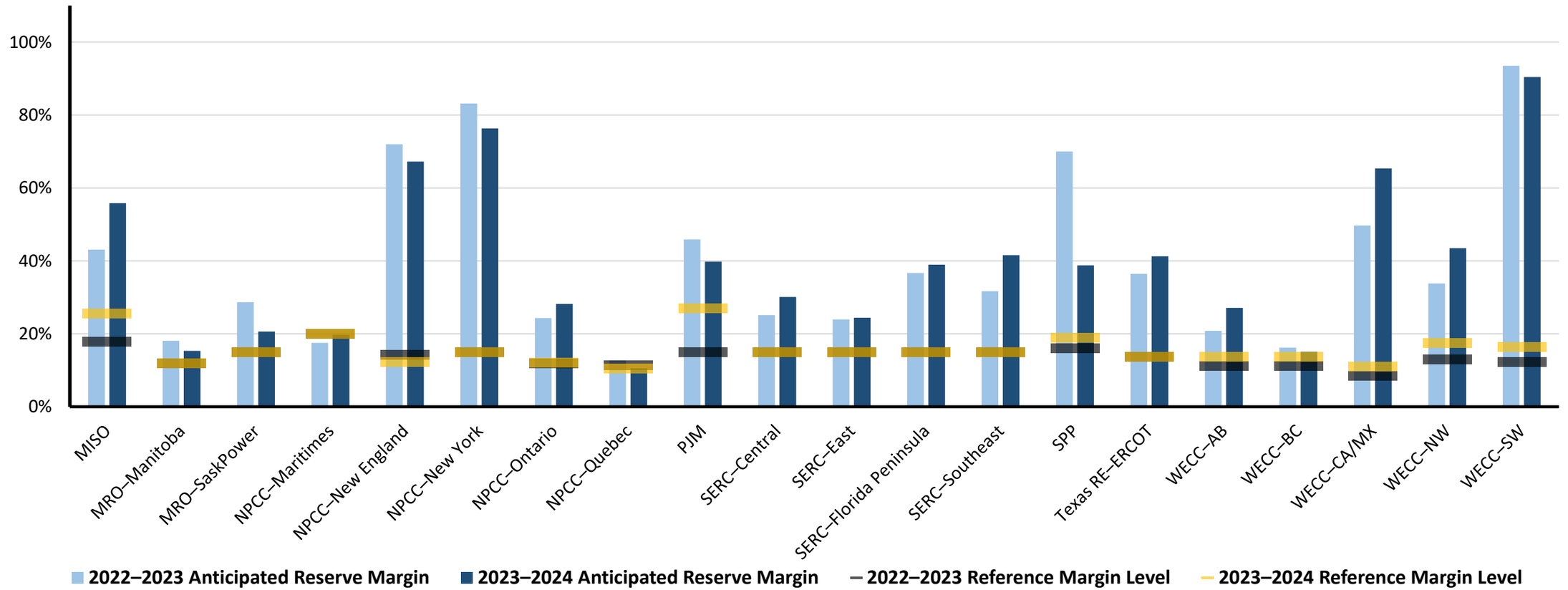


Figure 5: Winter 2022–2023 and Winter 2023–2024 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in **Figure 6**.[10] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections. Most assessment areas are showing increasing demand for the upcoming winter compared with the last WRA.

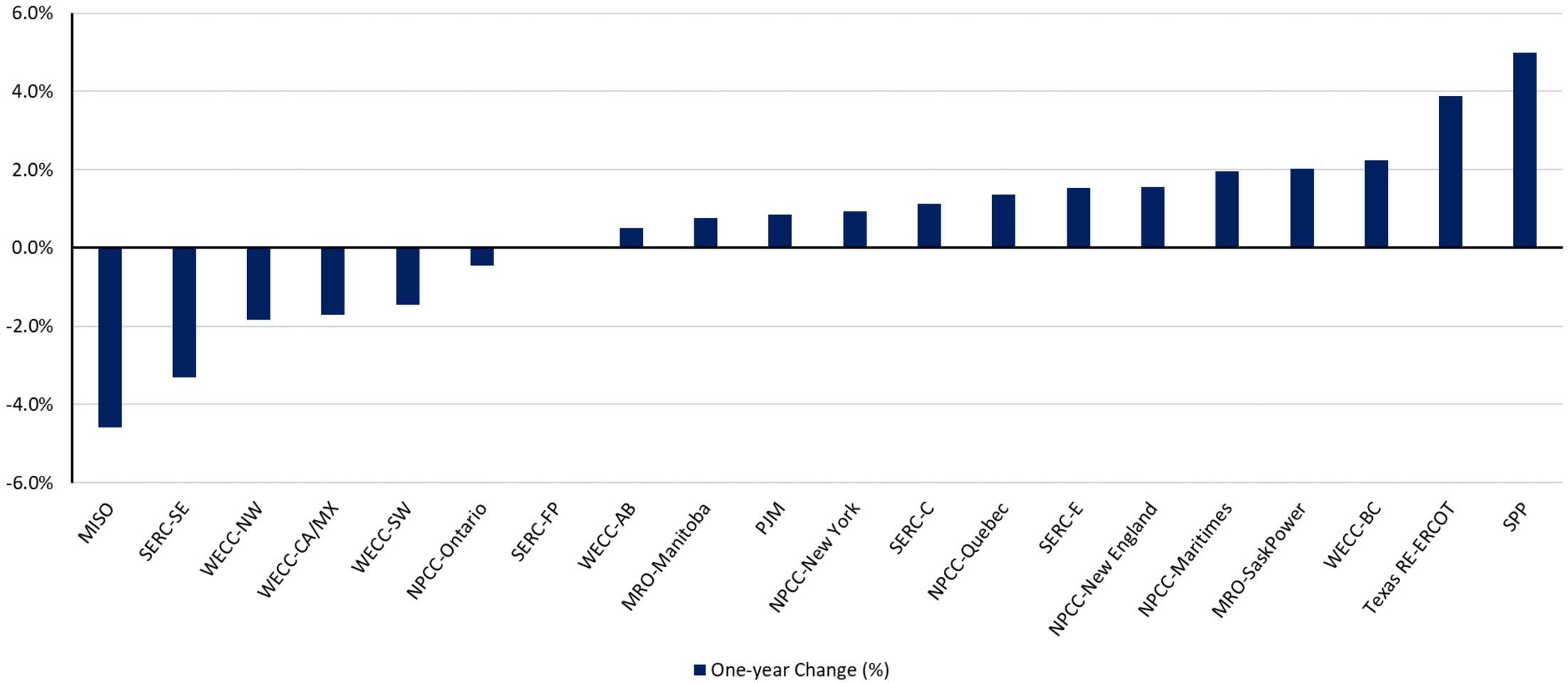


Figure 6: Change in Net Internal Demand—Winter 2022–2023 Forecast Compared to Winter 2023–2024 Forecast

[10] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Demand and Resource Tables

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

MISO			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	102,611	102,075	0.5%
Demand Response: Available	3,672	7,681	109.2%
Net Internal Demand	98,939	94,394	-4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	137,926	146,976	6.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,352	121	91.1%
Anticipated Resources	141,565	147,097	3.9%
Existing-Other Capacity	669	2,614	290.8%
Prospective Resources	148,125	153,003	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	43.1%	55.8%	12.7
Prospective Reserve Margin	49.7%	62.1%	12.4
Reference Margin Level	17.9%	25.5%	7.6

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,588	4,623	0.8%
Demand Response: Available	0	0	-
Net Internal Demand	4,588	4,623	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,705	5,864	2.8%
Tier 1 Planned Capacity	279	90	-67.8%
Net Firm Capacity Transfers	-566	-622	9.9%
Anticipated Resources	5,418	5,332	-1.6%
Existing-Other Capacity	33	36	9.5%
Prospective Resources	5,451	5,368	-1.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.1%	15.3%	-2.8
Prospective Reserve Margin	18.8%	16.1%	-2.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,781	3,839	1.5%
Demand Response: Available	67	50	-25.4%
Net Internal Demand	3,714	3,789	2.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,488	4,320	-3.8%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	250	-13.8%
Anticipated Resources	4,778	4,570	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	4,778	4,570	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.7%	20.6%	-8.1
Prospective Reserve Margin	28.7%	20.6%	-8.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	5,784	5,863	1.4%
Demand Response: Available	282	264	-6.4
Net Internal Demand	5,502	5,599	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,461	6,622	2.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	4	81	1925.0%
Anticipated Resources	6,465	6,703	3.7%
Existing-Other Capacity	0	0	-
Prospective Resources	6,465	6,703	3.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.5%	19.7%	2.2
Prospective Reserve Margin	17.5%	19.7%	2.2
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,009	20,269	1.3%
Demand Response: Available	610	570	-6.6%
Net Internal Demand	19,399	19,699	1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	32,129	31,795	-1.0%
Tier 1 Planned Capacity	162	187	15.2%
Net Firm Capacity Transfers	1,070	958	-10.5%
Anticipated Resources	33,361	32,940	-1.3%
Existing-Other Capacity	142	201	42.1%
Prospective Resources	33,769	33,641	-0.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	72.0%	67.2%	-4.8
Prospective Reserve Margin	74.1%	70.8%	-3.3
Reference Margin Level	14.3%	12.3%	-2.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,893	24,220	1.4%
Demand Response: Available	695	803	15.5%
Net Internal Demand	23,198	23,417	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,393	39,697	-1.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,097	1,589	-24.2%
Anticipated Resources	42,490	41,285	-2.8%
Existing-Other Capacity	0	0	-
Prospective Resources	42,490	41,285	--2.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	83.2%	76.3%	-6.9
Prospective Reserve Margin	83.2%	76.3%	-6.9
Reference Margin Level	15.0%	15.0%	-4.6

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,255	21,402	0.7%
Demand Response: Available	614	853	39.0%
Net Internal Demand	20,641	20,549	-0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,051	26,301	1.0%
Tier 1 Planned Capacity	112	24	-78.6%
Net Firm Capacity Transfers	-500	17	-103.4%
Anticipated Resources	25,662	26,342	2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	25,662	26,342	2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	28.2%	3.9
Prospective Reserve Margin	24.3%	28.2%	3.9
Reference Margin Level	11.8%	12.0%	0.2

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	39,699	40,642	2.4%
Demand Response: Available	2,759	2,914	5.6%
Net Internal Demand	37,217	37,728	1.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	42,113	42,423	0.7%
Tier 1 Planned Capacity	255	0	-100.0%
Net Firm Capacity Transfers	-417	-726	74.1%
Anticipated Resources	41,951	41,697	-0.6%
Existing-Other Capacity	0	0	-
Prospective Resources	43,051	42,797	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.7%	10.5%	-2.2
Prospective Reserve Margin	15.7%	13.4%	-2.3
Reference Margin Level	11.3%	10.5%	-0.8

PJM			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	132,980	132,667	-0.2%
Demand Response: Available	6,583	5,189	-21.2%
Net Internal Demand	126,397	127,478	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	185,102	179,060	-3.3%
Tier 1 Planned Capacity	0	0	0%
Net Firm Capacity Transfers	-726	-872	20.1%
Anticipated Resources	184,376	178,188	-3.4%
Existing-Other Capacity	0	0	-
Prospective Resources	184,376	178,188	-3.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	45.9%	39.8%	-6.1
Prospective Reserve Margin	45.9%	39.8%	-6.1
Reference Margin Level	14.9%	27.0%	12.1

SERC-East			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	44,648	45,044	0.9%
Demand Response: Available	1,180	912	-22.7%
Net Internal Demand	43,468	44,132	1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	53,287	54,229	1.8%
Tier 1 Planned Capacity	75	55	-26.6%
Net Firm Capacity Transfers	513	624	21.6%
Anticipated Resources	53,875	54,908	1.9%
Existing-Other Capacity	3	3	0.0%
Prospective Resources	53,877	54,910	1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.9%	24.4%	0.5
Prospective Reserve Margin	23.9%	24.4%	0.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	41,745	42,282	1.3%
Demand Response: Available	1,671	1,753	4.9%
Net Internal Demand	40,074	40,529	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,008	50,196	-1.6%
Tier 1 Planned Capacity	0	1,386	-
Net Firm Capacity Transfers	-868	1,145	-231.9%
Anticipated Resources	50,140	52,727	5.2%
Existing-Other Capacity	3,601	1,255	-65.1%
Prospective Resources	53,741	54,002	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.1%	30.1%	5.0
Prospective Reserve Margin	34.1%	33.2%	-0.9
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,582	48,470	-0.2%
Demand Response: Available	2,870	2,753	-4.1%
Net Internal Demand	45,712	45,717	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	61,987	62,679	0.8%
Tier 1 Planned Capacity	237	344	522.2%
Net Firm Capacity Transfers	250	509	103.6%
Anticipated Resources	62,474	63,531	3.2%
Existing-Other Capacity	3,618	1,563	-56.8%
Prospective Resources	66,092	65,094	-0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.7%	39.0%	4.3
Prospective Reserve Margin	44.6%	42.4%	-0.2
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,513	45,101	-3.0%
Demand Response: Available	1,954	2,018	3.3%
Net Internal Demand	44,559	43,083	-3.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	60,097	60,640	-0.8%
Tier 1 Planned Capacity	1,102	1,165	105.6%
Net Firm Capacity Transfers	-2,524	-815	-67.7%
Anticipated Resources	58,674	60,990	3.9%
Existing-Other Capacity	2,895	3,090	6.8%
Prospective Resources	61,569	64,081	4.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.7%	41.6%	9.9
Prospective Reserve Margin	38.2%	48.7%	10.5
Reference Margin Level	15.0%	15.0%	0.0

SPP			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	41,650	43,996	5.6%
Demand Response: Available	13	278	2006.1%
Net Internal Demand	41,637	43,718	5.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,131	61,173	-14.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-359	-498	-38.4%
Anticipated Resources	70,772	60,676	-14.3%
Existing-Other Capacity	0	0	-
Prospective Resources	70,496	60,630	-14.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	70.0%	38.8%	-31.2
Prospective Reserve Margin	69.3%	38.7%	-30.6
Reference Margin Level	16.0%	19.0%	3.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	66,436	70,451	6.0%
Demand Response: Available	3,302	4,868	47.4%
Net Internal Demand	63,134	65,583	3.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	85,478	92,387	8.1%
Tier 1 Planned Capacity	644	228	-64.6%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	86,142	92,635	7.5%
Existing-Other Capacity	0	0	-
Prospective Resources	86,710	93,203	7.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.4%	41.2%	4.8
Prospective Reserve Margin	37.3%	42.1%	4.8
Reference Margin Level	13.75%	13.75%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,901	11,961	0.5%
Demand Response: Available	0	0	-
Net Internal Demand	11,901	11,961	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,144	13,694	4.2%
Tier 1 Planned Capacity	1,234	1511	22.5%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	14,378	15,205	5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	14,378	15,205	5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.8%	27.1%	6.3
Prospective Reserve Margin	20.8%	27.1%	6.3
Reference Margin Level	11.1%	13.7%	2.6

WECC-BC			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,395	11,651	2.2%
Demand Response: Available	0	0	-
Net Internal Demand	11,395	11,651	2.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,223	13,166	-0.4%
Tier 1 Planned Capacity	20	134	574.4%
Net Firm Capacity Transfers	0	110	-
Anticipated Resources	13,243	13,410	1.3%
Existing-Other Capacity	0	0	-
Prospective Resources	13,243	13,410	1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	16.2%	15.1%	-1.1
Prospective Reserve Margin	16.2%	15.1%	-1.1
Reference Margin Level	11.1%	13.7%	2.6

WECC-CA/MX			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	38,978	38,328	-1.7%
Demand Response: Available	749	755	0.9%
Net Internal Demand	38,230	37,573	-1.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,287	56,405	2.0%
Tier 1 Planned Capacity	1,943	5400	177.9%
Net Firm Capacity Transfers	0	315	-
Anticipated Resources	57,231	62,120	8.5%
Existing-Other Capacity	0	0	-
Prospective Resources	57,326	62,136	8.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	49.7%	65.3%	15.6
Prospective Reserve Margin	50.0%	65.4%	15.4
Reference Margin Level	8.4%	11.0%	2.6

WECC-NW			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	58,605	57,408	-2.0%
Demand Response: Available	707	578	-18.3%
Net Internal Demand	57,898	56,829	-1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	76,477	77,389	1.2%
Tier 1 Planned Capacity	988	2188	121.4%
Net Firm Capacity Transfers	0	1,964	-
Anticipated Resources	77,465	81,541	5.3%
Existing-Other Capacity	0	0	-
Prospective Resources	77,730	81,558	4.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.8%	43.5%	9.7
Prospective Reserve Margin	34.3%	43.5%	9.2
Reference Margin Level	13.1%	17.4%	4.3

WECC-SW			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	16,004	15,743	-1.6%
Demand Response: Available	318	285	-10.6%
Net Internal Demand	15,686	15,458	-1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	29,799	28,306	-5.0%
Tier 1 Planned Capacity	553	1129	104.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	30,352	29,435	-3.0%
Existing-Other Capacity	0	0	-
Prospective Resources	30,352	29,587	-2.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	93.5%	90.4%	-3.1
Prospective Reserve Margin	93.5%	91.4%	-2.1
Reference Margin Level	12.2%	16.4%	4.2

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. In many areas, winter demand peaks in the early morning hours or other times of darkness, resulting in little or no electrical resource output from solar PV resources. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS.

BPS Variable Energy Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind (MW)	Expected Wind (MW)	Expected Share of Nameplate (%)	Nameplate Solar PV (MW)	Expected Solar (MW)	Expected Share of Nameplate (%)	Nameplate Hydro (MW)	Expected Hydro (MW)	Expected Share of Nameplate (%)
MISO	26,082	9,683	37%	2,559	130	5%	4,884	4,688	96%
MRO-Manitoba Hydro	259	52	20%	0	0	0%	6,220	5,548	89%
MRO-SaskPower	615	124	20%	0	0	0%	851	797	94%
NPCC-Maritimes	1,207	261	22%	42	0	0%	1,312	1,180	90%
NPCC-New England	1,463	397	27%	107	1	1%	3,565	2,472	69%
NPCC-New York	2,720	870	32%	154	13	9%	6,731	5,067	75%
NPCC-Ontario	4,943	1,433	29%	0	0	0%	8,985	5,185	58%
NPCC-Québec	3,820	1,375	36%	-	10	-	40,307	32,974	82%
PJM	11,992	3,695	31%	0	0	0%	3,027	3,027	100%
SERC-Central	28	8	28%	774	230	30%	4,967	3,315	67%
SERC-East	0	0	0%	6,245	1,483	24%	3,064	3,013	98%
SERC-Florida Peninsula	0	0	0%	3,499	1,264	36%	-	-	0%
SERC-Southeast	0	0	0%	5,234	1,889	36%	3,288	3,288	100%
SPP	33,120	6,856	21%	351	118	34%	5,465	4,996	91%
Texas RE-ERCOT	37,974	11,910	31%	16,403	2,547	16%	563	477	85%
WECC-AB	4,931	2,221	45%	0	0	0%	894	416	47%
WECC-BC	747	111	15%	0	0	0%	16,519	10,124	61%
WECC-CA/MX	9,443	848	9%	0	0	0%	13,957	4,606	33%
WECC-SW	3,121	994	32%	2,494	103	4%	1,202	844	70%
WECC-NW	20,697	6,319	31%	0	0	0%	41,860	22,752	54%
EASTERN INTERCONNECTION	120,404	35,318	29%	26,673	7,676	29%	52,316	42,578	81%
QUÉBEC INTERCONNECTION	3,820	1,375	36%	-	10	-	40,307	32,974	82%
TEXAS INTERCONNECTION	37,974	11,910	31%	16,403	2,547	16%	563	477	85%
WECC INTERCONNECTION	38,940	10,494	27%	2,494	103	4%	74,432	38,742	52%
INTERCONNECTION TOTAL:	**201,137**	**59,098**	**29%**	**45,579**	**10,337**	**23%**	**167,618**	**114,771**	**68%**

Probabilistic Assessment

Regional Entities and assessment areas provided a resource adequacy risk assessment that was probability-based for the winter season. Results are summarized in the table below.[11] The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include loss of load expectation (LOLE), loss of load hours (LOLH), EUE, and the probabilities of EEA occurrence.

Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
MRO-Manitoba	Verification of NERC 2022 Probabilistic Assessment (2022 ProbA)	The annual probabilistic statistics for model year 2024 for the 2022 Probabilistic Assessment (ProbA) show: • Base Case: 29 MWh per year of EUE • Risk Scenario (10th percentile water flow conditions): 477 MWh per year of EUE An expected unserved energy in the 29 to 477 MWh range is a reasonable estimate for the winter 2023–2024 based on the 2022 NERC ProbA Base Case for the year 2024 given comparable loads and resources, and that water flow conditions are, as of late summer 2023, below average but still above the 10th percentile.
MRO-SaskPower	Probability-based capacity adequacy assessment	Results indicate that the expected number of hours with operating reserve deficiency for the 2023–2024 winter season is 0.31 hours. The estimated probability of having generation forced outages of 350 MW or greater in the winter season is 11.2%. A Risk of supply shortfall exists when generation forced outages at this level coincide with periods of high demand.
NPCC	NPCC conducted an all-hour probabilistic reliability assessment that consisted of a base case and severe case examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring. Preliminary results are included in this table. NPCC will publish final probabilistic assessment results in December. [12]	The assessment forecasts that the NPCC Regional Entity will have an adequate supply of electricity this winter and a low risk of disconnecting load. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Results of the probabilistic analysis by assessment area are below. The assessment evaluates the probabilistic indices of LOLE, LOLH and EUE.
NPCC-Maritimes		NPCC's assessment preliminary results indicate that operating procedures are sufficient to maintain a balance between electricity supply and demand, if needed. Only the low likelihood reduced resource case, highest peak load scenario resulted in an estimated cumulative LOLE risk of ~0.1 days/period, with associated LOLH (<1 hour/period) and EUE (10.6 MWh) over the November–March winter period. The Maritimes area low likelihood resource case assumed that wind capacity would be de-rated by half (1,200 to 600 MW) for every hour in December through February to simulate icing conditions and a 50% natural gas capacity curtailment (610 to 305 MW) to simulate a reduction in gas supply for December through February (dual fuel units assumed reverting to oil) and reduced transfer capabilities.

[11] A probabilistic assessment for the 2023-2024 winter is not available for SPP at the time of publication. SPP's 2023 Loss of Load Expectation (LOLE) Study incorporates modeling assumptions based on recent winter events. SPP expects to complete the study prior to the end of 2023. For more information see the study scope document here: **2023 LOLE Scope**

[12] Based on October 2023 revised results. The final NPCC 2023–2024 Winter Reliability Assessment be available in December 2023.

Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-New England		NPCC's assessment preliminary results indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the November–March winter period, for all the scenarios modeled. The New England Area low likelihood resource case assumed 500 MW of additional maintenance outages, ~4,817 MW of gas-fired generation unavailable due to fuel supply constraints, and 50% reduced import capabilities of external ties (i.e., 1,850 MW total). The NPCC Probabilistic Assessment did not evaluate a prolonged, extreme cold weather event that threatens to exhaust stored liquid fuels.
NPCC-New York		NPCC's assessment preliminary results indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the November–March winter period for all the scenarios modeled.
NPCC-Ontario		NPCC's assessment preliminary results indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the November–March winter period for all the scenarios modeled.
NPCC-Québec		NPCC's assessment preliminary results indicate that operating procedures are sufficient to maintain a balance between electricity supply and demand, if needed. Only the low likelihood reduced resource case, highest peak load scenario resulted in an estimated cumulative LOLE risk of ~0.1 days/period, with associated LOLH (<1 hour/period) and EUE (92.7 MWh) over the November–March winter period. The Québec Area low likelihood resource case assumed: 1,000 MW of generation reductions.
PJM	Based on 2022 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves. PJM forecasts a 40% installed reserve margin, well above the target of 27%. The RRS analyzed a wide range of load scenarios (low, regular and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages and ambient derations. The RRS report was also influenced by the extreme weather experienced in December of 2022. NERC assesses an elevated risk of energy shortfall for the upcoming winter due to the potential for a weather event on the scale of Winter Storm Elliott to cause similar generation outages from fuel and winterization issues.
SERC	Verification of NERC 2022 ProbA Results	The 2022 Base Case results indicated adequate resources for the SERC Regional Entity. The base case did not include high-outage conditions similar to those experienced during Winter Storm Elliott.
Texas RE-ERCOT	ERCOT Probabilistic Reserve Risk Model	There is a 11.6% probability that ERCOT will declare an EEA1 during the highest-risk hour ending at 8:00 am. The Probabilistic Reserve Risk Model, which performs Monte Carlo simulations, determines the probability that capacity available for operating reserves for a seasonal peak load day is at or below the various EEA risk thresholds.
WECC	The 2022 Western Assessment of Resource Adequacy provides the most recent probability-based resource adequacy risk assessment for Summer 2023 across WECC's areas.	The Western Interconnection is experiencing heightened reliability risks heading into Summer 2023 due to increased supply-side shortages and fuel constraints along with ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events. The installation of new resources for the summer and the availability of the imports, especially during wide-area heat events, affects resource adequacy for the U.S. assessment areas. The reliability and resource adequacy of the Western Interconnection depends on the ability to move power throughout the footprint.
WECC-AB		Alberta is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile. When wind output is below average, imports are likely to be needed to meet operating reserves for normal and above-normal peak demand.

Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-BC		BC is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile. When hydroelectric generation output is below average, imports are likely to be needed to meet operating reserves for normal and above-normal peak demand.
WECC-CA/MX		WECC-CA/MX is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile.
WECC-NW		WECC-NW is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile. In a scenario involving high thermal generation outages, low wind output, and low hydroelectric generation output, imports are likely to be needed to meet operating reserves for normal and above-normal peak demand.
WECC-SW		WECC-SW is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile.

Errata

December 2023

- Updated On-Peak Reserve Margin graphics for NPCC-New York (page 18) and SERC-Florida Peninsula (page 25)
- Updated fuel mix chart for WECC-Alberta (Page 28)
- Updated Figure 5 to reflect NPCC-New York 2022-2023 Reference Margin Level and SERC-Florida Peninsula reserve margins (page 36)
- Updated capacity numbers provided by SERC-East, SERC-Florida Peninsula, and SERC-Southeast (pages 40–41)
- Revised percentage change numbers for SPP (page 41)
- Added footnote to reference SPP's probabilistic study (page 44)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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 2-92:
WECC 2024 Western Assessment of Resource Adequacy Demand at Risk Analysis

WECC
Electric Reliability and Security for the West

Demand at Risk by Subregion

WECC's annual Western Assessment of Resource Adequacy (Western Assessment) examines resource-adequacy-related risks concerning the reliability of the Western Interconnection over the next 10 years. Through an energy-based probabilistic approach, WECC looks at the risks throughout the interconnection and five subregions (See Figure 1). This work is meant to help stakeholders target specific areas and topics for deeper evaluation and mitigation.

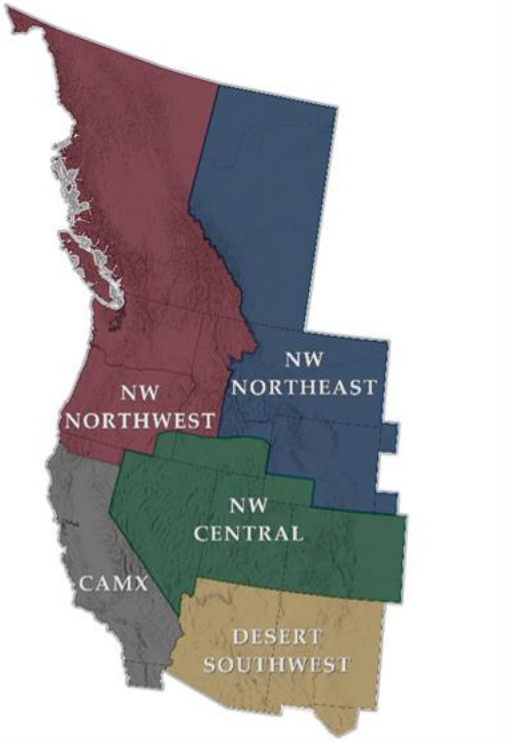


Figure 1: Map of the Western Interconnection with subregions

In the 2024 Western Assessment, WECC studied four resource addition scenarios. In the first scenario (All Additions), all planned resource additions come online in the year scheduled over the next 10 years. The remaining scenarios examine the effects on reliability if only 95%, 85%, and 55% of planned resource additions come online on schedule. This document provides noteworthy demand-at-risk takeaways within the subregions studied.

All Additions

There was demand at risk in one subregion, NW-Northwest, in the scenario in which all planned resource additions were made. A total of 89 demand-at-risk hours appeared in this scenario, with all but four of those hours occurring in the winter (See Figure 2). Most of the risk occurred in 2029 and later years, peaking at 26 hours in 2034.

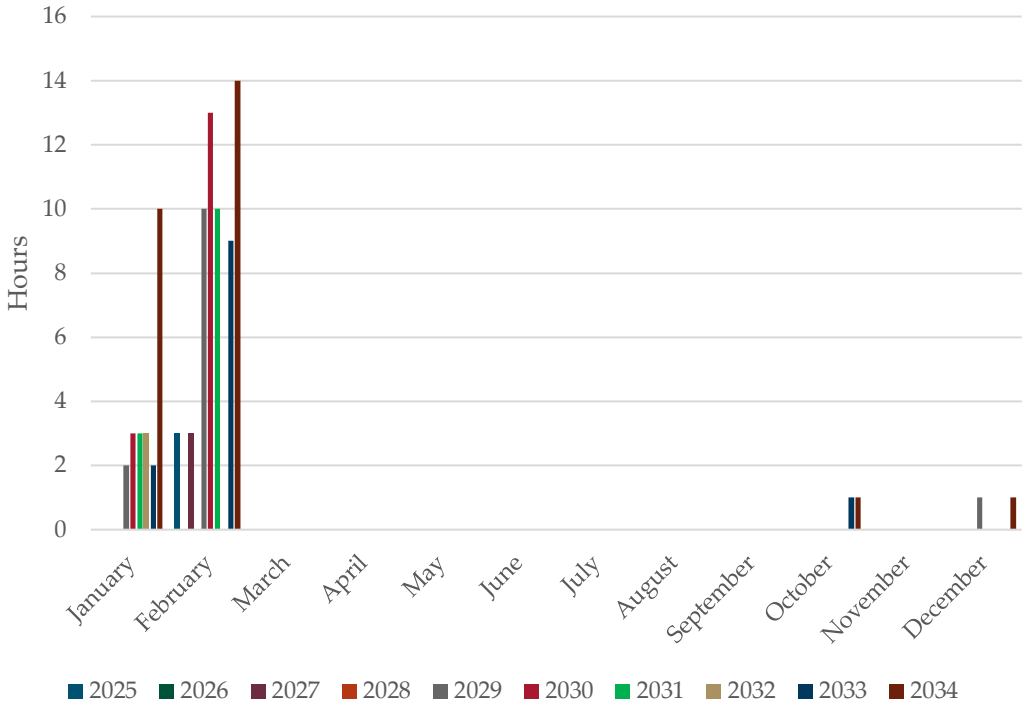


Figure 2: Demand-at-risk hours in the NW-Northwest subregion in the All-Additions scenario

95% Scenario

Demand at risk appeared in two subregions in this scenario: NW-Northwest and NW-Northeast. As in the 100% scenario, most of the demand at risk occurred in the winter months in the NW-Northwest (See Figure 3). In the NW-Northeast, all but four of the demand-at-risk hours occurred in August, beginning with one hour in 2027 and increasing to 51 hours in 2034 (See Figure 4).

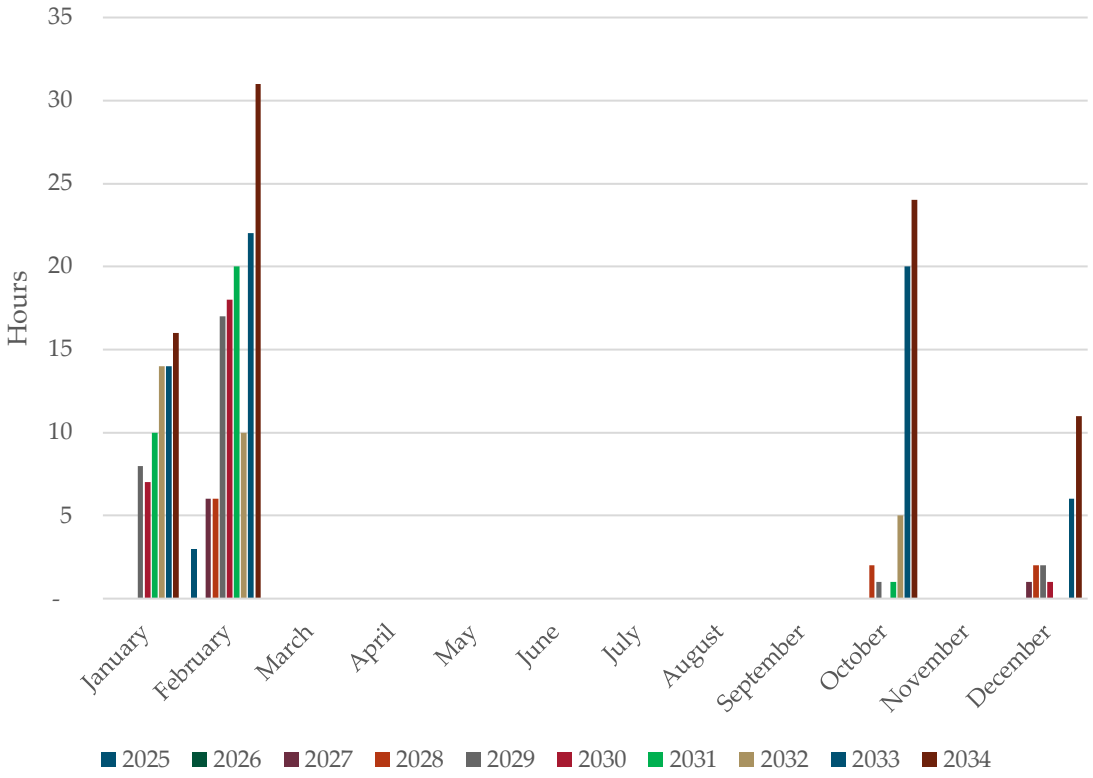


Figure 3: Demand-at-risk hours in the NW-Northwest subregion in the 95% scenario

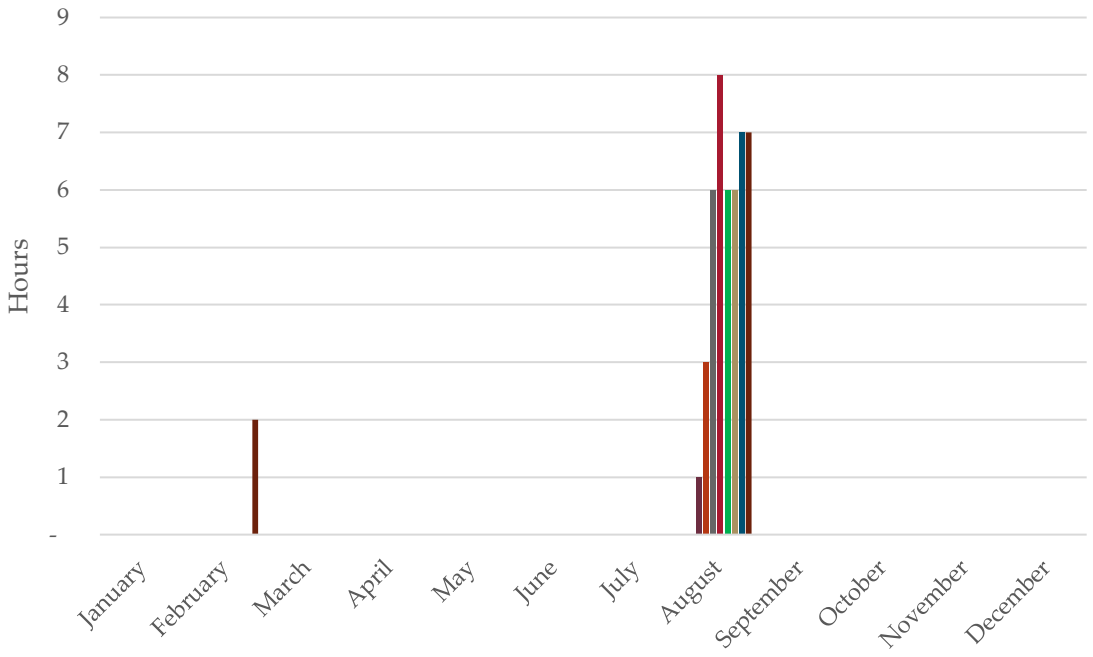


Figure 4: Demand-at-risk hours in the NW-Northeast subregion in the 95% scenario

85% Scenario

Demand at risk occurred in three subregions in this scenario: NW-Northwest, NW-Northeast, and NW-Central. Only one hour of demand at risk appeared in the NW-Northeast subregion (See Figure 6), in August 2034, while 94 hours appeared the NW-Central (See Figure 7), all between June and September and with almost half of that in 2034. In the NW-Northwest, 311 demand-at-risk hours appeared in this scenario, most of that in the winter (See Figure 5).

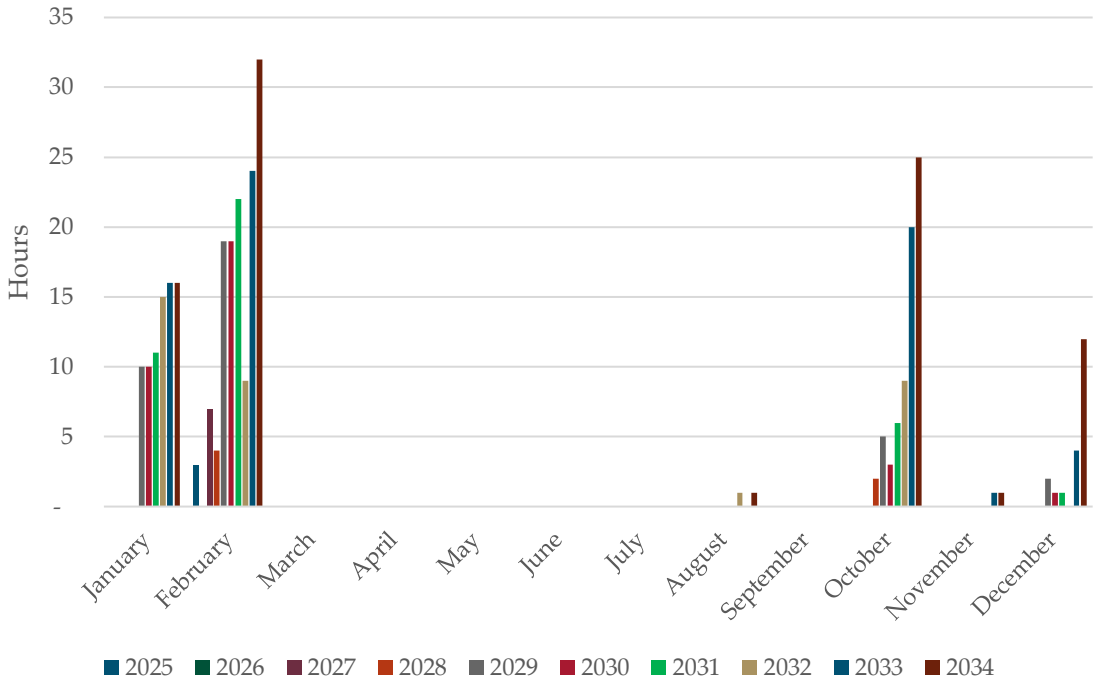


Figure 5: Demand-at-risk hours in the NW-Northwest subregion in the 85% scenario

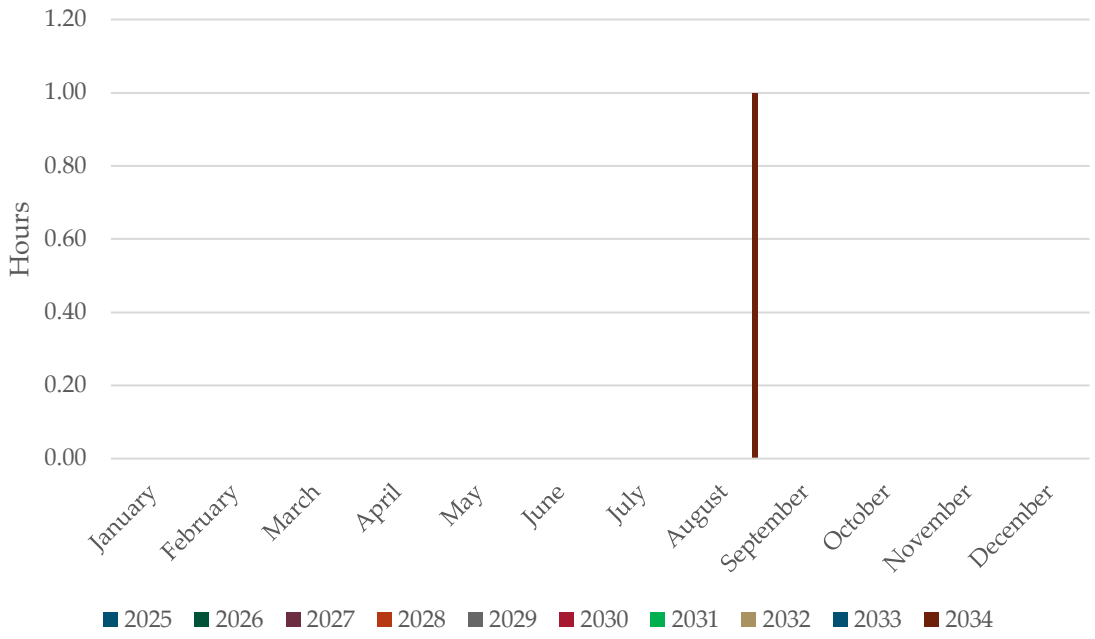


Figure 6: Demand-at-risk hours in the NW-Northeast subregion in the 85% scenario

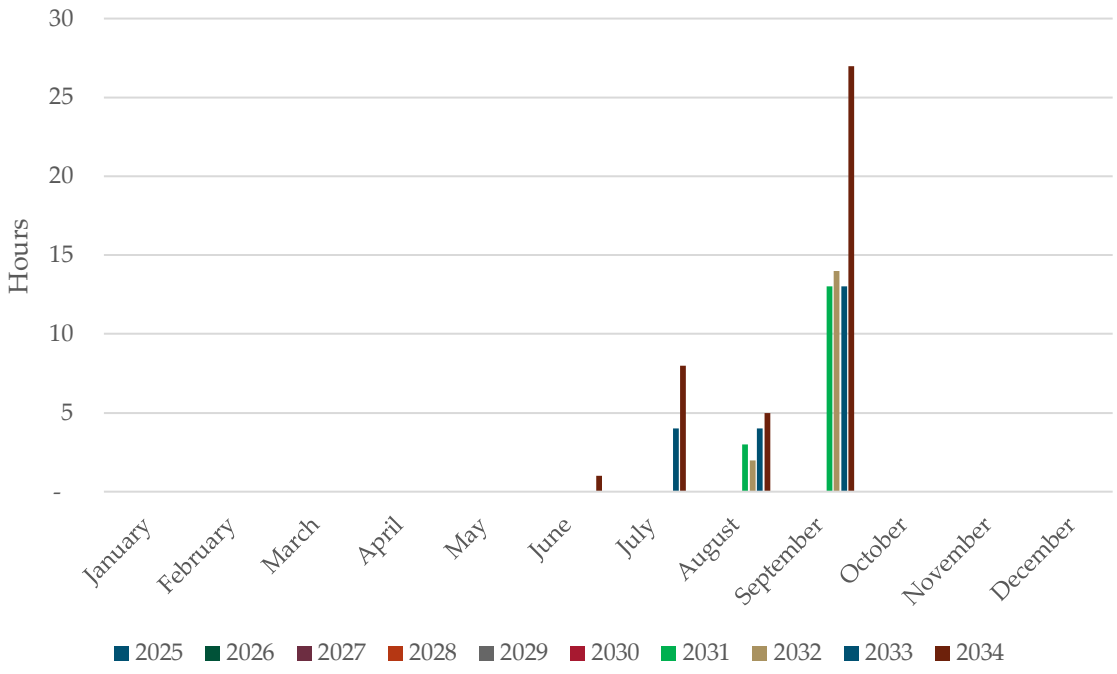


Figure 7: Demand-at-risk hours in the NW-Central subregion in the 85% scenario

55% Scenario

Demand at risk increased to four of the interconnection's five subregions in this scenario. Again, the most demand at risk occurred in the NW-Northwest in this scenario (See Figure 9), beginning in 2025 with eight hours and increasing to almost 800 hours in 2034. Most of the demand at risk in the other subregions occurred in the summer (See Figure 8, 10, and 11).

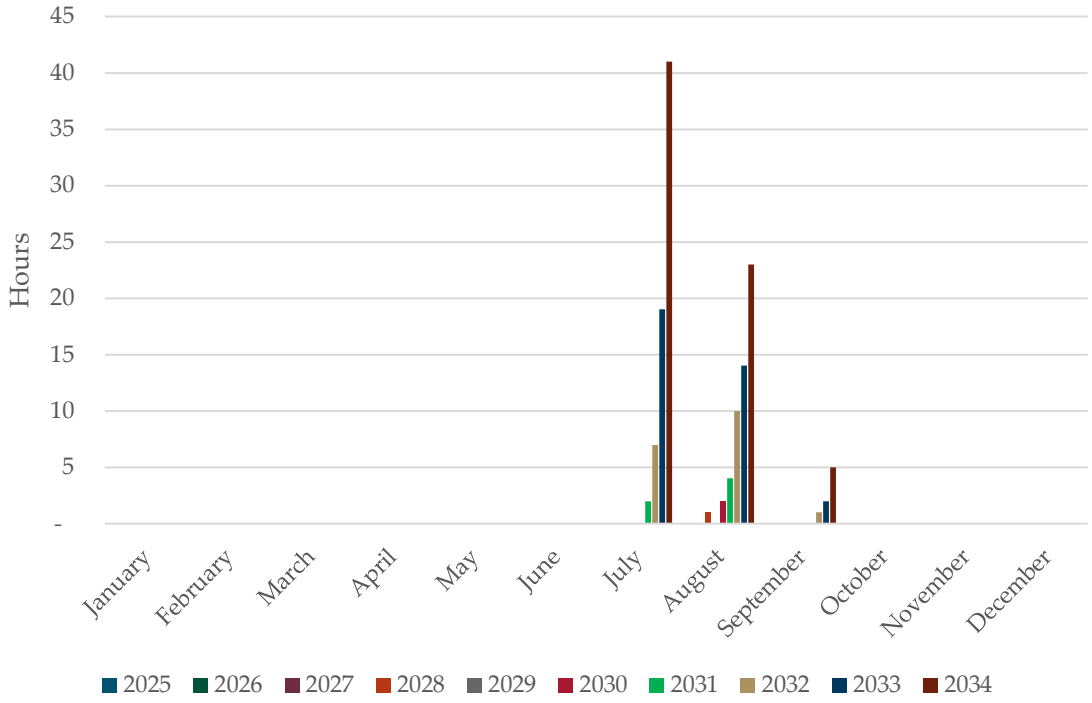


Figure 8: Demand-at-risk hours in the Desert Southwest subregion in the 55% scenario

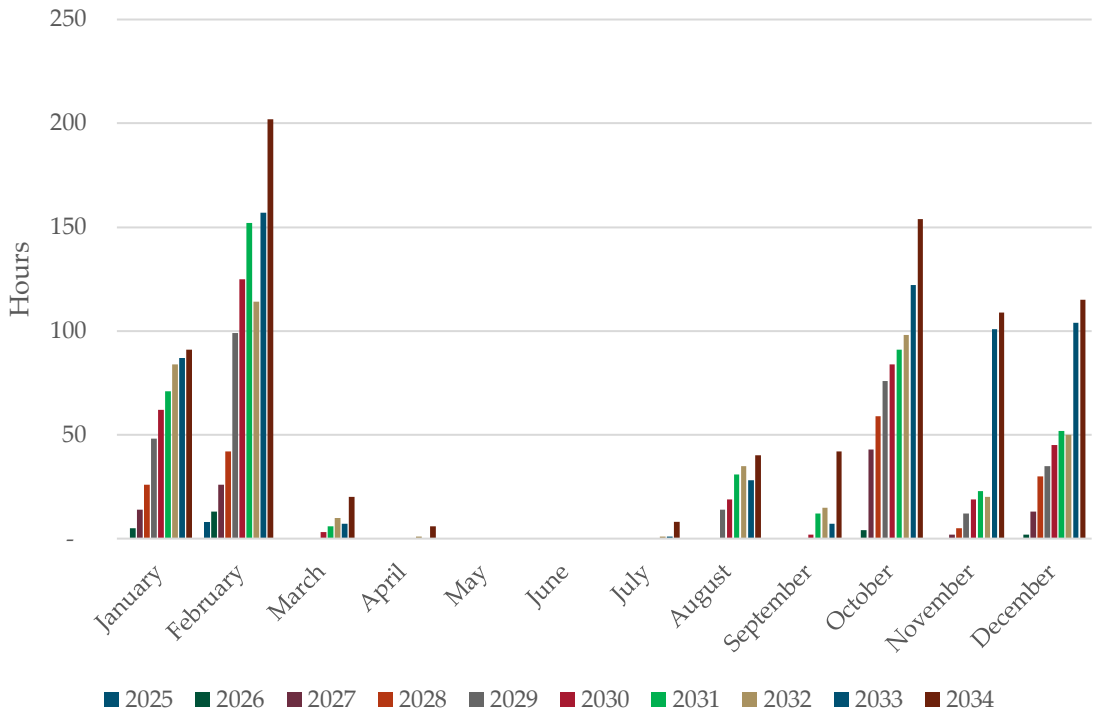


Figure 9: Demand-at-risk hours in the NW-Northwest subregion in the 55% scenario

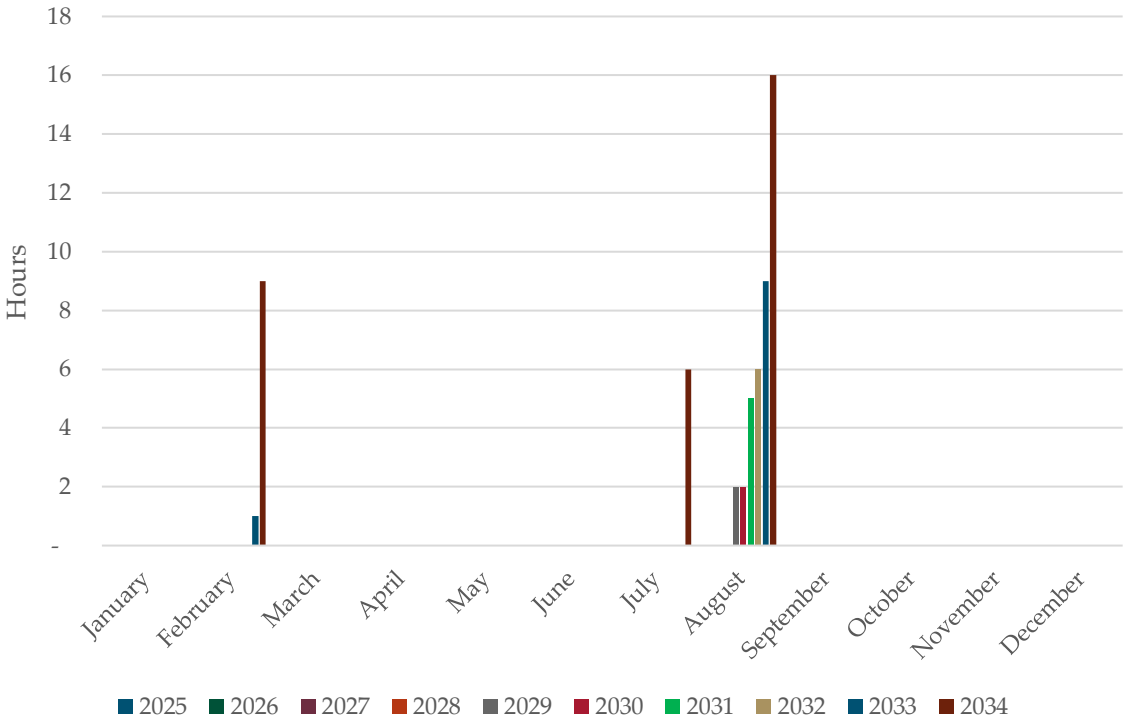


Figure 10: Demand-at-risk hours in the NW-Northeast subregion in the 55% scenario

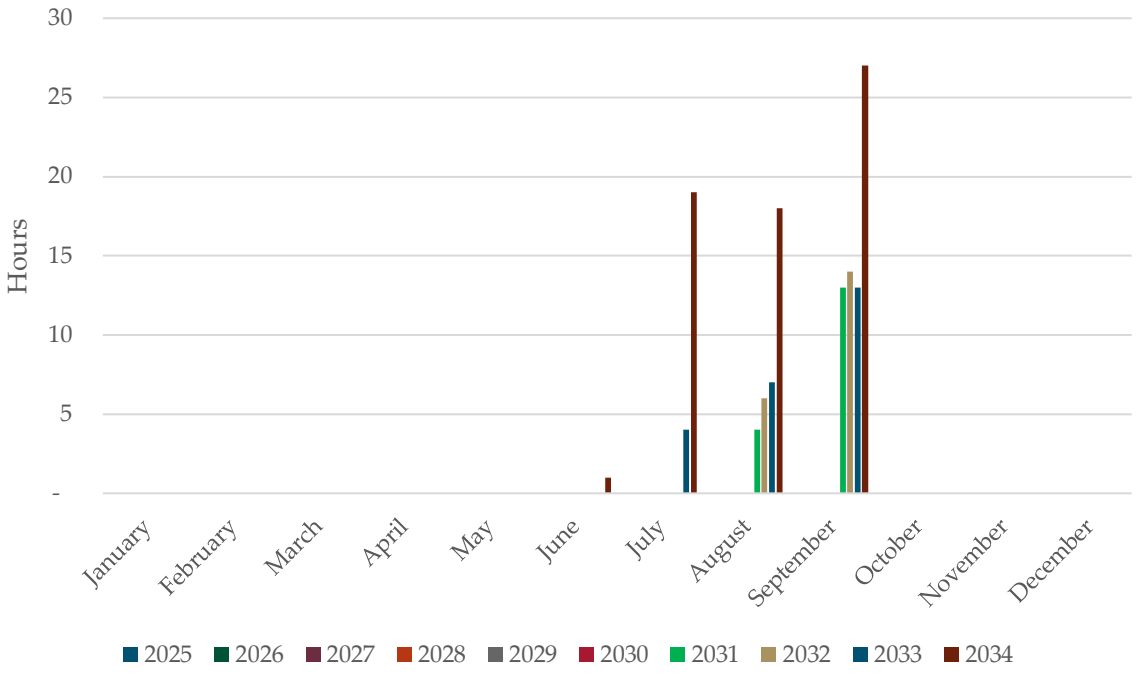


Figure 11: Demand-at-risk hours in the NW-Central subregion in the 55% scenario

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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 2-93:
Bonneville Day-Ahead Market Policy

Bonneville Power Administration

Day-Ahead Market Policy

May 9, 2025

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1. Executive Summary

The Bonneville Power Administration's Day-Ahead Market Policy (Policy) contains the policy direction of the Administrator of the Bonneville Power Administration based on the extensive stakeholder process analyzing Bonneville's potential day-ahead market participation in the California Independent System Operator's (CAISO) Extended Day-Ahead Market (EDAM) or the Southwest Power Pool's (SPP) Markets+. Bonneville conducted its stakeholder process from July 2023 through May 2025. During this time, Bonneville was, and continues to be, an active participant in both CAISO and SPP's stakeholder processes. The purpose of the Day-Ahead Market Policy is to transparently inform stakeholders about the scope of subsequent actions towards market participation.

On March 6, 2025, Bonneville issued its Day-Ahead Market Draft Policy, which proposed Bonneville should participate in a day-ahead market and pursue participation in Markets+ due to its superior market design, independent governance structure, and inclusive stakeholder process. This was followed by a 30-day formal comment period, which resulted in 1,614 comments. This Policy provides background information, addresses issues raised during the comment period and memorializes Bonneville's final direction and provides initial guidance on next steps.

After careful consideration of public input on Bonneville's evaluation principles and key considerations, governance and stakeholder processes, resource adequacy and resource sufficiency, price formation and market power mitigation, transmission and congestion rent and greenhouse gas accounting, Bonneville will adopt the recommendations in the draft policy and pursue participation in a day-ahead market and specifically pursue participation in Markets+.

Bonneville will now shift its focus to joining Markets+ by initiating a formal process to implement Markets+ participation. Bonneville will address customers' and stakeholders' impacts in future proceedings such as its rate case and tariff terms and conditions proceedings, and if Bonneville ultimately joins the market as a participant, it will address impacts in these forums as well as transmission business practice updates and a Provider of Choice power sales contract day-ahead market amendment process. Bonneville will leverage the lessons learned from its Western Energy Imbalance Market (WEIM) decision process, ultimately making a decision to go-live after reevaluating it through the implementation process, including any changes to the structure of Markets+ or underlying facts since the earlier phase of Markets+ final policy.

2. Introduction

In July 2023, Bonneville began to engage the region in a public process to evaluate its potential participation in a day-ahead market. As one of the largest wholesale power and transmission providers in the Western Interconnection, Bonneville's decision regarding day-ahead market participation will play a critical role in the energy and capacity market landscape for the region.

2.1. Description of the Bonneville System

Bonneville is a federal power marketing administration under the United States (U.S.) Department of Energy, is self-funding, and covers its costs by selling its products and services. Bonneville makes power sales and provides transmission service within its statutorily defined service territory in the Pacific Northwest,[1] including Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah, and Wyoming. Bonneville markets about 32% of the wholesale electric power generated in the Pacific Northwest[2] from 31 federal hydroelectric dams, one non-federal nuclear plant, and several smaller non-federal generating resources.[3] See Figure 1 for a visual of hydroelectric resources. Bonneville also operates and maintains more than 15,000 circuit miles of high-voltage transmission in its service territory, which is used to deliver power to its customers and transmit power for third-party transmission customers.

Figure 1 | Transmission System and Federal Dams



Bonneville's statutory mission is threefold: (1) to provide an adequate, efficient, economical, and reliable power supply to its firm power customers in the Pacific Northwest; (2) to provide a transmission system that is adequate to the task of integrating and transmitting power from federal and non-federal resources, providing service to Bonneville's customers, providing interregional interconnections, and maintaining electrical reliability and stability; and (3) to mitigate the impacts on fish and wildlife from the federally owned hydroelectric projects from which Bonneville markets power.

[1] In this Policy, the "Pacific Northwest" or "region" has the meaning set forth in the Northwest Power Act, 16 U.S.C. § 839a(14).
[2] Bonneville Power Administration, BPA Facts (Sept. 2024), *available at* https://www.bpa.gov/about/newsroom/fact-sheets.
[3] *Id.*; *see also* Bonneville Power Administration, 2024 Pacific Northwest Loads and Resources Study (Aug. 2024) ("The White Book"), *available at* https://www.bpa.gov/-/media/Aep/power/white-book/2024-white-book.pdf.

2.2. Development of Day-Ahead Markets in the West

As background, the Bulk Electric System in the U.S. is managed in six different regions.[4] The Western Interconnection is the largest region encompassing 38 Balancing Authority Areas (BAAs)[5] that are individually responsible for ensuring the reliable operation of the electric grid.[6] The regulatory Regional Entity approved by the Federal Energy Regulatory Commission (FERC) for the Western Interconnection is the Western Electricity Coordinating Council (WECC). The North American Electric Reliability Corporation (NERC) delegated some of its authority to create, monitor, and enforce reliability standards to WECC through a Delegation Agreement.[7] WECC promotes bulk power system reliability and security.

Historically, entities within the Western Interconnection have managed and balanced electricity supply and demand through bilateral transactions across forward contracts of varying duration, day-ahead transactions, and real-time transactions. The CAISO BAA is an exception in its role as an Independent System Operator (ISO).[8] Outside of the Western Interconnection, most regions have transitioned from a bilateral framework into ISOs or Regional Transmission Organizations (RTOs).[9] RTOs and ISOs manage about 60% of the U.S. electric power supply[10] and expand market activities through the consolidation of many BAAs into one BAA. They each maintain a single Open Access Transmission Tariff with standardized terms and conditions for transmission service and centralized transmission planning.

One component of RTOs and ISOs is the inclusion of a centrally organized market. A centrally organized market is administered by a market operator, which is a clearinghouse for bids and offers from market participants. Market participants continue to transact bilaterally on a forward time horizon but allow the market to dispatch generation and serve load across the day-ahead and real-time time horizons.[11] All centralized markets use Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) accompanied by a nodal network model with Locational Marginal Pricing

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[4] For more information, see Federal Energy Regulatory Commission (FERC), Electric Power Markets, *available at* https://www.ferc.gov/electric-power-markets.

[5] A BAA is defined as "The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area." North American Electric Reliability Corp., Glossary of Terms used in NERC Reliability Standards at 5 (Jan. 7, 2025), *available at* https://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf. In turn, a Balancing Authority is defined as "The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time." *Id.*

[6] BAAs are responsible for meeting North American Electric Reliability Corporation (NERC) reliability compliance standards (*see NERC*, *available at* https://www.nerc.com) and Western Electricity Coordinating Council (WECC) reliability compliance standards (*see* WECC, *available at* https://www.wecc.org).

[7] WECC, About WECC, *available at* https://www.wecc.org/about/about-wecc.

[8] FERC Order No. 888, 75 FERC ¶ 61,080, promoted the concept of ISO formation based on an earlier "power pool" concept. Several groups of transmission owners then formed ISOs, some from existing power pools Along with facilitating open access to transmission, ISOs operate the transmission system independently, and foster competition for electricity generation among wholesale market participants.

[9] In Order No. 2000, 89 FERC ¶ 61,285, FERC encouraged utilities to join regional transmission organizations (RTOs), which, like an ISO, would operate the transmission systems and develop innovative procedures to manage transmission equitably.

[10] U.S. Energy Information Administration, *About 60% of U.S. Electric Power Supply is Managed by RTOs* (Apr. 4, 2011), *available at* https://www.eia.gov/todayinenergy/detail.php?id=790#:~:text=Source:%20ISO/RTO%20Council,power%20marketers%20and%20energy%20traders.

[11] An RTO is an entity that is independent from all generation and power marketing interests and has exclusive responsibility for grid operations, short-term reliability, and transmission service within the region. Enerdynamics, Energy Knowledge Database, FERC Order 2000, *available at* https://energyknowledgebase.com/topics/ferc-order-2000.asp.

(LMP)[12] to create an "economic dispatch."[13] Section 1234 of the Energy Policy Act of 2005 defines "economic dispatch" as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[14]

CAISO operated an organized day-ahead and real-time market solely within its BAA footprint comprising most of California until 2014. In 2014, CAISO expanded its real-time market by offering the Western Energy Imbalance Market (WEIM) as an option for other BAAs in the Western Interconnection to join.[15] Voluntarily on an hourly basis, participants offer resources for within-hour dispatch by the market to manage the difference in energy for load and resources between what was scheduled ahead of time and what materializes in real-time. The market operator uses SCED to meet the within-hour real-time energy imbalances with the most cost-effective generation offered to the market. Unit commitment is generally performed by the market participants, not by CAISO in this real-time market. WEIM balances fluctuations in supply and demand by dispatching lower cost resources and it manages congestion on transmission lines to maintain grid reliability and to support integrating new resources.[16]

WEIM now includes 21 BAA participants operating the majority of the Western Interconnection.[17] CAISO's overarching market governance is entrusted to the CAISO Board of Governors. The Board has delegated certain authority for the WEIM to the Western Energy Markets (WEM) Governing Body, subject to the Board's oversight, in a model referred to as Joint Authority.[18] The CAISO Board of Governors is appointed by the Governor of California with the consent of the California State Senate.

In 2021, SPP launched a second imbalance market offering in the Western Interconnection, the Western Energy Imbalance Service market (WEIS). The WEIS has 16 participants. SPP's independent board of directors provides ultimate oversight of the administration of the WEIS market. In its role as the market operator, SPP performs analysis to ensure each balancing authority (BA) and market participant in each BA's boundaries have enough generation in their operating plan to satisfy the load and obligations for that

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[12] *See* SPP Markets+ Tariff, Attach. A § 3.2, *available at* https://www.spp.org/Documents/71376/Markets%20Plus%20Tariff%20amended%2020240405_filed%20version%202.pdf ("The LMP at a Pnode is the cost of delivering an incremental MW of Energy at that specific Pnode, while satisfying all operational constraints where such cost will include applicable Demand Curve prices if the incremental MW of Energy would result in a corresponding increase in shortage conditions. The LMP at any Pnode is the sum of three components: the marginal costs of Energy (the MEC), the marginal cost of losses (the MLC), and the marginal cost of congestion (the MCC)"). LMPs are the commonly accepted means for settling resources and loads in all centrally organized markets in the U.S. For more thorough details on the history and development of LMPs and the various considerations of how they are used within organized markets, see Harvey Scott & William Hogan, *Locational Marginal Prices and Electricity Markets* (2022), *available at* https://whogan.scholars.harvard.edu/sites/g/files/omnuum4216/files/whogan/files/locational_marginal_prices_and_electricity_markets_hogan_and_harvey_paper_101722.pdf.

[13] *See* FERC, Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations: A Report to Congress Regarding the Recommendations of Regional Joint Boards for the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act as Added by Section 1298 of the Energy Policy Act of 2005 (July 31, 2006), *available at* https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf.

[14] 42 U.S.C. § 16432.

[15] *See* CAISO, Western Energy Imbalance Market (WEIM) (2025), *available at* https://www.westerneim.com/Pages/About/default.aspx.

[16] *See* CAISO, How the Markets Work (2025), *available at* https://www.westerneim.com/Pages/About/HowItWorks.aspx.

[17] *See* CAISO, Western Energy Imbalance Market (WEIM) (2025). *available at* https://www.westerneim.com/Pages/About/default.aspx.

[18] *See* CAISO, Governance (2025), *available at* https://www.westerneim.com/Pages/Governance/default.aspx.

market participant and BA.[19] The WEIS accommodates a diverse set of resource types. This helps ensure the market operates as efficiently as possible and can take advantage of the capabilities of different resources.[20] As of 2022, WEIS balanced the demand for real-time energy and the power produced by more than 150 generating units in its multi-state footprint.[21]

Both CAISO and SPP have developed proposals to develop day-ahead markets that would manage a significant increase in the volume of transactions. CAISO began development of EDAM in 2019,[22] and SPP began development of Markets+ in 2022.[23,24] A day-ahead market is designed to optimize a participant's loads, resources, and transmission within the market footprint using a security constrained unit commitment and economic dispatch on a day-ahead basis with hourly granularity coupled with the underlying real-time market. In the real-time WEIM and WEIS markets, participants can submit voluntary bids for the next hour in sub-hourly (15-minute or five-minute) increments. In contrast, in a day-ahead market, participants can bid generation capacity and load for every hour in the day-ahead timeframe, which is then optimized by the unit commitments and economic dispatch accounting for constraints, including transmission availability and congestion. A day-ahead market continues to include a real-time market component, including voluntary submissions of any remaining real-time energy, much like the existing WEIM and WEIS.

Notably, CAISO and SPP employed different stakeholder participation models to develop the EDAM and Markets+ proposals. CAISO designed and authored the EDAM market offering, and Bonneville participated in stakeholder meetings, reviewed proposals, and provided written comments. CAISO ultimately determined which stakeholder suggestions to address and incorporate into the final EDAM design. Certain key issues that Bonneville raised were not fully addressed. In contrast, while SPP developed the initial conceptual framework for Markets+, stakeholder workgroups developed the Markets+ design elements to reflect the operational characteristics of the Western Interconnection. Bonneville participated in the committees, work groups, and task forces that developed Markets+ tariff language and business protocols. The collaborative design framework of Markets+ better addressed the many issues raised by Bonneville and other stakeholders.

2.3. Why is Bonneville Considering Joining a Day-Ahead Market?

Bonneville joined CAISO's WEIM in May 2022, eight years after its inception, after the market had grown into a large footprint and matured in its design elements. With FERC approval of two day-ahead market offerings, Bonneville expects day-ahead markets to gain a foothold, particularly with some states requiring utilities to transition to organized markets.[25] Based on its experience as a later entrant to the WEIM, Bonneville believes that early day-ahead market involvement will better meet its customer and stakeholder

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[19] *See* SPP, A Proposal for the Southwest Power Pool Western Energy Imbalance Service (WEIS) (2019)*, available at* https://www.spp.org/documents/60104/a%20proposal%20for%20spp's%20western%20energy%20imbalance%20service%20market.pdf.

[20] *See* SPP, Western Energy Imbalance Service Market (2025), *available at* https://www.spp.org/western-services/weis/.

[21] SPP, Annual Report 2022 at 4, *available at* https://spp.org/documents/70194/2022%20annual%20report%20-%209.26.23.pdf.

[22] *See* CAISO, Initiative: Extended day-ahead market, *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market.

[23] *See* SPP, Markets+, *available at* https://www.spp.org/western-services/marketsplus/.

[24] SPP is also developing RTO West in the Western Interconnection, with the corresponding tariff approved by FERC on March 20th, 2025. See *Southwest Power Pool, Inc., 190 FERC ¶61,169 (2025)*. RTO West is a separate offering from Markets+ and is not co-optimized with the Markets+ footprint.

[25] FERC Office of Public Participation, Western Energy Markets Explainer (Jan. 2025), *available at* https://www.ferc.gov/OPP/western-markets-explainer.

objectives because the first years of a market greatly influence development and maturation of the market design. The following are some categories of benefits that are associated with day-ahead market participation.

Continued Access to Trading Partners via a Liquid Market

Bonneville has observed a strong interest in day-ahead market development across the West, and many entities have already indicated their intent to pursue participation in the coming years. Today, Bonneville transacts bilaterally to ensure it meets its load service and operational obligations and to maximize the value of net-secondary revenue to keep rates low for customers. As entities joined the WEIM, Bonneville and others outside of the WEIM noticed reductions in the liquidity of the hourly bilateral market. Similarly, Bonneville expects that organized day-ahead market growth may result in reduced liquidity in both the day-ahead and real-time bilateral markets.[26] The expected result is fewer options for bilateral purchases of power or fewer counterparties to sell to, which could result in operational impacts and increased financial hurdles associated with these transactions. Participation in a day-ahead market will allow Bonneville continued access to a range of trading partners, without increasing hurdles and barriers to transact, so it can continue to carry out its objectives in the day-ahead and real-time horizons.

Optimization

An organized day-ahead market brings together a variety of resources and loads and enables an optimization to dispatch those resources to serve loads at the least cost. Both buyers and sellers can achieve economic benefit. Dispatched resources are compensated at their bid or higher for the energy they offered to supply. Resources that are not dispatched are given a concrete price signal to either conserve their resource for future periods of higher demand or offer a more competitive bid if they wish to be awarded. Loads can economically bid in day-ahead to indicate a price at which they are willing to purchase energy, and all loads are ultimately served in real-time through the least-cost economic dispatch. The optimization allows for a broader and more transparent exchange of pricing information. Compared to the bilaterial world of today, where there are numerous information asymmetries, a market optimization can provide participants, including Bonneville, with access to a more transparent picture of regional operations and tradeoffs, which aids both financial transactions and operational awareness.

In addition, joining a day-ahead market will give Bonneville better access to resources and loads across a broader footprint compared to bilateral markets. This allows for more flexible resources to respond to the needs of loads across that footprint. For resources with significant ramping capabilities, such as Bonneville's hydro resources, the more granular awards and dispatches of an organized market benefit both customers and the region more broadly.

Reliability

As a BA and a Transmission Operator (TOP), Bonneville is tasked with operating the electric grid in a reliable manner. Bonneville may utilize participation in an organized day-ahead market to reliably operate the grid. The market operator has a much wider view of transactional activity and grid operation compared to that of each individual BAA. Prior to real-time, the day-ahead market operator can forecast load needs and transmission constraints (i.e., areas on the transmission grid that may end up operating at their maximum transfer capacity based on expected system conditions), and award resources in a manner that honors those constraints in the day-ahead and real-time horizons. The market operator can also redispatch generation to reliably and most economically serve load (e.g., by supplying energy from a different resource

[26] *See* WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment (Sept. 2020), *available at* https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf.

that relieves a transmission constraint).[27] This ability of the market operator may reduce the likelihood and magnitude of transmission curtailments by Transmission Service Providers (TSP)/TOP.

Energy Resources

Bonneville has pledged to respond to customers' requests for integration of energy resources through the Evolving Grid initiative.[28] According to WECC's 2024 State of the Interconnection report, entities in the Western Interconnection plan to build close to 172 gigawatts (GW) of resources in the next 10 years. Addressing the changing resource mix and load shapes will be more successful through improved operation and coordination among many BAAs. An organized day-ahead market offers broader access to a larger portfolio of resources, which will enhance reliability because the market operator may dispatch resources within the broader market footprint.[29]

Timeliness

While many commenters have called for a delay in Bonneville's day-ahead market policy decision, for reasons including for additional time to comment, to allow EDAM governance to continue to develop, to conduct government-to-government consultation, and to conduct further economic analysis, Bonneville must declare a policy direction now. Strategically, Bonneville's timeline allows better coordination with other Bonneville efforts such as Provider of Choice, allows Bonneville an "early seat at the table" for participation in Markets+, places Bonneville on a similar timeline to other entities in the West who are joining day-ahead markets, and maintains two viable market options. In addition, it is necessary for Bonneville to provide clear expectations to its customers, sovereigns, and stakeholders now to mitigate uncertainty and to collaborate on next steps.

2.4. Day-Ahead Market Framework

A day-ahead market is a centrally organized financial and physical electricity market where participants submit hourly resource offers and bids for load. The market optimization combines all offers and bids to determine the least cost energy dispatch to serve load while recognizing physical system constraints. If the market optimization determines the offers and bids to be economical, the participant receives a financially binding award. The resource offers can be updated with the market operator to reflect operational changes, with the ultimate real-time dispatches of resources serving all load economically given physical system conditions. Market participants ultimately receive settlements from the market operator for all resources and loads cleared through the market.

The market operator uses a SCUC and SCED[30] accompanied by a nodal network model with locational marginal pricing to create an optimized dispatch plan.[31] "Unit commitment" determines the optimal

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[27] *See* Mareldi Ahumada-Paras, Michael Mastrandrea, and Michael Wara, Stanford Climate and Energy Policy Program, *Grid Regionalization in the West: Reliability Benefits from Increased Cooperation in Electricity Markets and Operations* (Aug. 2024), *available at* https://woodsinstitute.stanford.edu/system/files/publications/Woods_Grid_Regionalization_White_Paper_v05_WEB.pdf.

[28] *See* Declaring a National Energy Emergency, Exec. Order No. 14156, 90 Fed. Reg. 8433, 8434 (Jan. 20, 2025).

[29] *See* WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment (Sept. 2020) at 3, *available at* https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf.

[30] As a reminder, SCUC stands for security-constrained unit commitment and SCED stands for security-constrained economic dispatch.

[31] *See* FERC, Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations: A Report to Congress Regarding the Recommendations of Regional Joint Boards for the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act as Added by Section 1298 of the Energy Policy Act of 2005, *available at* https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf.

combination of resources to bring online from those that are available for some or all of the operating day.[32] "Economic dispatch" determines the optimal output of all committed resources relative to bid-in or expected load and other resource output forecasts to minimize total cost to serve load.[33] To ensure that the unit commitment and economic dispatch are feasible, the optimization is "security-constrained," which means that the optimization must adhere to certain limits (known as "constraints") such as flow across transmission elements and maximum ramp rate of generators. For instance, if increasing the output of a generator that is otherwise economic to serve load would cause flow on a transmission element to exceed its limit, the optimization will instead increase the output of the next least-cost resource that does not cause the flow on that element to exceed its limit.

To incorporate these constraints into the optimization, the market operator has a full nodal network model showing the locations and relevant characteristics of all transmission elements and generation resources of a certain size as well as approximations to represent load across the area. The market operator receives updated constraint information in day-ahead and real-time data submittals from market participants and reliability entities. Transmission Operators and BAs update constraint information on the elements or system areas that have new or existing limitations. Resource Owners/Operators submit hourly offer information about the minimum and maximum amount of generation they are willing to sell and the associated price between those output levels, as well as resource limitations (e.g., ramp rate, minimum or maximum run time when committed, etc.).

For day-ahead optimization, the SCUC and SCED solve simultaneously across all 24 hours of the next operating day. For real-time optimization, the SCED solves for a set number of sub-hourly intervals for the applicable operating hour. In between the day-ahead optimization and the real-time optimization, the market operator runs additional SCUCs.[34] These intra-day SCUCs are used to ensure enough generation is online and available to serve expected load as input information changes, such as load forecast increases or an unexpected outage on a previously committed generation resource.

Finally, the market produces financial settlements for all energy traded and load ultimately served. Settlements are for all location-nodes for day-ahead and real-time resources generated and load demand, as well as other associated payments or charges. All centrally organized markets in the U.S. settle based on LMPs, which generally represent the incremental cost to serve another megawatt (MW) of load at a given location. LMPs are composed of the following pricing components: energy, losses, and congestion. In a day-ahead market framework, the award from the day-ahead solution is settled at the day-ahead LMP and is used as the financial reference point for settlement of energy in the real-time solution.

3. Public Process

In July 2023, Bonneville started its public process to evaluate day-ahead market participation including hosting 11 public workshops (see below for a list of workshops and their respective topics) to share and discuss potential benefits and risks. A high priority for Bonneville is ensuring that customers and stakeholders understand the day-ahead market proposals and have multiple opportunities to provide substantive feedback on the decision. Bonneville has accepted public comments and concerns and posted all the written comments on its day-ahead market process website.[35] Stakeholder comments have provided valuable information about concerns and issues and have had a direct impact on the decision process. Bonneville appreciates the robust engagement and the feedback it has received.

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[32] CAISO, Technical Bulleting 2009-06-05, Market Optimization Details § 2 (Nov. 19, 2009), *available at* https://www.caiso.com/Documents/TechnicalBulletin-MarketOptimizationDetails.pdf.
[33] *Id.* § 3.
[34] Referred to as "Reliability Unit Commitment" in Markets+ and "Residual Unit Commitment" in EDAM.
[35] Bonneville Power Administration, Day-Ahead Market, *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.

Additionally, Bonneville coordinated with customers in the Provider of Choice public process to design power products that will be compatible with a day-ahead market for October 1, 2028 through September 30, 2044 contract period.[36]

Topics covered in the public workshops include:

No.	Meeting Date	Topics
1	July 14, 2023	• Why are we exploring day-ahead market participation? • Overview of public engagement for establishing a Bonneville policy direction on potential day-ahead market participation • Discussion on drafting Bonneville day-ahead market evaluation principles • Overview of day-ahead markets
2	September 11, 2023	• Update on day-ahead market development & update on developing GHG accounting in a day-ahead market • Bonneville will continue to supply electric power to customers in a day-ahead market • Draft day-ahead market evaluation principles • Review of comments received • Section 5(b) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act)[37] (Section 5(b))/day-ahead market compatibility • Tabletop scenario work with the Public Power Council
3	October 23, 2023	• Energy and Environmental Economics (E3) overview of Western Market Exploratory Group (WMEG) cost/benefit study • Initial takeaways from WMEG Result • Considerations for Bonneville's day-ahead market business case analysis
4	November 29, 2023	• Discussion of Section 5(b) obligations/day-ahead market compatibility • Review of Bonneville's policy direction public process • Considerations for Bonneville's day-ahead market business case • GHG Update and consideration of GHG business case
5	February 1, 2024	• Update on Bonneville's decision process and timeline for CY 2024 • Review of Bonneville's day-ahead market evaluation and decision criteria • Update on Bonneville's day-ahead market public comment tracking • Responses to public comments at this workshop
5.5	May 3, 2024	• Tabletop scenario refresh (from workshop 2) • Workshop 6 scenarios
6	May 8, 2024	• Review of Bonneville's Staff Recommendation on Day-Ahead Market Participation; update on decision process and timeline for CY 2024 • Baseline process and scenario discussions

[36] *See* Bonneville Power Administration, Provider of Choice (Post-2028), *available at* https://www.bpa.gov/energy-and-services/power/provider-of-choice.
[37] 16 U.S.C. § 839c(b).

7	June 3, 2024	• Review of Bonneville's comments on Pathways April 10 proposal and legal analysis • High-level congestion rent scenario • Congestion rent design • Congestion revenue scenario with congestion rights
8	July 18, 2024	• Update on the Pathways initiative • Day-ahead market from the transmission perspective
9	November 4, 2024	• Timeline update and key dates for CY 2025 • Update on Markets+ FERC filing and EDAM engagement • Transmission update • Bonneville's continued decision process • Evaluation of market governance developments • Bonneville's supplemental production-cost analysis/result interpretation
10	January 29 & 30, 2025	• Review of Bonneville's day-ahead market decision process • E3 Case Result – Hydro Operational Limitations Scenario • Expected transmission revenue impact • Day-ahead market participation & implementation fees • Day-ahead market seams, reliability and operational impacts
11	March 19, 2025	• Opportunity to ask clarifying questions of the draft policy

Based on stakeholder feedback, Bonneville also considered potential day-ahead market participation through the lenses of firmness of power supply and certainty of delivery. This Policy addresses firmness of power supply in section 6.2, focusing on ensuring adequate supply through resource planning. Certainty of delivery is addressed in section 6.7, which describes how a day-ahead market paradigm would build upon existing constructs. Section 5.2.5 on GHG accounting addresses how market designs can provide for transparent accounting of environmental attributes.

4. Day-Ahead Market Evaluation Process

Bonneville has been evaluating potential day-ahead market participation based on eight evaluation principles. This section provides further detail for each evaluation principle.

4.1. Discussion of Evaluation Principles

While potential benefits, like those listed in section 2.3, are an important part of Bonneville's evaluation, there are additional considerations for Bonneville to weigh in its evaluation. In its decision process, Bonneville is assessing the business case for day-ahead market participation based on both quantitative and qualitative evaluation components. Bonneville assessed day-ahead market participation based on the following evaluation principles. These principles were shared with stakeholders in public workshops and include revisions based on stakeholder feedback:

- Statutes – Bonneville meets its statutory, regulatory, and contractual obligations.
- Reliability – Bonneville maintains efficient, economical, and reliable delivery of power and transmission service to its customers.
- Reliability – Market design includes resource sufficiency and/or resource adequacy frameworks that ensure reliability.
- Business – Bonneville's participation is supported by a sound business rationale.

- Strategy – Bonneville's participation is consistent with Bonneville's 2024-2028 Strategic Plan.
- Governance – The market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Decision-making and stakeholder engagement occur in a transparent and inclusive manner.
- Customers – Bonneville's evaluation of day-ahead market participation includes transparent consideration of the commercial and operational impacts on its products and services.
- GHG – Bonneville will evaluate how participation will impact GHG emissions attributed to the federal system and its regional firm power customers' ability to comply with applicable state carbon programs. Participation must maintain the value of the low-carbon nature of the federal system to the extent possible.

The sections below highlight how a day-ahead market meets our evaluation principles.

4.1.1. Statutes – Bonneville meets its statutory, regulatory, and contractual obligations.

Bonneville has not identified any legal barriers to day-ahead market participation. See Appendix A for a discussion of Bonneville's statutory authority to participate in Markets+.

4.1.2. Reliability – Bonneville maintains efficient, economical and reliable delivery of power and transmission service to its customers.

Maintaining the reliability of the power and transmission systems for all of Bonneville's customers is one of the most important aspects of Bonneville's various roles. Indeed, reliability is foundational to accomplishing many of the other principles, objectives, and goals upon which Bonneville focuses.

Day-ahead markets and market operators do not assume any of the reliability roles of a utility. Bonneville will retain its reliability roles, such as Transmission Planner, BA, and TOP, and remain responsible for compliance with applicable NERC reliability standards. Further, Bonneville and its federal generating partners maintain full control of federal resources, including authority to manage output and make energy available to the market. Thus, Bonneville will continue to serve its direct role in operation of the federal power and transmission systems and maintaining system reliability.

As described in Section 2.3, participating in a day-ahead market will provide Bonneville opportunities to support or improve reliability due to system optimization and geographic diversity benefits. As Bonneville moves into a day-ahead market implementation phase, Bonneville will continue to assess any potential reliability concerns, identify and design necessary mitigations, and work with the market operators to ensure the markets are able to support those mitigations where necessary.

4.1.3. Reliability - Market design includes resource sufficiency and/or resource adequacy frameworks that ensure reliability.

Bonneville believes that it is important for a day-ahead market to address long-term Resource Adequacy (RA) as well as short-term resource sufficiency. Resource sufficiency generally refers to resources' availability to produce power (energy and capacity) to serve the expected load in the short term (e.g., moving into the next week, day or hour). RA generally refers to long-term planning and acquisition of resources, if needed, to serve the expected peak or critical load in a season or upcoming year. RA aims to have enough "steel in the ground" (resources built and accessible) to serve a forecasted peak load, while resource sufficiency considers the current operational landscape (e.g., outages or derates, up-to-date variable generation and load forecasts, etc.). The two concepts work in concert to minimize scarcity, emergency, or loss-of-load events.

In a day-ahead market, market participants continue to be responsible for their own RA and sufficiency, and thus they are obligated to bring a resource portfolio (including power purchases) able to meet their

expected load to the market; the market is then able to optimize the dispatch of resources, along with any independently-offered resources, creating a more efficient and economical load service plan reflecting the current system landscape. Market design frameworks try to ensure that market participants are held accountable for this responsibility to receive the shared benefits of an integrated market through penalties or limitations on market access.

Both day-ahead market options include an evaluation for resource sufficiency. EDAM has a set of resource sufficiency evaluation tests and Markets+ has a must-offer obligation, both of which compare an entity's day-ahead load and uncertainty requirements to its available resources to ensure they have sufficient resources to meet their loads or are held accountable. However, as explained further in section 5.2.2, Bonneville prefers the design in Markets+, primarily because it also includes a long-term RA requirement. Markets+ includes a standardized RA requirement, requiring all load responsible entities (LREs)[38] to participate in the Western Resource Adequacy Program (WRAP) administered by the Western Power Pool. While the CAISO BAA has its own RA framework, this framework is not extended to other entities outside of CAISO's BAA in general, and the EDAM design does not include a requirement for entities to participate in any RA program. Bonneville believes that Markets+ requiring participation in WRAP, a standardized RA framework, will better meet this principle.

4.1.4. Business - Bonneville's participation is supported by a sound business rationale.

With the emergence of day-ahead market offerings by both CAISO and SPP, most entities in the Western Interconnection are evaluating participation in an organized day-ahead market. While economic value is an important factor, a decision about day-ahead market participation encompasses many considerations beyond just economic value.

Production Cost Modeling (PCM) provides an initial analysis of various simulations. Bonneville joined WMEG and contracted with E3 to explore the economic possibilities. In Section 5.1 Bonneville describes the benefits and limitations of the PCM studies. However, for the evaluation of a day-ahead market, a sound business rationale must encompass factors beyond the short-term economic results. The long-term industry trends must also be considered. These trends could include more entities joining day-ahead markets, new variable energy resources integrating into the system which causes power purchase changes, and the potential development of an RTO. Joining a day-ahead market allows Bonneville to continue to align with the majority of the industry on the business of power markets.

4.1.5. Strategy - Bonneville's participation is consistent with Bonneville's Strategic Plan.

The "Evolving Grid" sets the agency's path for the Pacific Northwest, including the use of Bonneville's transmission system. Through the evolution, Bonneville will maximize the value of the federal hydropower and transmission systems. As the needs of its customers evolve, so must the products and services it offers. Bonneville must address customer demand for more renewable generation and amplifying RA concerns brought about by a changing resource mix. An objective in meeting this goal is fostering market evolution to enhance the delivery of cost-effective, reliable power and transmission service while modernizing business systems and processes. The flexible and reliable power of the Federal Columbia River Power System (FCRPS), coupled with the expansive high-voltage transmission grid, is the bedrock Bonneville will build on to meet these future needs.

4.1.6. Governance – The market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Decision-making and stakeholder engagement occurs in a transparent and inclusive manner.

Bonneville performed a rigorous assessment of day-ahead market offerings from a governance perspective because insufficient independence and limitations on stakeholder engagement pose risks to creating a fair

[38] A Load Responsible Entity (LRE) is an entity directly responsible for ensuring an electrical load is served.

and equitable market that brings equitable value to all participants. Risks arise from market governance that retains authority for a single state, entity, or customer class.

At the highest level, the decision-making body for the market must be free of disproportionate obligation to the policies of a single state, entity, or customer class to ensure that market design is on an equal footing for all participants, including Bonneville. In CAISO markets, Bonneville has observed disadvantages for market participants outside of California during market design development and in times of outlier events.[39] The staffing and process for decision development and stakeholder engagement should equitably weigh the policies or priorities of all states, entities, and customer classes. Bonneville finds that the governance structure for Markets+ meets that standard.

As it engaged in the stakeholder processes for the development of both markets, Bonneville strongly advocated for the inclusion of sound independent governance principles in market design. Bonneville believes its efforts have positively impacted the governance structures of both EDAM and Markets+.

4.1.7. Customers - Bonneville's evaluation of day-ahead market participation includes transparent consideration of the commercial and operational impacts on its products and services.

Bonneville has conscientiously considered the needs of its large customer base as it evaluated joining a day-ahead market, including public customer/stakeholder workshops[40] exploring how a decision to participate in day-ahead markets may impact different customer types and how its various power and transmission products and services may work in a day-ahead market. Bonneville also collaborated with customers to design a long-term power sales contract[41] that includes provisions to adapt to potential day-ahead markets to ensure the flexibility to meet a changing landscape. Further, in the public processes for EDAM and Markets+ development, Bonneville advocated for policies and designs to unlock additional value from the federal hydropower and transmission systems that benefit Bonneville and its customers.

Bonneville expects to continue holding day-ahead market public workshops. It will also work through various day-ahead market specifics in its rate cases and tariff terms and conditions proceedings, contract negotiations, business practice change forums, etc., as appropriate. Throughout these various processes, Bonneville will continue to comprehensively address the impacts of day-ahead market participation on the products and services it offers to customers.

4.1.8. GHG - Bonneville will evaluate how participation will impact GHG emissions attributed to the federal system and our regional firm power customers' ability to comply with applicable state carbon programs. Participation must maintain the value of the low-carbon nature of the federal system to the extent possible.

Bonneville is not subject to any state GHG programs in the region. However, Bonneville customers have repeatedly expressed the importance of the low-carbon attributes of their power purchases from Bonneville.[42] Bonneville markets power from the federal hydropower system, Columbia Generating station,

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[39] Examples include wheel through priorities in August 2020 and greenhouse gas allocation market design.

[40] Bonneville Power Administration, Day-Ahead Market, *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.

[41] Bonneville Power Administration, Provider of Choice (Post-2028), *available at* https://www.bpa.gov/energy-and-services/power/provider-of-choice.

[42] Examples of customer comments related to GHG emissions can be found in Bonneville's Final Energy Imbalance Market Close-Out Letter § 5.2.3 (Sept. 2021), *available at* https://www.bpa.gov/-/media/Aep/projects/energy-imbalance-market/final-eim-close-out-letter.pdf (full comments available at https://publiccomments.bpa.gov/CommentList.aspx?ID=421); Bonneville's Provider of Choice Policy Record of Decision § 8 (Mar. 2024), *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2024-rod/rod-20240321-bonneville-power-administration-provider-of-choice.pdf (full comments available

and other resource acquisitions and market purchases. Today, market purchases are the only resources in the federal system to which state programs attribute emissions. These purchases are an important component of Bonneville's power supply and have historically comprised 3 to 10% of the FCRPS.

Organized markets change GHG accounting dynamics because, absent a GHG accounting design, the market does not specify which resources are dispatched to meet a particular load. For example, when Bonneville joined the EIM in May 2022, the volume of unspecified purchases included in Bonneville's federal system fuel mix slightly increased. This was due to increased transfers of energy to meet load imbalance between Bonneville's BAA and other BAAs, which states accounted for at an unspecified emission factor. Currently, WEIM only employs a GHG accounting mechanism to support implementation of California's cap-and-trade program.

Both EDAM and Markets+ developed mechanisms to support the implementation of carbon pricing programs generally including California's program and Washington's cap-and-invest program. Over 60% of Bonneville's long-term power sales are to customers in Washington and are subject to the state's cap-and-invest program as well as the state's Clean Energy Transformation Act. Bonneville also has customers in Oregon that are subject to Oregon's GHG reporting requirements. Bonneville has participated in day-ahead market GHG accounting conversations mindful of impacts to customers in those states with the goal of ensuring customers can continue to claim low-carbon attributes associated with power purchases from Bonneville. As discussed in section 5.2.5, Bonneville believes the Markets+ design better reflects environmental attributes related to its firm power sales to its customers.

5. Day-Ahead Market Participation Evaluation

Bonneville has spent over two years evaluating whether to join a day-ahead market, and if so, which of the two available day-ahead markets options Bonneville should join. With the principles described in Section 4 in mind, Bonneville has considered quantitative analyses, market design elements, footprint, and other relevant information in its evaluation. On the whole, Bonneville finds that joining a day-ahead market will result in benefits to its customers.

Bonneville contracted with E3 to analyze economic costs and benefits using PCM. The initial PCM results depicted a wide range of economic benefits for day-ahead market participation. Bonneville's assessment is that the forecasted benefits justify participation in either EDAM or Markets+. Subsequent sections of this document further discuss the initial PCM results as well as supplemental analysis Bonneville contracted for with E3.[43] These results should not be viewed with the expectation of achieving specific forecasted revenues. The PCM results are forecasts that can be influenced by other factors that may alter the projected outcome. For example, modifications to market design items such as Congestion Rent, Scarcity Pricing, or LMP computation can impact benefits. PCM models also do not account for qualitative elements such as differences in market governance structure that can also produce quantitative impacts.

Overall, the PCM results showed:

- Participation in the EDAM market produces the highest net cost benefit in the cases studied.
- Markets+ offers the lowest cost to serve load but also forecasts reduced generation revenue.

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at https://publiccomments.bpa.gov/CommentList.aspx?ID=480); and in customer comments received to-date in Bonneville's Day-Ahead Market process (comments available at https://www.bpa.gov/learn-and-participate/projects/day-ahead-market).

[43] Energy and Environmental Economics, WMEG Cost Benefit Study (CBS), BPA Day-Ahead Market Participation Workshop presentation (Oct. 23, 2023), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/e3-wmeg-benefits-study.pdf; Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation (Nov. 4, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf.

- Although the net cost looks favorable, remaining a WEIM-only participant carries significant risk not easily reflected in the quantitative case result.

As mentioned in section 4, one of the eight evaluation principles is governance. Bonneville is specifically looking for a market that has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Bonneville's evaluation considers the relevant factors associated with governance structures under both Markets+ and EDAM to identify the best governance structure available for Bonneville's decision regarding day-ahead market participation. RA and resource sufficiency are included in the reliability evaluation principle in market design. RA aims to have enough physical resources (both transmission and generation) to serve a forecasted peak load well into the future (often years or multiple months), while resource sufficiency considers the current operational landscape (outages or derates, up-to-date variable generation and load forecasts, etc.).

Price formation and market power mitigation ensures that market rules provide appropriate price signals, which compensate resources at prices that reflect both the value of the services that resources provide to the market and the operational conditions under which the resource is awarded. EDAM and Markets+ are broadly similar in the way they model constraints and manage transmission, with some key differences, particularly regarding allocation of congestion rents, which are described in section 5.2.4. The market design for GHG accounting—how resources and their associated emissions are assigned to market participants—is critical to ensuring Bonneville's customers can continue to claim the low-carbon attributes of their federal system power purchases for applicable state programs or for their own utility purposes.

This section discusses the economic and market design benefits associated with Bonneville's Policy direction to participate in Markets+ with emphasis on governance, RA and resource sufficiency, price formation and market power mitigation, transmission and congestion rent, and GHG.

5.1. Economic Costs/Benefits Analyses

As part of its day-ahead market evaluation, Bonneville assessed costs and benefits using PCM. PCM is an industry-standard approach for analyzing costs and revenues associated with energy trading and load service. PCM is explained below in section 5.1.1.1.

Many entities in the Western Interconnection, including Bonneville, employ PCM in their evaluations of day-ahead markets, in integrated resource planning, and when assessing long-term transmission expansion costs. Bonneville also included consideration of the economic impact to its Power and Transmission business lines, reflecting both the PCM results and additional considerations. Further, Bonneville has considered the implementation costs (both internal to the agency and those paid to the market operator) as well as on-going participation fees associated with the day-ahead market options. These analyses and considerations are discussed in this section.

5.1.1. Production Cost Modeling

Bonneville was part of two separate cost-benefit analyses using PCM as part of its day-ahead market evaluation. Bonneville joined the WMEG in the summer of 2022. WMEG is a group of 25[44] BAAs within WECC that came together to examine participation in day-ahead market offerings. WMEG hired E3 to provide PCM analysis for each respective BAA across varying market footprints and varying years (2026,

[44] The 25 WMEG members represented are AEPCO, APS, Avista, Balancing Authority of Northern California (BANC), Black Hills Energy, Bonneville, Chelan County PUD, El Paso Electric (EPE), Grant County PUD, Idaho Power Company, Los Angeles Department of Water & Power (LADWP), NV Energy, PacifiCorp, Public Service of new Mexico (PNM), Platte River power Authority, Public Service of Colorado (PSCO), Puget Sound Energy (PSE), Salt River Project (SRP), Tacoma Power, Tucson Electric Power (TEP), Tri-State Generation and Transmission Authority (TSGT), and Western Area Power Administration (WAPA), which was modeled in 5 separate areas (SNR, CRCM, LAP, WALC/DSW, and WAUW). The rest of the WECC was represented as non-WMEG.

2030, 2035). Following the WMEG analysis, Bonneville contracted directly with E3 in 2024 for supplemental analysis using the WMEG data set to test additional market footprints and sensitivities of a number of other variables. This section discusses both sets of PCM analyses.

5.1.1.1. What is Production Cost Modeling?

PCM is an industry standard simulation software tool that attempts to model a day-ahead market by producing a least-cost dispatch to serve load based on a set of static input data. PCM incorporates SCUC and SCED, which are the processes the day-ahead market uses to optimize participants' loads, resources, and transmission.[45] The analysis produces hourly generation dispatches and associated electricity production costs to serve load based on numerous operational inputs. Such inputs include loads, generation resources, weather, fuel, and transmission connectivity/constraints.

There are many underlying assumptions that must be made to model such a complex system. In particular, the study results are highly dependent on the composition of the market footprint (i.e., which load, generation, and transmission are included in the market optimization). Identifying a market footprint requires assumptions about which market a utility may choose to join. The footprint composition brings together the resources that will be optimized to serve load at the least cost and is constrained by the transmission connectivity that is utilized by the market to deliver all the footprint resources to load. Adjusting the market participants, and therefore changing the footprint, can offer additional load to be served, additional generators to serve load, and new transmission connectivity that expands the possible solutions of the market optimization. Therefore, the composition of the market is an important and influential component in PCM.

PCM must also assume the cost associated with transmission within a market (usually assumed to be zero) and transmission and other incremental "friction" between markets (sometimes called the "hurdle rate"). Hurdle rates represent the "friction" between markets, which could come in the form of actual costs associated with sales across markets, or as a representative cost representing the inefficiency of two separate optimizations (one for each footprint) as opposed to a single optimization. This could show up as price divergence between markets such that the price in one market must be high enough to incentivize exporting from the other market. Much like the footprint composition, the adjustment (i.e., reduction and variation) in the hurdle rate also proved to be a notable operational model input.

PCM is a powerful tool that relies on a range of assumptions to produce modeling results that provide direction and magnitudes of market participation outcomes. PCM comes with both strengths and limitations. It produces simulations that optimize dispatch of resources to meet demand at the lowest possible cost, facilitate long-term planning and investment decisions, inform policy making and potential regulatory impacts, and provide insight for market dynamics and analysis to help understand price trends and identify opportunities for cost savings. The limitations of PCM are discussed further in the section below.

5.1.1.1.1. Production Cost Modeling Limitations

PCM is a useful industry-standard tool, however, it is accompanied by certain limitations. In PCM, a range of assumptions are required to produce effective modeling. While PCM results are useful in providing market participation outcomes, these results do not represent an exact expected outcome. Moreover, while PCM is a valuable industry standard method to simulate friction and hurdle rates, it is prudent to acknowledge that actual real-world values of friction and hurdle rates may differ from simulated results because of the inherent complexity, uncertainty, and variability associated with the assumptions and data quality in the model. For example, some entities view long-term firm transmission cost as a sunk cost and therefore do not include it in their price evaluation in their decision of whether they transact between

[45] For information on day-ahead market processes, see section 2.4 above.

markets. Further, there is not a single value that uniformly represents the risk that sellers are willing to take on, and thus a modeled hurdle rate can never perfectly represent reality.

In the supplemental analysis, E3 ran case studies to simulate scarcity events through the application of stressed conditions.[46] Specifically, E3 applied stressed conditions to the following market footprints 1) Business-as-usual, 2) West-wide market, 3) Alt Split 4A (current market declarations). In the results of these cases, net costs showed a minimal decline and prices in the model did not rise nearly as significantly as would be expected.

The minimal change in forecasted benefits in the PCM results stand in stark contrast to real-world outcomes from recent events such as the 2024 Martin Luther King, Jr. (MLK) holiday weekend winter storm. During that short period of time, the region faced significant competition for available resources to meet load accompanied by hourly prices exceeding the WECC soft-offer cap of $1,000 per megawatt-hour (MWh). There was also significant congestion on key transmission paths and congestion revenues within WECC exceeded $100 million dollars. The 2024 MLK weekend event represents an extreme outlier that a PCM cannot replicate. A typical scarcity outlier, experienced over a few days to a week, will likely see multi-hour, peak load block prices rise to triple digits. Frequently, evening hourly prices will rise above this into the mid-to-high hundreds, sometimes exceeding the WECC soft-offer cap, as loads are peaking and renewable resources are ramping down. The pricing levels reflected in the PCM captured neither the extreme event like a 2024 MLK, nor the more typical scarcity event of sustained elevated prices. The PCM pricing outputs simply do not reach the magnitude nor the daily sustained level of pricing that we would expect to see, even under the stressed load parameters. The minimal decline in net cost results for stressed conditions in the PCM study demonstrates that the financial impacts of a scarcity event are not captured in the modeling. Regardless of day-ahead markets, such events occur, and Bonneville simply acknowledges that these risks are not fully represented in the PCM study.

Additionally, PCM studies do not reflect various market design elements such as GHG pricing programs, market power mitigation, out-of-market actions, and market bid caps. Lastly, PCM results cannot account for market design changes and modifications to market rules influenced by the market's governance structure. Bonneville explores a number of these design elements in section 5.2.

5.1.1.2. WMEG Study

Bonneville participated in WMEG with 24 other BAAs in a joint exploration of day-ahead market participation. The WMEG group sought economic analysis results that would help forecast costs and benefits associated with day-ahead market participation for each BAA participating in the study. E3 used PCM to develop categorical results, discussed below in section 5.1.1.2.2, for each BAA. The categorical results were summed together to create a single "net cost" number, which was intended to indicate whether costs or benefits were likely for a given BAA's participation in a day-ahead market. The PCM studies were modeled across three different time horizons of 2026, 2030, and 2035. The 2026 scenarios depicted initial day-ahead market launch. The 2030 scenarios assumed maturation of the day-ahead market by layering on some BAA consolidation and an ancillary services market. The 2035 scenarios modeled a full RTO, which consisted of a single consolidated BAA (however, it did not include any estimates of transmission cost savings). Load, generation, and transmission were also augmented in future cases, reflecting anticipated growth in each category. Each participating BAA received only their respective results, though they were free to share their results on a wider basis. Bonneville publicly released its WMEG PCM results in the fall

[46] Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation at 4, 11 (Nov. 4, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf (Task 3: Low Water Year (+ Stressed Load)).

of 2023 in public workshop 3.[47]

5.1.1.3. WMEG Data Elements

Each WMEG member provided generation, transmission, and load data to E3 for use in the PCM to model market activity and calculate categorical costs and benefits. This data was retained by E3 following the completion of the initial WMEG study and used in the supplemental analysis that Bonneville requested.

5.1.1.3.1. WMEG Cost Benefit Categories

The PCM results consisted of eight distinct categories: load costs, generation costs, reserve costs, reserve revenue, generation revenue, wheeling revenue, congestion revenue, and GHG revenue. It is important to emphasize that the results are reported such that costs are represented as positive numbers and revenues are represented as negative numbers (as indicated by the positive or negative sign in the category list below). The eight categories were then added together to create a "net cost," which indicated whether the WMEG member should expect a cost or benefit. Again, a positive "net cost" indicated cost to the WMEG member because of day-ahead market participation, and a negative "net cost" indicated benefits to the WMEG member because of day-ahead market participation.

Net Variable Cost = Load Cost + Generation Cost + Reserve Cost – Reserve Revenue – Generation Revenue – Wheeling Revenue – Congestion Revenue – GHG Revenue

The following are the categories from the PCM results accompanied by their applicable sign:

PCM Results Categories (as defined in E3's Western Markets Exploratory Group: Western Day -Ahead Market Production Cost Impact Study)[48]

1. Load Costs (+)

Entities incur a cost to serve load based on (a) the hourly quantity of load (in MWh) that the entity is obligated to serve in each zone of the model times (b) the hourly zonal energy price

2. Generation Costs (+)

The model reports variable production costs for each generating unit as the sum of fuel costs, startup costs, and variable O&M cost for that resource. Generation Costs are attributed to each entity as (a) the total variable production cost of the unit times (b) the percentage share of that unit that is owned or contracted to the entity.

3. Reserve Costs (+)

In the Business-as-Usual (BAU) Case, E3 enforces ancillary service reserve requirements at the BAA level but does not settle these products at a market clearing price. For all the market cases, day ahead forecast error reserves are enforced at the level of a subregion within each market (e.g. the Northwest portion of Markets+), and each entity is assigned a Reserve Cost responsibility based on of (a) the hourly quantity of reserves that entity needs times (b) the hourly market price for reserves within that market sub-region.

4. Reserve Revenue (-)

Each entity is also awarded Reserve Revenue from the market based on (a) the quantity of reserves that are contributed by generators owned or contracted by the entity times (b) the hourly market price for reserves

[47] For results, see Bonneville Power Administration, Day-Ahead Market, *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market (*see* Workshops, Oct. 23, 2023, WMEG Materials).
[48] Energy and Environmental Economics, Western Markets Exploratory Group: Western Day Ahead Market Production Cost Impact Study at 9-11 (June 2023), *available at* http://www.oasis.oati.com/woa/docs/NEVP/NEVPdocs/3._E3_WMEG_Western_Day_Ahead_Market_Production_Cost_Impact_Study_-_Final.pdf.

within that market subregion. In the 2030 and 2035 CBA cases, Reserve Costs and Reserve Revenues are calculated separately for each reserve product (spinning reserves, non-spinning reserves, and regulating reserves, as well as day ahead forecast error reserves)

5. Generation Revenue (-)

Generation Revenue is first calculated for each resource based on (a) the hourly energy produced by the generator, times (b) the hourly price at the generator's zone. This Generation Revenue is then attributed to each entity based on the percentage share of each resource that is owned or contracted to the entity

6. Wheeling Revenue (-)

Wheeling revenue is revenue that transmission providers earn by selling transmission service. In the BAU Case, total Wheeling Revenue is calculated in the model for each entity based on the product of (a) the amount of energy exported over transmission lines connected to that entity, times (b) the OATT rate or market wheeling rate applicable that BAA or transmission entity, plus an additional $/MWh charge for bilateral day ahead market friction. In the RT stage of the BAU Case, wheeling is not charged for transactions between entities in the WEIM or WEIS market. In the DA markets cases, total wheeling revenue is first determined at a market-footprint level based on the (a) amount of energy flowing exported over transmission lines connected to each market footprint times (b) the load-weighted average of OATT rates of zones participating in that market, plus an additional $/MWh charge for transactional friction on seams between the markets. This total market wheeling revenue is then distributed among market participants based on each participant's percentage share of total load in the market (load-ratio share basis).

7. Congestion Revenue (-)

Price differentials between zones due to transmission constraints creates congestion between entities, resulting in loads paying higher prices than remote generators receive on the other side of congested interface. The value of this difference is assigned back to the entities in the BAU case and for lines within each market footprint. Congestion on the border of each market is allocated among all participants in that market on a load ratio share basis.

8. GHG Revenue[49] (-)

Revenue associated with any MW of generator output that was attributed as an import into a state with a pricing program (CA/WA). The way Bonneville elected to model its resources in the E3 studies resulted in minimal attribution of imports.

9. Net Cost (+) OR (-)

The difference between the Net Variable Costs for an entity in a market case compared to that entity's Net Variable Revenues.

5.1.1.3.2. Bonneville's Modified Calculation of Net Cost

As Bonneville examined the PCM results, it became evident that certain categories could be set aside, and a net cost could be recalculated with the remaining categories. Bonneville set aside generation cost, reserve cost, and reserve revenue because they were a static or negligible value, meaning there was zero or almost zero difference among scenarios. Further, after some conversation with E3 regarding wheeling revenue, Bonneville and E3 determined that the study approach did not attempt to capture existing transmission contracts. Instead, it assumed that all transactions outside of or between markets required incremental purchase of transmission and that all transactions within a market required no purchase of transmission. These assumptions do not approximate likely transmission purchase patterns for Bonneville customers and therefore do not appropriately reflect a likely outcome of market participation. Therefore, Bonneville

[49] The text of Result Category No. 8 has been modified from the E3 report for clarity.

removed the wheeling revenue category from the net cost computation when analyzing the PCM results.[50] Based on the negligible value category exclusions and wheeling revenue exclusion, the results discussed throughout the rest of this document focus on PCM results for load costs, generation revenue, congestion revenue, and GHG revenue, and a net cost summing those four categories (reported as "Net Cost without Wheeling" for clarity). Bonneville separately provides an analysis of the potential impact to transmission revenues in section 5.1.1.7.

Net Cost = Load Cost – Generation Revenue – GHG Revenue – Congestion Revenue

5.1.1.3.3. WMEG Footprints

Of the 38 BAAs in WECC, spanning from Canada to Mexico, 25 participated in the WMEG study. In all cases except for a "business as usual" (BAU) case, each BAA in WECC was designated to fall within one of two categories to comprise a day-ahead market footprint:

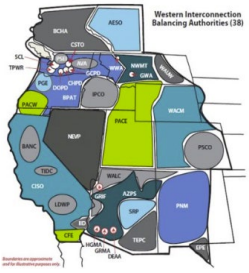
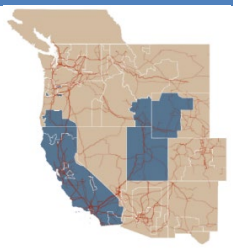
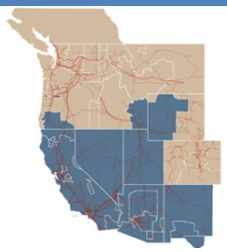
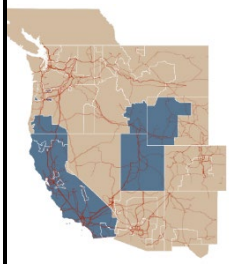
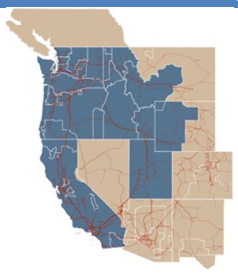
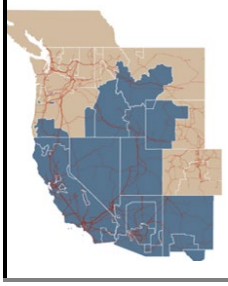
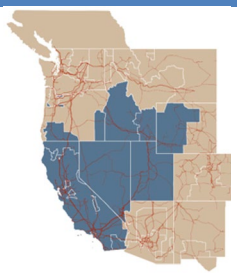
1) The BAA participates in EDAM,

2) The BAA participates in Markets+

During the initial 2023 PCM analysis, WMEG members designed a number of footprint scenarios representing the footprints that they determined were most plausible to test the impacts of different market footprints on the benefits. WMEG also included a BAU scenario to represent continued bilateral trading without any entities joining a day-ahead market. These footprints are shown in Table 1 on the next page.

[50] Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation at 20.

Table 1 | Footprints used in WMEG studies

Business-as-Usual	Main Split
 This footprint was intended to model the operational and trading world as it exists today. Bilateral trading (no centralized market) in day-ahead; EIM & EIS cover most of WECC in real-time stage	 PacifiCorp (PAC) + all of California (including Western Area Power Administration Sierra Nevada Region (WAPA SNR)) in EDAM; rest of WECC in Markets+
EDAM Bookend	**Alternative Split 1**
 All US WECC in EDAM; British Columbia Hydro only in Markets+	 PAC + California (excluding WAPA SNR) + SW (AZ + NM + NV) in EDAM; rest of WECC in Markets+
Markets+ Bookend	**Alternative Split 2**
 PAC, CAISO, Los Angeles Department of Water & Power. Turlock Irrigation District, Balancing Authority of Northern California (BANC) (not WAPA SNR) in EDAM; rest of WECC in Markets+ (including WAPA SNR)	 PAC + California (including WAPA SNR) + NW (WA, OR, ID, NWMT) in EDAM; rest of WECC in Markets+
Alternative Split 3	**Alternative Split 4**
 PAC + California (excluding WAPA SNR) + SW + ID + NWMT in EDAM; rest of WECC in Markets+	 PAC + California (excluding WAPA SNR) + ID + NV in EDAM; rest of WECC in Markets+ [Same as Markets+ Bookend, but NV & ID move to EDAM]

5.1.1.3.4. Bonneville's WMEG PCM 2023 Results

Table 2 shows a summary of Bonneville's results across the footprint scenarios. The top half of the table reflects the categorical results as absolute costs (positive numbers) or revenues (negative numbers). The bottom half calculates the delta result for each scenario relative to the BAU scenario. Again, a positive number represents an increased cost or a decreased revenue (and is accompanied by a red dot), and a negative number represents a decreased cost or an increased revenue (and is accompanied by a green dot).

The full set of Bonneville's initial WMEG results are available on Bonneville's website.[51]

Table 2 | Bonneville's WMEG Results (Fall 2023, units in millions of dollars)

	A	B	C	D	E	F	G	H	I	J
1	Footprint									
2		Cost/Benefit Category	BAU (2026)	EDAM Bookend (2026)	Main Split (2026)	Markets Bookend (2026)	Alt Split 1 (2026)	Alt Split 2 (2026)	Alt Split 3 (2026)	Alt Split 4 (2026)
3	Category Value	Load Costs	921	944	924	902	919	982	840	861
4		Gen Costs	131	131	131	131	131	131	131	131
5		Gen Revenues	-1341	-1490	-1370	-1329	-1360	-1515	-1152	-1220
6		Congestion Revenues	-50	-60	-53	-53	-48	-49	-51	-48
7		GhG Revenues	0	0	-1	-1	-1	0	-1	-1
8		**Net Costs w/o Wheel**	**-339**	**-475**	**-369**	**-349**	**-359**	**-451**	**-233**	**-277**
9	Δ Category vs. BAU	Δ Load Cost		23	3	-19	-2	61	-81	-60
10		Δ Gen Revenue		-149	-29	12	-19	-174	189	121
11		Δ Congestion Revenue		-10	-3	-3	2	1	-1	2
12		Δ GhG Revenue		0	-1	-1	-1	0	-1	-1
13		**Δ Net Cost w/o Wheel**		**-136**	**-30**	**-10**	**-19**	**-112**	**107**	**62**

Green = Benefit Greater than BAU **Red = Increased Cost from BAU**

Starting with the top half of the table, the PCM results forecast Bonneville to achieve net benefit in each of the eight cases in Table 2 (see row 8). Moving to the bottom half of the table, benefits greater than BAU are achieved in five out of seven footprints (all footprints except Alt Split 3 and Alt Split 4). Alt Splits 3 and 4 results forecast reduced benefits relative to BAU. While those footprints project significant cost savings in serving load,[52] the reduction in projected benefits relative to BAU is driven by generation revenues declining[53] more than the load costs decline. The generation revenue declines are driven by lower marginal prices observed in these footprints, as Bonneville is a net exporter in the generation data provided, resulting in the impact to revenue outweighing the savings to load.

Notably, Bonneville determined that the BAU scenario studied by E3 assumes all utilities forgo day-ahead market participation and cannot account for what entities will do in the long term. As discussed above in section 5.1.1.2.4, the BAU case fundamentally assumes continued use of bilateral trading activity as the primary tool for energy trading and limited organized market activity (i.e., real-time only). With many entities in WECC evaluating participation and declaring intent to join organized day-ahead markets, the bilateral world, as it is today, is not expected to persist. Bonneville included modeled costs and benefits relative to BAU to provide a sense of the magnitude, and the direction of the impact day-ahead market participation has relative to today. BAU does not represent a realistic future scenario.

5.1.1.4. Bonneville's Supplemental Cost/Benefit Analysis 2024

Bonneville engaged E3 to perform additional supplemental analysis to enhance its modeling and assumptions for its evaluation of potential day-ahead market participation. Following the release of the WMEG PCM results and review of stakeholder comments on Bonneville's WMEG results, Bonneville requested E3 to assess additional market footprints and identified scenarios or variables. For the supplemental tasks that used years 2030 and 2035, there were no market maturation pieces layered on the analysis. The new studies applied only load growth, modifications to generation resources (e.g., new builds and retirements), and additions to the transmission grid (e.g., new transmission lines) to the respective year-based cases. The additional PCM analyses are listed below. The full set of Bonneville's PCM results are

[51] Bonneville Power Administration, Day-Ahead Markets *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.

[52] Alt Split 3 Load Cost reduced by $81m as shown in cell I9; Alt Split 4 Load Cost reduced by $60m as shown in cell J9.

[53] Alt Split 3 Gen Rev declines by $189m as shown in cell I10; Alt Split 4 Gen Rev declines by $121m as shown in cell J10.

available on Bonneville's website.[54]

Note: During the development and execution of the supplemental analysis, Bonneville and E3 identified an issue regarding data underlying the "generation revenue" category. The generation values supplied by Bonneville to E3 were reflective of all generation, including generation applicable to the Slice product. Bonneville and E3 decided to apply a 15% reduction to generation revenue results in the supplemental analysis to ensure generation revenue more accurately reflected Bonneville's estimated share of generation. This reduction was discussed with all stakeholders during the public workshop on November 4, 2024.[55]

5.1.1.4.1. Supplemental Analysis Tasks

1) (Single West-wide Market) | Compute PCM cost benefit values for Bonneville for the EDAM Bookend Footprint for 2030 and 2035.
2) Lower Market to Market Hurdle Rates | Adjust the Market-to-Market hurdle rates by running three sensitivities that progressively reduce the hurdle rates.
3) Low Water Year (& Stressed Conditions) | Compute PCM cost benefit values for Bonneville for reduced hydro resources due to poor rain and snowpack. Model increased loads to mimic stressed conditions resulting from a multi-day heat and multi-day cold event.
4) Bonneville WEIM-Only | Compute PCM cost benefit values for Bonneville where Bonneville decides not to participate in a day-ahead market but remains a participant in CAISO WEIM. Neighboring and adjacent BAAs proceed with day-ahead market participation.
5) Additional Transmission Capacity | Compute PCM cost-benefit values for Bonneville where transmission connectivity between the Pacific Northwest and the Desert Southwest is increased.
6) Potential Capacity Value | Estimate the range of potential capacity benefits associated with day-ahead market participation.
7) Market Seam at California Border | Compute PCM cost benefit values for Bonneville where only entities lying within the state boundary of California participate in EDAM.
8) Alt Split 4A – Market Declarations | Compute PCM cost benefit values for Bonneville utilizing a two-market footprint that reflects the current market declarations and leanings.
9) Alt Split 2NV Pacific Northwest & Nevada join | Compute PCM cost benefit values for Bonneville where the Pacific Northwest, California, Nevada, and PAC BAAs are modeled as participants in EDAM while the Desert Southwest BAAs are modeled in Markest+.

Supplemental Analysis that was identified but unable to be modeled in PCM - No results were provided by E3

1) Market Interactions with WRAP | Understanding the potential difference in ability of either market's rules & practices to enable realization of RA benefits.
2) GHG Regulation | Understanding the impact that Markets+ vs. EDAM rules regarding GHG import treatment and pricing specific to the treatment of resources contracted to load in a GHG zone.

5.1.1.4.2. Supplemental Analysis Footprints

The supplemental analysis used several of the initial WMEG footprints in conjunction with the new footprints in Table 3. Each new footprint was added for a specific reason. Alt 2NV was designed to represent a more realistic scenario in which Bonneville is in EDAM while the Desert Southwest, which is unlikely to

[54] Bonneville Power Administration, Day-Ahead Markets *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.
[55] *Id.*

join EDAM, is in Markets+. Alt 4A was designed to reflect utilities' market declarations and publicly stated leanings available at the time of the analysis. The Non-California West-wide Market footprint was added to see what west-wide benefits could be realized without the complexities presented in attempting to address CAISO's governance. These three additional footprints were used in various combinations with some of the above tasks, but not all additional footprints were tested for every task above.

Table 3 | Updated footprints for additional E3 studies

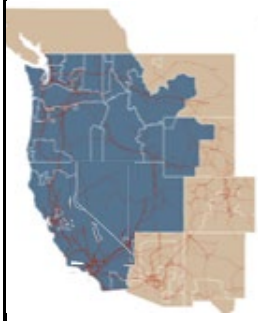
Alternative Split 2NV	Alternative Split 4A
 **EDAM:** California, PacifiCorp, NV Energy & all Pacific Northwest BAAs **Markets+:** BAAs located in the Desert Southwest and Rockies	 **EDAM**: California, PacifiCorp, NV Energy, Idaho Power, Portland General Electric, Seattle City Light **Markets+:** Rest of US WECC and British Columbia ***Reflects current day-ahead market declarations & leanings***
Non-CA Westwide Markets+	
 **EDAM:** California LSE's Only **Markets+:** Rest of US WECC and British Columbia	

Table 4 | Supplemental PCM Case Results[56]

- Section 1 of the table shares the raw case results by category for each of the supplemental analysis cases supplied by E3.
- Section 2 calculates the delta for each category of each case against anchor point BAU.
- Section 3 calculates the delta for each category of each case against anchor point Alt Split 4A.
- Positive numbers are costs and negative numbers are benefits.
- Red dots indicate a cost increase between the case and the anchor point.
- Green dots indicate a benefit increase between the case and the anchor point.

Table 4 | E3 Supplemental PCM results | Δ Supplemental case vs BAU | Δ Supplemental case vs Alt Split 4A

	Supplemental Analysis																						
	Cost/Benefit Category	BAU (2026)	T9 | Alt Split 4A (2026)	T2 | Alt Split 4A M2M (2026)	T2 | Alt Split 4A M2M2 (2026)	T2 | Alt Split 4A M2M3 (2026)	T2 | Main Split M2M (2026)	T2 | Main Split M2M2 (2026)	T2 | Main Split M2M3 (2026)	T3 | BAU Low Water (2026)	T3 | BAU Low Water & Stressed Loads (2026)	T3 | Alt Split 4A Low Hydro (2026)	T3 | Alt Split 4a Low Hydro & Stressed Loads (2026)	T3 | EDAM Bookend Low Water (2026)	T3 | EDAM Bookend Low Water & Stressed Loads (2026)	T4 | Alt Split 4A BPA EIM ONLY (2026)	T4 | Alt Split 4A BPA EIM ONLY Low Hydro Stress Load (2026)	T4 | EDAM Bookend BPA EIM ONLY Low Hydro Stress Load (2026)	T5 | Alt Split 4A Straw (2026)	T5 | Hypothetical New Additional TX (2026)	T10 | Non-CA WestWide M+ (2026)	T11 | Alt Split 2NV (2026)
E3 Supplemental PCM Results	Load Costs	921	739	818	874	910	961	981	983	1104	1132	957	1001	1043	1067	908	1109	1018	780	811	890	873
	Gen Costs	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131
	Gen Rev**	-1140	-835	-987	-1097	-1166	-1231	-1365	-1279	-1201	-1218	-1032	-1067	-1184	-1201	-1129	-1203	-1203	-1104	-977	-1182	-1156
	Congestion Rev	-50	-65	-59	-56	-57	-52	-54	-57	-30	-30	-39	-39	-39	-38	-69	-31	-31	-58	-88	-46	-44
	GhG Rev	0	0	0	0	0	-1	-1	-1	0	0	-1	-1	0	0	0	0	0	0	0	0	0
	Net Cost w/o Wheel	**-138**	**-30**	**-98**	**-148**	**-182**	**-192**	**-208**	**-222**	**4**	**15**	**16**	**26**	**-50**	**-42**	**-160**	**5**	**14**	**-61**	**-123**	**-207**	**-195**
Δ BAU vs Supplemental Case	Δ BAU | Load Cost		-182	-103	-47	-11	40	60	62	183	211	36	80	122	146	-13	188	97	-141	-110	-31	-48
	Δ BAU | Generation Rev		305	153	43	-26	-91	-125	-139	-61	-78	108	73	-45	-62	11	-63	36	226	163	-42	-15
	Δ BAU | Congestion Rev		-15	-9	-6	-7	-2	-4	-7	20	20	11	11	11	12	-19	19	19	-8	-38	4	6
	Δ BAU | GhG Rev		0	0	0	0	-1	-1	-1	0	0	-1	-1	0	0	0	0	0	0	0	0	0
	Δ BAU | Net Cost w/o Wheel		**108**	**41**	**-10**	**-44**	**-54**	**-69**	**-84**	**142**	**153**	**154**	**164**	**89**	**96**	**-22**	**143**	**152**	**78**	**15**	**-69**	**-57**
Δ Alt Splits 4A vs Supplemental	Δ Alt 4A | Load Costs	182		79	136	171	222	242	245	366	393	218	262	305	328	169	371	280	42	72	151	134
	Δ Alt 4A | Gen Rev	-305		-152	-262	-331	-397	-430	-445	-366	-384	-198	-232	-350	-367	-294	-369	-270	-79	-142	-347	-320
	Δ Alt 4A | Congestion Rev	15		6	9	8	13	11	8	35	35	26	26	26	27	-4	34	34	7	-23	19	21
	Δ Alt 4A | GhG Rev	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Δ Alt 4A | Net Cost w/o Wheel	**-108**		**-67**	**-118**	**-152**	**-161**	**-177**	**-192**	**35**	**45**	**47**	**56**	**-19**	**-12**	**-129**	**36**	**44**	**-30**	**-92**	**-177**	**-165**

Green = Benefit Greater than anchor point Red = Increased Cost than anchor point

**Generation Revenue has been reduced by 15% to reflect slice revenue reduction

Table 5 | Consolidated supplemental case results for Alt Split 4A, Alt Split 4A WEIM Only, Alt Split 2NV, Alt Split 4A M2M, Alt Split 4A M2M2, and Alt Split M2M3

[56] During the development and execution of the supplemental analysis, Bonneville and E3 identified an issue regarding the "Generation Revenue" category. The load values provided by Bonneville to E3 reflected the preference load that Bonneville serves. The Generation values supplied by Bonneville to E3 were reflective of all generation including generation applicable to the Slice product. Bonneville and E3 decided to apply a 15% reduction to Generation Revenue results in the supplemental analysis to ensure Generation Revenue reflected Bonneville's estimated share of generation. This reduction was discussed with all stakeholders the public workshop 9 on November 4, 2024.

	A	B	C	D	E	F	G
	BPA Day-Ahead Market →	Markets+	No DAM Market WEIM-Only	EDAM	Markets+	Markets+	Markets+
1		Alt Split 4A (2026)	Alt Split 4A BPA WEIM-Only (2026)	Alt Split 2NV (2026)	Alt Split 4A M2M (2026)	Alt Split 4A M2M2 (2026)	Alt Split 4A M2M3 (2026)
2	Cost/Benefit Category				Declining Hurdle Rates		
3	Load Costs	739	908	873	818	874	910
4	Gen Rev	-835	-1129	-1155	-987	-1097	-1166
5	Gen Costs	131	131	131	131	131	131
6	Congestion Rev	-65	-69	-44	-59	-56	-57
7	GhG Rev	0	0	0	0	0	0
8	**NC w/o Wheel**	**-30**	**-160**	**-196**	**-97**	**-148**	**-182**
9	Δ Alt 4A | Load Costs	--	169	134	79	136	171
10	Δ Alt 4a |Gen Rev	--	-294	-320	-152	-262	-331
11	Δ Alt 4A |Congestion Rev	--	-4	21	6	9	8
12	Δ Alt 4A | GhG Rev	--	0	0	0	0	0
13	**Δ Alt 4A |Net Cost w/o Wheel**	**--**	**-130**	**-166**	**-67**	**-118**	**-152**
14	**Δ Alt 4A M2M's vs Alt Split 4A WEIM-Only Net Cost w/o Wheel**	--	--	--	**63**	**12**	**-22**
15	**Δ Alt 4A M2M's vs Alt Split 2NV Net Cost w/o Wheel**	--	--	--	**99**	**48**	**14**

These PCM cases were the most stakeholder-cited cases in responses to the Draft Policy.

Supplemental Case Results[57]

On the next page, Bonneville discusses the results from the supplemental analyses. In each case, the figures show raw case results and do not reflect differences against any other study case, though the original BAU result is plotted for reference. Negative numbers represent forecasted benefit, and positive numbers represent forecasted costs.

Figure 2 | All Supplemental Case Results

Figure 2 plots each of the supplemental case results together on a single chart. 2026 case results are depicted with circles, 2030 case results are depicted with triangles, and 2035 case results are depicted as diamonds. Yellow and orange denote dry water years and dry water years accompanied by stressed loads. Purple shades denote modifications to hurdle rates in the model.

[57] Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation (Nov. 4, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf.

Figure 2 | E3 PCM results

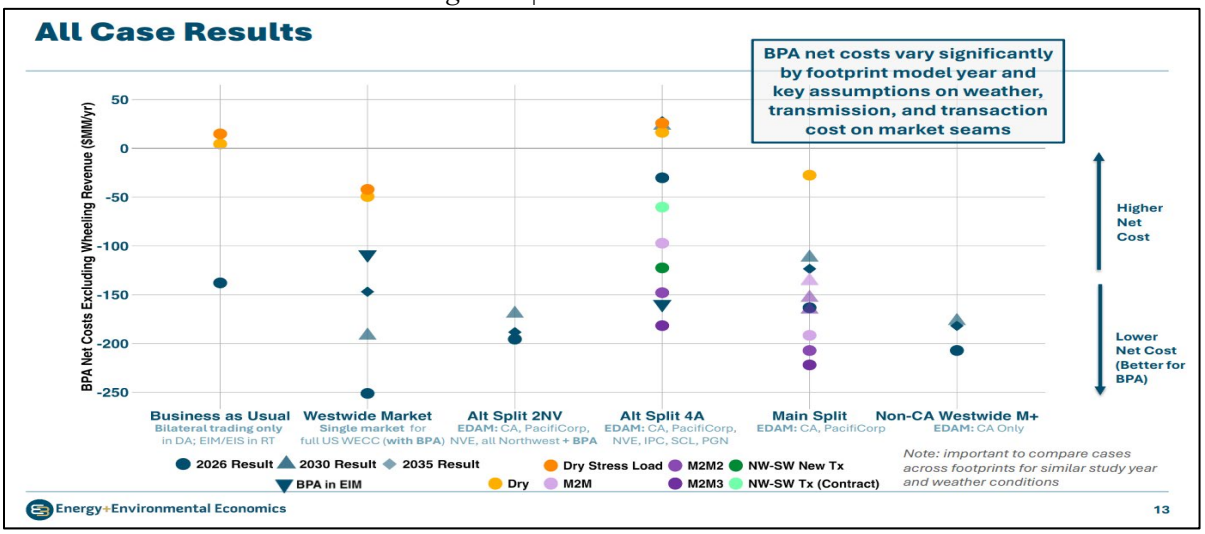


***Figure 2 Takeaway*:** Range of possible outcomes depending on various factors.

This graph shows the comparative impact of individual variables against each other. The graph illustrates an array of potential outcomes impacted by footprint composition, transmission connectivity, and other tested sensitivities. While Figure 2 plots all supplemental case results, not all case results are discussed in detail in the following sections. West-wide Market, Main Split, and Non-CA West-wide M+ are not feasible footprints due to market participation declarations already issued by BAAs.

Figure 3 | 2026 Base Footprint Results

Figure 3 plots 2026 supplemental case results including the new footprints as defined above plotted against some of the original WMEG footprints. We see that both the Alt Split 2NV case and the Non-California West-wide Market result in benefits above the BAU case, whereas Alt Split 4A results in benefits less than the BAU case.

Figure 3 | E3's 2026 Results

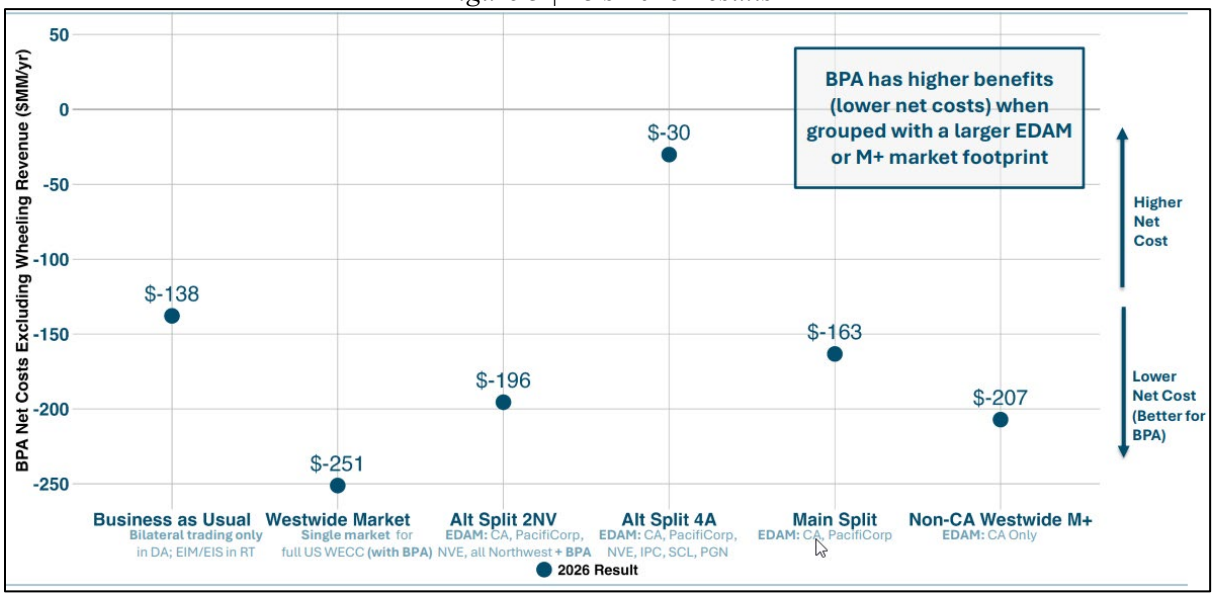


Table 6 | Alt Split 4A vs BAU

	N	O	R
1			
2	**Cost/Benefit Category**	**BAU (2026)**	**T9 | Alt Split 4A (2026)**
3	Load Costs	921	739
4	Gen Costs	131	131
5	Gen Rev	-1140	-835
6	Congestion Rev	-50	-65
7	GhG Rev	0	0
8	**Net Cost w/o Wheel**	**-138**	**-30**
9			
10	Δ BAU | Load Cost		-182
11	Δ BAU | Generation Rev		305
12	Δ BAU | Congestion Rev		-15
13	Δ BAU | GhG Rev		0
14	**Δ BAU | Δ Net Cost w/o Wheel**		**108**

Table 7 | Alt Split 2NV vs BAU

	N	O	AK
1			Supplemental
2	**Cost/Benefit Category**	**BAU (2026)**	**T11 | Alt Split 2NV (2026)**
3	Load Costs	921	873
4	Gen Costs	131	131
5	Gen Rev	-1140	-1155
6	Congestion Rev	-50	-44
7	GhG Rev	0	0
8	**Net Cost w/o Wheel**	**-138**	**-195**
9			
10	Δ BAU | Load Cost		-48
11	Δ BAU | Generation Rev		-15
12	Δ BAU | Congestion Rev		6
13	Δ BAU | GhG Rev		0
14	**Δ BAU | Δ Net Cost w/o Wheel**		**-57**

***Figure 3 Takeaway*: Footprint is a primary driver of results.**

As discussed previously, the PCM results are highly dependent on the market footprint. Because Bonneville is a net exporter in the generation input data provided, footprints with higher LMPs, particularly during times of surplus hydro, result in increases to generation revenue that outstrip the increases to load cost. We see this in the Alt Split 4A results, where load costs go down by $182 million (see cell R10), but generation revenues go down by more ($305 million, see cell R11). Alt Split 2NV seems to balance this impact. The results show a smaller decrease to load costs than Alt Split 4A ($48 million, see cell AK10), but an increase to generation revenue ($15 million, see cell AK11). This is likely due to the timing of price fluctuations.

It is not possible to predict with absolute certainty which footprint will ultimately materialize. As seen in Figure 2 and Table 2, the initial and supplemental PCM analyses resulted in a range of cost or benefit outcomes. Given that there are two day-ahead market options in the region, both with substantial support from various entities across the West, Bonneville determined that it is best to look at the results for footprints with multiple markets. Based upon the information and the modeled footprints available, Bonneville sees Alt Split 4A (see Table 6) as the most realistic footprint with Bonneville in Markets+ and Alt Split 2NV (see Table 7) as the most realistic footprint with Bonneville

in EDAM.

Alt Split 4A is a two-market scenario that divides participation between EDAM and Markets+. Geographically, Markets+ is divided into two regional areas. The first being the Pacific Northwest and the second being the Desert Southwest. EDAM participants are forecasted to lie between these two regional areas, creating a geographic division. The Net Cost without Wheeling Revenue forecast is an annual benefit of $30 million (as noted in Table 2 T9 – Alt Split 4A 2026), which is a decrease from the BAU case. The decline in benefit appears to be driven by a notable drop in Generation Revenue. Interestingly, this case also forecasts significant savings in Load Cost. Both the Generation Revenue decline and Load Cost savings are the product of lower locational marginal prices in Markets+ (relative to BAU). This footprint demonstrates the dichotomy between seeking the lowest cost to serve load and seeking to maximize value for surplus generation. Bonneville must weigh the challenges of seeking the greatest revenue value for surplus generation, while recognizing that customers may also benefit from the lowest costs to serve load.

Alt Split 2NV is a two-market scenario in which Bonneville, the Pacific Northwest, California, Nevada, and PacifiCorp's service territory are depicted as EDAM participants. Entities located in the Desert Southwest are modeled as Markets+ participants. This footprint creates geographical division, but, unlike in Alt Split 4A, each market maintains contiguous transmission connectivity. The Net Cost without Wheeling Revenue forecasts a benefit of nearly $200 million. When compared to BAU, Alt Split 2NV forecasts to be nearly $60 million better. Examining the categorical differences between cases shows that $48 million in Load Cost savings is driving the forecasted benefit.

Figure 4 | Base Footprint Results & WEIM-Only Results

Figure 4 plots 2026 supplemental case results and layers on the two WEIM-only scenarios that were modeled. In the WEIM-only cases, Bonneville remains outside day-ahead markets while continuing to be a WEIM participant, and the other entities in WECC participate in the day-ahead market in varying footprints. The WEIM-only option was evaluated for the West-wide Market footprint and Alt Split 4A footprint. (Note that Bonneville had not yet developed the Alt Split 2NV footprint for use in this task, so it was not modeled.) The arrows indicate the change in benefit to Bonneville of remaining a non-day-ahead market participant in the respective cases. Specifically, benefits for the West-wide market footprint decline from $251 million to $109 million. Conversely, Alt Split 4A sees an increase in benefit from $30 million to $160 million should Bonneville remain solely a WEIM participant. These are raw case results and do not reflect differences against any other study case.

Figure 4 | WEIM-only scenario

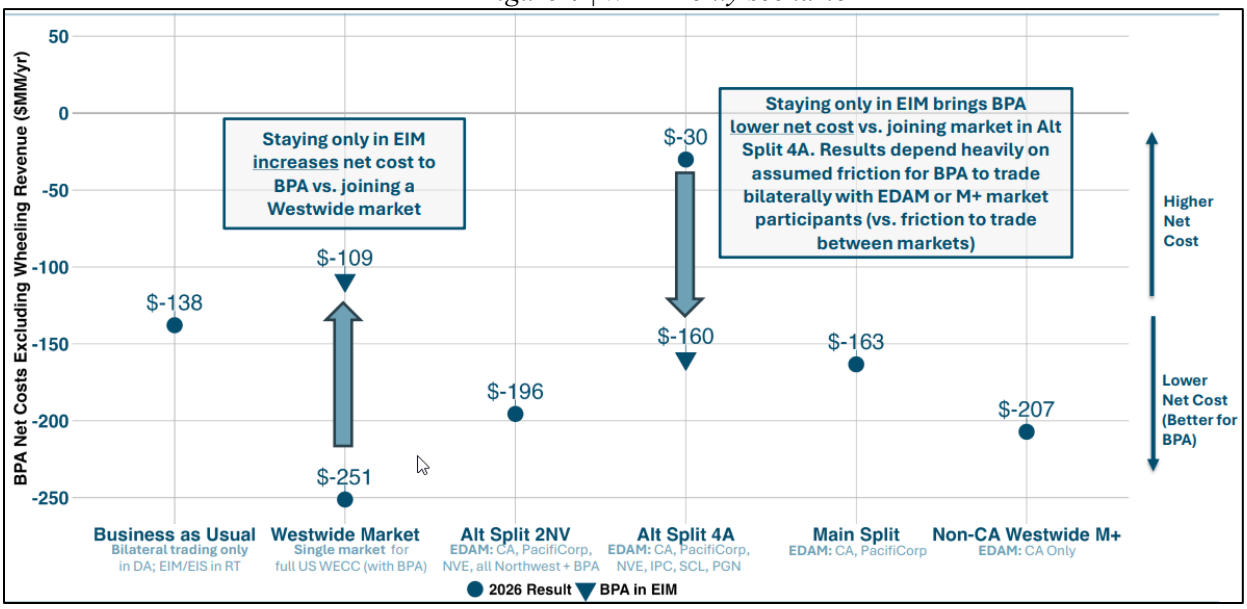


***Figure 4 Takeaway*: WEIM-only benefits appear positive but the analysis does not consider long-term viability questions.**

The results suggest Bonneville achieves benefit remaining outside of a day-ahead market, depending on the footprint. Compared to BAU, Bonneville would achieve benefits slightly greater than those in the current bilateral world if the Alt Split 4A footprint otherwise materializes. Comparing this WEIM-only case to that of Bonneville participating in Markets+ suggests that Bonneville achieves greater benefit by staying out of a day-ahead market. Alternatively, if the West-wide Market footprint materializes and Bonneville remains WEIM-only, Bonneville is modeled to see less benefit than being in EDAM and less benefit than BAU. However, these results cannot be viewed in a vacuum. Bonneville stresses that a significant limitation in these results is the assumption of a simple hurdle rate to access either market, which does not reflect the potential for decreased liquidity in the bilateral markets or increased friction to access either market as those markets grow. In addition, the reduction in access to trading partners may significantly degrade these results and make remaining a WEIM-only participant an unsustainable option in the long term.

Figure 5 | Base Footprint Results & Changing Hurdle Rates

Figure 5 plots 2026 supplemental case results testing multiple sensitivities of market-to-market (M2M) hurdle rates. The hurdle rates cases are noted in shades of purple (with lighter color representing a higher hurdle rate and darker color representing a lower hurdle rate) and were applied to Alt Split 4A and the Main Split footprints. The arrows indicate change in benefit for the respective cases. Both footprints demonstrate increased benefit as the hurdle rates are lowered. These are raw case results and do not reflect differences against any other study case.

As a reminder, hurdle rates are costs affiliated with transacting from one market to another. If no hurdle rate existed in the model, the market dispatch results would effectively be co-optimized results (like a single market footprint). This case study proposed to progressively lower the market-to-market hurdle rates with each new sensitivity. This was simulated through adjustment to transmission costs.

Table 8 | Hurdle Rate Descriptions & Value for M2M Cases

Hurdle Rates - Markets+ Footprint Exports						
WMEG	**Supplemental Analysis**					
	M2M		**M2M2**		**M2M3**	
Weighted Average OATT Rate of Market + Friction + Congestion Risk	**DA**	**Weighted Average OATT +$6 adder**	**DA**	**Weighted Average OATT + $3 adder**	**DA**	**50% of Weighted Average OATT + $3 adder**
	M2M DA = $10.50/MWh		**M2M2 DA = $7.50/MWh**		**M2M3 DA = $5.25/MWh**	
	RT	**Weighted Average OATT + $3 adder**	**RT**	**Weighted Average OATT + $3 adder**	**RT**	**50% of Weighted Average OATT + $3 adder**
$14.50 /MWh in DA & RT	**M2M RT = $7.50/MWh**		**M2M2 RT = $7.50/MWh**		**M2M3 DA = $5.25/MWh**	

**** Adder encompasses value for Friction & Congestion Risk***

Figure 5 | Hurdle Rate Sensitivities

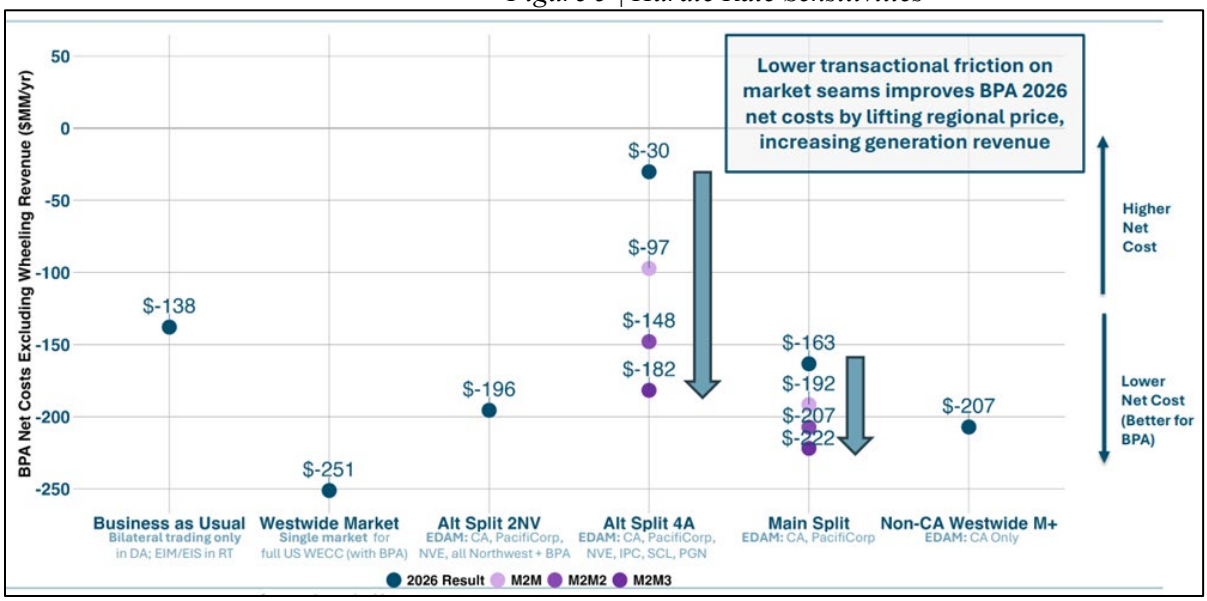


***Figure 5 Take-away*: Hurdle rates drive differences in footprint benefits; Bonneville can achieve benefits above BAU, including with the current expected Markets+ footprint.**

In both footprints tested, Bonneville's results improve with each reduction in the hurdle rate. For the Alt Split4A footprint, all three sensitivities forecast benefits for Bonneville. Two of the three cases forecast benefits greater than BAU. This suggests that Bonneville can achieve incremental net benefits in Markets+ in the Alt Split 4A footprint if it can still access EDAM with minimal friction, and that Bonneville would benefit from working to minimize that friction with both market operators. FERC recently noted that while seams are sure to materialize the market operators, BAAs, and stakeholders should coordinate to develop solutions that minimize friction at the seams. Bonneville concludes that lower hurdle rates are more likely than those initially modeled in the WMEG studies, providing better information that participating in Markets+ participation will result in benefits above business-as-usual.

Figure 6 | Base Footprint Results & Changing Timeline

Figure 6 plots 2026 supplemental case results and layers on future year scenarios which include augmentation of load, generation, and transmission (but do not include any changes to market design). Results for 2030 are plotted with triangles and results for 2035 are plotted with diamonds.

Figure 6: Cases over time 2026-2035

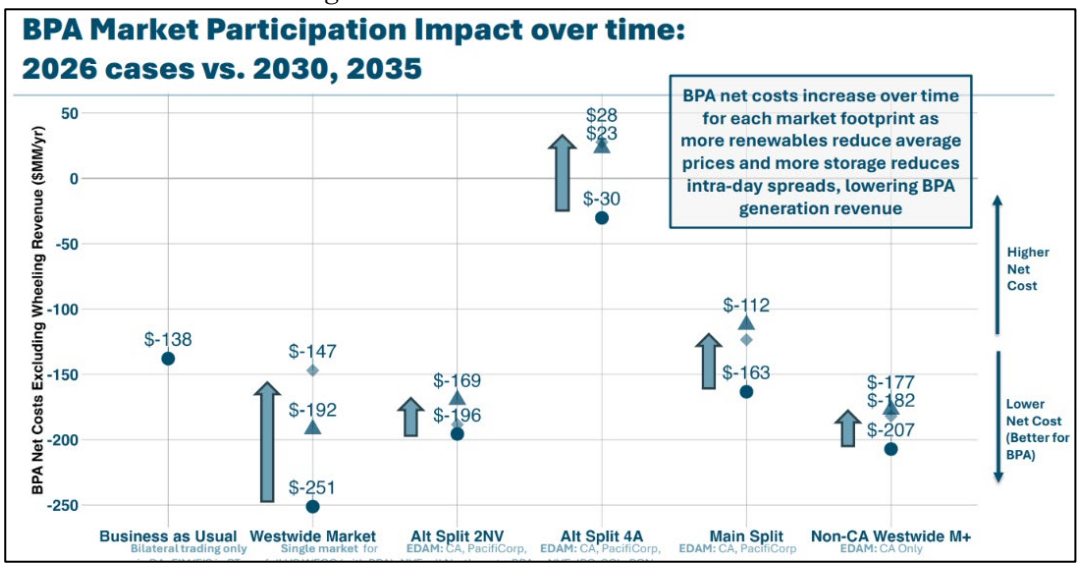


***Figure 6 Takeaway*: Changing regional resource mix may result in declining benefits over time.**

The supplemental PCM analysis also produced study case results for future years of 2030 and 2035. An interesting trend emerged when comparing the case study footprints from 2026 to 2035. In each footprint tested, forecasted Net Costs increase for Bonneville. As time progresses, benefits continue to decline. E3 identified this trend as the result of continued renewable resource participation and the expansion of storage resources. These resource additions result in reduced intra-day price spreads, limiting the value of shapeable hydro. Bonneville would see increased competition from those additional resources within the market and is unable to capture the same amount of Generation Revenue as depicted in early case results.

5.1.1.5. Concluding thoughts on PCM results

PCM results provide general direction (i.e., cost or benefit) and magnitude around market participation. The models offer an array of outcomes that are strongly impacted by the modelled footprint and hurdle rate.

Context for Magnitude of Benefits

To put these numbers in context, Bonneville's Fiscal Year 2026 Power Revenue Requirement is $3,451,708,000,[58] and provides the basis for recovering generation-related costs associated with the Federal Columbia River Power System (FCRPS), including the federal investment in hydro generation, fish and wildlife, conservation costs, non-federal power supply, and market purchases.[59] Bonneville's Fiscal Year 2026 Transmission Revenue Requirement is $1,626,696,000,[60] and provides the basis for rates to Federal Columbia River Transmission System (FCRTS) costs, including recovery of the federal investment in transmission and transmission-related assets, operations and

[58] Power Revenue Requirement Study Documentation - BP-26-E-BPA-02A Table 1A.
[59] Power Revenue Requirement Study - BP-26-E-BPA-02.
[60] Transmission Revenue Requirement Study Documentation - BP-26-E-BPA-09A TABLE 1-1.

maintenance and expenses associated with transmission and ancillary services.[61]

Bonneville's Power revenue uncertainty, largely driven by its power net secondary revenue uncertainty, has a standard deviation of approximately $250 million per year and a range of $2.2 billion.[62] This is not to diminish the significance of potential increased costs to Bonneville, but it is an important frame to place around the overarching strategic decision, the various other market design considerations, and the highlighted limitations of the PCM results. The general range of potential costs or benefits generated by Bonneville's PCM results of ~$150 million. This amounts to roughly +/- 3% of Bonneville's annual revenue requirement. This falls within Bonneville's range of Bonneville's net secondary revenue uncertainty.[63]

Participation in EDAM

Participation in EDAM produces the highest Net Cost benefit in the cases studied. However, examination of the sub-categories comprising the Net Cost illustrates that there are tradeoffs. Higher locational marginal prices drive up Generation Revenues in EDAM cases. The higher prices also result in greater cost to serve load. While Bonneville aims to maximize secondary revenue from surplus generation, it also aims to serve load at the lowest cost. Further, there is no guarantee Bonneville will continue to have significant surplus generation available to market, so the higher projected costs to serve load in EDAM may not always be offset by higher revenue associated with surplus.

Remaining a WEIM-only participant

Remaining a WEIM-only participant, which would require continued reliance on bilateral trading in all time-horizons prior to real-time, carries risks not easily reflected in the PCM. As discussed in section 2.3, staying outside a day-ahead market as other participants join presents risks to bilateral liquidity and introduces additional barriers to access trading partners.[64] Market participating entities are expected to focus on trading in their respective day-ahead markets and may be unwilling to or limited in the extent they can transact outside the market in the day-ahead time frame. Bonneville anticipates that convincing trading partners to trade bilaterally, instead of offering their resource to the market, may require a premium. This dynamic makes the longevity of remaining solely a WEIM participant unclear.

Participating in Markets+

Markets+ offers lower cost to serve load but also forecasts reduced Generation Revenue. Similar to participating in EDAM, there is tension created between the objectives of serving load at least cost and maximizing surplus revenue. The market hurdle rate sensitivity cases add further context, as they indicate that in the right conditions, Bonneville may achieve benefits greater than BAU.

Overall Takeaways

These PCM results provide good indicators of direction and magnitude regarding day-ahead market participation. However, these results should not be viewed with the expectation of achieving specific forecasted dollars. The PCM results are forecasts that can be influenced by other factors that may alter the projected outcome. For example, modifications to market design items such as Congestion Rent, Scarcity Pricing, or Locational Marginal Price

[61] Transmission Revenue Requirement Study - BP-26-E-BPA-09A. BP-26-E-BP-05A.
[62] BP-26-E-BP-05-CC01, Power and Transmission Risk Study, at 89 Table 1: Rev Sim Net Revenue Statistics for FY 2026 through FY 2028; *see also* Transmission Revenue Requirement Study Documentation, BP-26-E-BP-05A.
[63] Power and Transmission Risk Study, BP-26-E-BPA-05-CC01, at Table 1 (RevSim Net Revenue).
Power and Transmission Risk Study, BP-26-E-BP-05-CC01, at 89, Table 1 (Rev Sim Net Revenue Statistics for FY 2026 through FY 2028); *see also* Transmission Revenue Requirement Study Documentation, BP-26-E-BP-05A.
[64] *See* WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment, *available at* https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf.

computation can impact benefits. PCM models also do not account for qualitative elements such as differences in market governance structure, nor do they account for the way in which governance structure can impact market design, which impacts quantitative outcomes.

Bonneville views the PCM results as one component of a much larger decision framework for day-ahead market participation. While the PCM results are useful, they alone do not lead to a direct conclusion about which market participation decision Bonneville should make. These PCM results must be used in conjunction with the principles that Bonneville has proposed to inform a day-ahead market decision. The market design aspects discussed in section 5.2 provide important considerations for the broader potential benefits of Markets+ participation.

As explained earlier, one limitation of PCM is that it does not account for impacts to various types of power and transmission customers. The next section discusses Bonneville's proposed direction to continue assessing economic impacts.

5.1.1.6. Business Line Economic Impacts

Day-ahead market growth in the region is expected to impact Bonneville's costs, revenues, trading activity, and net secondary revenue volatility. While Bonneville's decision around day-ahead market participation will affect these impacts, changes are expected to occur regardless of whether Bonneville pursues day-ahead market participation. Bonneville is unable to forecast the financial impact around rates, products, and the volatility for any option prior to issuing its day-ahead market Policy.[65] This is because the specifics needed to conduct financial analysis, such as final market design, footprint, seams agreements, etc. are not yet known. Inventory and market price risk represent key drivers of overall financial risk to Bonneville, which exist in both bilateral and organized markets.

Most of the quantitative economic analysis on day-ahead market options were performed by E3 using PCM that produce a cost-benefit analysis. This analysis provides insight into the potential economic effect of different day-ahead market footprint options and a high-level evaluation of the overall economic effect on Bonneville. While informative, it does not provide the full range of inputs needed for Bonneville's finance models to show the full impact to setting and modeling rates nor the risk around those costs and revenues. Quantitative evaluation and modeling within both Power and Transmission Services also inform the range of financial impacts to both business lines, and to Bonneville as a whole. However, given what was modeled, Bonneville can understand some of the large drivers for costs and revenues.

5.1.1.7. Power Services

Joining a day-ahead market means that all resources and loads are served through the market clearing process. If customers or other utilities join a day-ahead market as their own market participant (Markets+) or Scheduling Coordinator (EDAM), they will bid and settle their own resources with the market and will have their load settled with the market operator directly. If a Bonneville customer is not a direct market participant, they will not be directly exposed to the day-ahead market settlements; instead, any financial impacts would be passed on through Bonneville rates.

In the context of what that means for cost-based rates, Bonneville will continue to conduct rate proceedings as described in Appendix A, and forecasted Net Secondary Revenue (NSR) will remain a meaningful component of calculating rates. The two main drivers of Bonneville's NSR forecasts in rates are Riverware modeling (forecasted hydro inventory) and Aurora modeling (forecasted energy prices). Aurora modeling results are frequently driven by price expectations for natural gas, and the fuel for frequent marginal resources in the modeling runs. These key drivers of NSR expectations will not be affected by Bonneville's decision to join a day-ahead market, as they will be subject to the same fundamentals regardless of day-ahead market participation. For example, the key drivers that influence prices, such as load demand, hydro inventory, and natural gas prices are fundamental conditions that will drive prices in bilateral markets as well as organized markets. Therefore, the forecasting of these drivers of NSR,

[65] See sections 5.1.1.6 and 5.1.1.7 below for a discussion of impacts to Power and Transmission customers.

which feed into rate proceedings, are not expected to change with a day-ahead market decision.

NSR represents a forecast of what Bonneville reasonably expects or targets for revenue outside of its long-term contract sales to preference customers (see section 6.7). In addition to continuing to provide long-term contracts, Bonneville expects that it will continue to conduct some level of bilateral forward transacting, however, frequency, volume, and terms may change with the evolution of markets within the region. Instead of bilateral trading in the day-ahead timeframe, Bonneville will see resources and loads cleared through the day-ahead market. As is the case today, actual NSR will deviate from rate case expectations, with the difference being reflected as an increase or decrease to Bonneville's financial reserves. Any financial impacts from day-ahead market participation will be a non-itemized portion of NSR to ensure consistency with the Bonneville objective of maximizing the value of its entire generation portfolio by optimizing across all market options.

The key area of difference introduced is that instead of bilateral transactions in the day-ahead timeframe, Bonneville will trade through the market, introducing financial settlements for resources and loads. In the same way that Bonneville must manage inventory and market price risk presented by regional fundamentals, Bonneville will continue to optimize the system through both commercial and operational actions, while minimizing risks. This will continue to be managed closely to minimize costs and maximize revenue for customers, as done today in the bilateral markets.

5.1.1.8. Transmission Services

The evolution of markets in the Pacific Northwest is ushering in day-ahead markets that will impact Bonneville as a BA and TSP. Just as the WEIM required Tariff, Rates, and Business Practice changes, the day-ahead market will require changes as well. This will affect both Network Integration Transmission Service (NITS) customers and Point-to-Point (PTP) transmission service customers. Bonneville needs to ensure that customers continue to receive reliable service. Bonneville's transmission customers rely on Bonneville for delivery of resources to load, whether in Bonneville's BAA or as a path to another BAA.

As Bonneville has seen two day-ahead markets developing, it has become reasonably certain that several of Bonneville's current transmission customers will be in BAAs that have joined a day-ahead market, even if Bonneville does not move to the same or any day-ahead market. Because Bonneville's transmission will be used in day-ahead, real time, and bilateral markets, Bonneville recognizes concerns about potential transmission cost shifts between these different markets. Bonneville will propose changes to its rates, tariff, and business practices to align cost impacts with cost-causation and ensure customers are informed to adjust their respective future business models as needed to account for the new market paradigm.

Both CAISO and SPP realize that day-ahead markets introduce a potential reduction of both short-term and long-term transmission revenues to participating TSPs.[66,67] This potential reduction results from the market design principle that all transmission of a participating TSP is available for the market to use, unless that transmission has been explicitly removed from the market's calculations. Because the market has access to all of the TSP's transmission, there is less incentive for entities to purchase transmission.

The E3 PCM analysis attempted to quantify the impact to transmission revenue, but Bonneville removed it from its PCM assessment.[68] Instead, Bonneville performed its own analysis on the potential impact that day-ahead market participation may have on its transmission revenue. Bonneville focused on PTP transmission because those customers mainly purchase PTP to wheel through Bonneville's BAA, while NITS customers mainly take service and remain in the Bonneville BAA. Bonneville assumed that sales of NITS transmission would remain the same.

[66] *Cal. Indep. Sys. Operator*, FERC Docket No. ER23-2686, Transmittal Letter at 22-23 (Aug. 23, 2023) ("CAISO EDAM Filing").
[67] *Sw. Power Pool*, FERC Docket No. ER24-1658, Transmittal Letter at 9-10 (Mar. 29, 2024).
[68] For more information on the removal of the "Wheeling Revenue" category from the PCM analysis, see section 5.1.1.2.3 above.

Bonneville estimated potential bookends for a potential decrease in transmission sales from $20 million to $200 million over time.[69] Fortunately, both Markets+ and EDAM have a mechanism to help the TSP recover some of the lost transmission revenues due to the day-ahead market; however, they are slightly different approaches.

Markets+ encourages transmission customers to retain and purchase long-term firm transmission rights through its congestion rent design that includes an allocation to transmission rights holders. This allocation allows a transmission customer to directly receive congestion rents if the customer holds firm PTP rights of monthly duration or longer or NITS rights (see section 5.2.4). The EDAM design does not provide the same direct allocation between OATT rights and congestion rents (see section 5.2.4), resulting in a less direct incentive for maintaining long-term transmission rights.

In addition to congestion rent, there are other incentives to maintain long-term firm transmission rights. These include transmission for load service, to meet the WRAP firm transmission requirement, and for interchange transactions importing, exporting, and wheeling through market footprints.

Furthermore, Bonneville has over 65 GW of long-term transmission service requests in its transmission queue, indicating significant demand that could mitigate potential losses of long-term firm sales. Although these customers can remove their requests, Bonneville has not experienced a reduction in its queue. If Bonneville did see a significant reduction of long-term revenues, Markets+ has a robust stakeholder process and governance model that would allow stakeholders to bring concerns up for review.

For the potential revenue loss associated with short-term transmission revenues, both the EDAM and Markets+ day-ahead market designs include a transmission revenue recovery mechanism allowing a participating TSP to recover the potential revenue loss resulting from releasing unsold available transfer capability (ATC) to the market. In Markets+, the Market Transmission Use (MTU) charge mitigates for short-term firm revenue losses, by allowing the TSP to recover the difference between its historical short-term revenue requirement and current short-term revenues.[70] The EDAM Access Charge provides a recovery mechanism for short-term revenue reductions, potential lost short-term revenues associated with future transmission capacity, and potential wheeling revenue shortfalls.[71] The MTU will be applied in the same manner for all TSPs in Markets+. The EDAM Access Charge, however, will be applied differently for CAISO than for other EDAM Entities because of differences in transmission service offerings.[72]

In summary, although participation in day-ahead markets may potentially reduce transmission revenues, both day-ahead market designs have mechanisms that help participating TSPs mitigate this impact. In addition, after entry into a day-ahead market, Bonneville will continue to monitor actual transmission revenue recovery and, if needed, advocate through the market stakeholder process for additional market design adjustments to mitigate any potential loss of transmission revenues.

5.1.2. Participation and Implementation Cost Estimates

Both EDAM and Markets+ have participation and implementation fees. Further, there would be implementation work associated with participation in either option. Cost estimates of each option are provided below. These are

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[69] *See* Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day-Ahead Market (DAM) Participation – Workshop 10 at 15 (Jan. 29-30, 2025), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2025/dam-workshop-10-presentation-20250129.pdf.

[70] SPP Markets+ Tariff, Attach. A § 7.11 (Market Transmission Use).

[71] CAISO EDAM Filing, Attach. A-2 (Clean Tariff) § 33.26.1 (EDAM Access Charges).

[72] For example, for potential wheeling revenue shortfalls "the EDAM transmission owner[] will be compensated for the transmission use that supports the excess wheeling at the EDAM transmission owner's non-firm hourly point-to-point transmission rate or the CAISO participating transmission owner will be compensated for excess wheeling through transmission use at the applicable wheeling access charge transmission rate." *Cal. Indep. Sys. Operator*, 187 FERC ¶ 61,154, at P 20 (2024).

based on Bonneville's BAA. Bonneville assessed implementation and participation costs from CAISO, SPP, and internal projections based upon the best available estimates in early 2025.

5.1.2.1. Market Operator Implementation Fee Estimates

EDAM Implementation Fees

CAISO's EDAM transmittal letter to FERC discusses implementation fees.[73] CAISO estimates the standard fee to be $1.2 million for each BAA that elects to join EDAM.[74] Fees can be larger due to the complexity and size of the joining entity, or if an entity seeks additional market simulation or parallel operations time.[75] CAISO projects typical implementation to take 18 months for each BAA. The timeline can be extended beyond 18 months to accommodate additional market simulation and parallel operations.

Bonneville is one of the largest transmission providers and BAAs in the Western Interconnection and expects a higher than standard implementation fee and a longer than average implementation timeline. If Bonneville were to elect to join EDAM, CAISO estimates the implementation fee to be between $2.5 million and $3 million, and the implementation time frame to be between eighteen and twenty-four months.[76]

Markets+ Implementation Fees

Based on Bonneville's proportional share among all likely funding participants, the estimated share of Phase 2 costs is approximately $26.8 million.[77] The implementation costs to join Markets+ are higher than those for EDAM because Markets+ will have its own software separate from SPP's other markets, whereas EDAM is an extension of the current CAISO day-ahead market, and WEIM and is implemented with the same software.

5.1.2.2. Ongoing Market Participation Fee Estimates

EDAM On-Going Fees

CAISO has annual operating fees to run the market. These fees cover the staff, tools, and applications needed for the market. These fees are collected through CAISO's Grid Management Charge (GMC). The GMC is charged to each EDAM transaction. Bonneville requested that CAISO provide a forecast of the annual GMC fees assuming that entities who have made declarations or provided market leanings are included in the EDAM footprint. CAISO projected that Bonneville could anticipate $29 million annually in GMC.

Markets+ On-Going Fees

Markets+ will also have an annual operating fee. This fee will cover staff, tools and applications needed to run and operate the market. The operating fee will be collected based upon the volume of transactions for each respective market participant. Bonneville contacted SPP to request a forecast of Bonneville's anticipated portion of these annual operating expenses. SPP estimated that Bonneville's expense could be between $13 and $15 million annually.

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[73] CAISO EDAM Filing, Transmittal Letter at 105-07.
[74] CAISO, Extended Day-Ahead Market Final Proposal at 126 (Dec. 7, 2022), *available at* https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf.
[75] CAISO EDAM Filing, Transmittal Letter at 105.
[76] *See* Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day-Ahead Market (DAM) Participation - Workshop 10 presentation at 18-19 (Jan 29-30, 2025), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2025/dam-workshop-10-presentation-20250129.pdf.
[77] *Sw. Power Pool*, FERC Docket No. ER25-1372, SPP Markets+ Phase 2 Funding Agreement at 24 (Feb. 21, 2025).

Table 9 | Estimated Fees Paid to the Market Operator ($M)

Estimated Fees for Bonneville	**On-going Participation Fee (Paid to MO)***	**One-time Implementation Fee (Paid to MO)***
EDAM	~$29M /year	~$3M
Markets+	~$15M /year	~$26.8M
*BAA value/Bonneville share based on Load/Resource Activity		

Table 9 provides a summary of the on-going participation fees (based on footprints reflecting the current declarations and leanings) and the one-time implementation fees for EDAM and Markets+. While EDAM's implementation fee is quite low at $3 million, the recurring annual fee is double that of Markets+. The ongoing market participation fees above were provided by each respective market operator in early 2025. These are only preliminary estimates based on the information currently available. These estimates can be subject to change. The fees and cost allocations for each market may evolve as each market operator refines their annual market operating expense.

Bonneville has determined that the higher upfront Markets+ implementation fees are justified by the anticipated market benefits, including the superior design elements (discussed primarily in Section 5.2) and lower ongoing participation fees.

5.1.2.3. Internal Implementation Cost Estimates

Joining a day-ahead market would change the operations and systems for Bonneville across Power and Transmission Services. Bonneville performed an initial estimate of the costs to implement either day-ahead market. This assessment was separate from the E3 PCM cost-benefit analysis, which did not evaluate implementation costs. Any assignment of implementation costs to a particular business line will be done as part of an integrated program review process.

To develop the estimate for the implementation cost of joining a day-ahead market, Bonneville identified projects across the agency that would be required for implementation (e.g., metering, outage management, schedule submission, bid curve development, and settlements). The implementation cost of each project was then estimated based on the complexity in project execution. The cost estimate for each market is further broken into the non-labor and the labor components. The non-labor component reflects initial costs for software and hardware upgrades needed for supporting the technological or operational requirements for joining a day-ahead market, while the labor component reflects the incremental staffing costs. Non-labor costs are provided as a range to reflect the uncertainty around the ongoing EDAM and Markets+ design and development.

Bonneville's estimated implementation costs for EDAM and Markets+ are as follows in Table 10[78] :

Table 10 | Internal Implementation Costs ($M)

Market	**Non-Labor**	**Incremental Labor**	**Total Cost (Non-Labor + Incremental Labor)**
EDAM	$11.6M - $19.7M	$18.3M	$29.9M - $38M
Markets+	$26.8M - $47.3M	$26.9M	$53.7M - $74.2M

[78] CAISO's and SPP's one-time market implementation fees and annual operating fees are not included.

The estimated implementation cost for EDAM is about half of Markets+, as a large portion of Bonneville's existing infrastructure built for the WEIM could likely be used in EDAM. SPP has been developing Markets+ consistent with SPP's existing systems and processes, which are different than CAISO's and will require system modifications to enable Bonneville's market participation. Additionally, the higher estimate of the Markets+ implementation cost is also driven by an assumption that Bonneville may choose to switch Bonneville's Reliability Coordinator (RC) from CAISO RC West to SPP RC Services. While the RC change is included in the estimated costs for transparency, the change is not certain and would depend on future policy development.

5.2. Market Design Considerations

Bonneville has thoroughly evaluated various day-ahead market design elements and participated in the design development process for both EDAM and Markets+. While much of the design is similar between the two markets, there are several differences that Bonneville considers significant in its evaluation. These elements are discussed below.

5.2.1. Governance

Independent market governance continues to be paramount to Bonneville's Policy direction towards participation in Markets+. Bonneville defines its governance principle for market participation as "the market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders" and that "decision-making and stakeholder engagement occurs in a transparent and inclusive manner."[79] Joining a day-ahead market would represent a significant change to how Bonneville operates. The electric industry is grappling with complex issues, and there will surely be additional difficult issues and circumstances in years to come. While Bonneville can never eliminate all risk, Bonneville believes a governance model tailored to support collaborative, unbiased decisions on current and future issues will mitigate risk inherent to the evolution of the industry. It is not possible to quantify a dollar value for the attributes of independent governance, but substantial value comes through in the decision process for market design and Bonneville's ability to influence that design. As noted, current examples include, but are not limited to congestion revenue, fast start pricing and GHG accounting.

Through its public discussion of market participation and consideration of market platforms, Bonneville has heard near-consensus agreement that independent governance is a core principle for regional market design.[80] Bonneville's evaluation considers the relevant factors associated with governance structures under both Markets+ and EDAM to identify the best governance structure available for Bonneville's decision regarding day-ahead market participation. While entities may disagree about what level of governance is sufficiently independent, Bonneville wants the decision-making body for a market to be free of disproportionate obligation to the policies of a single state, entity or customer type. Ideally, management and operations of the market would be independent of any single state or participating entity. In the near term, at the management level, the staffing and process for decision development and stakeholder engagement should equitably weigh the policies or priorities of all states, entities, and customer classes. Finally, the market's design and policies should be equitable in its consideration of the approaches established by all states with participating entities. The following discussion explains the evaluation under each of these factors.

Independence of the decision-making body

In its consideration of EDAM and Markets+, Bonneville evaluated the independence of their respective decision-

[79] Section 4.1.6 above.

[80] *See, e.g.*, Letter from Western State Utility Regulators to the Western Interstate Energy Board (July 14, 2023), *available at* https://www.westernenergyboard.org/wp-content/uploads/Letter-to-CREPC-WIEB-Regulators-Call-for-West-Wide-Market-Solution-7-14-23-1.pdf.

making bodies.

Today, governance for EDAM is entrusted to the CAISO Board of Governors. The Board has delegated certain authority to the Western Energy Markets (WEM) Governing Body, subject to the Board's oversight, in a model referred to as Joint Authority.[81] The CAISO Board of Governors is appointed by the Governor of California with the consent of the California State Senate. Board members oversee CAISO in both its role as the market operator and largest BAA in the market. Members of the WEM Governing Body are nominated from stakeholder sectors and approved by current members of the Governing Body. The Governing Body acts on recommendations developed under the CAISO stakeholder process, which is largely CAISO staff driven. CAISO utilizes working groups to develop the initial stages of policy initiatives then proposals are developed by staff with open comment opportunities for all stakeholders.

The Governor of California's selection of the CAISO Board of Governors risks undue influence of a single state over EDAM. In addition, California law establishing authority for the CAISO Board of Governors requires it to act in the interests of the people of California.[82] While these governance elements were reasonable for the original CAISO market that only operated within California, they are significant flaws in the governance of a regional market that includes participants in other states. These flaws require mitigation that is currently only proposed.

As addressed in Appendix B, a number of regional entities have acted in pursuit of this objective through Pathways,[83] which will be discussed in more detail. Pathways has continued development of proposals for a new entity with an independent governance structure that is capable of overseeing an expansive suite of West-wide wholesale electricity markets and related functions. In 2024, the CAISO Board of Governors and the WEM Governing Body jointly approved additional governance changes that were recommended from Step 1 of Pathways. These changes placed the sections of the CAISO Tariff for WEIM and EDAM under the primary authority of the independent WEM Governing Body. WEM Governing Body decisions will be reviewed by the CAISO Board of Governors on a consent agenda. If the Board disagrees with the Governing Body's decision or vice versa, CAISO will prepare and submit dual filings to FERC on behalf of each body. The CAISO Board of Governors may exercise sole authority for FERC filings in exigent circumstances. Critically, the day-to-day management of policy development and market operations remains with CAISO management who ultimately report to the CAISO Board of Governors. Additionally, the Board's considerations as a BA have the potential to influence its decisions as the market operator.

In contrast, Markets+ will be governed by the Markets+ Independent Panel (MIP).[84] MIP members must be independent of market participants. They are selected through a nomination process of the Markets+ Governance and Nomination Committee and confirmed by the Markets+ Executive Committee. One independent member of the SPP Board of Directors serves on the MIP. The SPP Board of Directors retains authority for specific financial oversight of Markets+. The independent board acts on recommendations developed through a transparent process involving all market participants and stakeholders. The participants and stakeholders collaborate in working groups that have proven effective to build consensus and, where consensus is elusive, to frame the different perspectives for the independent board's consideration in its decisions.

Markets+ decision-making will be under the authority of the MIP whose members, save one representative of the SPP Board, are selected by the Markets+ participants. Additionally, Markets+ is separate from the SPP RTO, so its only focus is on being a market operator. From this comparison, Bonneville finds that the independence of the

[81] *See* CAISO, Governance (2025), *available at* https://www.westerneim.com/Pages/Governance/default.aspx.
[82] Cal. Pub. Utils. Code § 345.5 (2025).
[83] *See* Western Interstate Energy Board, West-Wide Governance Pathways Initiative (2025), *available at* https://www.westernenergyboard.org/wwgpi/.
[84] SPP Markets+ Tariff, Attach. O (Markets+ Governance) § 4.2 (Markets+ Independent Panel). Pending initiation of operations as Markets+, this independent board role is exercised by the Interim Market Independent Panel (IMIP) of three members of the SPP Board. References to the ongoing role of the Markets+ independent governing board will be to the MIP.

Markets+ decision-making body is superior to that of the EDAM and is more likely to result in decisions that create a fair and equitable market that allows Bonneville to meet its load service, power marketing, and transmission obligations.

Decision development and stakeholder engagement

In Bonneville's experience, a market's structure for both stakeholder engagement and decision development are critical to ensuring fair and equitable decision outcomes. Bonneville places great weight on the supporting structure for market decision development through market operator staff and the roles of participants and stakeholders in policy development. This structure is critical to ensure that Bonneville's interests are heard and adequately addressed in the decision process. The difference is not theoretical; Bonneville has been an active participant in both EDAM and Markets+ stakeholder processes and has experienced the difference in terms of decision-making for agenda priorities, collaborative process, and consensus decisions.

Bonneville has observed that the Markets+ structure has a proven track record of effectiveness. Notably, the structure delivered the complete tariff design on an abbreviated schedule through 2023. The structure involved working groups and task forces of market participants and stakeholders who conducted their discussions in publicly noticed and accessible meetings. The structure uses "indicative voting" to document support and opposition from participating stakeholders individually and by sectors. The use of indicative voting promoted collaboration among participants and built confidence in the outcomes. A prime example of the success of the Markets+ governance structure is the development of a mechanism for GHG accounting that meets customer compliance obligations for multiple states and pricing approaches while not adversely affecting states without those obligations.

Bonneville proposed and obtained consideration of its statutory and contractual obligations through the Markets+ process. The working group processes are publicly accessible and consider perspectives from utilities, states, and independent organizations. Stakeholders themselves can set the agenda for issues to be considered by the Interim MIP (IMIP). SPP staff provide appropriate facilitation and technical support roles while respecting the decision-making roles of market participants. The Markets+ Executive Committee (MPEC) ultimately votes on decisions to be brought before the MIP, providing a final opportunity for input from the sectors. Decisions reflected negotiation and compromise, with the IMIP returning issues to the MPEC when insufficient consensus had been reached.

The Markets+ governance structure relies on the time and abilities of market participants and stakeholders to develop market design proposals and deliberate on recommendations. Bonneville acknowledges concerns about that level of commitment. From Bonneville's perspective, this time is well invested for the value of collaboration among participants, shared understanding of the issues and tradeoffs involved, and for durable outcomes. The experience to date has been demanding, to be certain. However, it has yielded unparalleled engagement in the complex challenge of establishing a market. As the market moves into implementation, the cadence of participant work should be more manageable and provide opportunities for entities to combine their efforts.

Bonneville has not experienced the same depth of balanced stakeholder consideration in the staff-driven CAISO engagement model. Bonneville acknowledges the knowledgeability of CAISO staff and CAISO's efforts to develop a more participatory stakeholder engagement process. Bonneville appreciates and respects the professionalism and expertise that CAISO staff routinely display in their stakeholder process. This process, however, could be enhanced through increased stakeholder leadership in policy and implementation development, evaluation, and decision processes. The CAISO governance model also continues to present challenges in resolving contentious regional issues. CAISO must navigate competing priorities for staff and management time on regional issues versus the demands for attention to its own BAA and participating transmission owners.

Bonneville concludes that the Markets+ decision development and stakeholder engagement process is the best approach to ensure a fair and equitable market across multiple states and fair consideration of Bonneville's objectives and obligations.

Reasonable harmonization of state policies

The influence of an individual state in market design can manifest in the obligation of the market to incorporate that state's regulatory or policy design as predetermined conditions. Bonneville, especially from its role as serving utility customers in seven states, seeks a governance model that fosters harmonizing differing state policies.

The structure of the Markets+ policy process supports treatment of different state policies on an equal basis. The policy development process invites market participants to bring their state compliance obligations to the market design and includes the active participation of state representatives. Bonneville observes that this structure has allowed consideration of different state policy designs to arrive at a high degree of consensus on designs that serve the goals of multiple states and the utilities that serve them.

By contrast, CAISO market design rests on a foundation of California state policies. In the design of a regional wholesale market, this approach carries forward to a choice that either California's policy design, for example in GHG accounting, must be accepted as the market standard, or that the market must develop and incorporate alternative designs for those participants outside California.

Bonneville determines that the equivalent consideration of state policies by the Markets+ governance design is superior to that of the EDAM. Currently, there are two FERC approved day-ahead market tariff options available to Bonneville but one—Markets+—is superior with respect to stakeholder engagement, decision-making, and overall market governance.

5.2.1.1. Impact of Pathways on Bonneville's -Day-Ahead Markets Decision

Bonneville has assessed the progress made by Pathways in evaluating its day-ahead market alternatives. Through the Pathways engagement, Bonneville has supported the option for creation of an independent entity with independent administration and operation. While Pathways has made progress in advancing the governance of the WEIM and EDAM, the initial structure proposed in the Step 2 final proposal does not meet Bonneville's standards for independent governance as discussed in detail in Appendix B. The proposed approach is also dependent on legislation successfully passing in California to enable the Regional Organization (RO) structure as proposed, and allowing expansion to greater independence as described in the Step 2 proposal. California Senate Bill540 seeks to enable the Pathways Step 2 recommendation. The legislation would authorize the CAISO and California investor-owned utilities to participate in voluntary energy markets governed by an independent regional organization. Proposed legislation responds to a delicate balance between the interests of parties outside of California, including Bonneville, that the independent regional organization be wholly separated from undue influence of California state government; and the interests of parties in California that the regional organization support California energy and environmental policies. To achieve this balance, the current legislation seeks to reassure California that there are adequate safeguards for respecting California policies through providing for rights of withdrawal as ordered by the California Public Utilities Commission (CPUC). The proposed legislation provides that the CPUC may order California IOUs to withdraw in response to market rules or operations that it deems "detrimental to California consumers or California procurement, environmental, reliability, or other public interest policies." While presented as a "savings" provisions representing current CPUC authority, this scope of authority is made explicit by the proposed legislation. In continuing legislative committee discussions, the bill author and legislators have discussed adding more "guardrails" to ensure market respect for a broad list of California policies and adding requirements for additional legislative review of the RO structure and functions. In emphasizing these authorities as a means of reassuring California policy leaders, it causes reasonable and substantial concern for entities outside of California. Entities outside of California, including Bonneville, will be in a difficult negotiating position within the regional organization governance structure when any proposed rule or business practices can be referred to the CPUC or Legislature for a determination that the proposal will be "detrimental" to a broad and general set of policies. The legislation does leave available improvements in the stakeholder process and market design process to make it more equitable for parties inside and outside of California. Nevertheless, Bonneville is concerned that the legislation as drafted may not meet Bonneville's governance requirement. At the time of this Policy direction, uncertainty remains regarding whether 5B 540 will ultimately be passed and, if so, in what form.

5.2.2. Resource Adequacy and Resource Sufficiency

As discussed in section 4.1.3, a primary aspect of reliability impacted by market design is resource sufficiency and by extension, RA. RA generally refers to long-term planning and procurement of resources to serve expected peak or critical load in a year or season. Resource sufficiency generally refers to procurement of enough resources to serve expected load in the short term (e.g., moving into the week/day/hour). In considering generation and transmission, RA aims to have enough physical resources (e.g., long term expected generation output, new generation or transmission construction) to serve a forecasted peak load well into the future (often many months or years), while resource sufficiency considers the current operational landscape (e.g., outages or derates, up-to-date variable generation and load forecasts, etc.). The two concepts work in concert and are both vital to minimizing scarcity, emergency, or loss-of-load events. The market operator does not take on the role of LRE in either day-ahead market option.[85] All day-ahead market participants are still responsible for their adequacy and sufficiency, and thus obligated to enter the day-ahead market timeframe with a resource portfolio (including power purchases) that can meet their expected load.

Markets+ contains both an RA and resource sufficiency requirement. As a prerequisite to joining Markets+, entities that are LREs must participate in WRAP.[86] WRAP is a regional RA program that increases transparency into the resources and transmission needed to reliably supply power to meet a participant's existing and future load demands. Participation in WRAP requires consistent planning from all participants (which is measured using common RA metrics applied consistently to all participants), to help prevent any entity from leaning on the power supplies of others. Current WRAP participants include most utilities within the Western Interconnection outside the state of California.[87] For long- and short-term planning, the WRAP Forward Showing program requires entities to demonstrate that they have the available generation capacity needed to meet its forecasted peak P50 obligations plus an established planning reserve margin, and 75% of the transmission (as firm transmission) needed to bring generation to load.[88] While Markets+ participation is not required to be a WRAP member, Markets+ is the only day-ahead market choice in the West that requires participants to be in a common RA program, in this case, WRAP.

WRAP feeds into Markets+ via the market's day-ahead and real-time Must Offer Obligations. The Must Offer Obligations require all entities to bring at least the amount of generation needed to meet their forecasted load. If an entity fails to meet its Must Offer Obligation, that entity is financially penalized to discourage failures in the future, but physical market transfers and the optimization of the market footprint are not impacted. This simplified approach is supported by the Markets+ common RA metrics provided by universal WRAP participation because market participants are not only checked for day ahead and real-time sufficiency, but are also assessed for RA much farther out than real time. The inclusion of WRAP and the potential charges for failure to be resource adequate disincentivizes utilities who do not have adequate resources from leaning on other market participants in order to serve load in a manner that is stronger than the EDAM design, which, as explained below, relies only on penalties in the operational timeframe.

The EDAM design does not propose a uniform RA metric nor require EDAM entities to participate in an RA program. EDAM does leverage a Resource Sufficiency Evaluation (RSE) to ensure its footprint is adequate heading into the day-ahead and real time operating periods. EDAM's design leverages the WEIM design which calls for the limiting of an entity's BAA-BAA market transfers for entities that ultimately fail the real time RSE unless entities elect to accept

[85] A Load Responsible Entity (LRE) is an entity directly responsible for ensuring an electrical load is served.
[86] SPP Markets+ Tariff, Attach. A § 5.1.1; *id.* Appendix 3 (Attestation Regarding RA and Participation in WRAP).
[87] Western Power Pool, WRAP Participant Map (last mod. Dec. 30, 2024), *available at* https://www.westernpowerpool.org/news/wrap-area-map.
[88] Western Power Pool, WRAP Tariff § 16.3 (FS Transmission Requirement), *available at* https://www.westernpowerpool.org/private-media/documents/WRAP_Tariff_Effective_1.27.25.pdf ("The FS Transmission Requirement must be met with NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service or network integration transmission service, from such Participant's Qualifying Resource(s) or from the delivery points for the resources identified for its Net Contract QCC or for its RA Transfer to such Participant's load.").

energy transfers through Assistance Energy Transfers, which include an associated penalty charge.[89]

The Markets+ Must Offer Obligation and the EDAM RSE serve a similar purpose, which is to evaluate whether each entity has procured enough resources to support its anticipated demand for the coming day, but the Markets+ integration of WRAP helps ensure equal and prudent planning and resource acquisition in the longer term. By leveraging the WRAP Forward Showing Program through its day-ahead and real-time Must Offer Obligations, Markets+ standardizes, simplifies, and solidifies each market participant's requirements to bring sufficient resources to the market to serve its loads. The more simplified resource sufficiency tests that Markets+ employs in the day-ahead and real-time also have the potential to provide benefits to Bonneville and other Markets+ participants. WRAP participation and the Markets+ Must Offer Obligations ensure sufficiency in a manner that sends strong financial signals that disincentivize future failure to bring sufficient capacity to the market and compensate those who make up any shortage, while still allowing all entities, and the market as a whole, to maintain a reliable, optimized footprint.[90]

While some California utilities are subject to RA requirements under the CPUC jurisdiction, these metrics may be different than those used in WRAP. Further, EDAM participants outside of California may be participants in WRAP, but they are not required by the EDAM market to participate in any RA program. EDAM's lack of common RA metrics makes it difficult to assess whether the footprint as a whole will be resource adequate in the planning horizon. While the EDAM RSEs are intended to prevent market participants from leaning on other market participants by failing to provide sufficient resources to meet their own loads absent market optimization, there are limited options in the day-ahead timeframe for addressing footprint wide sufficiency issues. A lack of a common RA program leaves the task of disincentivizing leaning solely to the EDAM RSE. Limiting transfers for entities that fail the real time RSE is suboptimal for all market participants, and the AET rate alone does not provide as robust an incentive for participants to maintain resource adequacy or resource sufficiency as the design of Markest+.[91] As long as EDAM entities find it more economical or convenient to pay the AET, they can lean on other EDAM entities as a substitute for effective long-term planning to meet their load obligations. The combination of both WRAP charges and the Must Offer Obligation makes such a determination less likely in Markets+.

As concerns continue to grow about RA in the Western Interconnection,[92] the Markets+ design is objectively superior to EDAM because it combines a common long-term RA metric with short-term resource sufficiency obligations, ensuring adequate supply, reliability, and fair compensation. Therefore, Bonneville views Markets+ as the superior day-ahead market choice for supporting regional RA.

5.2.3. Price Formation and Market Power Mitigation

Appropriate price formation ensures that market rules provide appropriate price signals, which compensate resources at prices that reflect both the value the resources provide to the market and the operational conditions that drive the need to procure certain energy or capacity products. Price formation should also ensure that resources respond appropriately and accurately to dispatch instructions from the market. Key aspects of price formation[93] issues can include: uplift payments (including bid cost recovery which can undermine actionable price signals), offer caps and offer mitigation usage, scarcity pricing, fast start pricing, and operator actions (and any associated impacts, or lack thereof, on pricing).

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[89] CAISO, Extended day-ahead market resource sufficiency evaluation discussion at 8 (Oct. 21, 2022), *available at* https://www.caiso.com/Documents/ExtendedDay-AheadMarketResourceSufficiencyEvaluation-Presentation-Oct21_2022.pdf. CAISO, WEIM Resource Sufficiency Evaluation Enhancements – Phase 2 (November 7, 2022), *available at* https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-ResourceSufficiencyEvaluationPhase2-Nov7_2022.pdf.

[90] SPP Markets+ Tariff, Attach. A §§ 5.1.1(C), 5.1.2(C).

[91] CAISO, Extended day-ahead market resource sufficiency evaluation discussion at 8.

[92] WECC, 2024 State of the Interconnection (Sept. 2024), *available at* https://feature.wecc.org/soti/index.html.

[93] For more information see FERC, Energy Price Formation (June 17, 2020), *available at* https://www.ferc.gov/industries-data/electric/electric-power-markets/energy-price-formation.

Related to price formation and necessary for a well-functioning electricity market, is the monitoring and mitigation of market power. The exercise of market power is when one or more entities reduce output below competitive levels so as to raise market-clearing prices.[94] Due to the nature of the deregulated electricity industry, with several large suppliers, who are regionally concentrated and loads with limited ability to exercise price sensitive demand, there is a possibility for the exercise of market power by certain entities. While organized markets are structured to encourage competitive and efficient outcomes through their formation, structural or behavioral issues may allow exercises of market power, which can be mitigated by design. Market power mitigation tests and rules, when effectively implemented, ensure that resources can bid their marginal costs, but are not able to exercise market power. Both market operators and market monitoring departments are committed to monitoring for and mitigating the exercise of market power, though they have different methodologies for assessing the market.

In EDAM, the Market Power Mitigation (MPM) assessment is an extension of the existing WEIM methodology, which looks to address structural market power in participating BAAs. BAA-level MPM uses a dynamic competitive path assessment to evaluate whether the available generation within the participating BAA can competitively meet its own demand without additional transfer imports. If the dynamic competitive path assessment conditions are deemed non-competitive, then all participating resources in the affected BAA are adjusted to the competitive locational marginal price or a lower value of their submitted bid or applicable Default Energy Bid (DEB).

Under the pivotal supplier assessment for MPM, large entities flowing on constrained paths are more likely to be considered a pivotal supplier and face price mitigation measures, by the nature of their structural location, leading to potential over-mitigation. Given the geographical structure of western BAAs, the mitigation assessment based on the pivotal supplier is determined on the participant's potential ability to exercise market power, rather than on the participant's observed behavior. Bonneville appreciates that CAISO is reviewing this aspect of the market design in its Price Formation Enhancements initiative.

In contrast, the Markets+ design leverages the conduct and impact framework for MPM which is used in other organized markets.[95] The conduct test evaluates whether a resource offer is significantly higher than the reference cost of energy, and the impact test determines whether that offer would significantly impact the market prices. If suppliers have been found to fail both conduct and impact tests, then mitigation measures can be applied. Under this framework, resource offers are actively assessed and a negative outcome to the market must occur in order to be considered an exercise of market power. Basing mitigation assessments on the perceived potential to exert market power, as EDAM does, particularly during times of scarcity, creates misaligned incentives and market signals which can prevent appropriate market outcomes. The Markets+ conduct and impact approach is more effective because it mitigates based on the exercise of observed market power, not the potential for market power, thus minimizing over mitigation.

In addition to the assessment for MPM, a key aspect of the market design is to ensure that the reference price calculation, the offer price used when a resource is mitigated, is appropriate. The methodology to determine the reference price for a mitigated offer curve will vary by resource type. For resources such as storage hydro, a key aspect is the opportunity costs associated with future generating periods. For storage hydro, the Markets+ and EDAM are very similar, as the Markets+ design was built upon the approach utilized in WEIM. Bonneville's internal opportunity cost estimation, a component of bid formulation, is dynamic and based on non-public information, making independent verification impossible, though both markets attempt to approximate Bonneville's

[94] For more information see Scott Harvey and William Hogan, Market Power and Withholding (Dec. 20, 2001), *available at* https://scholar.harvard.edu/files/whogan/files/market_power_withholding_harvey-hogan_12-20-01.pdf.

[95] *See* SPP Markets+ Tariff, Attach. B (Market Power Mitigation Plan) & Attach. C (Market Monitoring Plan); *see also* SPP Markets+ Protocols § 11 (Market Monitoring and Mitigation), *available at* https://www.spp.org/Documents/73199/MarketsPlus%20Protocols%20-%20Combined%20-%20MPEC%20Approved%20as%20of%2020250131.pdf.

cost for mitigation purposes. Imperfect cost verification (conduct verification) further reinforces the important role of an impact test to reduce inappropriate over-mitigation.

In EDAM, CAISO employs the DEB model for hydroelectric resources. The DEB uses a formula to estimate the opportunity cost of hydro, focused on three main pricing components: a gas-price floor, short-term energy prices, and a long-term geographic floor. This approach specifically tailors the DEB of a participating resource to its geographic location. Markets+ stakeholders worked with SPP's Market Monitoring Unit to develop the Seasonal Hydroelectric Offer Curve (SHOC) framework. The SHOC is very similar to the DEB but also accounts for a hydro project or aggregation of projects' seasonal storage horizon as part of the opportunity cost calculation.[96] Both designs do their best to account for the flexibility of the system, allowing participants to preserve the value of hydro for future months when appropriate for their resource(s), helping other market participants benefit from the flexible nature of these resources. Bonneville prefers the Markets+ SHOC approach because it distinguishes between hydro resources with and without significant storage availability.

CAISO has undertaken stakeholder initiatives, such as the Day-Ahead Market Enhancements (DAME) and Price Formation Enhancements, to review and address changes to products and prices within its market. During its DAME[97] effort, CAISO created the Imbalance Reserve Product, which recognized the need to procure additional flexible products that can be economically awarded to help provide additional capacity and reduce out-of-market actions by the market operator. The CAISO/EDAM footprint had a demonstrated need for this product due to the uncertainty swings in the load-resource balance caused by the variable renewable resource mix within the footprint and the need for dispatchable resources that are deliverable and can ramp between fifteen-minute intervals[98]. While Bonneville was initially very supportive of this product, the final product design changed significantly in the final stages of the stakeholder process, at which point Bonneville identified a number of significant areas of concern, as did other stakeholders[99]. While Markets+ does not include a comparable product, WRAP includes financial incentives to ensure equitable procurement of capacity to prevent leaning on the capacity of others, as well as compensation for holdback and energy deployment. Bonneville accepted the position that developing a similar product in Markets+ without a demonstrated need could impose additional and unnecessary costs to load service and agreed to move the topic to the Markets+ "parking lot" for consideration after go-live. Bonneville will monitor its participation in Markets+ and consider whether it feels a similar product would be necessary and/or beneficial to the Markets+ design. Bonneville is confident that the Markets+ stakeholder process will address any concerns that arise.

In the Price Formation Enhancements initiative,[100] scarcity pricing and fast-start pricing are critical elements because they can ensure resources are appropriately incentivized and compensated for the attributes they bring to a market dispatch, while reducing the need for out-of-market actions. In addition to ensuring accurate prices in the short term, price formation can help send better price signals for developing supply to meet future demand. Transparent and equitable price formation is an important step toward increasing market efficiency through increased competition, potentially ensuring supplier cost recovery while reducing the cost load pays.

CAISO has mechanisms for implementing a level of scarcity pricing when the system is low on reserves and

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[96] *See* SPP Markets+ Tariff, Attach. B (Market Power Mitigation Plan) & Attach. C (Market Monitoring Plan); *see also* Markets+ Protocols § 11.

[97] See the CAISO Day-Ahead Market Enhancements Initiative page for more details on these efforts and for Bonneville-submitted comments, *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements.

[98] *Id.*; *see also* CAISO, Day-Ahead Market Enhancements Stakeholder Technical Workshop presentation at 6 (June 20, 2019), *available for download at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements.

[99] *See* CAISO, Day-Ahead Markets Enhancements Initiative (comments submitted by Western Power Trading Forum, Vistra, The Energy Authority, and Powerex) *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements.

[100] *See id.*

network modeling needs to solve for tighter bid-supply conditions, but it does not currently have a design that includes compensation for fast-start pricing. Fast start pricing allows a generator's commitment costs, in addition to marginal fuel costs, to be considered in economic bid evaluation and directly captured in LMPs paid to all resources. CAISO is currently reviewing these topics as part of its Price Formation Enhancements initiative, in which Bonneville is actively engaged, although many stakeholders continue to oppose the adoption of fast start pricing. The absence of fast start pricing in CAISO reduces costs for California load by reducing fair and transparent compensation for generation in both California and throughout the West, including Bonneville's generation. In contrast, Markets+ incorporates fast-start as well as scarcity pricing into its day-ahead market design, which Bonneville believes helps to ensure accurate, fair compensation for all suppliers of flexible and reliable generation.

Bonneville's position on price formation and market power mitigation assessments has not changed from the April staff recommendation.[101] These are cornerstones of organized markets. Markets+ design elements ensure that resources can efficiently respond to market signals and be appropriately compensated, while avoiding over mitigation and ensuring transparent market pricing. Therefore, Markets+ design is more aligned with Bonneville's perspective regarding MPM and price formation, which can help improve outcomes for both resources and loads.

5.2.4. Congestion Modeling and Congestion Rent

Generally, the overall transmission design between EDAM and Markets+ is similar. Both day-ahead market frameworks rely upon transmission made available by market participants, TSPs, and transmission customers to facilitate the transfer of energy across the market footprint.[102] Market participants and participating TSPs in EDAM and Markets+ must make their transmission available for market use as a condition of participation, unless specifically opted out according to the respective market's rules. The CAISO EDAM Tariff allows participating entities to let transmission customers designate any of the transmission rights they hold as non-participating. The EDAM design intends for the EDAM Entity to make the ultimate decision to enable this market feature in its BAA.[103] The SPP Markets+ Tariff includes the opt-out of transmission from the market as part of the market design and has already established a communication process to opt-out transmission. In addition, both markets are designed to recognize market participants' existing transmission rights that can still be exercised in the day-ahead and real-time horizons. This is further explained in Section 6.8.

Physical Congestion Modeling

Ultimately, both EDAM and Markets+ will model constraints and manage transmission similarly. From a BAA perspective, each market will have to ensure that each participating and adjacent BAA can continue to calculate its

[101] Bonneville Power Administration, Staff Recommendation on Day-Ahead Market Participation (Apr. 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/02-day-ahead-market-attachment-1-staff-recommendation.pdf.

[102] SPP Markets+ Tariff, Attach. D (Markets+ Transmission) § 1.0 (General); CAISO EDAM Filing, Tariff Appendix B.33 (EDAM Transmission Service Provider Agreement (EDAMTSPA)).

[103] The CAISO EDAM tariff provides:

> **Transmission Not Available in the Day-Ahead Market**. If the CAISO is informed through the prospective EDAM Entity implementation process or by the EDAM Entity Scheduling Coordinator for the EDAM Transmission Service Provider that accommodation of incremental intra-day schedules in the Real-Time Market should be unavailable in the Day-Ahead Market according to the EDAM Transmission Service Provider tariff, the CAISO will accept a notification from the EDAM Entity Scheduling Coordinator associated with the EDAM Transmission Service Provider and will adjust Day-Ahead Market availability of the impacted transmission elements and the associated transmission service rights.

Cal. Indep. Sys. Operator Corp., FERC Docket No. ER23-2686, Transmittal Letter, Attach. A-2, Tariff § 33.18.3.3 (Aug. 23, 2023).

Net Scheduled Interchange (NSI), Net Actual Interchange, manage area control error (ACE)[104] in real-time, and perform After the Fact (ATF) energy accounting. Further, capacity or energy transfers from each BAA (EDAM and Markets+) must accurately account for Bonneville transmission rights that were used to facilitate the transfers. At times, these BAA-to-BAA rights and transfer accounting models in each market may end up being constrained and produce congestion revenue which will need to be allocated. Further, each market will also be able to model physical constraints (e.g., flowgates, paths, or lines). When the physical limit (or allocation of a physical limit) is reached in either the day-ahead or real-time, each market will attempt to honor the limit and potentially produce congestion revenue. Any congestion revenue would be allocated under the market tariff or under the participating BA's tariff in the case of EDAM, as described below.

Congestion Rent Allocation

Congestion rents[105] are payments to participants that occur within a market when the types of constraints described above become limiting (i.e., when congestion occurs). When congestion occurs at a constraint, the least-cost energy cannot be awarded to be delivered to all loads while respecting the constraint limits. The price to serve an incremental MW of load on either side of the constraint is different, resulting in different costs to serve demand in different locations.

To illustrate, a hypothetical generator clears at $25/MW and some portion of its output is serving load across a constraint. Due to congestion, it cannot send an incremental MW of energy across the congested element. Another resource offers $35/MW. The load will pay $35/MW rather than $25/MW because its incremental MWs are served by the other resource offering $35/MW. In this scenario, the market operator will have received more money than it distributed due to the congestion that caused price separation between LMPs.[106] The market operator must then allocate these congestion revenues in some manner to ensure that it remains revenue neutral. Methodologies for how a market allocates this congestion revenue vary, but generally the aim is to return it to the loads and to the transmission rights holders.

n most RTOs and ISOs, this allocation is effectuated by the conversion of physical OATT rights to Congestion Revenue Rights (CRRs) or similar path-specific financial rights, which can also be procured through auctions. However, neither Markets+ nor EDAM will rely on these financial instruments. Congestion rent is instead dictated by the respective market design and as applicable, the participating TSP OATT. The congestion rent designs and allocation methodologies for the proposed day-ahead markets are quite different.

EDAM breaks all congestion rents into two categories: congestion revenue and transfer revenue. In EDAM, congestion revenues are allocated to the BA where the binding constraint is modeled.[107] Transfer revenue is

[104] Area Control Error (ACE) is a real-time calculation performed by every BAA's Automatic Generation Control (AGC) system that indicates when something has changed and the BAA or interconnection is not balanced, such as: BAA load deviated from forecast, generator deviated from schedule, interchange deviated from schedule, or interconnection frequency deviated from schedule. ACE is measured in megawatts (MW).

[105] Congestion management includes all operational actions taken by grid/transmission operators to **proactively** and efficiently manage congestion, maintain the smooth flow of energy, and minimize the need to take operator actions in real-time. One aspect of congestion management is ensuring that a Market Operator honor the operational limits provided by TSPs and TOPs and that these operational limits are reflected in the market dispatch. Respecting these operational limits can result in price separation between loads, which results in congestion revenue or rent. Congestion revenue or rent is the money collected by the market operator due to the operational limitations that result in price separation between load and generation. Congestion rent is the term used in Markets+ and how we will refer to this topic generally. EDAM specifically differentiates between congestion revenue and transfer revenue as two components of the allocation of these congestion rents.

[106] To see a more detailed example of congestion, please see Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 7 presentation (June 3, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-7-presentation-060324.pdf.

[107] *See* CAISO EDAM Filing, Tariff § 33.11.1.2 (Congestion Revenue).

collected when the net EDAM Transfer scheduling limit is reached in the day-ahead market, representing price separation between neighboring BAs in EDAM.[108] The transfer revenue is allocated equally between the two BAs, unless there is an alternative commercial arrangement.[109] An EDAM transfer rights holder that makes capacity available to CAISO is eligible to receive transfer revenue and congestion revenue settlements through the Scheduling Coordinator.[110] The allocation of congestion revenue and transfer revenue collected by the EDAM entity will be suballocated according to that EDAM BAA's OATT. The suballocation of congestion rents is thus subject to the individual rules of the transmission service provider's Tariff. This can present undue complexity for customers by producing a wide set of outcomes depending on the tariff or tariffs to which a customer is subject.

A fundamental challenge Bonneville sees with the EDAM approach to congestion rent is the allocation being based on BAs, rather than a footprint-wide allocation which focuses on rights attributable to key constraints. A transaction occurring inside of EDAM, even a scheduled delivery that exists entirely within one BA, could be exposed to congestion that occurs elsewhere within the EDAM footprint. Per the EDAM design, the revenues of this transaction would be solely distributed to the BA where the congestion is binding. Due to the nature of physical flows, this could be a frequent occurrence. Without the means to recover revenue from congestion that may have occurred in a neighboring BAA, entities are presented with the potential to be exposed to congestion charges without the means to adequately hedge or recover revenue from the costs incurred by load. When the congestion revenue occurs within the BAA, there is no guarantee that the BA's OATT will allocate congestion by constraint within their BAA, presenting additional risk that loads will be exposed to costs and unable to recover offsetting congestion revenue.

Issues with the EDAM design and concerns regarding parallel flows became apparent when PacifiCorp filed its Tariff revisions with FERC to enable its participation in EDAM.[111] Protesters raised concerns that the EDAM design did not allow for "a sufficient congestion hedge to transmission customers exercising their transmission rights."[112] In response to these protests, CAISO initiated an expedited stakeholder initiative to address these concerns. CAISO's proposal is "to allocate parallel flow congestion revenues to the EDAM balancing area where these revenues accrue associated with the exercise of long-term firm and monthly firm Point-to-Point and Network Integration Transmission Service rights based on submitted day-ahead balanced source and sink self-schedules."[113] While this proposed change presents a better hedge than the current design, Bonneville's concerns regarding the BAA sub-allocation design and the lack of direct hedging by constraint remain. In addition, proposed tariff revisions of entities pursuing participation in EDAM require self-scheduling in order to receive congestion rent.[114] Incentivizing self-scheduling significantly reduces economic participation in the market and limits optimization benefits.

Markets+ takes a very different approach to the allocation of congestion rents. It does not differentiate between congestion occurring within BAAs or between BAAs, but rather it evaluates allocations across the entire footprint, specifically the rights associated with individual constraints. The allocation of eligible rights by physical constraint across the entire footprint, rather than allocating by BAA, mitigates the concerns with the EDAM design highlighted above. In Markets+, congestion rents associated with physical constraints are allocated directly and proportionally to the transmission rights holders of firm and conditional firm PTP transmission service, network integration

[108] *See id.* § 33.11.1.1 (Energy Transfer Revenue). This language allows for either a 50/50 allocation or another pre-existing commercial arrangement.
[109] *See id.*
[110] *See id.* § 33.18.4 (CAISO Transmission at EDAM Interties).
[111] *PacifiCorp*, FERC Docket No. ER-25-951-000.
[112] *Draft Final Proposal: EDAM Congestion Revenue Allocation* at 3 (April 16, 2025) (available at: https://stakeholdercenter.caiso.com/InitiativeDocuments/Draft-Final-Proposal-EDAM-Congestion-Revenue-Allocation-April-16-2025.pdf.
[113] *Id.* (parentheticals omitted).
[114] *Portland Gen. Elec.*, FERC Docket No. ER-25-1868-000, Transmittal Letter at 17 (April 3, 2025); *PacifiCorp*, FERC Docket No. ER-25-951-000, Transmittal Letter at 18-19 (Jan. 16, 2025).

transmission service, and legacy transmission service of monthly or longer service increments whose rights are associated with that physical path, who have not opted these rights out of Markets+.[115]

Under the Markets+ design, PTP eligibility will be based on the eligible transmission service request (TSR), while NITS eligibility is tied to an allocation cap based on the customers' monthly peak load and the allocation across paths is based on the designated network resources offered to serve their loads.[116] However, if NITS customers use secondary NITS service, the Markets+ design does not include secondary service in the direct congestion rent allocation. In these cases, there may be congestion revenue, but SPP will not allocate it directly to the Market Participant. SPP will allocate any undistributed congestion revenue to the TSP, and the TSP will allocate those revenues according to its tariff.[117] In addition, the congestion revenue design will be monitored by the Markets+ stakeholders, with an emphasis on ensuring equity between customer types, and evaluated for potential changes in the future that may result in updates to the Markets+ design if appropriate[118]. If participants require an allocation between two binding BAAs to be enabled, similar to what is done for transfer revenue in EDAM, the Markets+ Tariff allows for an allocation between binding BAAs.[119]

Based on an assessment of these two approaches, Bonneville believes that the Markets+ constraint-level congestion rent design is more robust because it better recognizes the topology of the market footprint and directly aligns with how Bonneville models and manages transmission constraints. For this reason, along with the concerns regarding the EDAM design methodology for allocation of congestion revenue, Bonneville strongly supports the congestion revenue allocation methodology of Markets+.

5.2.5. Greenhouse Gas Accounting

Bonneville is not subject to any state GHG programs in the region. However, it is important to many of Bonneville's customers to maintain the low-carbon attributes of the federal system. The market design for GHG accounting—how resources and their associated emissions are assigned to market participants—is critical to ensuring Bonneville's customers can continue to claim the low-carbon attributes of the federal system to comply with various state-mandated GHG programs or for their own utility purposes. This is a particularly challenging area because the various state GHG-reduction programs have created a patchwork of inconsistent policy goals and economic drivers across the West that can be challenging for utilities to navigate in wholesale power markets. EDAM and Markets+ meet the GHG accounting needs of states and participants in two ways.

First, a dispatch-based solution has been developed that supports state carbon pricing programs like California's cap-and-trade program and Washington's cap-and-invest program. The dispatch-based solutions incorporate a price on carbon for generation located in the state subject to the state program and electricity imports to the state. The market optimization selects resources to be attributed to serving load in the state based on the most economically efficient outcome for the market, including the carbon price for the applicable state.

Second, out-of-market (i.e., non-dispatched based) tracking and reporting mechanisms are being developed to support the needs of states and participants generally. This accounting supports a participant's ability to claim their owned and contracted resources for GHG reporting purposes. Bonneville considered how a day-ahead market GHG accounting design will impact Bonneville's customers across the region. Bonneville believes that a market design must address GHG accounting in a way that works fairly and equitably for all participants and states and does not

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[115] *See* SPP Markets+ Tariff, Attach. A § 7.16 (Congestion Rent Eligible Transmission Service Reservation Verification).
[116] *Id.* § 7.16 (Congestion Rent Eligible Transmission Service Reservation Verification).
[117] *Id.* § 9.2.15 (Day-Ahead Excess Congestion Rent Allocation Distribution Amount).
[118] This monitoring plan was approved as part of the MCRTF protocols. SPP, Markets+ Monitoring Metrics Congestion Rent (Aug. 14, 2024), *available at*: https://www.spp.org/Documents/72193/Congestion%20Rent%20Monitoring%20Approach%20Clean.docx.
[119] SPP Markets+ Tariff, Attach. A § 7.16 (Coordinated Interchange Scheduling Limits). Similar to the EDAM design, this language allows for either a 50/50 allocation or another mutually agreed upon ratio.

prioritize a single state's policy.

Generally, day-ahead markets can improve GHG accounting by providing greater transparency and granularity of dispatch data, providing more specific emissions information associated with serving load inside the market footprint.[120] In recent years, markets have needed to develop solutions for addressing GHG accounting to support state program requirements and individual participant needs. Where state programs have enacted a price on GHG emissions, the market needs a way to determine what is least-cost for the entire market and simultaneously least-cost for meeting load in a state with the pricing program. In addition, the market needs a method for assigning dispatch of specific resources (and their associated emissions) to specific loads to support the GHG reporting needs and emission reduction goals for states and individual utilities.

GHG accounting and reporting for organized markets is an actively evolving area with markets developing solutions to meet state program GHG requirements and state programs updating rules to adapt to market design. There are still uncertainties about how organized market GHG accounting will work with state GHG reporting, and additional uncertainties as to how this transpires into the GHG reporting provided to states for purchases from the federal system. While Bonneville cannot provide explicit details on what GHG reporting will look like for Bonneville's customers with participation in a day-ahead market, significant progress has been made related to GHG market design and related state GHG reporting in recent years and there is sufficient information available to describe and assess generally how the market design will work. The GHG market designs are described below.

There is currently insufficient information to determine if joining a day-ahead market will increase or decrease emissions attributed to federal power purchases from Bonneville. There are a number of unknown factors that are material to overall emissions impacts, including what resources are participating in the market, the market's GHG tracking and reporting rules combined with state-specific GHG reporting requirements, and changes in market behaviors of participants (e.g., shifts from use of traditional bilateral markets to organized markets). Nevertheless, there is enough information available for Bonneville to determine that the Markets+ design is superior to the EDAM design as described below.

5.2.5.1. GHG Accounting for Carbon Pricing Programs

EDAM and Markets+ have developed solutions that dispatch and attribute least-cost resources (including GHG costs) to load in a carbon pricing state to support the needs of states with carbon pricing programs, like California and Washington. The market operators aim to meet the needs of states and utilities subject to the carbon pricing program without negatively impacting states and utilities without such a program. However, in many cases, challenging trade-offs are inevitable because the market must balance the differing policies of states with respect to GHG reduction.

Bonneville believes that Markets+ GHG accounting design for carbon pricing programs achieves a reasonable approach to a market design that supports states with carbon pricing programs while not unfairly impacting states and entities not subject to carbon pricing. Conversely, Bonneville finds that CAISO's design falls short. As explained below, Bonneville anticipates CAISO's current design could have adverse financial impacts to Bonneville's customers and jeopardize customers' abilities to continue to report the low-carbon attributes of their power purchases from the federal system. There are two fundamental differences in design features that lead Bonneville to this conclusion.

5.2.5.1.1. Markets+ "Type 1A" attribution ensures attribution of federal system power contracted to utilities in states with carbon pricing programs

For customers located in Washington and subject to the state's cap-and-invest program, Markets+ design is superior because it better supports customers' ability to claim the low-carbon attributes of the federal system. Markets+

[120] *See, e.g.*, CAISO, Average Emissions Rate Report, *available at* https://www.caiso.com/library/average-emissions-rate-reports.

design (for "Type 1A" attribution of power to a state) will result in greater assurance that power from the federal system will be attributed to Bonneville's Washington customers. Markets+ design allows participants to register resources as "Type 1A" if they have contracts with load in the GHG Pricing Zone.[121] This "Type 1A" treatment recognizes that utilities have entered into contractual arrangements to procure clean or low-carbon energy and honors those contractual agreements by attributing the resource (if it is economical within the market dispatch) to load in the state. This "Type 1A" treatment is a critical feature that will allow customers to identify federal resource amounts that are contracted to its customers in Washington[122] and the market design will ensure those resources are attributed to Washington load if dispatched.

The Markets+ design recognizes contractual commitments that meet certain qualifications as "Type 1A" resources. Type 1A resources are optimized in the same way as in-state resources, resulting in the inclusion of the appropriate GHG adder in the offer prices and attribution to load in the state with the GHG pricing program. Thus, the design ensures attribution of the low carbon attributes of the federal system to Washington loads that have contracted with Bonneville.

EDAM's design recognizes contractual commitments[123] but not in an equivalent manner to Markets+ Type 1A treatment. EDAM's design recognizes contractual commitments, but does not guarantee the federal system, if dispatched, will be attributed to Washington. The market will seek the most economic solution for the market, including the carbon pricing states (both California and Washington). The federal system could be dispatched and attributed to Washington or it could be dispatched and used to meet load in the rest of the market, when it is the most economical solution for the entire market footprint (this is more akin to Markets+ Type 1B).[124] Thus, EDAM's design, if extended to Washington, would not provide the same level of assurance that federal power would be attributed to Washington loads. Further, EDAM does not appear to support assured attribution, even for self-scheduled resources (although, if it did, self-scheduling would not be an efficient market design because it would not allow for an optimized dispatch when appropriate).

EDAM's market design, paired with the design of Washington's cap-and-invest program, could dispatch fossil fuel generation located inside Washington to help meet power balance of the market as a whole, and attribute the resulting GHG emissions to load across Washington, including that of Bonneville's preference customers. At the same time, less expensive federal power could also be dispatched by the market but not attributed to Bonneville's power customers in Washington. This could occur because in-state resources[125] always have the GHG adder[126] in their dispatch, so the market optimization will by default first deem all in-state resources to be serving load inside the carbon pricing state, to achieve a least-cost solution for the entire footprint of the market. This could happen even if the market also dispatches a cheaper out-of-state clean resource that is contracted to Washington load. While this is a good solution for economic efficiency when considered across the entire market footprint, it can create unintended consequences for Washington loads that have contracts with clean or low-carbon resources located outside of the state. This inability to ensure federal power is attributed to Washington prevents Bonneville's

[121] *See* SPP Markets+ Tariff, Attach. K §§ 2, 3.2.2.
[122] Currently, in Bonneville's BAA, only its customers in Washington will have load included in a GHG Pricing area.
[123] *See* CAISO, Extended Day-Ahead Market Final Proposal § 7(c) and (d) (Dec. 7, 2022), *available at* https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf.
[124] Type 1B is energy from a resource with an agreement to supply load inside a GHG pricing zone. Type 1B energy is only attributed to the GHG pricing zone if it is the most economic solution for meeting power balance for the entire market. *See* SPP Markets+ Tariff § 1 (Definitions, Type 1B Energy) and Attach. K § 3.2.3.
[125] In-state resources are generally resources physically located in the state with the GHG pricing program (*e.g.*, Washington). However, pursuant to Washington's Climate Commitment Act, the federal system is considered to be external to the GHG Pricing Zone. *See* Wash. Rev. Code § 70A.65.010(42)(c).
[126] A GHG adder represents the monetary value of an individual resource's emission factor multiplied by the cost of compliance with the respective state program (e.g. cost of allowances). *See* CAISO EDAM Filing, Tariff § 29.32(a) (GHG Bid Adders); SPP Markets+ Tariff § 1 (Definitions, Specified GHG Adder).

Washington customers from claiming the low carbon attributes of the system and therefore equates to increased costs for Bonneville and its long-term firm power purchasers.

5.2.5.1.2. Markets+ Baseline "Threshold" Run recognizes Bonneville's load obligations in determining energy eligible for attribution, limiting the risk that energy contracted to other utilities will be attributed to states with GHG pricing programs

For customers located outside Washington, Markets+ design (the "threshold enhanced floating surplus" approach)[127] gives Bonneville the ability to manage how much energy from the federal system can and cannot be attributed to load in a state with carbon pricing (referred to as a GHG pricing area). Bonneville expects that the low-carbon nature of the federal system will often make it a least-cost option (including GHG cost), and, thus, result in attribution to load in California or Washington. Markets+ design includes market mechanisms that largely limit the amount of energy (aside from contracted amounts) that can be attributed to a GHG pricing area to circumstances when that energy is surplus to a market participant's total load obligations.

Markets+ design enables the resource owner to set a threshold reflective of the market participant's load obligations. Markets+ uses a baseline run that takes those obligations (the "threshold") into account by only making amounts dispatched over the threshold available for attribution to a GHG pricing area. The threshold run looks at the entire footprint of the market and is currently expected to run approximately every 15 minutes[128] and should yield results that are fairly aligned with the optimization and ultimate dispatch of the resource. In other words, the existing load obligations of the resource are a direct consideration of how much energy is eligible for and ultimately attributable to a GHG pricing area. This is a key feature of Markets+ design that would help ensure that Bonneville's customers can continue to claim the low-carbon attributes of their federal system power purchases for applicable state programs or for their own purposes.

While the newly adopted EDAM design will allow a participant to indicate how much energy they are willing to attribute to a GHG pricing area,[129] there is no in-market mechanism that aligns the participant's load obligations to the baseline run or optimization and resource dispatch. Rather, EDAM's baseline run (the "reference pass")[130] takes a broader look at resources across the market footprint to establish eligibility for attribution. As the CAISO explained in its EDAM filing, the EDAM counterfactual will "approximate how a balancing area outside the GHG regulation areas will meet its own load with its internal generation as well as supply from other balancing areas outside of the GHG regulation area. The goal of the GHG reference pass is to reflect how supply resources can optimally serve demand in the EDAM footprint without net imports into the GHG regulation areas and the associated cost of compliance with GHG regulation."[131] As a practical result of this, EDAM limits attribution of a resource to amounts that are determined to be surplus to the load needs of the entire market footprint rather than surplus to the participant's load obligation.[132]

Bonneville has two concerns with the EDAM design. First, this design incorrectly assumes that the best way to prevent leakage[133] is by assuming the load obligations of all market participants external to the GHG pricing area

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[127] *See* SPP Markets+ Tariff § 1 (Definitions, Surplus Threshold) and Attach. K §§ 3.4, 3.7.
[128] Email exchange between Bonneville and SPP (on file with author).
[129] *See* CAISO, Extended Day-Ahead Market Final Proposal § 7(b)(3)(a) (Dec. 7, 2022), *available at* https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf.
[130] *See* CAISO EDAM Filing, Transmittal Letter at 163-69; CAISO, Extended Day-Ahead Market Final Proposal § 7(b)(3)(c).
[131] See CAISO EDAM Filing, Transmittal Letter at 163-69.
[132] The EDAM excludes committed capacity from the baseline run. In other words, committed capacity will always be eligible for attribution to the GHG pricing area that the load it is contracted to is in.
[133] "Leakage" as used in this context is a reduction in GHG emissions within one jurisdiction that is offset by an increase in GHG emissions in another jurisdiction. See, for example, the definition of leakage in the California Global Warming

must be met before a resource could have surplus energy available for attribution to the GHG pricing area. This unnecessarily limits attribution from a particular resource, which may not be fully obligated (or obligated at all), which can disadvantage not only the seller of clean and low-carbon energy but also the state with the pricing program because the remaining resources eligible for attribution tend to be higher cost. Rather, the more appropriate measure is whether an individual resource (or system of resources, in Bonneville's case) has surplus energy available above its particular load obligations. As discussed above, Bonneville believes the Markets+ design appropriately focuses on energy amounts surplus to an individual resource's load obligations.[134]

Bonneville notes that there is a related concern with CAISO's BAA net export constraint,[135] which limits attribution from resources in a BAA where that BAA is a net importer.[136] However, the BAA is also not the appropriate measure of whether an individual resource has surplus energy available to meet load in a GHG pricing area. While the Bonneville BAA as a whole may be a net importer, that does not identify whether individual non-federal resources or the federal system is surplus in relation to each resource's individual load obligations.

Second, under EDAM's design, the actual optimization could dispatch the resource at levels lower than those reflected in the reference pass, which could result in significant amounts of the federal system being attributed to California even though that power is contracted to Bonneville's customers in other states under long-term power sales contracts. While this can happen as well with Markets+'s design, the risk is minimized because, as discussed above, the threshold run is 1) based on all loads and resources in the market and 2) expected to be run every 15 minutes.

CAISO's existing market, the WEIM, demonstrates Bonneville's second concern. In the WEIM, there are often times when the amount of federal system WEIM dispatches that are attributed to California are greater than the amount that Bonneville's BAA is exporting to the WEIM. Specifically, when there is a non-zero GHG shadow price, meaning some carbon emitting resources are being attributed to California,[137] about 90% of Bonneville's WEIM power sales are being attributed to California. This occurs even though there may be a negative imbalance[138] in Bonneville's BAA (i.e., Bonneville BAA is importing from the WEIM) and customers have contracts with Bonneville for forward supply. A day-ahead market would subject a larger portion of the federal system to this effect. CAISO has taken recent steps to improve the GHG accounting design in EDAM by switching to a baseline

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Solutions Act of 2006 (Assembly Bill 32, or AB32), *codified as* Cal. Health and Safety Code Div. 25.5, §§ 38500-99.11. CAISO uses the term "secondary dispatch" to identify when leakage is occurring in its market design because a resource has been attributed to a jurisdiction (California) at levels below the resource's baseline.

[134] Bonneville notes that emissions leakage (also referred to as secondary dispatch in a markets context) is a state issue as opposed to a markets issue. Individual state programs may have differing views on whether leakage needs to be addressed and, if so, how stringently. CAISO's approach to minimize leakage is purportedly a California approach as the California Air Resource Board's cap-and-trade program was the only pricing program in effect with guidance on leakage at the time of EDAM development. Conversely, SPP's approach provides more state flexibility to determine parameters around the appropriate amount of leakage. This is because a resource owner's threshold can be informed by guidance from a state on what constitutes surplus energy that is eligible for attribution to the state.

[135] *See* CAISO EDAM Filing, Tariff § 29.32.1.

[136] The EDAM net export constraint does not apply when the BAA is located in a GHG pricing zone and does not limit committed capacity from being attributed to a GHG pricing zone.

[137] Bonneville uses its Asset Controlling Supplier emission factor to inform its GHG bid offer for California, resulting in a very low, but non-zero GHG emissions cost.

[138] The WEIM Transfer is an algebraic quantity (positive for export and negative for import) for the net energy exchange between a given BAA and the remaining BAAs in the WEIM Area. *See* CAISO Business Practice Manual for the Western EIM, Appendix A: Mathematical Formulation for WEIM Transfer § 16.2.1.1.1, *available at* https://bpmcm.caiso.com/BPM%20Document%20Library/Energy%20Imbalance%20Market/BPM_for_Energy%20Imbalance%20Market_V33_Clean.docx.

run[139] and adding the BAA next export constraint for EDAM. Bonneville expects that these updates will help reduce this effect but not minimize it as effectively as the Markets+ design. In the event this occurs in EDAM, it could undermine the ability for Bonneville's customers in other states, like Oregon, to claim energy from the federal system for GHG reporting purposes, despite the fact that they hold long-term contracts for federal system purchases.

5.2.5.2. GHG tracking and reporting for non-pricing programs and general needs of market participants

Both EDAM and Markets+ are also developing more broadly applicable GHG accounting solutions that could support meeting the requirements of states with non-pricing programs (e.g., emission reduction standards that do not explicitly place a price on carbon), as well as the GHG accounting needs of any individual market participant. Bonneville views these solutions as essential to its customers' ability to retain the GHG benefits of the federal system.

Markets+ has developed and adopted a novel out-of-market GHG accounting solution designed to support the needs of market participants, whether to meet requirements of a state non-pricing program, local requirements, or individual utility goals.[140] The accounting framework will assign to a market participant the dispatched energy for the market participant's owned and contracted-for resources up to the amount of the market participant's load. This will ensure (subject to state GHG reporting rules) that market participants can claim and report the clean resources in which they have invested. Bonneville has confidence that the Markets+ solution will support Bonneville's customers' ability to continue to claim the low-carbon attributes of the federal system regardless of the state in which the customer is located.

EDAM work to develop a similar approach is in progress.[141] In December 2024, CAISO published an issue paper that outlines reporting design options and some tradeoffs.[142] It is uncertain whether the approach CAISO ultimately adopts will support the needs of Bonneville customers. At this time, Bonneville has more confidence that the Markets+ design for accounting and reporting will meet the needs of its customers.

5.2.5.3. GHG Takeaways

Markets+ includes a GHG accounting design that fairly assigns Bonneville's carbon-free generation to Oregon and Washington customers. The EDAM design continues the status quo of California customers obtaining disproportionate credits for out-of-state low-carbon generation. As these market design differences persist, they serve to increase costs for Bonneville's Washington customers who participate in Washington's carbon pricing program, and they result in Oregon customers receiving less credit than they are entitled to meet their state's requirements.

As described above, Bonneville has made an informed comparison between the market designs of EDAM and Markets+ related to GHG accounting. Bonneville believes that the Markets+ GHG accounting approach (the dispatch-based solution for carbon pricing programs combined with a broadly applicable out-of-market resource

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[139] The EIM currently limits attribution of a resource to a GHG pricing area to the difference between the resources Upper Economic Limit and Base Schedule. In the future, for EDAM participants, the CAISO will use the difference between the day-ahead market energy schedule and day-ahead market GHG award. *See id.* § 11.3.3.2; CAISO Extended Day-Ahead Market Final Proposal § 7(b)(3)(c).

[140] *See* SPP, Markets+ GHG Task Force, *available at* https://www.spp.org/stakeholder-groups-list/western-energy-services-stakeholder-groups/marketsplus-stakeholder-groups/marketsplus-independent-panel/marketsplus-participant-executive-committee/marketsplus-design-working-group/marketsplus-ghg-task-force/; SPP Markets+ Protocols § 5.8 ([GHG] Tracking and Reporting).

[141] *See* CAISO, Greenhouse Gas Coordination Work Group, *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Greenhouse-gas-coordination-working-group.

[142] CAISO, Greenhouse Gas: Accounting and Reporting Issue Paper (Dec. 20, 2024), *available at* https://stakeholdercenter.caiso.com/InitiativeDocuments/AccountingandReportingIssuePaper-GreenhouseGasCoordination-Dec202024.pdf.

and emissions assignment available to all market participants) is an equitable approach to the needs of all market participants to meet various reporting programs, and provides a path for Bonneville's customers to continue to report low-carbon attributes associated with purchases from Bonneville. Further, the Markets+ governance structure enabled it to successfully continue to refine a widely supported solution for GHG accounting. In addition, SPP's stakeholder process provides superior flexibility, allowing participants the opportunity to revise the GHG accounting design to account for changes in the GHG reporting landscape. Bonneville recognizes the market participants' ability to make stakeholder-driven improvements and adjustments to market design is particularly important in this complex and evolving area.

5.3. Summary Recommendation

Bonneville recognizes that its day-ahead market Policy direction towards participating in Markets+ will play a critical role in the energy and capacity market landscape for the region, and it will have direct impact on a number of other entities' decisions regarding day-ahead market participation. Bonneville has carefully considered the financial analyses, design comparisons, expected footprints, and various other details through the lenses of our evaluation principles. Bonneville sees participation in a day-ahead market as an important step in maintaining access to trading partners to continue meeting obligations and marketing surplus to maintain low rates for customers.

Bonneville has determined that Markets+ is the best option because of its superior governance and stakeholder process and its superior design, and believes it has the potential to offer financial benefits that are greater than business as usual. While several market design issues described above, such as congestion revenue allocation, GHG accounting, and fast start pricing, cannot be decisively quantified, Bonneville believes the Markets+ design is likely to provide economic benefit and partially offset the financial benefits attributed to EDAM by the PCM studies. Bonneville will work diligently to meet the needs of its power and transmission customers, including by maintaining access to trading partners and minimizing market-to-market friction. Bonneville acknowledges the potential financial tradeoff and potential increased implementation and participation complexity given differing decisions by other adjacent entities. However, these tradeoffs must be evaluated along with potential mitigation and the business drivers associated with relevant quantitative and qualitative factors. Based on comprehensive business evaluations presented in this Policy, Bonneville concludes that the design of Markets+ is best positioned to satisfy Bonneville's business needs, statutory and contractual obligations, and the broad and evolving needs of Bonneville's customers.

6. Preliminary Implementation and Participation Considerations for Markets+

Throughout Bonneville's public process, Bonneville explained generally how a day-ahead market will affect Bonneville and its customers. Bonneville discusses a summary of Markets+ implementation and participation elements in this section. Further details will continue to be developed as Bonneville progresses through implementation of day-ahead market participation in Markets+.

Bonneville's Policy direction to join Markets+ impacts all generation and load in the Bonneville BAA to some degree. In addition to requirements laid out in the market tariff and associated supporting documentation, Bonneville will memorialize requirements and rate information specific to its BAA in its tariff, rate schedules, and business practices as part of the public processes it carries out for each of these documents.

6.1. Generation Resource Participation in Markets+

Bonneville anticipates the following details of participation framework in Markets+.

All output is settled

In Markets+, all resources above a certain size[143] in Bonneville's BAA will be subject to the market tariff and rules,

[143] In the WEIM, Bonneville requires all generators above 3 MW to be modeled. *See* Bonneville Power Administration, Energy Imbalance Market (EIM) Business Practice V.5 §§ D.3, G.6 (May 30, 2023).

which Bonneville will propose to incorporate into its Tariff and business practices.[144] Under the terms of the Markets+ Tariff, all generation output will be settled at market prices.[145] The basic energy settlement equations are described in Section 6.6.[146]

All resources participate, but can self-schedule

In the context of the WEIM, "participating resources" are resources registered directly with the WEIM that can offer flexible range to the market via a bid curve, and "non-participating resources" are all other resources that do not bid directly into the market. In both day-ahead markets, all resources are considered "participating" because their full output impacts the market solution, and they are settled for that full output. However, this does not mean that all resources must offer flexibility. In addition to the ability to offer price-sensitive energy between a minimum and maximum generation point, both markets also allow for "self-scheduling" which is an indication to the market that a resource plans to generate a specific MW amount and is not offering price-sensitive flexibility to the market. The resource will still be settled for that submitted self-schedule at the relevant market LMP, as the submitted self-schedule becomes the day-ahead market solution award for that resource, and that resource will still be settled for real-time output relative to that day-ahead award.

Resources can still export out of the BAA

Joining Markets+ will not prevent or limit resources in the Bonneville BAA from transacting with entities outside the Markets+ footprint. Entities can still export from their resources out of the footprint as long as the export is properly tagged, as is required today to sell an export out of the Bonneville BAA. Note that this does not require a resource to opt their transmission out of the market. Resources can schedule on their transmission to indicate the export, and then either self-schedule enough output to serve the export or offer the resource into the market and let the market choose the most economic resource mix to serve the export obligation. This is further discussed in section 6.8.

Resources and loads must have a direct relationship with the Market Operator

In Markets+, all registered resources and loads must have a direct relationship with the Market Operator via a Market Participant[147] Agreement. Multiple resources and multiple loads can be registered under a single market participant. The market operator will directly receive data submissions from the market participant and will settle directly with the market participant for nearly all charge codes. This differs from the WEIM framework, where the market settles with the BA for all loads and non-participating resources and the BA subsequently sub-allocates the charges. At this time, Bonneville has not determined whether it will offer options for resources in its BAA to schedule into the market through Bonneville (e.g., simply by submitting a schedule to Bonneville via e-tag or Bonneville's Customer Data Exchange, as is done for non-participating resources in the Bonneville BAA for WEIM today). Note that for the few charge codes paid to the TSP or BA, Bonneville will determine the suballocation of those funds in a future Rate Case proceeding.

Independent resources do not have an automatic must-offer obligation

The Markets+ Must-Offer Obligation is measured at the market participant level. Independent resources do not have individual must-offer obligations unless they have export schedules (in which case, they must offer or self-schedule their resource to fulfill the export schedules). Otherwise, individual resources contribute to meeting the Must Offer

[144] *See* Section 5.1.1.6 (Power Business Line) above and Section 6.6 (Markets+ Settlements) below for more details.
[145] SPP Markets+ Tariff, Attach. A § 6.2(6). An MP must register all gen in footprint above 0.1 MW unless behind the meter under 10MW (note: the BPA BA uses 3MW, not 10MW, for BTM in EIM, as indicated in the previous footnote).
[146] *See also* SPP Markets+ Tariff, Attach. A §§9.2 (Day-Ahead Market Settlements), 9.3 (Real-Time Balancing Market Settlements).
[147] Pursuant to the Markets+ Tariff Definitions: "Market Participant (MP): An entity that executes the Market Participant Agreement in Attach. E, or on whose behalf an unexecuted Market Participant Agreement has been filed at FERC."

Obligations of market participants with load by being a resource within that market participant's registration. The market participant can also indicate a contract with the resource that they put toward their must-offer obligation.

Resources must provide offer information in accordance with market timing

The timing for the day-ahead market run to "close" (at which point the day-ahead market optimization begins, and no new input information can be incorporated) in Markets+ is 10 a.m. on the day prior to the relevant operating day, with results expected to be posted by 1:30 p.m. Markets+ runs the Reliability Unit Commitment (RUC) process at least every four hours between the day-ahead market solution and real time. The RUC provides unit commitment information to resources that have indicated their willingness to be committed by the market but is otherwise not financially binding for purposes of energy settlement. The timing for the real-time market run to close is 30 minutes prior to the relevant operating hour ("T-30"). Offer information, including MW amounts and associated pricing, can be changed after the 10 a.m. day-ahead close at any point until the T-30 deadline and is incorporated into any subsequent RUC and real-time optimizations.

Potential for non-BA requirements

Note that the information in this section generally pertains to participation based on Markets+ requirements and the expected framework in the Bonneville BAA. For resources that are owned by or contracted to power customers of Bonneville Power Services, there may be further requirements. Those requirements will be determined as part of a public process as discussed in Section 6.7.

6.1.1. Federal Generation

Markets+ will allow resources to be registered as individual units or as aggregated resources. Bonneville intends to use the same resource aggregations as is used in WEIM. Resource aggregates are further discussed in Section 6.1.1.2.

Bonneville will prioritize its statutory obligations such as fish passage and flood control over market actions, as it does today, which may limit Bonneville's ability to participate in the market during times of limited hydraulic flexibility.

Bonneville expects to use self-schedules and offer ranges to ensure the FCRPS operates within its limits while allowing for system optimization. In addition to hourly minimum/maximum constraints, Markets+ has also developed an additional constraint, allowing Bonneville to communicate a daily energy maximum for each resource in the day-ahead optimization in addition to the hourly offer range limits. Setting a daily energy maximum helps ensure that Bonneville can honor operational obligations and constraints while still allowing for economic optimization of the system. Further, because offers can be updated through real-time, Bonneville will be able to make adjustments to its planned operations in the market as fuel certainty materializes.

6.1.1.1. Impacts on Hydro Operations in Relation to Fish & Wildlife

In Markets+, Bonneville will continue to meet its statutory obligations, including those under the Northwest Power Act, Endangered Species Act (ESA), and National Environmental Policy Act (NEPA). Bonneville's power marketing services and activities, and its actual power operations to meet load obligations, are conducted consistent with applicable Biological Opinions and are within existing operating constraints and normal operating limits of FCRPS projects. The Markets+ framework allows Bonneville to manage FCRPS operations with other project purposes and system-wide operating constraints, including operations to support ESA-listed fish and to provide equitable treatment for fish and wildlife with other system purposes as required by the Northwest Power Act.

6.1.1.2. Use of aggregation model for Federal resources

As part of the decision to enter the WEIM, Bonneville opted to use the aggregation model to represent the Big 10

hydro resources.[148] The aggregation model has worked well in the WEIM, and Bonneville plans to maintain this approach for day-ahead market participation in Markets+.

The resources within an aggregation model are hydraulically interdependent; water released out of upstream resources will affect the operation of downstream resources within a matter of hours. Hydro operators must account for this relationship along with fuel uncertainty (e.g., expected water flows versus real water flows due to weather, third party resource operations, etc.). This dynamic, combined with the various non-power constraints and physical project limitations, results in the need for hydro operators to have flexibility to adjust between resources as necessary. Aggregation of hydro resources allows Bonneville and its federal partners to maintain this flexibility to manage the impacts of market activity and uncertainty in operational and hydraulic objectives.

In the WEIM, Bonneville uses three aggregations to provide maximum flexibility for hydro operators while providing the market with maximum ability to redispatch resources for congestion relief. Bonneville grouped the resources that were most interconnected based on river reach area (Upper Columbia,[149] Lower Snake,[150] and Lower Columbia[151] areas).[152]

Bonneville has worked closely with SPP and stakeholders in the Markets+ process to design an aggregation model for use in Markets+. Bonneville has not yet determined if there are other groups of resources in the federal hydro system that would benefit from aggregation but plans to consider that question during implementation.

6.2. Ensuring Adequate Supply in Markets+

Today, Bonneville works across all timeframes to preserve and maximize the value of the FCRPS for customers through prudent operational planning and marketing practices. Bonneville sets its system up to provide the most economic and reliable energy supply to customers while planning for contingencies and required operations such as those for fish and wildlife. Bonneville also plans the system to make economic purchases and high-value surplus sales to bring added revenue to help lower firm power rates. Bonneville's primary goal in its proposed participation in Markets+ will be a continuation of what it does today: provide firm power supply for its long-term power sales contracts. Bonneville will continue to plan for its long-term firm power load service obligations by managing its existing resources and by acquiring resources in advance based on forecasted need. Bonneville does this in its Pacific Northwest Loads and Resources Study (also known as the White Book) and through its Resource Program, both of which supplement the regional power plan prepared by Northwest Power and Conservation Council pursuant to the Northwest Power Act.

Bonneville's future participation in WRAP binding operations and Markets+ will provide greater transparency and documentation as to how these obligations are met. Bonneville's loads and resources planning for its long-term power customers will be reflected for long term planning in its WRAP obligations and for short term planning in the requirement that Bonneville meet the Markets+ resource sufficiency mechanism, the Must Offer Obligations. The Must Offer Obligation is a minimum requirement for each market participant in Markets+ with load and/or export obligations to bring enough supply to "cover" those obligations. Through its long-term planning (reflected in the WRAP Forward Showing program and Bonneville's White Book), and its short-term planning practices (demonstrated in the Must Offer Obligations and WRAP Operations Program), Bonneville will ensure that its long-term firm power sales contract obligations are satisfied.

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[148] The "Big 10" Hydro Resources are: Grand Coulee, Chief Joseph, Lower Granite, Little Goose, Lower Monumental, Ice Harbor, McNary, John Day, The Dalles, and Bonneville Dams.
[149] Aggregation of Grand Coulee and Chief Joseph Dams.
[150] Aggregation of Lower Granite, Little Goose, Lower Monumental, and Ice Harbor Dams.
[151] Aggregation of McNary, John Day, The Dalles, and Bonneville Dams.
[152] For more information on this decision, please see Bonneville Power Administration, EIM Participation Letter to the Region, Attach. A § III.e.1 (June 20, 2019), *available at* https://www.bpa.gov/-/media/Aep/projects/energy-imbalance-market/20190620-western-energy-imbalance-market-letter-to-the-region.pdf.

6.3. Ancillary and Control Area Services

Ancillary and Control Area Services (ACS) are services necessary to support the transmission of energy and capacity while maintaining reliable operation within and among BAAs. Bonneville is required to offer ancillary services under its Tariff, and transmission customers may purchase certain ACS from Bonneville or self-supply through a customer's own resources. In general, ACS are necessary to maintain the reliability of the BAA. There are typically two components to most ACS: capacity (the ability to produce energy when needed) and energy (the actual production of energy). Energy and Generation Imbalance, which are used for the sub-hourly provision of energy to maintain load-resource balance within the BAA, are two important ACS that Bonneville currently offers. Bonneville currently provides Energy and Generation Imbalance service through the WEIM under Schedules 4E and 9E of Bonneville's Tariff.[153] There is currently no centrally organized market for the capacity component of ACS proposed for Markets+ or EDAM, which Bonneville provides under Schedules 3 and 10 of its Tariff.

Participation in Markets+ does not eliminate Bonneville's requirement to offer ACS, as the market operator will not be taking over this responsibility. Markets+ includes the Real-Time Balancing Market (RTBM), which is similar to the WEIM. The RTBM is an intra-hour (or real-time) centralized energy market used to economically dispatch participating generation resources to balance supply, transfers between BAAs (interchange), and load across the market's footprint. Like the WEIM, RTBM is not a capacity market. Bonneville does not expect Markets+ to change how ACS is provided. However, Bonneville will likely need to revise its tariff, rates, and business practices to incorporate Markets+. Those revisions will occur separately in the appropriate processes.

6.4. Operational and Commercial Seams

As described by FERC, seams issues include differences in transmission rules as well as differences in power market rules. Operational seams include multifaceted matters such as coordination of generation and transmission maintenance schedules, determining how path flows affect outside areas, congestion management procedures, operating rules for recalling firm transmission capacity, demand response rules, and communication protocols. Commercial seams encompass different market constructs such as bidding rules, market product definitions, market price intervention practices, different business practices, generation and transmission scheduling practices, and processes to verify transactions between market operators and market participants.[154]

Bonneville and other BAAs will need to manage new operational and commercial seams as entities join day-ahead markets. For example, Bonneville has generation and load in other BAAs that are likely to join EDAM, such as the PacifiCorp (PAC) and Portland General Electric (PGE) BAAs. In addition to the obligation to customers located in those BAAs, many entities affected by the implementation of day-ahead markets will need to manage commercial seams and possibly multiple markets. These seams can be mitigated through coordination across the various participants, including market operators, BAAs, market participants, and the various regional groups who coordinate among WECC today.

As explored in detail in Appendix D, the development of day-ahead markets will create new operational seams in the Western Interconnection. Bonneville's transmission system covers large portions of the Pacific Northwest and is not always contiguous. There are also a number of transmission asset owners, BAAs, and transmission capacity owners of operational paths within Bonneville's Pacific Northwest service territory, including the Pacific DC Intertie (PDCI) and Northwest AC Intertie (NWACI). Bonneville will be able to manage operational complexities like congestion management by developing coordinated operating agreements like those for WEIM.

CAISO and SPP will have their own RC offerings tasked with ensuring system reliability for their registered

[153] Bonneville is providing imbalance service under Schedules 4 and 9 during the periods that Bonneville pauses WEIM participation.

[154] *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, 67 Fed. Reg. 55,452 55,464-65 (Aug. 29, 2002).

Transmission Operators. RCs, market operators, and market participants will develop agreements to manage seams to support reliable operations, like they have in the eastern states for decades. The ability of a region with multiple energy markets in it to effectively manage congestion is strongly dependent on both markets calculating impacts on a path the same way, so that actions taken during congestion management have the desired effect in both market footprints.

6.4.1. Commercial Seams

As also explored in detail in Appendix D on seams management, the development of day-ahead markets will create new commercial seams. Today, many of Bonneville's commercial seams are between the bilateral and non-bilateral markets. The industry has created tools and means of transacting which mitigate the impacts of these commercial seams such as ensuring power sales and purchases have some uniform provisions by largely adopting the WSPP, Inc. (formerly Western Systems Power Pool) standardized WSPP Agreement.[155] Multiple day-ahead markets within the West would require the development of new tools and methodologies to manage commercial seams.

6.4.2. How market participation may impact transmission congestion issues

Bonneville has observed the ability of WEIM to manage operational constraints and expects even greater congestion management effectiveness with the addition of a security constrained day-ahead market optimization. However, Bonneville acknowledges that two day-ahead markets will create a need for operational coordination between the markets, particularly given the non-contiguous nature of the potential market footprints. The ability of an energy market to effectively manage transmission system congestion depends on the footprint and size of that market. This includes the size, location, and offered flexibility of the resources supplying energy to that market, the size and location of the loads purchasing that energy, and the volume of transmission available to that market relative to those resources and loads. The day-ahead schedules and awards from each market, if properly implemented and coordinated, should be physically feasible within the market-available transmission capacity.

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. Appendix E discusses in more detail those impacts as they are related to congestion management. Bonneville expects agreements, constraints, and market design to mitigate operational and commercial seams issues. Given the complexity of the Western Interconnection, the potential for non-contiguous market and RC footprints, and the number of parties involved, multiple types of agreements will be necessary.

6.5. Operational Tools

Bonneville employs many operational tools to reliably operate the federal power and transmission systems to meet its Tariff, compliance, and environmental requirements. At this time, Bonneville expects to continue to use a majority of these operational tools in Markets+.

Some of these tools will require adjustments to work within the framework and day-ahead market timelines of Markets+. Bonneville will continue to identify which operational tools will require adjustments as part of implementation scoping and will work with the market operators as necessary as part of that scoping process.

6.5.1. Curtailment Advisor

Bonneville anticipates adjusting its Curtailment Advisor tool used for performing transmission curtailments in real time when flow on a path exceeds the established limit. Today, when initiated, Curtailment Advisor curtails e-tag schedules impacting the given path in real time according to NERC curtailment priority. In the real-time market, the market optimization will redispatch every five minutes in real-time to maintain market flows within the established market transmission limit. If the market is unable to redispatch enough to avoid violating the limit, responsibility reverts to the TOP to determine if actions are needed to protect the path. However, because BAA-to-BAA e-tags with "system" sources are typical in a day-ahead market framework, Bonneville will need to develop

[155] *See WSPP, Inc.*, FERC Docket No. ER25-178, Letter Order (Dec. 13, 2024).

a method to address effective transmission curtailments based on NERC priority. Bonneville anticipates working through this topic as part of its implementation phase.

6.5.2. Operational Controls for Balancing Reserves (OCBR)

OCBR is a real-time operational tool used by Bonneville to manage reliability when balancing reserve capacity is depleted. Balancing reserve capacity is capacity held to address sub-hourly load and generation error as measured against an hourly schedule across the Bonneville BAA. Incremental or "INC" capacity is deployed when there is under-generation relative to load and decremental or "DEC" capacity is deployed when there is over-generation relative to load.

Before Bonneville's entrance into the WEIM, the use of OCBR for an INC depletion event resulted in the curtailment of hourly schedules to actual generation levels for significantly under-generating resources. The use of OCBR for a DEC depletion event resulted in limiting generation to the scheduled amount for significantly over-generating resources.

Upon joining WEIM, Bonneville adjusted the design of the OCBR tool to better fit with the real-time market structure and leverage the additional sub-hourly energy available in the market. For example, Bonneville shifted the measurement of balancing reserve depletion to consider only the portion of balancing reserves served exclusively by Bonneville's own resources (regulation), and not the portion served by WEIM dispatches (non-regulation).

Bonneville expects few, if any, changes to OCBR when joining Markets+. OCBR[156] is a real-time tool and the day-ahead market elements of Markets+ should not have any impact. As RTBM in Markets+ operates similarly to the WEIM, OCBR should work with the RTBM in the same manner.

6.5.3. Oversupply Management Protocol

Oversupply Management Protocol (OMP) is an operational tool used to address certain environmental conditions in the Columbia River, while maintaining reliability in Bonneville's BAA. During times of high river flows, typically in the spring when loads in Bonneville's BAA are low, water must be passed through the dams in one of two ways: spilled over the dams or run through the turbines to generate electricity. When water is spilled over the dams, it creates bubbles of air in the water that, at certain levels, can be harmful to salmon and other aquatic species. This is referred to as total dissolved gas and is regulated by Oregon and Washington under the Clean Water Act.

When the Columbia River reaches total dissolved gas limits, Bonneville must limit spill by passing water through the generating turbines, thus creating electricity. Bonneville sells this electricity at market rates, but, in the Spring, there are occasions when there is not sufficient load to use the electricity, even at zero cost. As a result, Bonneville adopted Attachment P to its Tariff, creating a least-cost cost curve for displacing generation in the BAA and reimbursing displaced generators for certain costs related to the displacement so that Bonneville can pass water through its generating turbines and maintain load-resource balance. Attachment P has been approved by FERC under section 211A of the Federal Power Act.

Bonneville expects to retain OMP in Markets+ and will review if any process changes are necessary to adapt to market rules and timing. While Markets+ may provide Bonneville additional opportunities to market generation during times of high flows, Bonneville still needs a mechanism to ensure compliance with its environmental responsibilities. As Bonneville gains more experience in Markets+, it will monitor the need to adjust or retain OMP.[157]

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[156] *See* Bonneville Power Administration, Operational Controls for Balancing Reserves, *available at* www.bpa.gov/energy-and-services/transmission/ancillary-services/balancing-reserves/operational-controls-for-balancing-reserves.
[157] *See* Bonneville Power Administration, Oversupply, *available at* www.bpa.gov/energy-and-services/transmission/oversupply.

6.6. Markets+ Settlements

Markets+ will settle directly with each market participant for the majority of its charge codes, including day-ahead awarded energy and imbalance energy. Settlement volume will be larger in a day-ahead market than in a real-time only market. As discussed in section 6.7, Bonneville expects to be the market participant on behalf of Load Following customers in the Bonneville BAA and thus will settle with Markets+ on behalf of those customers. Other market participants[158] will receive their settlements directly from Markets+.

Markets+ settlements are more streamlined than EDAM. Markets+ utilizes a simpler 12-month settlement process with three settlement statements and ~40 charge codes, as opposed to the EDAM settlement period of 24-months with five settlement statements, and a much larger number of charge codes to manage.[159] Markets+ settles directly with market participants. Receiving settlements directly through the Market Operator, rather than suballocated by the BA, as is done in WEIM, allows for more direct payments and charges, as well as more timely financial resolution. These aspects are likely to be especially favorable to independent power producers and other larger participants, as well as to Bonneville and its customers, by reducing the workload and associated costs of handling settlements for large entities within the BAA.

While there are a number of charge codes, the most essential settlements are for day-ahead energy awards and real time imbalance energy. As previously described, the award from the day-ahead solution is settled at the day-ahead LMP and is used as the financial reference point for settlement of energy in the real-time solution.

The general equation for energy settlement[160] for a resource is:

Total Energy Settlement = Day-Ahead Award * Day-Ahead LMP + ((Real-time Output – Day-Ahead Award) * Real-time LMP)

And for a load is:

Total Energy Settlement = -1*(Day-Ahead Cleared Load * Day-Ahead LMP + ((Real-time Load Consumption – Day-Ahead Cleared Load) * Real-time LMP))

In the load settlement equation, multiplication by -1 indicates a settlement in the opposite direction (i.e., a payment versus a charge).

6.7. Bonneville Power Services Customer Participation in Markets+

Bonneville's participation in Markets+ will be consistent with the obligations of its Provider of Choice power sales contracts. These contracts include the terms and conditions of the products and services that Bonneville offers its power customers and defines the obligations that both Bonneville and the power customer must meet. Bonneville will look to accommodate power customers' participation in the market consistent with the obligations associated with their product and service elections.

Bonneville recognizes that it does not currently have enough information to include language in the ongoing development of its next long-term power sales contract that would adequately address all the necessary day-ahead market terms and conditions. The Provider of Choice power sales contracts will include a provision that will enable the parties to amend the power sales contracts as needed. Such amendments will include any necessary changes to align with both an updated Bonneville Tariff and the Markets+ Tariff (including associated settlements under Markets+). Bonneville will hold a public process to review proposed standardized amendment language and offer an opportunity for public comment on that language. The Provider of Choice power sales contracts will also include

[158] *E.g.*, Planned Product customers, independent power producers, etc.
[159] Bonneville has federal resources and preference loads in EDAM BAAs, so to the extent settlements are required, Bonneville will coordinate with EDAM or its participating BAAs and affected customers.
[160] Day-ahead markets contain many other charge codes. This is a simplified example showing basic energy settlement.

a provision establishing that Bonneville will conduct a subsequent public process on the topic of settlements for the Slice Product following Bonneville participating in the day-ahead market.

For Load Following customers, Bonneville expects to be the market participant on behalf of customer loads that are in the Bonneville BAA. Bonneville will work with Load Following customers with load outside the Bonneville BAA to determine the appropriate participation model. Load Following customers for which Bonneville is the market participant and that have dedicated non-federal resources may be eligible to have those resources participate in the day-ahead market consistent with their contractual obligations and requirements. For example, Load Following customers with dispatchable resources may be allowed to offer flexibility to the day-ahead market. Bonneville expects that Load Following customers that elect to offer their own resources into the market for dispatch would be expected to offer capability to the market consistent with any peaking requirements defined in their contracts.

Planned product customers include Slice/Block customers and Block customers. For planned product customers that are in the Bonneville BAA, Bonneville anticipates that a planned product customer will act as the market participant for both their own load and any non-federal resources they wish to bid into the market. Bonneville will work with planned product customers with load outside the Bonneville BAA to determine the appropriate participation model. Bonneville will work with planned product customers to determine how the power supplied by Bonneville is accurately reflected in both Bonneville's and the planned product customers' market participation. Planned product customers will continue to purchase power consistent with their planned obligation and would be expected to be responsible for any day-ahead or real-time load variances.

As an overall observation, Bonneville does not expect day-ahead markets to impact certainty of delivery for power customers. Bonneville would continue to schedule contract deliveries in advance of the market operation based on existing transmission rights as necessary. Transmission customers would continue to be entitled to the same curtailment priority under Bonneville's Tariff as they are today. The market dispatch, however, would account for transmission constraints and attempt to redispatch around them, reducing the need for curtailment and improving certainty of delivery.

6.8. Bonneville Transmission Services Customer Participation in Markets+

Bonneville's Tariff provides two types of Transmission Service: PTP[161] Service and NITS.[162] PTP Service allows the customer to move power from a Point of Receipt to a Point of Delivery and is billed on reservation capacity. NITS is available only for service to network load, billed based on metered network load, and includes planning obligations. Markets+ is consistent with the current terms and conditions for transmission service set under the existing Tariff to a great extent, including through the administration of the Open Access Same-Time Information System, and sale of firm and non-firm transmission service. The Markets+ design recognizes that the market does not assume the role of TSP and respects the prevailing OATT framework in the West.

With day-ahead market participation, Bonneville is anticipating some changes in how its customers may utilize their Bonneville transmission rights. Bonneville transmission contract holders will still have the ability to exercise their transmission rights (e.g., schedule, redirect, and resale existing transmission rights) consistent with Bonneville's Tariff, business practices, and any another relevant agreements as they do today during the day-ahead and real-time horizons, though there may be different implications of doing so.

Bonneville shared its preliminary assessment of how transmission may work in a day-ahead market construct at the

[161] Bonneville Power Administration, Point to Point Transmission Service (PTP): An Overview (rev. Oct. 1, 2001), *available at* https://www.bpa.gov/-/media/Aep/transmission/ptp-service/ptp-product-overview.pdf.
[162] Bonneville Power Administration, Network Integration Transmission Service (NT): An Overview (rev. Nov. 10, 2001), *available at* https://www.bpa.gov/-/media/Aep/transmission/nt-service/nt-product-overview.pdf.

public workshop 8 on July 18, 2024.[163] Bonneville shared a Markets+ process timeline for transmission activities for both the TSP/BA and the transmission customer perspective highlighting the complete cycle from pre-market (registration and modeling set-ups) to day-ahead and real-time activities and concluding with settlements. Bonneville provided examples of how transmission rights, both available for the market and opted-out, would be communicated to the market operator along with the associated Service Flow Constraints[164] (SFCs) that will be configured into the market operator's system(s).

By default, Bonneville's transmission customers' transmission rights and unsold ATC will be made available to the market unless specifically opted out as described in the next paragraph. As described in the day-ahead market framework Section 2.4, on a day-ahead basis, Bonneville will communicate the available transmission capacity on various paths to the Market Operator, and the Market Operator will respect those limits in its market optimization in order to commit and award resources to serve the expected load. In real-time, Bonneville will communicate any changes to ATC to the market, and market flows will continue to be able to use any real-time, unscheduled transmission capability on the Bonneville system.

Markets+ permits transmission customers to "opt-out"[165] their transmission rights according to the market rules, which includes no more than once per month and timely communication to the market operator. Informed by stakeholder input, Markets+ has developed a process for the opt-out communication from the TSP/BA to the MO.[166] Furthermore, the frequency of the opt-out communication was set to align with the TSRs congestion rent eligibility verification timeline. The "opt-out" of transmission rights removes that capacity entirely from reflection in the market and potentially any market settlement implications. However, by doing so, the transmission customer will forego the potential congestion rent revenue on the contracted paths if those paths become binding, as well as use of the market to help meet the schedule. The market rules and associated procedures for transmission opt-outs were set to provide an equitable and timely process for Market Participants that may need to opt-out transmission but to also address market power concerns on transmission usage. While Bonneville believes the current design mitigates any concerns with market power related to transmission usage, the Market Monitoring Unit (MMU) will monitor for transmission withholding by market participants that would violate the Markets+ Tariff.[167] Bonneville transmission contract holders that want to participate in another market (e.g., EDAM) may want to "opt-out" transmission from Markets+ so that generation in that market can be optimized across that transmission. Any additional requirements Bonneville places on transmission opt-outs would be determined in a future Tariff proceeding and/or business practice process.

Note that opting-out transmission is not required in order to (a) self-schedule or (b) individually transact outside of the Markets+ footprint. First, for self-schedules, the market optimization still respects generation self-scheduled within the market footprint. If a generator self-schedules, it consumes a portion of market-available transmission capacity, lowering the amount of transmission across which the market can optimize. This transmission capacity is still "in" the market and the transmission rights holder is still eligible for congestion rent allocation. Second, for transactions that cross the boundary of the Markets+ footprint, those transactions can be established within the

[163] Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 8 presentation (July 18, 2004), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-8-presentation.pdf.

[164] Service Flow Constraints are intended to represent a commercial constraint that manages market flows attributed to the market, not total flow expressed as a mega-watt (MW) value.

[165] SPP Markets+ Tariff, Attach. D § 1.2 (Obligation to Communicate Markets+ Transmission Capacity Availability Changes).

[166] Markets+ TSPs/BAs will need to develop their own opt-out process with its transmission customers that will ultimately feed into the Markets+ opt-out process. SPP Markets+ Protocol, 8.2.2 Markets+ Transmission Capacity Opt-Outs and Exhibit 8-2: Transmission Opt-Out and Congestion Rent Process Timeline.

[167] SPP Markets+ Tariff, Attach. C § 4.5 (Monitoring for Potential Transmission Market Power Activities)

market using an e-tag. [168] The market will incorporate the additional load obligation (for an export) or generation injection (for an import) within the optimization. Markets+ also allows for price-sensitive bidding at the market footprint in the day-ahead optimization, which requires an e-tag as well.

As the region moves towards participation in a day-ahead market, Bonneville understands that utilities, which may also be Bonneville transmission contract holders, are making their own independent market participation decisions and may want to use their Bonneville transmission rights in those markets. As a result, regardless of Bonneville's decision to join a day-ahead market, Bonneville may need to reflect tariff revisions and/or business practice updates to clarify the requirements for transmission customers to use their transmission rights for their respective market participation.

Bonneville will need to address necessary tariff changes for implementation. Bonneville will discuss potential tariff changes through the tariff process. Bonneville may also need to update its business practices for implementation and will do so through the established business practice process.

6.8.1. Transmission Product Availability

As discussed previously, Bonneville does not expect the general transmission products or terms and conditions to change due to Bonneville joining Markets+. However, joining Markets+ will impact the reservation and scheduling timelines of its short-term products, specifically, the hourly firm, hourly non-firm, and non-firm secondary products. Currently, Bonneville's hourly firm transmission window opens at 9 a.m. Pacific Time of the WECC preschedule day, and non-firm window for hourly and secondary products opens at 10 a.m. of the WECC preschedule day.[169] These transmission windows will need to be evaluated because the availability of these short-term products will need to conform to the day-ahead market timelines for the day-ahead (e.g., 10 a.m. deadline for the day-ahead market clearing process to start and initial RUC) and real-time horizons (e.g., intra-day RUC and T-30 for each operating hour), in order to afford customers enough time to buy transmission and meet market deadlines. Transmission customers in WECC are accustomed to navigating TSP timing windows for reserving transmission, not just Bonneville's, which vary and may be set in different time zones. Understanding the updated TSP timing windows for reserving transmission for day-ahead markets will be another consideration to navigate in the near future.

In addition, participating TSPs are required to pause processing of TSRs in the queue for the next operating day during the day-ahead market clearing process (approximately from 10 a.m. to 1:30 p.m. Pacific Time on day-ahead) so the market optimization has a static set of transmission constraints to develop the market solutions. While the queue is paused, transmission customers will have the ability to submit TSRs but those TSRs will remain in the queue in queue order. Once the market operator posts the awards associated with the market solutions and the TSPs have accounted for any incremental transmission used by the market, TSPs will resume processing TSRs in the queue.

As noted above, Bonneville understands that it will have transmission customers that may wish to use their Bonneville transmission rights for transactions/schedules that source or sink outside the BAA or for wheeling across the BAA, including for optimization in another market (e.g., EDAM). Bonneville will need to address how it will make its transmission available for use in other markets, as well as implementation of the reservation timelines in a future tariff proceeding and, as necessary, through the business practice process.

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[168] E-tags are used to schedule power transactions that include who is supplying the power, how much power (expressed as MWs), timeframe, purchasing/selling entities involved, BAAs involved, the transmission paths, and who is receiving the power.

[169] Bonneville Power Administration, Requesting Transmission Service Business Practice V.47 § C.1 (Jan. 22, 2024), *available at* https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/requesting-transmission-service-bp.pdf.

6.8.2. Transmission Losses

As energy is physically delivered across a transmission system, there is a natural degradation or "loss" that occurs because of physical factors such as distance and the overall loading of transmission facilities. Transmission losses represent additional physical generation that is necessary to make up the difference between a scheduled amount of energy from a generator and what is "lost" on the way to serving a load. Bonneville currently requires transmission customers to either designate to return transmission losses in kind (e.g., with a physical delivery of energy concurrently) or settle them financially.

In joining the WEIM, Bonneville did not need to make significant adjustments to the provision of losses because the majority of losses still occurred outside of the market (associated with the base schedules submitted ahead of the market). However, for the WEIM, Bonneville elected the "donation model" of Transmission Rights by Interchange Rights Holders[170] to be used for WEIM transfers that source or sink in the Bonneville BAA. The donation of these transmission rights into WEIM does not eliminate the transmission loss obligation of the Interchange Rights Holders, yet to avoid "double-payment," Bonneville exempted loss returns for WEIM transfers using Bonneville transmission during WEIM participation because the market accounts for losses associated with incremental market transfers within the optimization.

In Markets+, both the day-ahead and real-time optimizations procure sufficient energy to serve losses across the market footprint. Transmission losses for both the day-ahead awards and the incremental real-time dispatches are settled financially by the market and reflected in the LMP. Bonneville will discuss with stakeholders the extent to which Markets+ may lead to changes in Bonneville's current policies regarding transmission losses. Specifically, Bonneville will need to focus on two areas: 1) transmission that is not available to the market, and 2) transactions/schedules that use Bonneville transmission but source or sink outside the Markets+ footprint. Bonneville will address these details in applicable rates, tariff or business practice proceedings.

7. NEPA & Environmental Obligations

Consistent with NEPA, 42 U.S.C. § 4321 et seq., Bonneville is in the process of assessing the potential environmental effects that could result from the proposed participation in a day-ahead market. Bonneville believes this proposal appears to be the type of action typically excluded from further NEPA review pursuant to U.S. Department of Energy NEPA regulations, which apply to Bonneville. However, Bonneville will consider all public comments concerning NEPA compliance and/or potential environmental effects of the proposal that Bonneville received during the public discussions for this proposal.

8. Tribal Obligations

The Day-Ahead Market Policy does not impact tribal treaty rights or resources. First, the Policy is a decision on a policy direction, it is not a binding implementation decision to join Markets+. Any decision to join a day-ahead market will be made after further consideration. Second, any future DAM participation will not change Bonneville's ability to meet obligations under existing laws and contracts, including FCRPS operations, river management, or fish and wildlife mitigation. As discussed in section 6.1.1, Bonneville can communicate various operational constraints for its generators as part of its market offers in order to meet both power and non-power obligations, and will continue to prioritize meeting all obligations. Therefore, this Policy does not impact Bonneville's tribal treaty or general trust responsibilities.

9. Conclusion and Next Steps

The preceding Day-Ahead Market Policy represents an extensive analysis of the options available to Bonneville in

[170] Bonneville Power Administration, Energy Imbalance Market (EIM) Business Practice V.5 § J.

response to the developments of day-ahead markets in the West. Bonneville examined the market designs of both EDAM and Markets+ with a particular focus on the elements pertaining to governance and stakeholder process; RA and resource sufficiency; price formation and market power mitigation; transmission and congestion rent; and GHG accounting. Additionally, Bonneville has carefully considered the operational complexities, implementation challenges, and potential for sunk costs presented by each market option. The results of this analysis have been weighed against each of Bonneville's day-ahead market participation principles. Throughout this analysis, Bonneville has held a series of 11 public workshops to provide transparency into Bonneville's evaluation, responses to comments received, day-ahead market offerings, Pathways, and impacts to various aspects of Bonneville's business and products.

Governance has specifically been a central factor in Bonneville's evaluation. Markets+ successfully developed and implemented a governance structure that met Bonneville's criteria. In the meantime, Pathways performed significant work to develop recommendations to improve independence of the governance of the CAISO-run WEIM and EDAM markets. To date, its recommendations have resulted in an approved future transition to primary authority for the independent WEM Governing Body. Several entities have requested that Bonneville delay its day-ahead market decision until the end of 2025 to allow more time for the California legislature to act on proposed legislation to move the Pathways vision forward and for the governance model to continue to evolve towards full independence. While Bonneville applauds the considerable work done by Pathways, its recommendations do not enable the level of independence that is offered by Markets+. The legislation that has been introduced would confirm this limited scope of independence. For that reason, Bonneville does not see benefit in waiting for California's legislative consideration.

The Pathways Step 2 proposal suggested future considerations to expand the independence, and the market services offered. Those subsequent steps to greater independence would be incremental and subject to further studies and likely further legislative authorization. Ultimately, Bonneville prefers the stakeholder-driven governance structure of Markets+. Bonneville contends that the Markets+ development has resulted in a superior market design that is available today and believes it will remain a durable, equitable form of governance in the future.

Bonneville's analysis presented complex results regarding each day-ahead market option, including the status quo. The PCM studies showed a wide range of potential economic outcomes, including meaningful trends that joining EDAM could yield a greater financial benefit for Bonneville and that joining Markets+ has potential for significant monetary benefits under multiple scenarios. It is important to note that these results are not due to differences in market design but are driven from higher prices that come with being in a market with California and the connectivity offered by the current expected EDAM footprint. In almost every scenario, this potential greater monetary benefit was dependent on the assumption that Bonneville would continue to enjoy surplus generation, which adds uncertainty to the results as Bonneville's load and generation forecasts demonstrate a potential erosion of its surplus generation over time. As demonstrated, the benefits in the expected Markets+ footprint improved as hurdle rates were reduced, closing the gap between EDAM and Markets+ benefits and resulting in benefits above BAU.

Additionally, PCMs do not account for market design features, such as congestion rent, market power mitigation, and price formation, that can significantly impact monetary benefits realized from a day-ahead market. These design features are discussed in detail in this analysis and Bonneville believes the Markets+ design is likely to provide economic benefits to Bonneville and our customers through these features that at least partially offset the EDAM benefits estimated in the PCM studies. These design features in Markets+ were all constructed via an inclusive stakeholder process that should result in these market design features accounting for unique needs of market participants, and Bonneville is confident that the Markets+ stakeholder process will be responsive to requests to revisit these design elements if unexpected or unsatisfactory results are realized once the market is live. Bonneville has determined that the trends toward greater potential monetary benefits under the previously discussed assumptions and caveats in EDAM and in the short term for status quo do not outweigh the strategic benefits and

superior market design presented with Markets+.

The option of Bonneville remaining only in the WEIM while its neighbors join day-ahead markets was an option that Bonneville carefully considered, and one that the PCM results showed could bring significant monetary benefit. While Bonneville agrees this option shows short term appeal, Bonneville continues to have significant concerns about the long-term viability of this option due to the operational and economic risks, such as reduced liquidity in the bilateral market, that accompany this option. Remaining in WEIM would likely foreclose the option to join Markets+, leaving EDAM as the only day-ahead market option for Bonneville should it choose to pursue day-ahead participation in the future. Because the Pathways Step 2 proposal does not achieve desired independence, and legislation remains speculative, this option carries significant strategic risk. Other important elements that Bonneville examined in this process are the market seams and the potential operational complexities that will be present with multiple markets in the Pacific Northwest. Bonneville acknowledges that a single market in the Northwest would be operationally simpler, but the decisions of Bonneville's neighboring BAAs suggest that two markets are likely to operate in the Pacific Northwest. The presence of these challenges should not prevent Bonneville from joining a market with superior design and independence. Bonneville places great importance on its operational and reliability responsibilities in the region and stands ready to work with the entities in EDAM and within the region to collaboratively resolve these jointly owned issues.

Throughout this evaluation process, Bonneville has experienced the powerful impact of competition in motivating both SPP and CAISO to significantly improve market offerings in order to attract participants. Without this competition, Bonneville believes many of the creative market design solutions benefitting consumers that both market operators are pursuing may have never materialized. Bonneville also believes many of the changes contemplated and implemented in the CAISO governance and stakeholder processes and the recent urgency with which they have been pursued are a direct result of competition from another market operator. These CAISO initiatives are resulting in an improved market for entities that have or may choose EDAM participation. The continuation of this competition benefits Bonneville, its customers and all consumers in the west regardless of market participation choices by maintaining pressure on market operators to continue innovating and improving.

After thorough evaluation, analysis, and weighing of its participation principles, as well as the governance, market design, and strategic benefits presented by Markets+, Bonneville has concluded that its participation in Markets+ is the best long-term strategic direction for Bonneville, its customers, and the Northwest.

Bonneville would like to express profound appreciation for those who have engaged in the public process and provided insights to make this a robust, transparent, and effective evaluation of its potential participation in a day-ahead market. Bonneville looks forward to ongoing public review and input as implementation details are developed. Bonneville will be developing a stakeholder engagement plan to provide market design updates and technical implementation that will incorporate customer input. Bonneville will be utilizing the '6-step process' as a way to collaborate with customers on the policy issues through the tariff and rates proceedings.

Appendix A

Legal Assessment

1. Legal Authority to Join Markets+

Bonneville's decision to join any market must comport with multiple grants of authority, including, but not limited to, power marketing, providing transmission service, and operating in a business-like manner. In exercising such authorities, the Administrator must balance his ability to meet multiple statutory obligations, such as providing preference and priority in the sale of power when there are conflicting or competing requests, making firm power sales under section 5(b) of the Northwest Power Act, providing transmission service and operating the transmission system, setting rates sufficient to repay the federal investment, and fulfilling environment, fish and wildlife obligations. This legal assessment describes how Bonneville could meet these obligations while participating in Markets+. At a high-level, Bonneville would join Markets+ by agreeing to a set of contracts incorporating a day-ahead market tariff.

Bonneville would exercise its contracting authority under section 2(f) of the Bonneville Project Act[171] to agree to a day-ahead market tariff. This would be similar to actions Bonneville has taken to participate in WEIM and WRAP.[172] Similar to the WEIM and WRAP agreements, and like any contract with a market operator implementing a day-ahead market subject to an applicable tariff, an agreement to participate in a day-ahead market must expressly acknowledge and not infringe upon Bonneville's authority to meet its statutory obligations and contractual requirements. Based on the day-ahead market tariff offerings to date, Bonneville has not identified legal barriers to satisfying its statutory obligations while participating in a day-ahead market.

Bonneville has the business flexibility to participate in a day-ahead market.

Since its inception, Congress has imbued Bonneville with broad statutory authority to market the power produced by federal hydropower generating projects. In the Bonneville Project Act of 1937, Congress granted Bonneville broad contracting authority for the specific purpose of allowing Bonneville to operate like a business in the marketing of federal power.[173] As the designated "marketing agent" for all electric power generated by the Federal Columbia River Power System,[174] Bonneville's statutes are unique with repeated focus on the business-related aspects of the agency's authority.

Both Congress and the courts have reaffirmed Bonneville's authority to operate in a businesslike manner. As summarized in a 1977 Senate Report:

> [The] legislative history [of the statutes governing Bonneville's operations] reflects a congressional recognition of the significant role played by [Bonneville] in the Pacific Northwest, and an effort to enable this organization to operate in a businesslike fashion and to free it from the requirements and restrictions ordinarily applicable to the conduct of Government business. The transfer of the functions of [Bonneville] from the Department

[171] 16 U.S.C. § 832a(f).

[172] Bonneville Power Administration, Energy Imbalance Market Policy, Administrator's Record of Decision at 54-56 (Sept. 2019) (WEIM Policy ROD), *available at* https://www.bpa.gov/-/media/Aep/projects/energy-imbalancemarket/rod-20190926-energy-imbalance-market-policy.pdf; Bonneville Power Administration, Bonneville's decision to participate in the Western Resource Adequacy Program Phase 3B (Dec. 16, 2022), *available at* https://www.bpa.gov/-/media/Aep/projects/resource-adequacy/wrap-final-closeout-letter.pdf.

[173] Bonneville Project Act, 16 U.S.C. § 832a(f); *see* S. Rep. No. 79-469, at 13 (1945) ("[BPA] operates a business enterprise . . . .") (letter from Interior Secretary Ickes).

[174] Transmission System Act of 1974 § 8, 16 U.S.C. § 838f.

> of the Interior to the Department of Energy is not intended to diminish in any way the authority or flexibility which is a requisite to the efficient management of a utility business.[175]

The ability of Bonneville to adapt to the ever-changing landscape of the wholesale electric power industry like a business is particularly important because the Administrator must implement many, and often competing, statutory directives.[176] Similarly, the U.S. Court of Appeals for the Ninth Circuit has noted that "[The Administrator] must continue to run [Bonneville] like a business on a sound financial basis, enabling it to repay its debt to the federal treasury in a timely fashion, while discharging costly new public duties assumed after the Northwest Power Act's passage."[177]

In 1995, Bonneville adopted a Business Plan with a market-driven direction and a goal to be a more active participant in the competitive market for power, transmission, and energy services.[178] As stated in the 1995 Business Plan Record of Decision, Bonneville's objective is to use its success in markets to ensure the financial strength necessary to better produce the public benefits that Bonneville affords to the region.[179] The market-driven approach is designed to increase the value of Bonneville's business and generate expanded benefits to share with customers and constituents-including energy conservation and fish and wildlife mitigation.[180] By evaluating potential participation in a day-ahead market, Bonneville is continuing its long-standing business strategy to pursue options that could produce value for Bonneville's customers and the region.

This Policy discusses how Bonneville and the region as a whole are experiencing significant and unprecedented changes in the industry. Faced with competitive drivers and new regulatory requirements, electric utilities are devoting significant resources to develop and transition to market-based solutions that aim to reduce inefficiencies, improve power and transmission system reliability, lower production costs, and bolster resource adequacy, among other things. Bonneville and other utilities' participation in the Western Energy Imbalance Market are an example of one such development. These new competitive drivers are creating opportunities for Bonneville to modernize its business to preserve and enhance the value Bonneville provides to its customers pursuant to its statutory mission.

As Bonneville evaluates potential participation in a day-ahead market, some of its key objectives rooted in statute are to ensure an adequate, efficient, economical, and reliable power supply, and to encourage the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles. Therefore, Bonneville continues to assess whether participation would provide value for customers in terms of greater efficiency, lower costs, and increased reliability.[181]

2. Bonneville would fulfill its preference obligations and Northwest Power Act Section 5(b) firm power sales obligations while participating in a day-ahead market.

Bonneville's authority to market federal power is included in several statutes: the Bonneville Project Act

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[175] S. Rep. No. 95-164, at 30 (1977), reprinted in 1977 U.S.C.C.A.N. 854, 884.
[176] *Ass'n of Pub. Agency Customers v. Bonneville Power Admin.*, 126 F.3d 1158, 1170-71 (9th Cir. 1997).
[177] *Id*.
[178] Bonneville Power Administration, Business Plan Record of Decision (Aug. 15, 1995), *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/1995-rod/rod-19950815-business-plan-final-environmental-impact-statement.pdf.
[179] *Id.* at 1.
[180] *Id.* at 11.
[181] Bonneville Power Administration, Staff Recommendation on Day-Ahead Market Participation at 2-3 (Apr. 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/02-day-ahead-market-attachment-1-staff-recommendation.pdf.

of 1937, the Flood Control Act of 1944, the Pacific Northwest Consumer Power Preference Act of 1964, the Federal Columbia River Transmission System Act of 1974, and the Pacific Northwest Power Planning and Conservation Act of 1980. Collectively, these statutes form the basis for Bonneville's broad authority to market power. For Bonneville to participate in Markets+, it must market power consistent with these statutory authorities.

Bonneville recognizes that many stakeholders have requested explanations of how Bonneville will meet obligations in these statutes to provide public bodies and cooperatives preference and priority to federal power, and to offer contracts for the sale of electric power under section 5(b) of the Northwest Power Act, considering the paradigm shift that a day-ahead market would represent. As explained below, Bonneville will continue to meet its preference and section 5(b) obligations included in these authorities if it participates in a day-ahead market.

a. Bonneville must provide preference in sales of power at all times in the event of competing or conflicting applications for power.

Bonneville will continue to provide preference in the sale of power to public bodies and cooperatives in the event of competing applications. Bonneville would continue to offer long-term power sales contracts to 5(b) customers and would incorporate the day-ahead market dispatch framework into the contract terms and rates for such sales. Section 4(a) of the Bonneville Project Act of 1937 specifies, "[i]n order to insure that the facilities for the generation of electric energy at the Bonneville project shall be operated for the benefit of the general public, and particularly of domestic and rural customers, the administrator shall at all times, in disposing of electric energy generated at said project, give preference and priority to public bodies and cooperatives."[182] Section 4(b) further explains, "in the event that . . . there shall be conflicting or competing applications for an allocation of electric energy between any public body or cooperative on the one hand and a private agency of any character on the other, the application of such public body or cooperative shall be granted."[183] The Flood Control Act of 1944 similarly states that "[p]reference in the sale of such power and energy shall be given to public bodies and cooperatives."[184] Thus, Bonneville's earliest legislation established the foundational principle that Bonneville shall afford preference to public bodies and cooperatives in the event of competing or conflicting requests for power. Bonneville understands that providing preference in the event of competing applications is a fundamental component of its power marketing obligation that it will continue to meet if it chooses to participate in Markets+ for the benefit of its customers.

Section 5(a) of the Northwest Power Act reaffirms the preference and priority provisions from Bonneville Project Act by stating, "[a]ll power sales under this chapter shall be subject at all times to the preference and priority provisions of the Bonneville Project Act of 1937 . . . ."[185] The Northwest Power Act was enacted to resolve regional power customer fears about an impending allocation of low-cost Federal power. The House Report of the Commerce Committee on the Northwest Power Act emphasized that sales by the Administrator would be subject to existing preference provisions:

> The purpose of this provision is clear. The Committee wants to ensure that all preference customer contract requirements will continue to have a priority over sale to other customers

[182] 16 U.S.C. § 832c(a).

[183] 16 U.S.C. § 832c(b); *see also Aluminum Co. of Am. v. Cent. Lincoln People's Util. Dist.*, 467 U.S. 380, 393 (1984) ("[T]he preference system merely determines the priority of different customers when the Administrator receives 'conflicting or competing' applications for power that the Administrator is authorized to allocate administratively." (citing section 4(b) of the Bonneville Project Act)).

[184] 16 U.S.C. § 825s.

[185] 16 U.S.C § 839c(a)

> and other sales would be, in effect, subordinate to preference provisions of the Bonneville Project Act, including the 5-year withdrawal features for contracts with non-preference customers and the 20-year limitation on the terms of the contract.[186]

Bonneville finds that it will be able to continue to satisfy preference when there is a competing or conflicting application for power in a day-ahead market. As described above, in a day-ahead market context, Bonneville would continue to make long-term forward sales of power and would apply preference if faced with a limited supply of power. After the day-ahead market clears, any out-of-market requests for electric power from Bonneville are likely to fall within the context of a surplus sale. Bonneville would continue to meet its preference obligations for both long-term sales and surplus sales as described below.

b. Bonneville is authorized to acquire resources to meet all eligible customer requests for electric power under section 5(b) of the Northwest Power Act.

Bonneville's acquisition authority generally ensures that Bonneville can acquire to meet the needs of all customers requesting contracts for electric power and thereby avoid a preference allocation among competing or conflicting requests for power. Historically, there was no need for Bonneville to apply preference because Bonneville had an abundance of power. However, in the 1970s, projections showed that because of increased power demand, the Administrator would be required to apply preference and allocate the limited amount of federal power. Upon expiration of the power sales contracts with non-preference customers, the Administrator would no longer be able to sell power to non-preference entities because the preference clauses would obligate him to allocate the limited supply to public bodies and cooperatives. Congress drafted the Northwest Power Act to prevent the need for an allocation of power.[187] The Act solved the pending allocation and reduces the potential application of preference in the future by providing the Administrator with resource acquisition authority to meet his sales obligation.

Section 5(b)(1) of the Northwest Power Act provides,

> Whenever requested, the Administrator shall offer to sell to each requesting public body and cooperative entitled to preference and priority under the Bonneville Project Act of 1937 . . . and to each requesting investor-owned utility electric power to meet the firm power load of such public body, cooperative or investor-owned utility in the Region to the extent that such firm power load exceeds [customer resources].[188]

Section 5(b) thus establishes the Administrator's obligation to offer a contract for the sale of electric power to meet the firm power loads of any requesting regional public body, cooperative, or investor-owned utility in excess of non-federal resources used by the customer to serve such load. The Act not only requires the Administrator to offer a contract for the sale of electric power to all eligible requesting customers but also directed the Administrator to offer new power sales contracts to then-existing direct service industry customers.

To implement the Act in a timely matter, Congress deemed the Administrator to have sufficient resources and, most importantly, granted the Administrator authority to acquire resources to meet Bonneville's long-term power supply obligations. In sections 6(b), (c), and (d) of the Northwest Power Act, Congress granted

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[186] H.R. Rep. No. 97-976, Pt. I, at 34 (1980).

[187] As the Supreme Court has explained, "Congress moved to avert what appeared to be an emerging customer struggle for [Bonneville] power by enacting the [Northwest Power Act]." *Aluminum Co. of Am.*, 467 U.S. at 383. And as Congressman Swift remarked, "[t]he basic concept of this bill is simple: It permits BPA to avoid the need for an administrative reallocation of power by giving BPA the means to reduce loads and to acquire resources so that it should be able to meet the needs of all classes of customers . . . . This is a bill to solve a power allocation problem . . . ." 126 Cong. Rec. H27818 (daily ed. Sept. 29, 1980) (remarks of Rep. Swift).

[188] 16 U.S.C. § 839c(b).

Bonneville the authority to acquire resources to meet his long-term power supply obligations.[189] It is important to note that while section 5(b) requires the Administrator to supply the power requirements of all requesting public and investor-owned utility customers and to acquire resources when necessary, Congress also provided protections for preference customer rates when establishing rates pursuant to section 7(b).[190]

Importantly, section 5(b) contracts are not a response to "competing or conflicting" requests for power that would require an allocation of electric energy. The section 5(b) sales obligation operates in conjunction with long term loads and resource planning and the section 6 resource acquisition authority so that, in general, Bonneville does not need to allocate power among conflicting or competing applications. When a customer has a long-term power sales contract, they receive power under that contract and preference is not triggered.

While the obligation remains of paramount importance, preference only triggers if Bonneville is unable to acquire resources to satisfy its 5(b) obligations due to an insufficiency of resources or if Bonneville is offering to sell surplus electric power. The insufficiency and surplus scenarios are discussed in the following two sections.

c. Bonneville must apply preference in an allocation scenario.

In a scenario where Bonneville is faced with a limited supply of power in the planning horizon, preference would apply. In general, section 6 of the Northwest Power Act provides Bonneville with acquisition authority designed to ensure he can meet all requests for power. Section 11(b)(6) of the Transmission System Act also provides Bonneville with the authority to purchase electric power on a short-term basis to meet temporary deficiencies in power it is obligated to supply.[191]

Bonneville's ability to acquire power to meet its supply obligations generally avoids Bonneville having a limited amount of power that must be allocated through the operation of preference. Northwest Power Act section 5(b)(5) requires the Administrator to provide contractual mechanisms to apply preference in the unlikely event that Bonneville cannot acquire resources to meet its power supply obligations.[192] If the Administrator "cannot be assured on a planning basis of acquiring sufficient resources to meet such loads during a specified period of insufficiency" he is obligated to apply preference and allocate electric energy among customers in accordance with the section 5(b)(6) allocation provisions. [193]

If Bonneville were to determine that it cannot be assured on a planning basis to meet its long-term firm power sales, Bonneville would allocate power based upon the insufficiency and allocation methodology.[194]

Additionally, Bonneville's participation in a day-ahead market is likely to substantially mitigate the risk of an insufficiency. Bonneville will maintain its existing Resource Program, which incorporates guidance from Northwest Power and Conservation Council's Power Plan; continue to plan its resources on an annual, monthly, daily, and real-time basis to assure a firm power supply to meet its firm power sales obligations; and participate in WRAP. In the long term, day-ahead markets should lead to improved regional resource planning. Markets+ requires each participant, including Bonneville, to demonstrate a commitment that it has sufficient resources available to meet its forecast load obligations in the planning horizon by participating in the WRAP. Based on Bonneville's continued efforts and the benefits that coordination

[189] 16 U.S.C. § 839d(b)-(d).
[190] 16 U.S.C. § 839e(a)-(b).
[191] 16 U.S.C. § 838i(b)(6).
[192] 16 U.S.C. § 839c(b)(5).
[193] *Id.*; 16 U.S.C. § 839c(b)(6).
[194] *See* Notice of Publication of the Insufficiency and Allocations Exhibit for the Power Sales Contract, 61 Fed. Reg 11,389 (Mar. 20, 1996).

through a market will bring, there will be an even lower chance that Bonneville would be required to allocate power based on a projected insufficiency on a planning basis.

d. Bonneville will apply preference for competing and conflicting applications for surplus power.

The most common application of statutory preference is when Bonneville offers to make a surplus power sale. The Bonneville Project Act of 1937[195] and the Pacific Northwest Consumer Power Preference Act of 1964[196] specify the application of statutory preference when Bonneville markets surplus power. The Regional Preference Act specifies that, in the event of competing applications for available surplus power, and terms and conditions are mutually agreed upon, Bonneville will meet customer requests in the following order: 1) Pacific Northwest public utilities, 2) Pacific Northwest investor-owned utilities and direct-service industrial customers, and 3) Southwest public utilities. Thereafter, if additional power is available, Bonneville may also make surplus sales to non-preference customers.

In the Western Energy Imbalance Market Policy Record of Decision, Bonneville explained the specific mechanics of the notice of surplus power. Consistent with that analysis, in a day-ahead market, Bonneville intends to continue the regional notice format the agency has used for over 20 years.[197] Since the advent of modern markets, Bonneville has provided notice to its preference customers regarding the availability of short-term surplus power using a combination of: (1) annual letters providing notice of surplus availability and how regional customers may exercise their rights; (2) product specific letters/emails when Bonneville is preparing to sell a new type of product to a non-preference customer; and (3) a standing daily notification on Bonneville's website regarding the availability of surplus power and instructing regional customers on how to obtain it if they are interested. Bonneville is unaware of any instance during the past 20 years where regional preference customers took issue with the format of Bonneville's notice requirements. This format has been an efficient and effective way for Bonneville to participate in the short-term market while also notifying regional customers that Bonneville may have surplus power available for sale on a rolling basis.[198]

When Bonneville began to participate in the Western Energy Imbalance Market, it updated its daily standing notice to specify that, if surplus remains available prior to the market run, Bonneville may bid such surplus power into the market at its discretion. In a day-ahead market, Bonneville would follow the same approach. The agency would continue to provide public preference and Pacific Northwest regional preference to requests for surplus power before and after the day-ahead market run. Bonneville would continue to welcome customer inquiries regarding potential purchases of surplus power before and after the day-ahead market submission timeframe.

Similarly, Bonneville's participation in a day-ahead market will not impact its surplus sales approach. Bonneville will continue to market surplus power when available, prior to the day-ahead market generation and load bid submission window, and thereafter prior to the real-time market bid submission window. The day-ahead market resource schedule output does not ultimately determine real-time dispatch, the real-time market bid submission window allows for Bonneville to make additional sales if surplus power remains available. Bonneville will continue to meet its regional preference obligations when marketing uncommitted surplus power.

For the reasons described above, Bonneville's legal assessment is that it can participate in a day-ahead market consistent with its preference obligations, 5(b) firm power sales obligation, obligations to allocate power consistent with preference in the event of insufficiency, and obligations to provide preference when

[195] 16 U.S.C. § 832 *et seq.*
[196] 16 U.S.C. § 837 *et seq.*
[197] WEIM Policy ROD at 62.
[198] *Id.*

making surplus sales.

3. Day-ahead market participation would be akin to an interregional exchange of power.

Since the enactment of the Bonneville Project in 1937 through the passage of the Pacific Northwest Electric Power Planning and Conservation Act in 1981, Congress contemplated and included within the scope of the Administrator's authorities the authority to interconnect with power systems both within and outside the Pacific Northwest region and leverage these interconnections to make mutually beneficial interregional exchanges. For example, section 2(b) of the Bonneville Project provides:

> In order to encourage the widest possible use of all electric energy that can be generated and marketed and to provide reasonable outlets therefor, and to prevent the monopolization thereof by limited groups, the administrator is authorized and directed to provide, construct, operate, maintain, and improve such electric transmission lines and substations, and facilities and structures appurtenant thereto, as he finds necessary, desirable, or appropriate for the purpose of transmitting electric energy, available for sale, from the Bonneville project to existing and potential markets, and, *for the purpose of interchange of electric energy, to interconnect the Bonneville project with other Federal project and public owned power systems* constructed on or after August 20, 1937.[199]

The Northwest Power Act also includes provisions promoting interregional exchanges. Section 6(l)(1) provides:

> The Administrator is authorized and directed to investigate opportunities for adding to the region's resources or reducing the region's power costs through the accelerated or cooperative development of resources located outside the States of Idaho, Montana, Oregon, and Washington if such resources are renewable resources, and are now or in the future planned or considered for eventual development by nonregional agencies or authorities that will or would own, sponsor, or otherwise develop them.[200]

Section 6(l)(2) further provides:

> The Administrator is authorized and directed to investigate periodically opportunities for mutually beneficial interregional exchanges of electric power that reduce the need for additional generation or generating capacity in the Pacific Northwest and the regions with which such exchanges may occur.[201]

Congress understood that interregional transmission interties between the Pacific Northwest and adjoining regions, such as the Pacific Northwest Pacific Southwest Intertie, offer substantial benefits. At the time of the enactment of the Northwest Power Act, existing transactions reduced the need for new generating capacity, helped provide more reliable service to load, reduced the need to rely on fossil fueled resources, and reduced the costs of electricity. In a June 1981 report on Interregional Resource Potentials, Bonneville committed to continuing to work with entities in the region and adjoining regions to optimize the use of existing generating facilities and reduce the need for new generating facilities through mutually beneficial exchanges and other transactions.

Bonneville has a longstanding definition of interchange energy in the power marketing context.[202] Interchange energy means energy received by one utility system from another, usually in exchange for

[199] 16 U.S.C. § 832a(b) (emphasis added).
[200] 16 U.S.C. § 839d(l)(1).
[201] 16 U.S.C. § 839d(l)(2).
[202] *See* Bonneville Definitions (1993).

energy delivered to the other utility at another time or place. It is distinguished from a direct purchase or sale, although accumulated energy balances are sometimes settled in cash. Through interchange and interconnection, Bonneville has been able to enter into power-for-power exchanges, including some with payments of money incidental to the power that were justified as a suitable exchange term. Indeed, exchanges need not be simultaneous and the places where an exchange occurs may vary.

A day-ahead market will operate similar to an exchange of power because all market participants must bring sufficient resources to the market to serve their loads, which is designed to prevent participants from leaning on other participants. Rather than a bilateral exchange of power, power exchanged in the market will flow among the participants to make the most economical use of the transmission system. Thus, the power available under a day-ahead market is in effect exchanged between and among the participants resulting in all participants maintaining their load and resource balance. Here, Bonneville's participation in the interregional Markets+ day-ahead market falls within the scope of the section 6(l) directives to investigate such markets and the resources exchanged therein, including to increase supplies of electric power produced by renewable resources.

4. Bonneville policies will ensure that section 5(b) customers receive power with environmental attributes reflecting the system resource mix.

Bonneville's preference customers have requested acknowledgement of the inherent value of the low-carbon resources from which Bonneville supplies power. Bonneville committed in its Provider of Choice Policy to convey the environmental attributes of the power sold, including emissions and any Renewable Energy Certificates commensurate with a customer's firm power purchase amount and rate elections. Bonneville believes it is reasonable to conclude that these non-power characteristics should accompany Bonneville's physical sales of power. Bonneville's objective as an active participant in developing the day-ahead market GHGs framework designs has been to ensure that it can uphold its policy that non-power characteristics will accompany Bonneville's sales of power.

Bonneville markets power from the system mix of federal and non-federal resources, and this will not change in a day-ahead market. While some jurisdictions have concluded that environmental attributes are associated with power, such environmental attributes are defined through variously differing state laws and local regulations and are subject to change and are not applicable to Bonneville. Nevertheless, Bonneville believes a policy consideration regarding participation in a day-ahead market is whether the market rules support conveyance of environmental attributes associated with sales of power to Bonneville's public customers. Bonneville finds the Markets+ Tariff to meet its policy objectives notes that many of Bonneville's public power customers also support its greenhouse emissions accounting mechanisms. Bonneville will continue to work with its customers, and in the appropriate market design forums, as work on GHG accounting continues.

5. Bonneville would participate in a day-ahead market consistent with its authorities to provide transmission service and operate the transmission system.

Bonneville has broad authority under its governing statutes to set the terms and conditions of transmission service, as well as how to operate the system in order to provide transmission service and maintain reliability.[203] While participating in Markets+, Bonneville will continue to offer transmission service and Ancillary and Control Area Services under its OATT, which ensures that Bonneville and its customers take transmission service on a comparable basis. Bonneville will also be able to make transmission available for

[203] *See Cal. Energy Comm'n v. Bonneville Power Admin.,* 909 F.2d 1298, 1314 n.17 (9th Cir. 1990) (holding that the Administrator's authority to operate the transmission system "is broad, allowing the Administrator substantial discretion" and that "[t]his discretion is tempered only by the implied limitation that the Administrator's action not be inconsistent with other congressional decrees.").

market use, which is authorized under section 2(b) of the Bonneville Project Act.[204]

Joining a day-ahead market will require that transmission be made available for market use. Making transmission available for day-ahead market use falls within Bonneville's broad transmission authorities. Bonneville is monitoring day-ahead market policies to ensure benefits to transmission rights holders including through congestion rent policies, and to ensure compensation for any lost transmission sales through market transmission use charges. In addition, Bonneville will work through issues presented by entities holding transmission rights on the Bonneville system that want to participate in various day-ahead markets, as well as with Bonneville customers in other balancing authority areas that may be affected by a transmission provider's market participation.

6. Congress granted federal utilities authority to join transmission organizations.

In the Energy Policy Act of 2005 (EPAct '05), Congress provided authority for federal utilities, including power marketing administrations, to participate in transmission organizations, such as RTOs, consistent with their existing statutory authorities, obligations, and limitations.[205] When considering EPAct '05, the House Committee on Energy and Commerce, Subcommittee on Energy and Air Quality discussed the economic dispatch associated with organized markets and its potential benefits for fostering competitive electric markets and ultimately reducing costs to the consumer.

By 2005, RTO and ISO market designs had matured significantly since deregulation formally began in 1996.[206] RTOs had formed in many parts of the country and some included day-ahead and real-time energy markets based upon economic dispatch. Congress enacted the EPAct '05 with awareness of the context of evolving electricity markets, including Federal Energy Regulatory Commission Order No. 2000 regarding RTOs, which FERC Commissioner Bromwell explicitly discussed in her House committee testimony regarding the bill. Commissioner Bromwell explained that "RTOs that are fully independent of market participants can ensure non-discriminatory operation of the transmission facilities under their control. RTOs have FERC-approved market monitors, implement FERC-approved market mitigation plans, and conduct long-range planning all for the protection of customers. RTOs can perform economic dispatch over large geographic areas that will ensure the selection of least-cost generators. Finally, RTOs can offer organized markets and one-stop shopping that reduce transaction costs, provide transparent market rules and allow the opportunity for price discovery." [207]

Consistent with this sentiment, Bonneville views its EPAct '05 authority and Congress's understanding of organized markets as informative for its consideration of whether to participate in a day-ahead market. A day-ahead market is one element that is present across RTOs. In contrast to a full RTO, the proposed day-ahead market designs allow Bonneville to retain substantial control over its transmission assets and preserve its BAA responsibilities. Moreover, as the Supreme Court explained, "[t]he intention of Congress can be

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[204] *See* Bonneville Project Act, 16 U.S.C. § 832a(b) ("[T]o encourage the widest possible use of all electric energy that can be generated and marketed . . . the administrator is authorized and directed to provide, construct, operate, maintain, and improve such electric transmission lines . . . as he finds necessary, desirable, or appropriate for the purpose of transmitting electric energy . . . to existing and potential markets . . . .").

[205] 42 U.S.C. § 16431.

[206] Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*; *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 75 FERC ¶ 61,080 (1996); *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh'g*, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049 (1997), *order on reh'g*, Order No. 889-B, 81 FERC ¶ 61,253 (1997), *order on reh'g*, Order No. 889-C, 82 FERC ¶ 61,046 (1998); Order No. 2000, *Regional Transmission Organizations*, 89 FERC ¶ 61,285 (Dec. 20, 1999).

[207] *Comprehensive National Energy Policy: Hearings Before the Subcomm. on Energy and Air Quality of the Comm. On Energy and Commerce*, 108th Cong. 57 (Mar. 5, 2003) (Serial No. 108-7).

gleaned, at least in part, by reference to prior law, as Congress is presumed to be knowledgeable about existing law . . . ."[208] Thus, while the development of a day-ahead market is not an RTO, it is reasonable to conclude that Congress contemplated federal utilities would be authorized to participate in subcomponents of an RTO, like a day-ahead market, as part and parcel of that express authority.

7. Bonneville participation in a day-ahead market must be effectuated through rates and tariff terms and conditions.

If Bonneville participates in Markets+, it will continue to establish its power and transmission rates in Northwest Power Act section 7(i) rate proceedings, and it will set the terms and conditions for transmission service in tariff proceedings.[209] Under Section 7(a)(1) of the Northwest Power Act, the Administrator establishes "rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Such rates shall be established . . . to recover . . . the cost associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment . . . over a reasonable period of years and the other costs and expenses incurred by the Administrator . . . ."[210] Under section 7(a)(2), the Federal Energy Regulatory Commission reviews Bonneville's proposed rates to ensure they are 1) sufficient to assure repayment of the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs, 2) based upon the Administrator's total system costs, and 3) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system.[211]

In a day-ahead market, Bonneville's rates must continue to be sufficient to recover total system costs including the Fish and Wildlife program, the Residential Exchange Program, amortization of existing debt, Columbia Generating Station financing, conservation, depreciation expenses, costs associated with achieving financial policy objectives, and costs associated with market participation. Bonneville's rates must also equitably allocate the cost of the transmission system between federal and non-federal uses. Bonneville's rates are based on forecasts and risk adjustment mechanisms respond holistically to actuals differing from forecast. Bonneville anticipates aggregate treatment of market benefits, which may vary based on products and services. In a section 7(i) rate proceeding, Bonneville would assess how to reflect the costs and benefits of market participation in rates, considering the interaction of any new mechanisms with existing policies. Participation in a day-ahead market would not change the Administrator's obligation to set rates to recover total system costs.

In addition to rate updates, the agency would need to make changes to the terms and conditions of transmission service it provides to customers to enable participation in a day-ahead market. Bonneville's governing statutes grant the Administrator broad discretion to set the terms and conditions of transmission service, which would include any terms and conditions necessary to join a day-ahead market. Several statutory provisions provide the basis for Bonneville's authority to determine the terms and conditions of transmission service.[212] In general, these statutory provisions grant Bonneville the discretion to act in a business-like manner when selling transmission at cost-based rates and to make decisions to effectuate that goal. While the details of such changes would depend on the market design, Bonneville would continue to sell and provide transmission service under its OATT as it does today. Bonneville will continue to monitor the development of market rules associated with transmission, including potential changes in transmission

[208] *Native Village of Venetie I.R.A. Council v. State of Alaska*, 944 F.2d 548, 554 (9th Cir. 1992) (citing *Goodyear Atomic Corp. v. Miller*, 486 U.S. 174, 184–85 (1988)).
[209] 16 U.S.C. § 839e(i).
[210] 16 U.S.C. § 839e(a)(1).
[211] 16 U.S.C. § 839e(a)(2).
[212] 16 U.S.C. §§ 832a(b), 832a(f); 16 U.S.C. § 837e; 16 U.S.C. §§ 838b, 838d.

revenue due to market impacts and congestion rent design, to assess potential transmission customer impacts. Bonneville would conduct a terms and conditions proceeding to update its tariff with any changes necessary to enable day-ahead market participation. Section 9 of Bonneville's OATT describes the process for changing terms and conditions. Such a proceeding would be in accordance with Section 212(i)(2)(A) of the Federal Power Act.[213]

8. Bonneville will continue to meet its environmental obligations, including those under the Northwest Power Act, Endangered Species Act, and National Environmental Policy Act.

Another important set of Bonneville responsibilities involves the operation of the hydro system in coordination with the U.S. Army Corps of Engineers and the Bureau of Reclamation. The agencies manage the Federal Columbia River Power System for multiple project purposes including flood control, navigation, irrigation, fish and wildlife, power production, and recreation. Bonneville's participation in Markets+ cannot conflict with meeting non-power objectives, and Bonneville must continue to meet its environmental statutory obligations. As discussed herein, the designs include special considerations for hydro bid curves to recognize obligations and operational flexibilities of hydropower projects. The Markets+ designs do not appear to present a conflict with meeting these objectives, but as more details are developed it is essential that Bonneville maintain the flexibility and discretion necessary to meet non-power objectives. Bonneville will continue to ensure that Federal Columbia River Power System projects are managed for all project purposes and recognize system-wide operating constraints.

In a day-ahead market context, Bonneville would maintain operations to support ESA-listed fish species. Bonneville would also continue to meet Northwest Power Act requirements. Bonneville's power marketing services and activities, and its actual power operations to meet load obligations, would continue to be conducted consistent with applicable Biological Opinions and within existing operating constraints and normal operating limits of the projects. If Bonneville were to pursue participation in a day-ahead market, it would also assess the potential environmental effects that could result from implementing the decision consistent with the National Environmental Policy Act.

9. Conclusion

Bonneville's decision to join any market must comport with its legal obligations including to provide preference and priority in the sale of power, make firm power sales under section 5(b) of the Northwest Power Act, provide transmission service and operate the transmission system, set rates sufficient to repay the federal investment, and fulfill environment, fish and wildlife obligations. Bonneville has not identified any legal impediment to meeting these objectives if it joins Markets+.

[213] 16 U.S.C. § 824k(i)(2)(A).

Appendix B

West-Wide Governance Pathways Initiative Overview and Assessment

In July 2023, the West Wide Governance Pathways Initiative was launched with a mission to develop and form a new and independent entity with an independent governance structure capable of overseeing an expansive suite of West-wide wholesale electricity markets and related functions. This effort was led by a Launch Committee comprised of representatives from across a wide range of sectors. While its working meetings were closed, the Launch Committee held monthly public stakeholder workshops to provide updates on progress. Work products were released throughout the process and there was an opportunity for public comment. It is worth noting that the Western Area Power Administration, another Federal power marketing administration, participated on the Launch Committee. Bonneville participated in all public stakeholder meetings and provided comment at every opportunity. Bonneville was also an active participant in Pathways Step 2 work groups and contributed significant staff time to that effort.

The Pathways initiative resulted in two outcomes: Step 1 proposed a transition of the WEM Governing Body from a governance model of joint authority to one of primary authority with a provision for dual filing by the WEM Governing Body and CAISO Board of Governors at FERC in the case of an unresolvable dispute (discussed above). Step 2 proposes a significant transition to create a Regional Organization (RO) with an independent board that governs the WEIM and EDAM Tariff. Under the proposed approach, CAISO would continue to operate the market, would hold all financial and contractual liability, and maintain a shared tariff between CAISO and the RO. Some limited staff responsibilities may shift to the RO; however, the specifics of staffing remain open at the time of the final Step 2 proposal to be determined during the formation of the RO. The final proposal recommends that the new RO undertake a feasibility study within 9 months of formation to evaluate further advancements in market independence. The full Step 2 proposal can be found here.

Assessment of Pathways Step 1

Bonneville has evaluated the outcomes of the Pathways initiative as part of its day-ahead markets decision process. Bonneville believes that Step One, by itself, does not achieve the level of independence from any one state's authority that is necessary for a regional market. Bonneville does not view Primary Authority as more independent than Joint Authority. Bonneville is concerned that the transition to Primary Authority could lead to the CAISO Board of Governors being disconnected from WEIM and EDAM issues and could increase conflict between the Board of Governors and the WEIM Governing Body.

Under Step 1, the CAISO Board of Governors would retain sufficient authority to take back the steering wheel when certain conditions arise (to maintain fiduciary responsibility under California law) described as exigent circumstances. "Exigent circumstances" is a very broad concept, and by its nature, would likely be called upon during a crisis, e.g., a reliability event, a price spike, or a call by California-elected officials to take action. Such events will be sudden and chaotic. It would be concerning for parties outside of California to be exposed to a sudden assertion of control by the CAISO Board of Governors when the WEM Governing Body, by the nature of its primary focus on the market, may have superior understanding of the issues.

The Step 1 proposal does not achieve independent market governance to meet Bonneville's principle.

Assessment of Pathways Step 2

As described above, the Step 2 final proposal represents a significant shift from the current governance structure of the WEIM and EDAM. It moves governance of those markets to a Regional Organization with an independent board. Market operations would remain under the single CAISO Tariff that includes

CAISO's administration of its BA. The RO would hold sole authority for sections of the CAISO Tariff applying to market operations and joint authority with the CAISO BOG for tariff provisions of overlapping application to both markets and the CAISO BA. The RO acts as a policy organization, governing policy related to the markets. Operation of the market remains with CAISO, as does corporate and financial liability related to the market. The step 2 final proposal also describes significant changes to the stakeholder process to enhance the role of stakeholders and shift away from the staff-driven process that CAISO uses today.

In evaluating the Step 2 proposal, Bonneville assessed whether the proposed approach achieves independent governance for markets. Under the proposal, the RO board members would be nominated and chosen through an independent sector-based process; they would not be selected by the California governor and confirmed by the California Senate, which is an advancement from the current state. However, market operations and administration would remain under the direction of the CAISO Board of Governors and, therefore, would not achieve full independence from the State of California.

Bonneville does not believe the Pathways Step 2 achieves the independent governance contemplated in Pathways' charter. This appraisal is not a matter of subjective opinion about what degree of independence would be good enough; the proposal creates conflicts that undermine any claim of independent governance and operations. As discussed below, the Regional Organization proposed by Pathways does not achieve independent market operations, an independent tariff, independent contracts, and the ability to provide RTO services absent future legislation. The market contemplated by the proposal remains California's market, adding an independent policy board with limited authority for market operations and administration.

1. Independent Market Operations

First, the Regional Organization would not have independent oversight and administration of market operations. Instead, the market would continue to be operated by the market's largest BAA, CAISO. This sets up a conflict of interest. For governance to be independent, CAISO should have the same role as any other BA in the market.

The RO board may find itself in a frustrating situation. While it has authority in market design, it would have no executive authority to manage operations to ensure the market is faithfully implemented. Further, the RO will be forced to take market operations services from a single provider without regard to potential competitive market operation services. The proposal notes that, while a typical arms-length contract allows a dissatisfied party to choose to not continue doing business with the other, "[t]he RO would be more or less required to use the CAISO[.]" Operations would answer to a state entity, with no remedy available to the Regional Organization.

Without legislative change, CAISO and its employees would remain subject to California legal requirements to act for the benefit of California. *See* Cal. Pub. Util. Code § 345.5. The market would be operated by a single BA in the market footprint with duties to itself and its state. Pressure to favor California could manifest in subtle ways, such as how issues are framed and presented, and in prioritizing work under time and staffing constraints. Bonneville believes that California regulatory agencies and the state's legislature will retain disproportionate influence on policy development. The Pathways proposed role for the Regional Organization to weigh in on select hiring decisions is a small step forward but ultimately does not get to the heart of the issue.

Bonneville is also concerned that this conflict of interest and lack of operational authority for the RO will have impacts on participants in emergency or shortage situations. The Pathways proposal states it is standard practice for operators to be able to act in an emergency without seeking advance blessing from a board. Bonneville is not advocating for emergency operations to be brought to a board before responding to a crisis. Instead, it is imperative that operations are independent, so the operators have no incentive to

favor one participating BA. Until CAISO's load service responsibility and Western energy market operator responsibilities are performed by completely separate entities, the market will not be independent.

2. Independent Tariff

Second, the proposal recommends an integrated tariff with continued joint authority over many tariff sections. The Regional Organization would not have sole authority over the tariff. The CAISO tariff would remain the relevant tariff. An integrated tariff creates conflicts over who has authority over which provisions, and who decides how certain initiatives are classified. An independent market would not intentionally choose to integrate its tariff with that of a single participating BA. From a practical standpoint, joint management of a tariff would be needlessly cumbersome and inefficient. From a legal standpoint, the ambiguity regarding authority could result in unjust and unreasonable implementation of the tariff.

Joint provisions are not necessary. General provisions could be copied and pasted to create two separate tariffs. Provisions specific to CAISO BAA could be unwound from sections that should be under the Regional Organization's sole authority. For the Regional Organization to have independent authority, it must be clear what authority it possesses. If the reluctance to separate tariffs is driven by cost considerations or the difficulty of precisely defining CAISO's new role, it is worth the investment now to address the issues to ensure unambiguous, just, and reasonable terms and conditions rather than in the heat of a future controversy. In order to achieve an independent governance structure, separate tariffs are a necessity.

3. Independent Contracts

Under the Step 2 proposal, CAISO would remain the counterparty to contracts with other market participants. This status is unique among participating BAs. It creates conflicts if CAISO interprets the contract differently than the Regional Organization. This could be a problem for CAISO if CAISO disagrees with the Regional Organization over what market rules are required or prohibited by the contracts. This is problematic for the Regional Organization if it adopts market rules applicable to scheduling coordinators and participating generators but lacks privity to enforce any related contract action. It is not clear that the Regional Organization would have any authority to amend contracts if it determines such amendments are necessary or desirable. Even if CAISO and the Regional Organization attempt to coordinate and align on interpretations, this continues to give one market participant undue influence over contracts with all other market participants. One participating BA should not be able to wield influence over the contracts of all market participants. As proposed, this contractual influence would not be shared or checked even by the Regional Organization itself.

These conflicts would not simply be philosophical differences of opinion. Under option 2.0, CAISO would retain financial responsibility, liability, and compliance obligations, which represents significant risk for CAISO. Therefore, when conflicts occur, the stakes will be high, and CAISO will naturally be incented to act in its own interest. The party that sets market rules should be impacted by the practical financial and legal ramifications of those rules. When the relationship between authority and impact is severed, as they are in the Step 2 proposal, conflict is inherent.

Despite the foregoing critique, Bonneville supports and appreciates the advancements made in the stakeholder process in the Step 2 final proposal. It has been Bonneville's experience that a more stakeholder-driven approach leads to increased collaboration, compromise, and ultimately better outcomes for market stakeholders. The Pathways Step 2 proposal introduces a stakeholder process with an increased role for stakeholders, including a more empowered stakeholder representative committee and indicative voting. The final proposal also includes an appropriate role and representation for federal power marketing administrations in both the stakeholder process and public interest process.

Appendix C

Potential Regional Transmission Organization Formation

Consistent with Bonneville's strategic plan, Bonneville is considering an incremental approach to market expansion. While Bonneville is only considering day-ahead market participation in this process, Markets+ may offer more potential for further integration into an RTO. SPP is a fully independent entity that does not require any legislative changes to meet FERC's requirements for RTO operation. In contrast, Bonneville has not observed a similar pathway for CAISO to support a full, multi-state RTO, including BAA consolidation. Even the most aggressive Pathways Initiative phase results in California as an ISO with the potential for a separate RTO operating outside of California in multiple states. SPP also has decades of experience operating a multi-state RTO, and its stakeholder-driven governance framework effectively navigates complex issues, while building trust among stakeholders. Accordingly, the Markets+ design is better positioned to provide additional market evolution and business opportunities for Bonneville as it confronts an increasingly dynamic electric utility business environment. If Western utilities begin to contemplate RTO formation in the future, Bonneville would conduct a transparent public process to evaluate the potential impacts of joining an RTO.

Appendix D

Seams Assessment

1. Transmission Operations, Seams, and Related Agreements

Seams are not a new concern for utilities, load serving entities, merchants, or marketers operating in the Western Interconnection. There is a mix of both bilateral trading and participation in organized markets, such as CAISO markets (day-ahead, hour-ahead, and WEIM) and WEIS. Bonneville has a service territory spanning seven states and is a significant provider and operator of high-voltage transmission service in the Pacific Northwest. Bonneville also operates a BAA in the Pacific Northwest that is adjacent to 18 BAAs (~360 individual ties) and 15 TSPs, including several TSPs that are embedded within Bonneville's BAA. Further, Bonneville is currently participating in the WEIM along with 14 of its adjacent BAAs.

While many diagrams and maps of the WECC and the Pacific Northwest often show tidy contiguous borders between BAAs and TSPs, the reality is much more complicated, especially in the Pacific Northwest, where many BAAs are often non-contiguous with loads and resources pseudo-tied across multiple TSPs and geographic zones, including generation-only BAAs. Bonneville also plays an integral role in the WECC as a key TSP, TOP, and TO of transmission assets that provide connectivity both within the Pacific Northwest and between the Pacific Northwest and the rest of the WECC footprint.[214] Given the numerous and complex commercial and operational seams that Bonneville and other WECC entities deal with daily and that have been refined over 75+ years, the region and Bonneville will need to work collaboratively to address the introduction of multiple new day-ahead market seams.

Seams exist today and produce operational and commercial friction and inefficiencies that must be carefully managed. Bonneville will likely have generation, load, and transmission participating in or impacted by both markets requiring various agreements, constraints, protocols, procedures, and market designs to ensure operational and commercial seams issues are addressed. With the introduction of multiple day-ahead markets with their own footprints, designs, protocols, and procedures, avoiding negative operational and commercial externalities will be critical.

The operational and commercial situation in WECC stands in stark contrast to the RTOs/ISOs that exist in the Eastern Interconnection.[215] In eastern RTOs,/ISOs, they are vertically aligned among roles[216] as well as having mostly contiguous footprints (relative to WECC). As such, the types of seams and the negotiation of seams among the various operational and commercial concerns involve far fewer parties and less complexity. The introduction of additional day-ahead market seams in WECC will involve many more entities than would be present under an RTO/ISO regime.

To combat these complexities, Bonneville will engage entities early and with ideas of how to decrease the relative complexity. Depending on the footprint, multiple MOs and RCs will need to be involved in these conversations. Bonneville has extensive experience in developing transmission and operating agreements with multiple BAAs and Bonneville will bring that experience and understanding to the conversation.

The discussion below identifies examples of the types of commercial and operational seams that the region and Bonneville will need to address to implement multiple day-ahead markets in the WECC.

1.1. Operational Seams

1.1.1. Balancing Authority Area

[214] *E.g.*, Northwest AC Intertie (NWACI) and Pacific DC Intertie (PDCI).
[215] *E.g.*, SPP, Pennsylvania, New Jersey and Maryland Interconnection, Mid-Continent Independent System Operator.
[216] *I.e.*, RC, MO, BAA, TSP.

BAAs may experience increased operational complexity due to the need to manage interactions with multiple day-ahead markets simultaneously. Each market may have its own scheduling, dispatch, and settlement processes, requiring BAs to coordinate their activities to ensure integration of market transactions while maintaining reliability.

1.1.2. Reliability Coordination

Multiple non-contiguous RCs in the Pacific Northwest with complex seams will make it potentially more difficult to reliably manage operational issues when they arise given the additional coordination and lack of complete regional authority. Existing multiple RCs in the Pacific Northwest have much simpler seams today.

This may be further complicated by the difference in BAA and TOP areas (geographical or electrical). Bonneville is the TOP for facilities that are not in the Bonneville Transmission BAA (e.g. Heyburn/Unity are in Idaho Power's BAA and Drummond/Swan Valley are in PAC East's BAA). Under the NERC Rules of Procedure *(ROP Section 500, 1.4.1)*, all areas *(geographic or electrical)* are required to be "under the oversight of one and only one RC." There are currently no situations in the Pacific Northwest where a BA or TOP takes services from multiple RCs. If there are multiple markets within the Pacific Northwest with each taking primary RC services from the respective MO organization, this creates a possibility that some entities that perform these functions over areas that transcend the footprints of more than one market may be required to take services from more than one RC. This complexity may make it more difficult to reliably manage certain operational issues when they arise, as well as increase the communication and compliance burden.

RC-RC coordination will be critically important to minimize reliability risks. Bonneville has not made any determination regarding whether if Bonneville will switch RCs. However, having multiple non-contiguous RCs and MOs in the Pacific Northwest will pose many operational and commercial challenges due to:

- Potentially complex and non-contiguous boundaries;
- Competing priorities and objectives;
- Unique requirements, business practices, and complex coordination needs;
- Complex seams agreements.

These types of seams pose many challenges that, if not addressed and mitigated, will impact reliability. Through implementation, Bonneville will seek to lessen these impacts and risks.

1.1.3. Transmission Operations

The Pacific Northwest to California transmission corridor is one of the most important in WECC. A problem along this corridor can have serious implications for the entire Western Interconnection, and specifically, entities within the Pacific Northwest that depend on the Bonneville Transmission System. Further, many of the paths for which Bonneville is the TOP are shared amongst multiple asset or capacity owners and TSPs. These include, but are not limited to:

- **NWACI:** Many entities are involved in the NWACI. Bonneville is the operator and the BAA of the facilities north of the California Oregon Border. There are multiple asset owners (Bonneville, PAC, Portland General Electric [PGE]) and capacity owners, many who also provide service under an OATT as a TSP. The facilities that make up the NWACI support important transfers with CAISO, PAC, PGE, Idaho Power Company, BANC, and Nevada Energy, all of whom have either declared a leaning to join EDAM or signed an implementation agreement to join EDAM.
- **PDCI:** The PDCI is a controllable DC transmission path between the PNW (Bonneville

Transmission) and Southern California (LADWP), where LADWP has chosen to join EDAM. North of Nevada Oregon Border (NOB), Bonneville is the sole owner while south of NOB the ownership is split amongst multiple entities (LADWP, CAISO, Glendale, and Burbank). As operators of the DC converter stations at Celilo and Sylmar, Bonneville and LADWP control the PDCI dispatches and jointly manage the path.

- **South of Allston:** South of Allston is a shared path between Bonneville, PGE, and PAC, with the latter two having signed EDAM implementation agreements. Like other paths, Bonneville manages the path and determines the total transfer capability, which is subsequently allocated.
- **Other Shared Paths Include:** North of Echo Lake, West of Hatwai, North of Pearl, Montana-Northwest, and the Northern Intertie.

These types of shared paths impact multiple TSPs and BAAs and must be carefully managed and coordinated. Situations that increase the amount of coordination and seams issues on paths like these may increase the risk of adverse commercial and operational outcomes. Depending on the ultimate RC and market footprints, new agreements and procedures may need to be developed in order for everyday operations to continue to be reliable and efficient.

1.1.4. Mismatch Between Market Processes and Real-Time Operations

Each market may have differences in processes such as interchange scheduling rules, scheduling intervals, timing requirements, intertie bidding, rules for submitting bids and offers, and market clearing timelines. This misalignment can lead to difficulties in coordinating generation and transmission schedules between the two markets and aligning market schedules and dispatches with real-time operations. As part of implementation, Bonneville will need to consider all of these aspects as procedures and protocols are developed. The details will not be known until implementation.

1.1.5. Transmission Constraints and Market Congestion

Differences in how transmission constraints are modelled, market flows are calculated, and how subsequent flows are managed in each market can result in congestion at interfaces between or within the two market footprints. This "market congestion" or "commercial congestion" may affect the efficient utilization of transmission capacity and lead to suboptimal dispatches and pricing outcomes. Transmission opt-outs, SFCs, Transmission Corridor Constraints, ETSRs, and other nuances of each market's management of transmission constraints may cause the market(s) to be commercially constrained even though the transmission system is not physically overloaded.

1.1.6. Congestion Management

There is a potential of physical congestion occurring on transmission lines that serve as interfaces between the markets or transmission lines/flow gates/paths internal to one or the other market footprint. This congestion can occur regardless of being part of a market, but the management of congestion on transmission being used by two markets will likely require a more complex and nuanced approach. Managing congestion can also be more complex when market participants seek to arbitrage price differentials between markets, leading to potential congestion on specific transmission paths or flow gates. Seams agreements will likely be needed between the impacted entities[217] and the market operators to try and manage these types of operational risks.

1.1.7. Dynamic Transfer Capability (DTC)

Bonneville has numerous facilities with DTC limitations, such as the Northern Intertie, NWACI, PDCI,

[217] *E.g.*, BAAs/TSPs/TOPs.

Montana Intertie, and more generally across the Bonneville network. These limitations impact the ability of the system to reliably support large sub-hourly changes in flows and are addressed in Bonneville's Dynamic Transfer Business Practices. If there are multiple real-time markets within the Pacific Northwest, DTC will need to be allocated among multiple markets and managed via market constraints.

Further, the lack of DTC between two non-contiguous market zones (e.g., PNW and DSW) will limit sub-hourly optimization between the zones. Each zone, and the BAAs it contains, will need to manage intra-hour imbalances without the market's ability to economically transfer incremental energy dynamically between the zones. As a result, and to maintain reliability, the need for flexible resource capacity may increase, requiring either additional market procurements and/or additional reserves to be held by BAAs within each zone.

1.1.8. Interconnection Reliability Operating Limits (IROL)

Bonneville is currently subject to two IROLs, the Oregon Net Export IROL[218] and the NW WA Import IROL. Today, RC West is largely responsible for both IROLs. Having multiple non-contiguous RCs involved in managing IROLs, especially the Oregon Net Export IROL, will require the RCs to be tightly coordinated. Bonneville will continue to support large margins when studying and observing IROL limitations and also support the identification of a lead RC for each IROL.

1.1.9. Network Model Management / Coordination

Accurate models are critical to maintaining reliability. If there are multiple RCs, they will need to ensure they always have the same network models and that they communicate consistently to all BAs and TOPs. Bonneville will continue to advocate that RCs ensure network model alignment.

1.1.10. Operational Studies (assumption, datasets, outages, etc.)

Operational studies require not only an accurate network model, but also robust and accurate datasets and the ability to apply realistic assumptions. With multiple RC and market footprints in the Pacific Northwest, this may be a challenge and present risks across various time horizons.[219] Bonneville will continue to receive the assumptions from WECC as part of its offline studies, while the real-time contingency analysis tool will be using remote terminal units to receive real-time data and then perform state estimation.

1.1.11. Outage Coordination

Coordinating and managing outages across multiple MOs and RCs is critically important. In addition to using different Outage Management Systems, RCs and MOs may have differing requirements for outage submittals and timings and a single outage may require careful coordination with all entities depending on the nature of the outage. As part of any implementation, this will need to be further explored and coordinated.

1.2. Commercial Seams

1.2.1. Market Timing and Process Requirements (bi-lateral, day-ahead, real-time)

Differences in timing and process requirements between the various markets (day-ahead, real-time) may impact the ability to efficiently trade between market footprints. Business practices will need to be developed to address efficiency and accurate operation.

1.2.2. Resource Adequacy Programs (i.e., WRAP and CPUC)

Multiple RA programs may be difficult to reconcile across market footprints. There will need to be market-

[218] The Oregon Net Export IROL addresses the interactions between the NWACI and Path 75/Path 14.
[219] Week-ahead, day-ahead, hour-ahead, real-time contingency analysis, etc.

to-market coordination to ensure generation capacity, and any energy deliveries are accounted for.

1.2.3. Jointly Owned Transmission (network and interties)

Managing existing jointly owned (asset or capacity) transmission agreements, along with any commercial arrangement and operational protocols, may be more difficult than they already are if the owners are spread across multiple non-contiguous RCs and markets. This is especially acute when one TSP and owner is located within a BAA that is participating in a different market. It will take time and engagement from all entities in the Pacific Northwest to ensure reliable operation and market efficiency.

1.2.4. Remote Load (i.e., load service in another BAA via transfer service)

Many utilities, including Bonneville, have generation and load in other BAAs. If the entity with remote load, such as Bonneville, has a different RC or the two BAAs are in different day-ahead and real-time markets, Bonneville acknowledges that it may be more difficult to service that load as it would likely require merchants to participate in both markets as well as deal with market-to-market energy transfers and it will need to be further explored upon implementation.

1.2.5. ATC ID, OATT, Business Practice Discrepancies between Adjacent TSPs or Joint Owners

While ATC ID, OATT, and business practice discrepancies exist today, depending on the design of the markets (timings, transmission donation processes, TSR queue pausing, etc.) and how transmission availability is calculated and reserved, adjacent TSPs may end up with impactful differences. These differences may cause bilateral trading and market-to-market friction. Affected parties will need to coordinate to minimize potential impacts.

1.2.6. Price Formation (between markets)

A critical concern of all organized markets is price formation methodology. Differences in these methodologies, both temporal and procedural, may result in structural price differences between markets that create incentives that work against both markets objectives or produce unintentional hurdles that limit efficient bilateral trades or efficient transactions between markets.

1.2.7. Commercial Transmission Rights (Congestion Revenue Rights, ATC, etc.)

Markets need access to transmission to effectively operate. Markets may leverage donated rights, unused ATC within the market footprints, physical capability of the system, or any combination of the above. Timing and access to transmission for day-ahead market participants and customers not participating in a day-ahead market may be complex to coordinate. Parties will need to establish methods to determine priority, transmission rights, and dispute resolution to avoid over or under-utilization of the transmission system. Proper incentives will more effectively manage congestion. Bonneville believes these complexities can be addressed through the standard tariff, rates, and business practice processes.

1.3. Other Seams Considerations

There are many other potential impacts to multi-RC/multi-MO environment that will need to be carefully weighed, such as:

- State Carbon Policies and GHG accounting
- Remedial Action Schemes
- Rate Pancaking (market to market)
- Data Sharing
- Market Flow Calculation and Management

- Reserve Sharing (market to market)
- Interchange Scheduling (timing requirements, etc.)
- System Integration and communication between markets
- Oversupply Protocols
- Transmission Loss Accounting
- NT redispatch (FCRPS and Non-Federal redispatch)
- Standardization of scheduling timelines between markets
- Water Management (Bi-Op)
- International Treaties
- Jurisdictional Status
- Blackout Restoration

1.4. Seams Agreements

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. Bonneville expects agreements, constraints, and market design to mitigate operational and commercial seams issues. Given the complexity of WECC, the potential for non-contiguous market and RC footprints, and the number of parties involved, multiple types of agreement will be necessary.

2. Seams Conclusion

Bonneville recognizes the operational and commercial challenges posed by multiple markets and RCs, the impacts of their potential footprints, and the resulting seams. Bonneville also recognizes and is aware of the complexities posed by seams, both operational and commercial. So long as more than one RC, MO, BAA, and TSP exist in WECC, seams will exist. However, some create more operational and commercial challenges and complexity than others. Bonneville and others will need to work collaboratively to manage these seams while continuing to prioritize reliability.

Appendix E

Congestion Impacts

In a day-ahead market, congestion occurs when available least-cost energy cannot be delivered to some loads because transmission facilities do not have sufficient capacity to deliver the energy, or there is insufficient transmission rights made available. Market optimization will create a plan to dispatch least-cost resources until the optimization reaches an identified limit, at which point it will begin to add to the dispatch plan the next least-cost resource that does not further impact the "binding" limit. An indication that congestion is occurring is "price separation" between two locations; the next least-cost resource that does not further impact the limit that can serve load on one side of the constraint may have a different price than the next least-cost resource on the other side of the constraint. To see an example of congestion, please see materials from public workshop 7 on June 3, 2024.[220]

The market optimization engine delivers day-ahead awards with resource schedules different from those that may have been established bilaterally. Unlike bilaterally established resource schedules, the planned dispatch pattern that results from participating in a day-ahead market is security-constrained (i.e., factors generation and transmission constraints when creating the optimized dispatch). Bonneville Transmission Services would be using scheduling limits established from internal studies to determine the capability of each path. The planned dispatch pattern could fully use the capacity over a path based on the data it had been supplied. However, congestion may still occur.

On the next operating day, in real-time, operational constraints may deviate from what was expected in the day-ahead optimized dispatch. In real-time, resources are redispatched to reflect updated constraints as other inputs such as load changes, variable energy resource output changes, and generation or transmission outages and derates are adjusted relative to the day-ahead solution.

As stated in Section 6.4, Bonneville has had positive experiences leveraging the WEIM to manage operational constraints and expects even greater congestion management effectiveness with the addition of a security constrained day-ahead market optimization

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. It is possible that in a multi-day-ahead market scenario, the Pacific Northwest region will continue to see commercial congestion, rather than a reduction. Physical congestion represents the actual flow on a transmission element reaching the established reasonable maximum amount. Commercial congestion represents a limit to potential physical flow despite the physical limit not being reached. Because Bonneville will likely have transmission customers in both day-ahead markets, as well as in no market, Bonneville will have to determine how to allocate transmission capacity to each market. If each market is allocated a certain number of MWs on a flow-based path that are reflective of the transmission rights of that market's participants, each market may congest due to the commercial limits even though the physical limitation is not close to being reached. This could produce a less efficient solution for each market, especially in the day-ahead market, compared to if there was only one market or compared to how things are today in a bilateral market. This could also happen in the real-time horizon.

Another inefficiency that could be introduced is internal flow-based paths with expected counterflow and transmission rights that were originally sold based on non-coincidental use. Each market will have a unique portion of capacity for the same path, defined within their respective market. There could be the situation that the sum of all of the rights in a single direction add up to more than the capability of the path, in which

[220] *See* Bonneville's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 7 presentation (June 3, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-7-presentation-060324.pdf.

case scheduling limits would be needed for each market to fit the path limit. This would exacerbate the commercial congestion identified previously, because the non-coincident users may not be distributed between the markets in the same pattern as the coincident users. This might only be in the day-ahead market and then in the real-time market, scheduling limits could be relaxed based on the scheduled use.

As discussed in Appendix D, Bonneville plans to encourage the two market operators to begin developing a seams agreement that maximizes the efficient use of the transmission system while maintaining the reliable operations of the grid. With these future complexities in mind, Bonneville is proactively taking part in the Enhanced Curtailment Calculator Working Group (ECCWG) to advise on solutions for uniform congestion management process.

In summary, Bonneville believes there are likely congestion management benefits to transmission operations with Bonneville participating in a day-ahead market. In July 2023 and October 2024, Bonneville announced that it had identified multiple new transmission substation and line projects necessary to reinforce the Pacific Northwest's electric grid.[221] The completion of these projects will add capacity to Bonneville's transmission system, and the day-ahead market can deliver even more efficient dispatch solutions.

[221] *See* Press Release, Bonneville Power Administration, BPA takes major step to advance transmission projects for reliability and expansion (July 12, 2023*)*, *available at* https://www.bpa.gov/-/media/Aep/about/publications/news-releases/20230712-PR-08-23-bpa-accelerates-work-on-transmission-projects-final.pdf; Press Release, Bonneville Power Administration, BPA maintains transmission expansion momentum with 13 new proposed projects (Oct. 15, 2024), *available at* https://www.bpa.gov/-/media/Aep/about/publications/news-releases/20241015-PR-18-24-bpa-maintains-transmission-expansion-momentum-with-13-new-proposed-projects.pdf.

Appendix F

Implementation Feasibility Assessment

In order to evaluate the implementation feasibility for Bonneville's Markets+ participation, a capability gap analysis was conducted, and 12 projects were determined to close the identified capability gaps in the following areas:

- Bidding and self-scheduling
- Data integration
- Settlements
- Price and dispatch
- Load and renewable forecast
- Metering
- Outage management
- Transmission scheduling and operations technology
- AGC modification
- RC Switch (if applicable)
- End-to-end billing process
- Post go-live technical support

Bonneville is in the process of developing an implementation plan to execute these projects, including changes in software, hardware, data integration, business processes, policies, and staffing. The implementation plan also includes market entry preparation, such as staff training, systems testing, market simulation, parallel operations, and production cutover. Initial estimates for funding and resources necessary to support this effort were included in Table 8 in section 5.1.2.3.

The main challenge of this implementation effort is the transition between two organized energy markets (i.e., WEIM to Markets+), which could require more resources to maintain two sets of systems and processes during the transition period. In many cases, discreet hardware, software, and network connectivity will be required to operate in parallel. Bonneville will strive to minimize the staffing impact by setting an appropriate timeline for implementation activities to space out the workload over time.

Bonneville will focus on deliberate timing, adequate funding, and appropriate staffing in the implementation process while leveraging prior experience implementing the WEIM. In addition, Bonneville plans to get support from a consulting services firm specializing in the energy utilities industry with expertise in market-to-market transition as a critical component to a successful and effective market entrance.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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 2-94:
Power Council 2024 Resource Program Results

Jeffery C. Allen
Chair
Idaho

Ed Schriever
Idaho

Doug Grob
Montana

Mike Milburn
Montana

Northwest **Power** and **Conservation** Council

KC Golden
Vice Chair
Washington

Thomas L (Les) Purce
Washington

Ginny Burdick
Oregon

Louie Pitt, Jr.
Oregon

January 7, 2025

MEMORANDUM

TO: **Council Members**

FROM: **Jennifer Light, Director of Power Planning**

SUBJECT: **Bonneville's 2024 Resource Program Results**

BACKGROUND:

Presenters: Suzanne Cooper, Senior Vice President of Power Services
Ryan Egerdahl, Manager of Long Term Power Planning
Allie Mace, Manager of Market Analysis and Policy
Eric Federovitch, Manager of Long Term Power Sales and Purchase

Summary: Bonneville has finalized its 2024 Resource Program (also known as RP-24). Bonneville's resource program is an analysis of potential system needs and resources available to meet those needs. Bonneville staff will join the Council to share the results from the 2024 Resource Program and early thinking on preparations for its next resource program, which is planned to be completed in September 2026.

Relevance: The Resource Program is informational and not a decision-making process, nor a decision document, but the results do inform Bonneville's resource acquisition strategies. For the past several years, Bonneville has been working with its customers and the region on new contracts for the post-2028 period. These conversations have highlighted that Bonneville may need to acquire additional resources to serve its obligations under these new contracts. Bonneville has stated that the 2024 Resource Program is expected to provide insights to

customers on potential resource types that Bonneville might pursue to serve that obligation.

When acquiring new resources, Bonneville is required to act consistent with the Council's power plan. Therefore, it is critical for the Council to understand the results of the current resource program, and how the results align with the Council's current power plan (the 2021 Power Plan).

It is also worth keeping in mind that Bonneville is starting to work on its 2026 Resource Program (RP-26), which it plans to complete by September 2026. The timing of this next resource program overlaps significantly with the Council's planned development of its Ninth Power Plan.

Background: Bonneville recently completed its 2024 Resource Program and presented the results in a public workshop on December 19th, 2024. Bonneville has stated publicly that this resource program is expected to provide insights to customers around the types of resources it might acquire should it need to acquire new resources to meet its future obligations.

The 2024 Resource Program includes results for a base scenario along with several sensitivities, including sensitivities that look at market prices, market reliance, and load growth. Bonneville also conducted a specific study exploring potential resources for Tier 1 augmentation.[1] Bonneville will walk through the findings of this analysis at the January Council meeting.

The Council's current power plan, the 2021 Power Plan, provides specific recommendations to Bonneville, which include:

- Acquire between 270 and 360 aMW of cost-effective energy efficiency by the end of 2027, of which at least 243 aMW must be from programmatic savings, and at least 865 aMW by 2041
- Work to enable and encourage its customer utilities to pursue low-cost and high value demand response, including time-of-use rates and demand voltage regulation
- Look to mid-term and long-term market resources for additional energy when needs are beyond those met by the recommended energy efficiency and demand response resources
- Compare market products, both in price and capacity, to renewable power purchase agreements to ensure that the lowest-cost product that suffices to meet any need is identified.

[1] Under the Bonneville Provide of Choice Policy, which is guiding its post-2028 contract development, Bonneville has agreed to sell 7250 aMW of power at a Tier 1 rate. Based on the existing system capability, Bonneville may need to acquire additional resources to meld into the existing Federal Base System in order to meet that obligation. This study focused specifically on the question of which resources would be least-cost to meet that obligation.

It is worth noting that Bonneville's near-term results across all sensitivities (i.e. pre-2030 builds) and its Tier 1 augmentation study are consistent with the 2021 Power Plan recommendations. Staff recommend the Council focus more on these near-term results, given the Council is working to complete its next power plan by the end of 2026 and Bonneville will have an updated resource program in a similar timeframe.

While the near-term results make sense, and are consistent with the Council's power plan, staff does have some questions regarding the longer-term results. Staff shared these concerns with Bonneville at the December 19th public workshop. They include:

Modeling of Emerging Resources: Bonneville included one emerging resource option, small modular reactors (SMRs), in RP-24. Council staff recommend Bonneville consider more emerging resource options in RP-26. Since different emerging resources have different attributes, analyzing more options will provide better information to Bonneville on the types of resources needed for the long-term. For reference, Council staff are planning three emerging resource options for the next plan. Council staff also recommend Bonneville rethink some of the SMR specific assumptions, particularly around online date and lifetime. Bonneville assumed the SMR was available in the model as soon as 2030. The Council understands the online date for SMRs would be 2035 at the earliest based on statements from Energy Northwest staff. The timing of emerging resource availability may change resource decisions across the planning horizon. The Council plans to explore different online dates for emerging resources in its scenario modeling to understand the implications of this uncertainty. Additionally, Bonneville assumed a 60-year life for the SMR. The assumed lifetime can significantly change the economics of a resource, with a longer lifetime making a resource look cheaper in the modeling. In the 2021 Power Plan, the Council used a 40-year life, and utilities across the region have used a range of assumptions from 30-years to 60-years. Council staff are still working with its advisory committees on the best assumptions for the upcoming plan.

Improved Understanding of Modeling Approach: Bonneville developed a new approach to its resource optimization modeling for RP-24. The newly developed optimizer provided a good step forward for Bonneville over the previous approach. Council staff are interested in better understanding the model, particularly as some of Bonneville's results are counter intuitive. As we have found with our own model development, there is significant value in opening up the models to experts in the region. The rapidly changing power system requires new modeling approaches, which the whole region is struggling to resolve. Having the opportunity to dive deeper will increase understanding and ultimately improve the modeling for all parties.

Council staff intend to work closely with Bonneville on the development of the Ninth Power Plan and Bonneville's next Resource Program.

More Info: Materials related to Bonneville's Resource Program development are available on its website: https://www.bpa.gov/energy-and-services/power/resource-planning.



BPA 2024 Resource Program & Next Steps

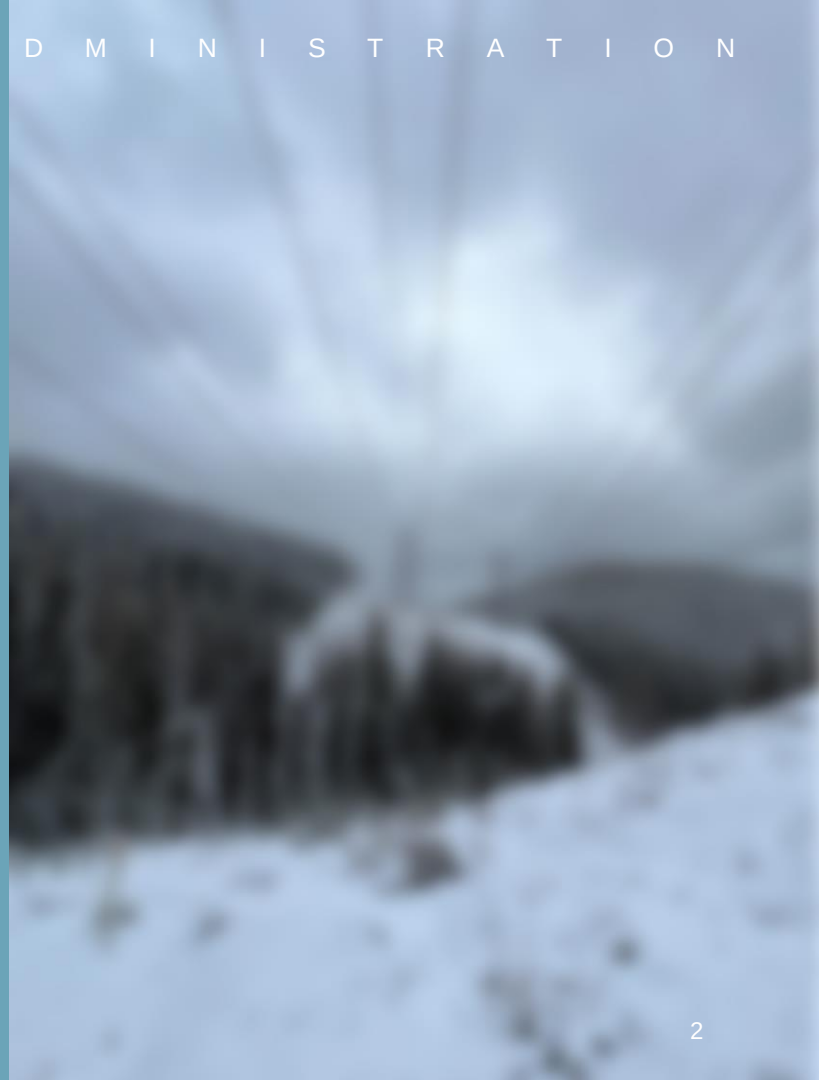
Presented to the Northwest Power and Conservation Council

January 14th, 2025

Introductory Remarks

Suzanne Cooper

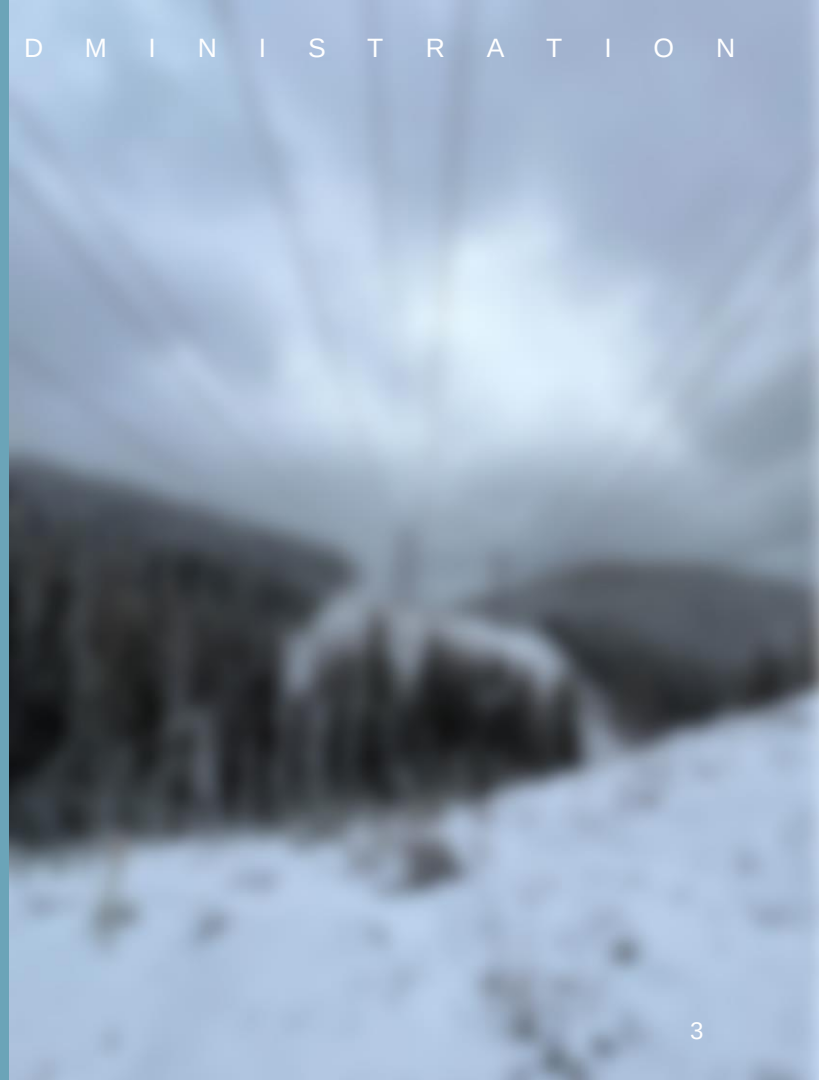
Senior VP, BPA Power Services



Resource Program Process Update and Next Steps

Ryan Egerdahl

Manager, Long Term Power Planning



Agenda

- Resource Program Process Update and Next Steps
- RP24 Resource Solutions
- Power Services Resource Acquisition Process

Reminder: Power Planning at BPA



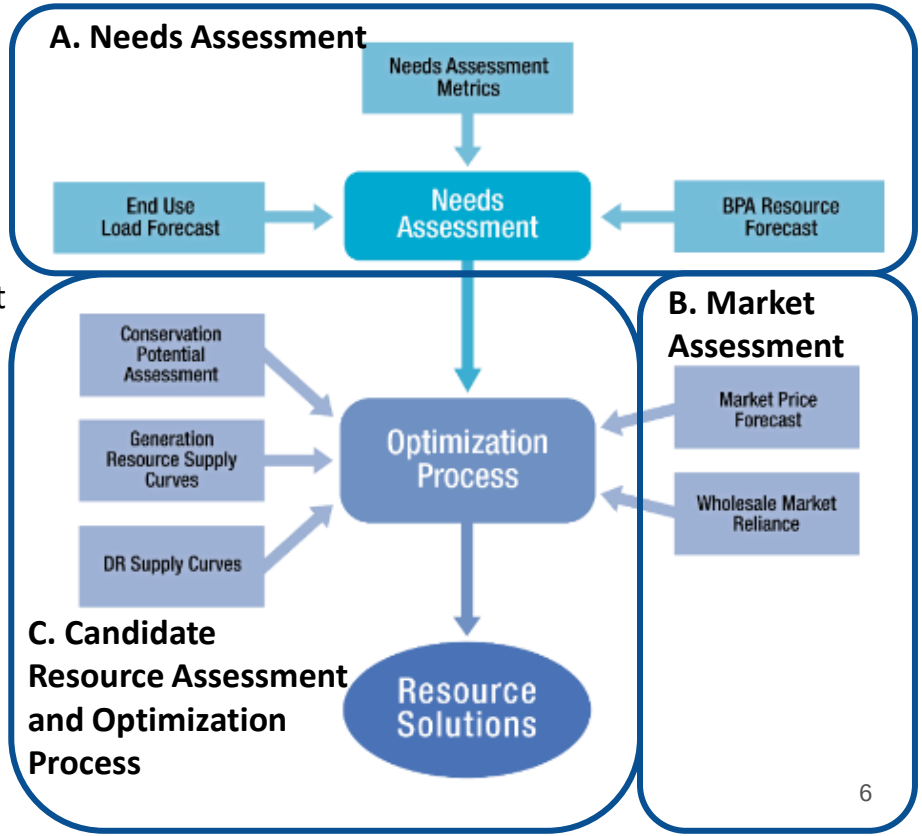
- Each year, BPA publishes the Pacific Northwest Loads and Resources Study – often referred to as the **White Book** - which analyzes BPA's projections of retail loads, contract obligations, contract purchases, and resource capabilities over a 10-year study horizon and describes expected energy and capacity surplus/deficits under varying water conditions.
- On a biennial basis, BPA conducts an IRP-like assessment collectively referred to as the **Resource Program** which examines uncertainty in loads, water supply, natural gas prices, and electricity market prices to develop least-cost portfolios of resources that meet BPA's obligations.
- These processes are voluntarily undertaken to inform acquisition strategies and provide valuable insight into how Bonneville can meet its obligations cost-effectively. They are neither decision documents nor a process required by any external entity.

Resource Program Process

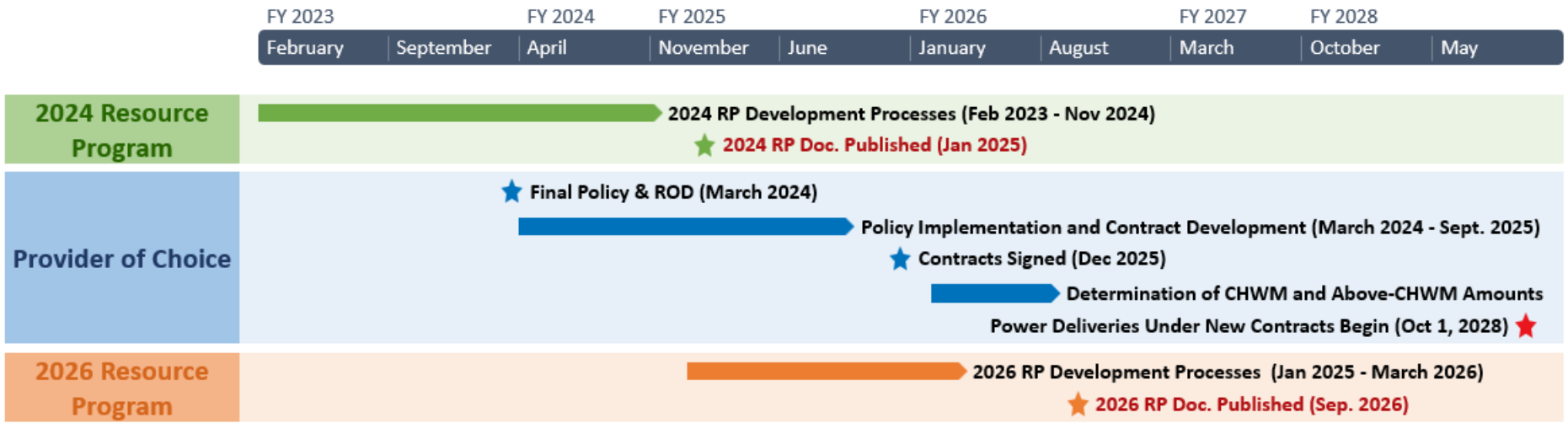
A. The **Needs Assessment** measures the federal system's expected generating resource capabilities to meet projected load obligations

B. The **Market Assessment** simulates the evolution of power markets in the Western Interconnect to generate a long-term forecast of Mid-Columbia prices and market availability under a variety of generation, load, and economic conditions

C. The **Candidate Resource Assessment and Optimization Process** explores how the varying costs, performance, and availability of candidate demand-and-supply-side resources (including conservation, demand response, market purchases, and generating resources) as well as wholesale market reliance can be used to provide a least-cost resource strategy for meeting identified needs



Resource Program and Provider of Choice



Possible Enhancements for RP26

- Based on feedback to RP24, BPA will consider exploring a range of modeling enhancements for RP26, including but not limited to:
  - Assess capacity metric under extreme weather and low water
  - Reintroduce balancing reserves study to Needs Assessment
  - Connect resource solutions to WRAP forward showing position
  - Include additional candidate resource options
  - Refine and refresh characteristics for candidate resources, including performance of renewables
  - Enhance linkages between resource solutions, market assessment, and needs assessment modeling
- We will also solicit additional feedback from stakeholders as RP26 planning gets underway

Next Steps and Additional Information

Next Steps:

- Publication of 2024 Resource Program expected in January 2025
- Release of BPA and Energy Northwest joint CGS EPU business case and RP24 addendum study expected spring 2025
- 2026 Resource Program to kick off in winter 2025; publication expected September 2026

Resource Program Contacts:

Ryan Egerdahl, Resource Program Manager, rjegerdahl@bpa.gov
Brian Dombeck, Resource Program Coordinator, bjdombeck@bpa.gov

Find Us:

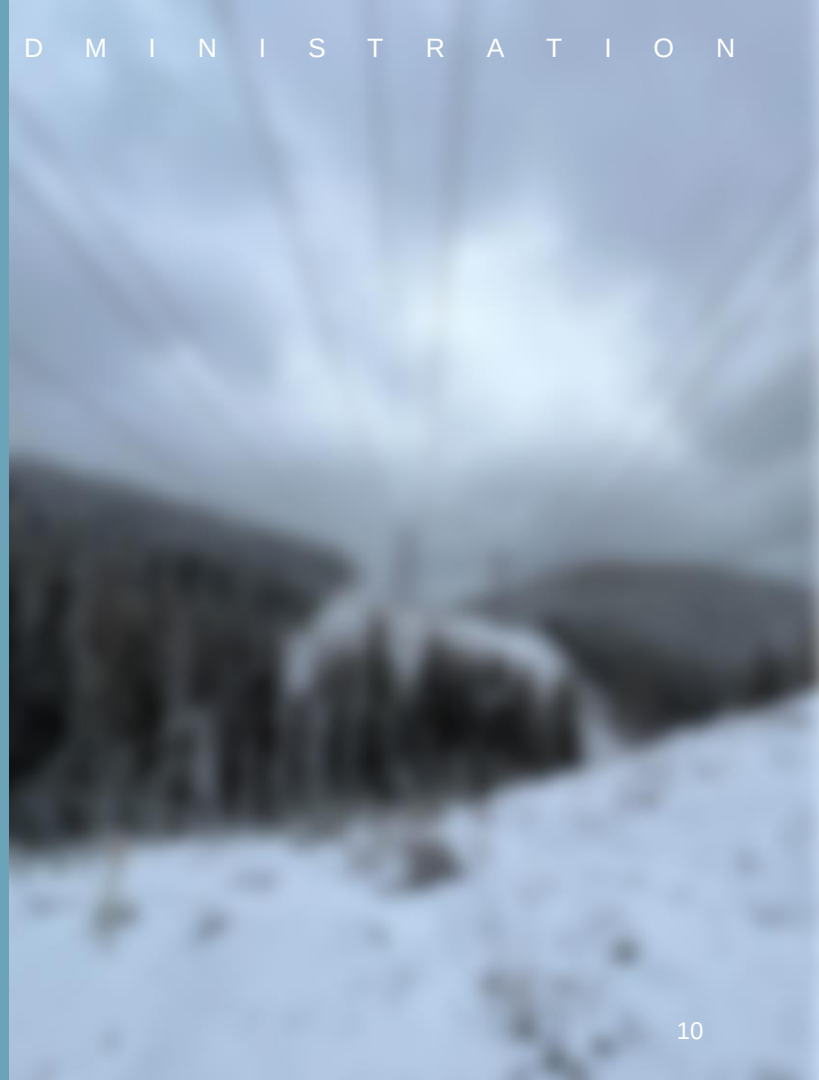
Email: ResourceProgram@bpa.gov
Web: Resource Planning (bpa.gov)



Resource Solutions

Allie Mace

Manager, Market Analysis and Policy



Key Takeaways – Resource Solutions

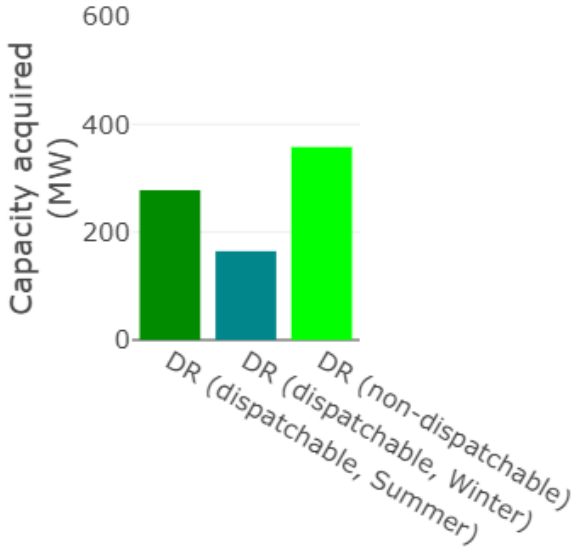
- We continue to rely heavily on **energy efficiency, demand response, and market purchases** to meet BPA needs.
- As loads grow or we add further limits on access to the market, resource acquisitions grow quickly.
- Acquisitions are driven primarily by **Flat** and **HLH energy needs**, rarely by super-peak or 18-hour capacity needs. There is not a single binding metric.
- Supply side acquisitions tend to focus on **solar** and **wind** resources due to their low costs and their contributions to energy needs.
- Supply side acquisitions in SWEDE are needed only if loads are higher than in the base scenario.
- **Resources in the model cannot meet needs in 2 sensitivities**: no market and high load. Shortfalls are in **winter/April 2026-2028**.

Base scenario: Key takeaways

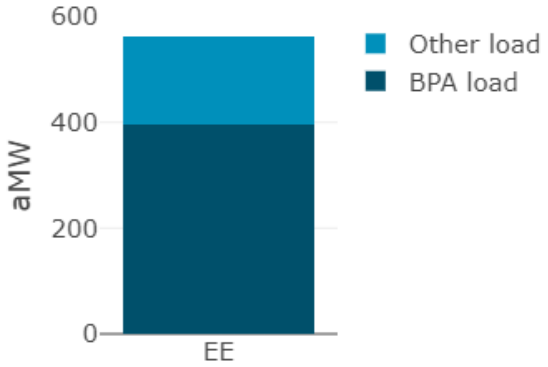
- P10 needs are met primarily by market purchases and energy efficiency (EE)
- Lowest-cost portfolio also includes several demand response (DR) programs and 300 MW solar power

Base scenario resource acquisitions

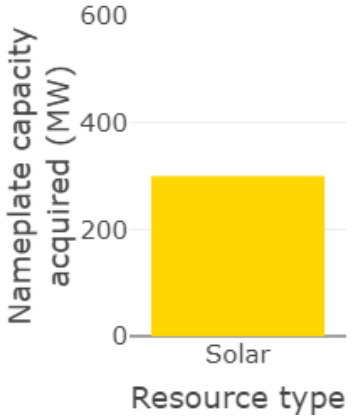
Demand response (DR):



Energy efficiency (EE):



Supply-side:



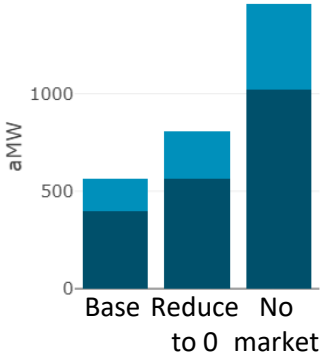
All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity. Capacity value for non-dispatchable DR is sum of max. capacity across all products.

Market limit sensitivities

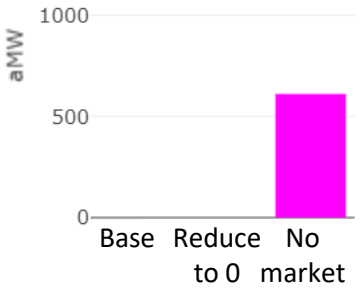
- **Reduce SPK/HLH by 25%:** Limits to SPK and HLH purchases are 75% of forecast market depth
- **Reduce SPK/HLH by 50%**
- **Reduce all market purchases by 50%**
- Reduce to 0: Limits start at 50% of forecast market depth and decline to 0
- **No market**: No market purchases allowed

Market limits: resource acquisitions

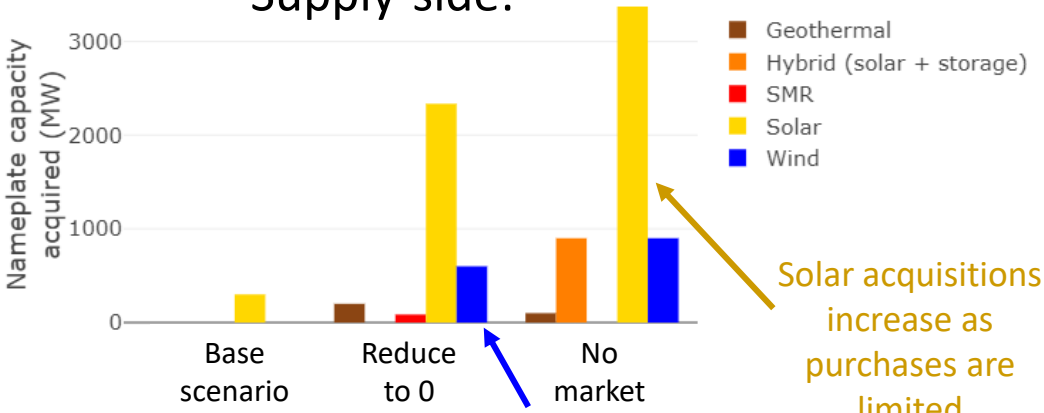
Energy efficiency:



Unmet needs:



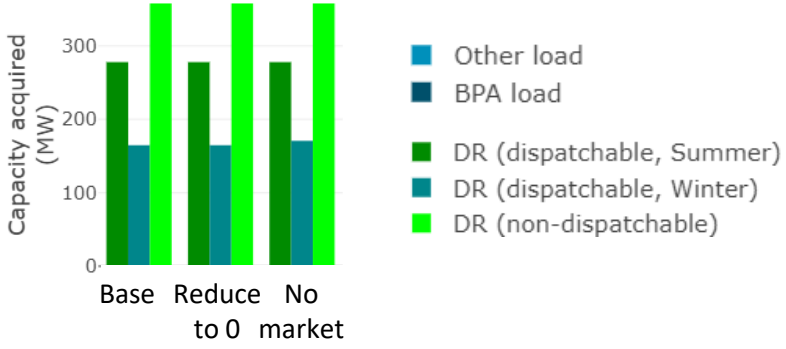
Supply-side:



Solar acquisitions increase as purchases are limited

Wind acquisitions are present whenever LLH purchases are limited

Demand response:

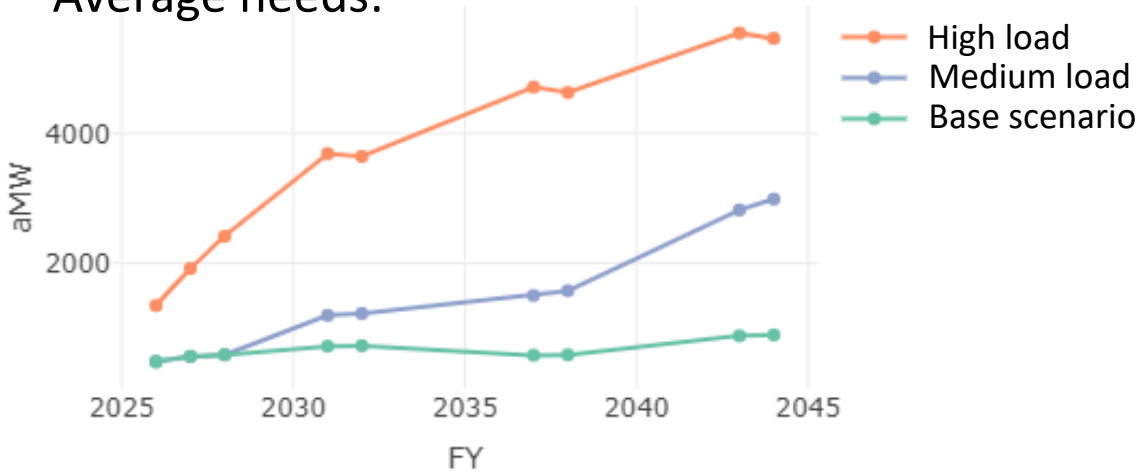


All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity. Capacity value for non-dispatchable DR is sum of max. capacity across all products.

Load adder sensitivities

- **High load adder (aka, NR)** is a flat block load added to every hour uniformly across the year.
- **Medium load adder (aka, T2)** is shaped load added to each hour. Shaping is based on current Slice Block load shape.

Average needs:

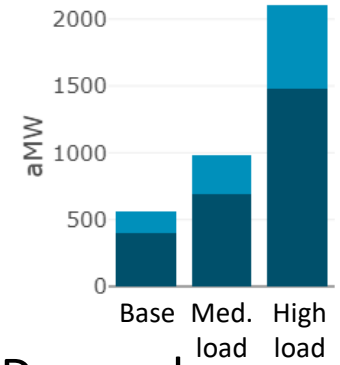


Load adder sensitivities: Key takeaways

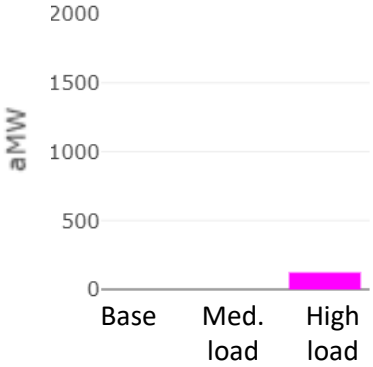
- Acquisitions are primarily driven by HLH energy needs
- Loads in the high load adder sensitivity are difficult to serve:
  - We do not have enough resources in the model to meet needs in 2026-2028 (but the shortfall is relatively small)
  - Portfolio cost is > $35 billion
- Solutions to both sensitivities include large (1,000+ MW) acquisitions of SMR
- Most acquisitions in the medium load adder sensitivity happen late, in 2043

Load adder sensitivities: resource acquisitions

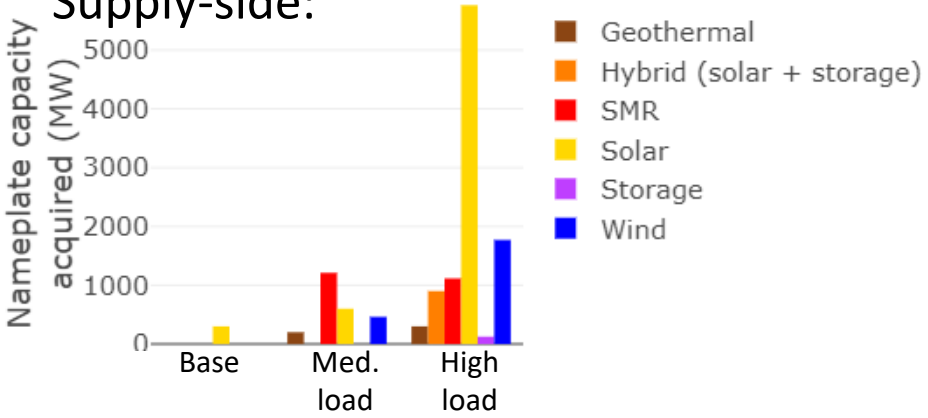
Energy efficiency:



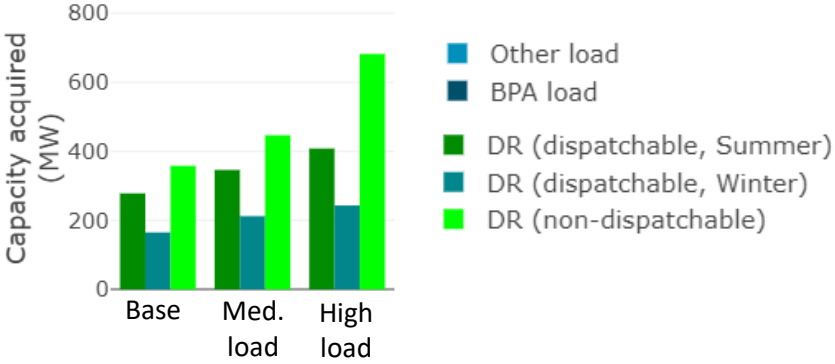
Unmet needs:



Supply-side:



Demand response:



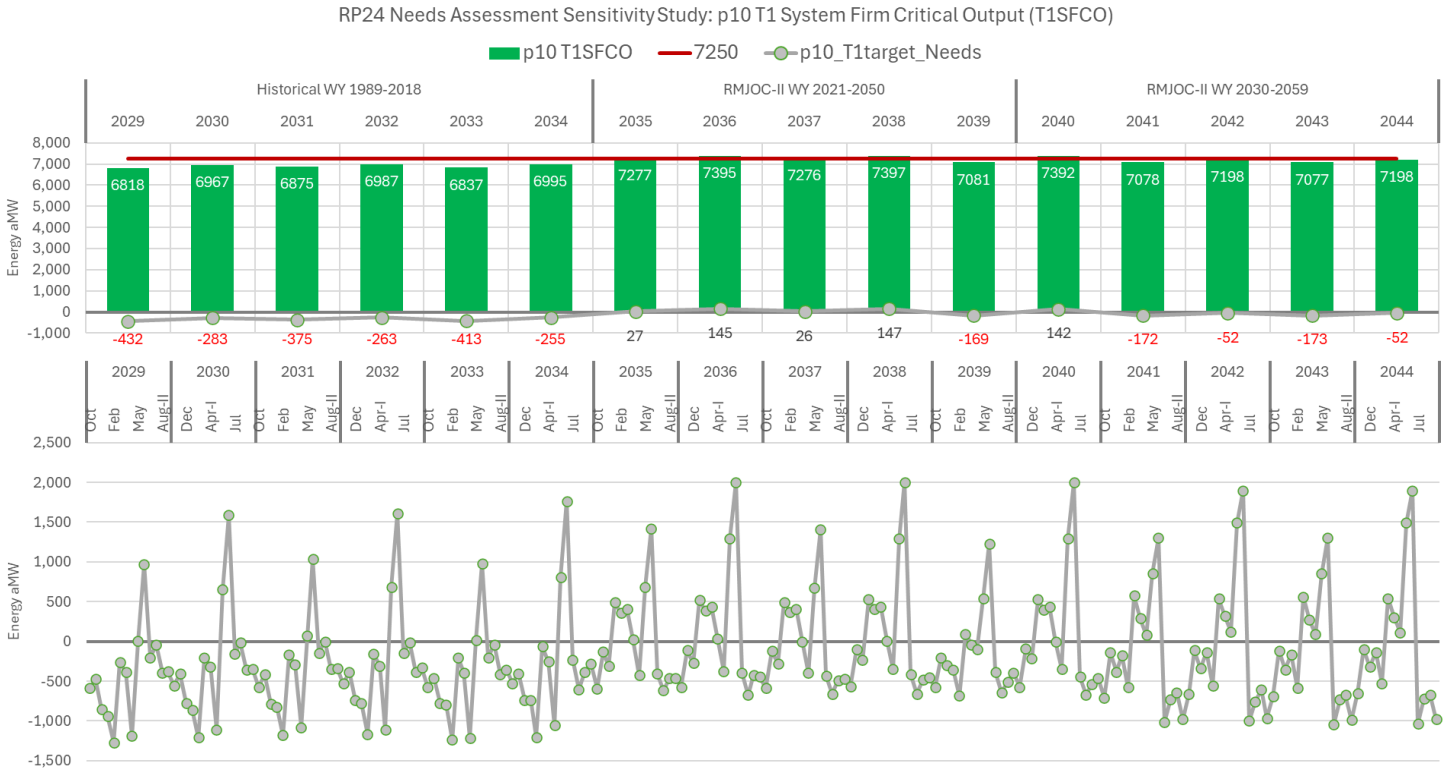
All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity. Capacity value for non-dispatchable DR is sum of max. capacity across all products.

Tier 1 augmentation

- This sensitivity grows the T1 System Firm Critical Output (T1SFCO) to **7250 annual aMW** shaped to reflect **forecasted hourly shape of T1 obligations**, starting in **2029**
- Needs are modeled as average monthly energy needs at the **whole-system level** (no distinction between SWEDE and Mid-C zones)
- **Only supply-side resources** are allowed to contribute to the growth in T1SFCO
- **Current results are preliminary**: **CGS uprate** is not yet in the model. We expect to repeat this analysis when those inputs become available.

T1SFCO vs Target Augmentation

- Annualized view of output (top) masks variation at monthly level (bottom)
- Fluctuations in resource capability due to CGS refueling, system operations, and streamflow sets over 20-yr study horizon



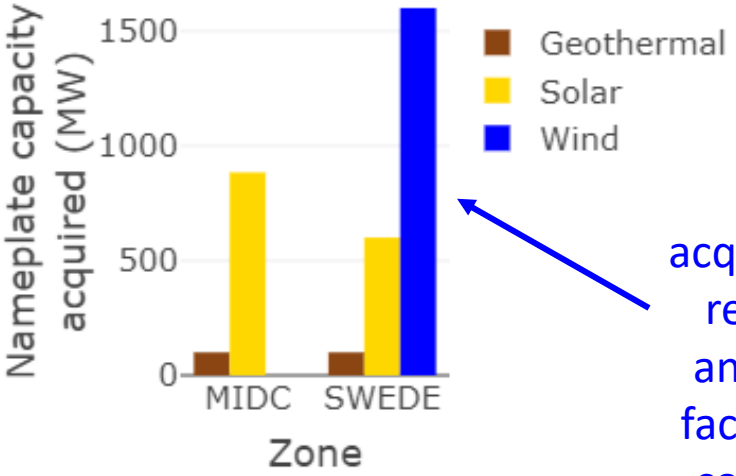
Tier 1 augmentation – Key takeaways

- Meeting T1 load exclusively with supply-side resources requires very substantial acquisitions:
  - P10 needs in the tightest month drive acquisitions
  - Generation greatly exceeds needs most of the time
- Augmentation is achieved with wind, solar, and geothermal power
- In the least-cost portfolio, most energy is generated in the SWEDE region

T1 augmentation: Resource acquisitions

We did not allow EE, DR, or market purchases to contribute to the T1 augmentation

Supply-side:



Large wind acquisitions in SWEDE reflect lower costs and higher capacity factors in that region compared to Mid-C

All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity.

Natural Gas Assessment

- Consistent with the previous resource program, we are not including natural gas (NG) resources as options directly in the solver.
- The diversity of carbon policies across the BPA service territory complicate the modeling of natural gas in the optimization process. This would significantly expand the scope of the resource program modeling as multiple approaches would be needed for each scenario and sensitivity.
- Modeling natural gas also includes other technical challenges that led to the decision to not include it in the model.
  - Incorporation of NG price risk modeling, this model has caused significant delays and errors in other applications
  - Uncertainty around costs and availability of firm fuel
  - Uncertainty around costs and key characteristics of transitioning NG resources to clean fuels (H2 / biofuels)
- The exclusion of NG resources from the solver does not preclude BPA from acquiring any resource necessary to meet needs at the lowest cost / in a cost-effective manner, as outlined in the Northwest Power Act and consistent with sound utility practice.

- We will gather feedback on NG modeling for RP26 and determine direction for future modeling.

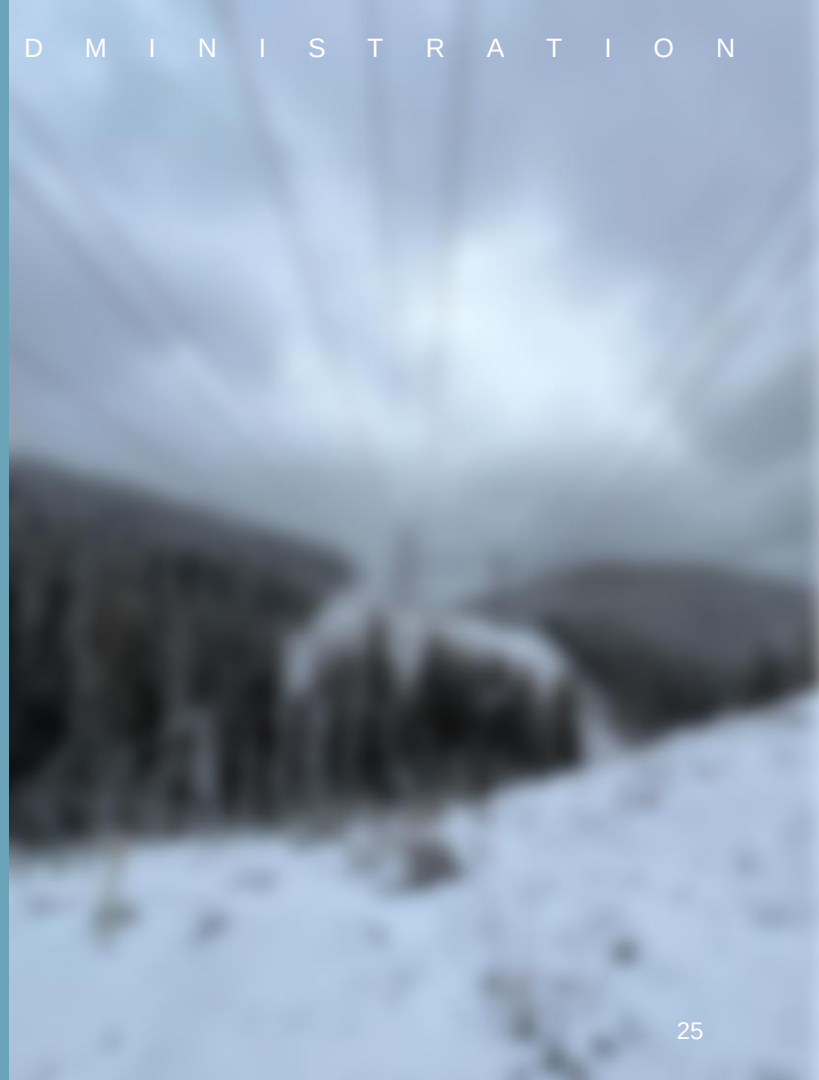
Natural Gas Assessment: Key takeaways

- Including new NG would not change results or lower portfolio costs for the base case or any associated sensitivities. This depends on the following assumptions:
  - A new NG plant built for BPA could not be online before 2035 and would only serve as a bridge resource until 2045
  - Carbon emission costs are considered
  - SMRs beginning operation in 2035 are available and eligible for Inflation Reduction Act tax credits, will not cost substantially more than baseline estimates, and will remain online for 60 years
- Using the above assumptions, the NG assessment for RP24 tests whether the solver would have selected a new NG resource.

Resource Acquisition Process

Eric Federovitch

Manager, Long Term Sales and Purchases



BPA Power Services and Resource Acquisition

- BPA is defining its processes for potential resource acquisitions, and refining existing ones related to assessing and implementing cost-effective uprates of existing FCRPS projects

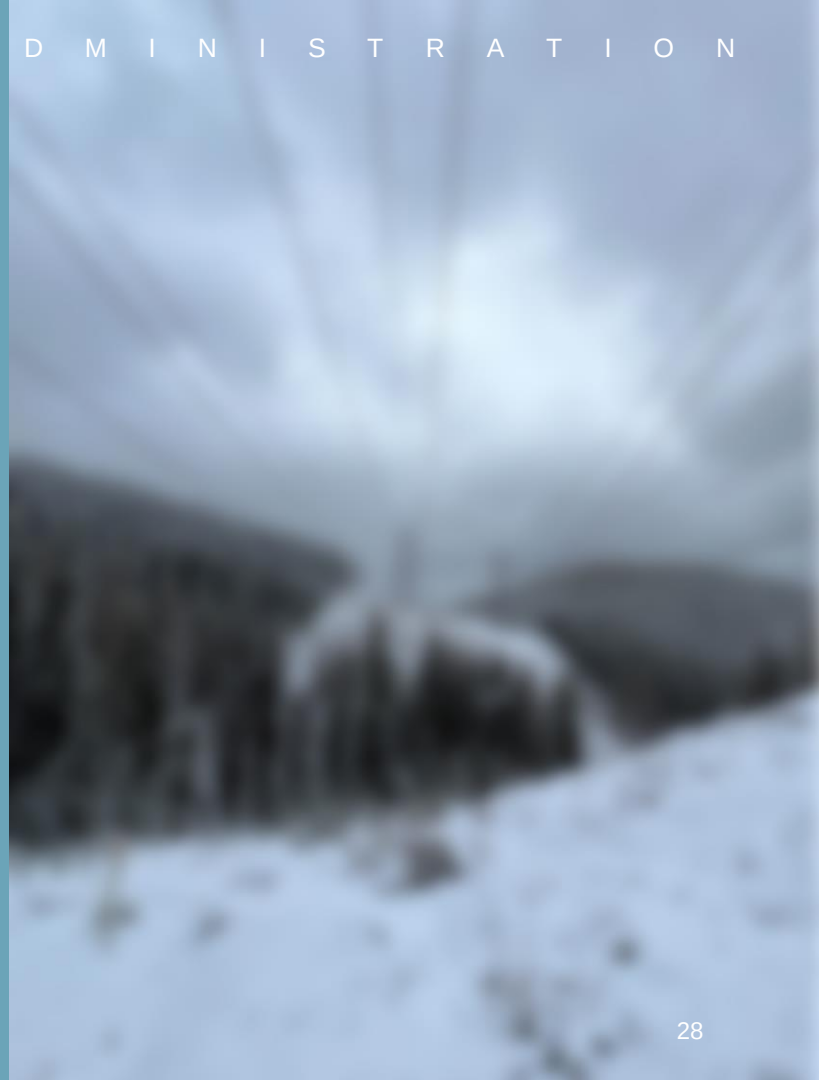
- We continue to explore the possibility of solidifying a resource acquisition commitment before new long-term power sales contracts are signed, as well as opportunities to modernize 6(c) procedures and policy in collaboration with the Northwest Power and Conservation Council

- RP26 will provide information on the type, timing, and quantity of potential resource solutions which may be used to inform a formal resource solicitation process

Acquiring Major Resources – Summary

- Provider of Choice process and Resource Programs inform major resource acquisition decisions, but are not the decision making processes
- BPA is aware of and considering potential approaches to acquire resources on the timeline needed to meet customer obligations post-2028
  - BPA and Council staff are reviewing the current Section 6(c) Policy and considering revisions to update the Policy consistent with the NW Power Act and efficient acquisition practices
  - BPA has benchmarked processes of other utilities to gather best practices and insights to incorporate into process for potential resource acquisitions
- Continuing to explore cost effective opportunities e.g. FCRPS uprates, cost-effective market purchases and minor supply-side acquisitions, experimental 6(d) acquisitions
- Under development project plan to include: Commercial solicitation and contracting, legal/6(c), environmental compliance, transmission considerations, financial

Questions and Discussion





Appendix

Resource Solutions

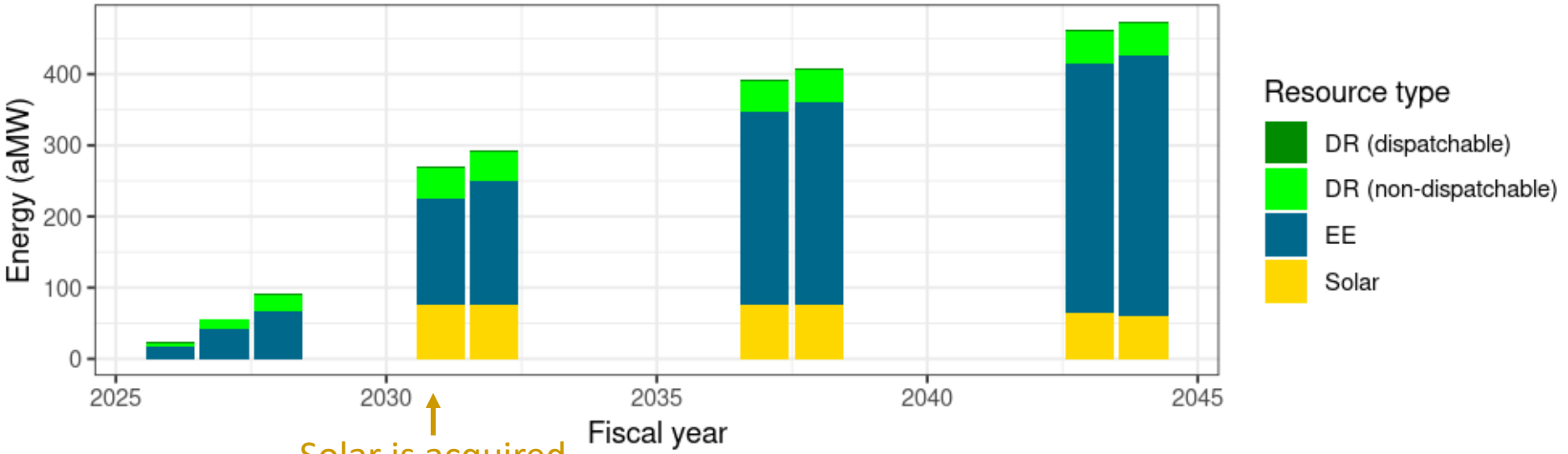
Base scenario: EE and DR

- Non-dispatchable DR programs acquired:
  - Residential Time of Use (TOU) Pricing
  - Utility Demand Voltage Reduction (DVR)
- Dispatchable DR programs acquired:
  - Commercial, industrial, and residential Critical Peak Pricing (CPP)
- EE achieved by 2045:
  - Total: **564 aMW**
  - Serving BPA load: **395 aMW***
- More in-depth EE + DR analysis to come

*About 70% of the total EE achieved by BPA reduces the BPA load obligation. The remainder reduces customer obligations. The percentages vary by EE measure and by customer, but for modeling purposes, we assume 70% for all EE programs.

Base scenario: Mid-C annual aMW

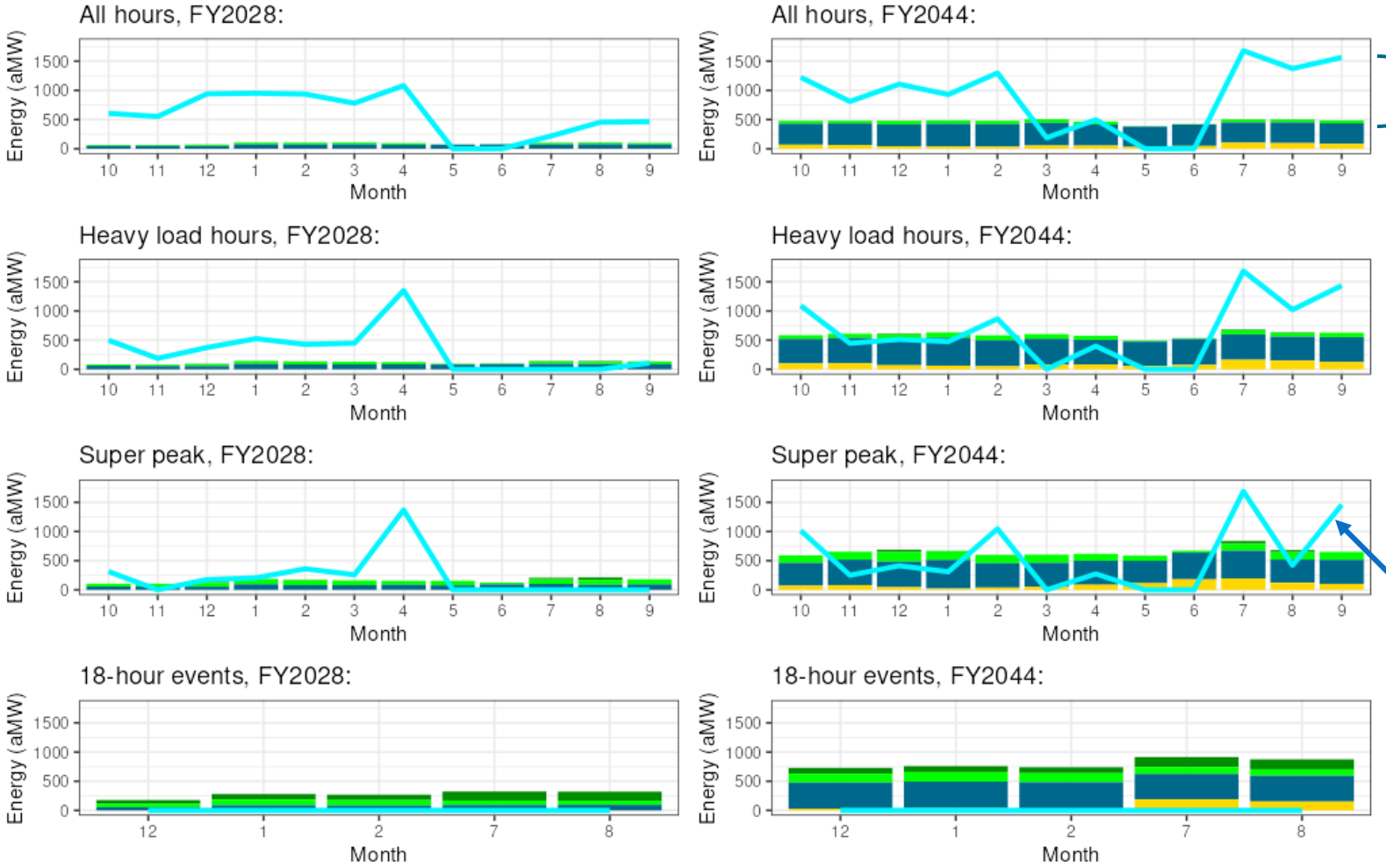
EE and DR programs are started in 2026 and ramp up over time



Solar is acquired in 2031

EE aMW shown is the portion serving BPA load. Total EE acquired in Mid-C is 30% higher.

Base scenario, Mid-C needs and resource contributions:



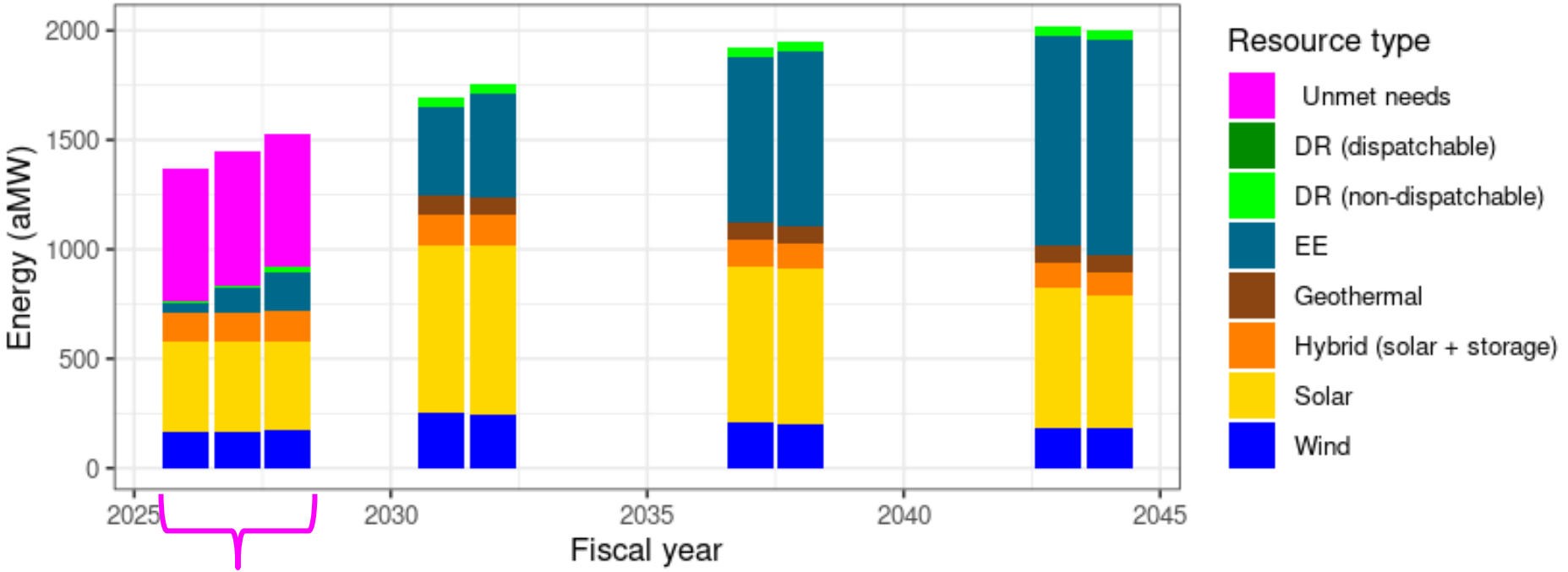
Market purchases fill in remaining needs

Needs are for P10 water conditions (except 18 hr capacity)

Market limits sensitivities: Key takeaways

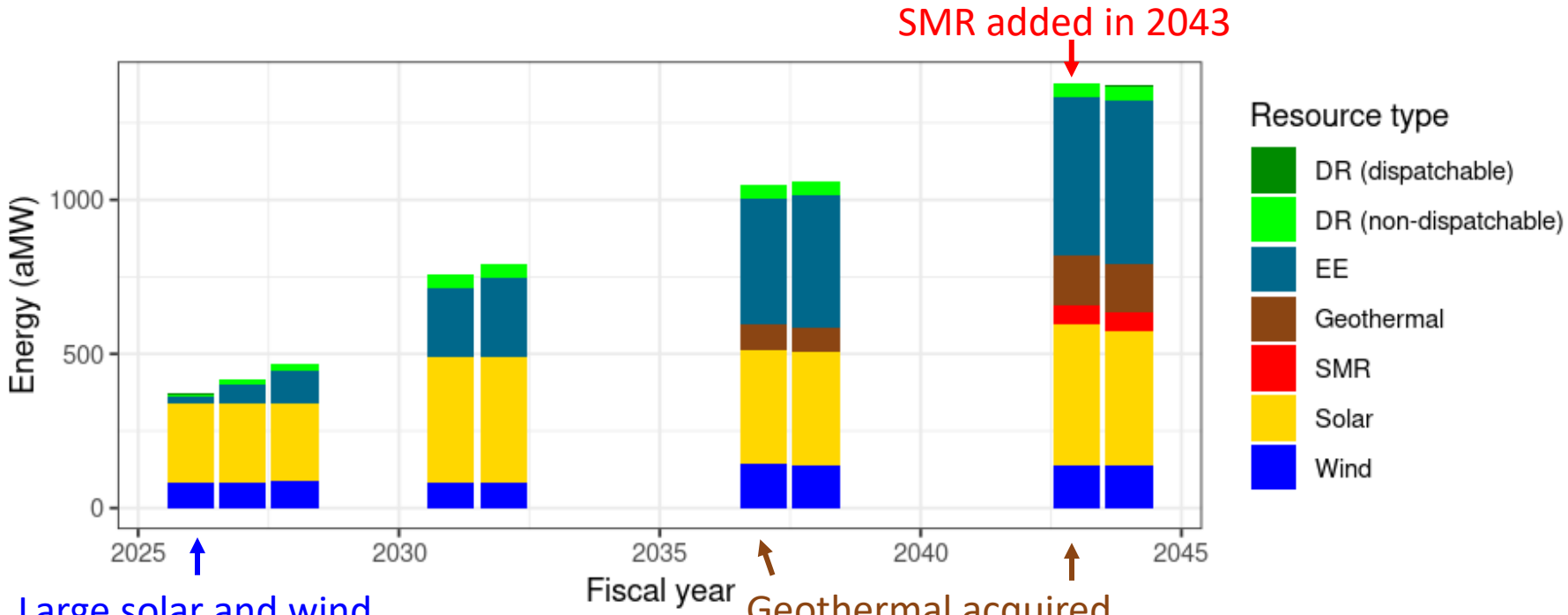
- Needs in 2026-2028 have a strong influence on results
  - Meeting needs in winter and April in this period requires large market purchases (or resources not currently in the model)
- Resource acquisitions are driven primarily by flat energy needs
- Market purchases are replaced primarily with solar and wind

‘No market’ sensitivity: Mid-C annual aMW

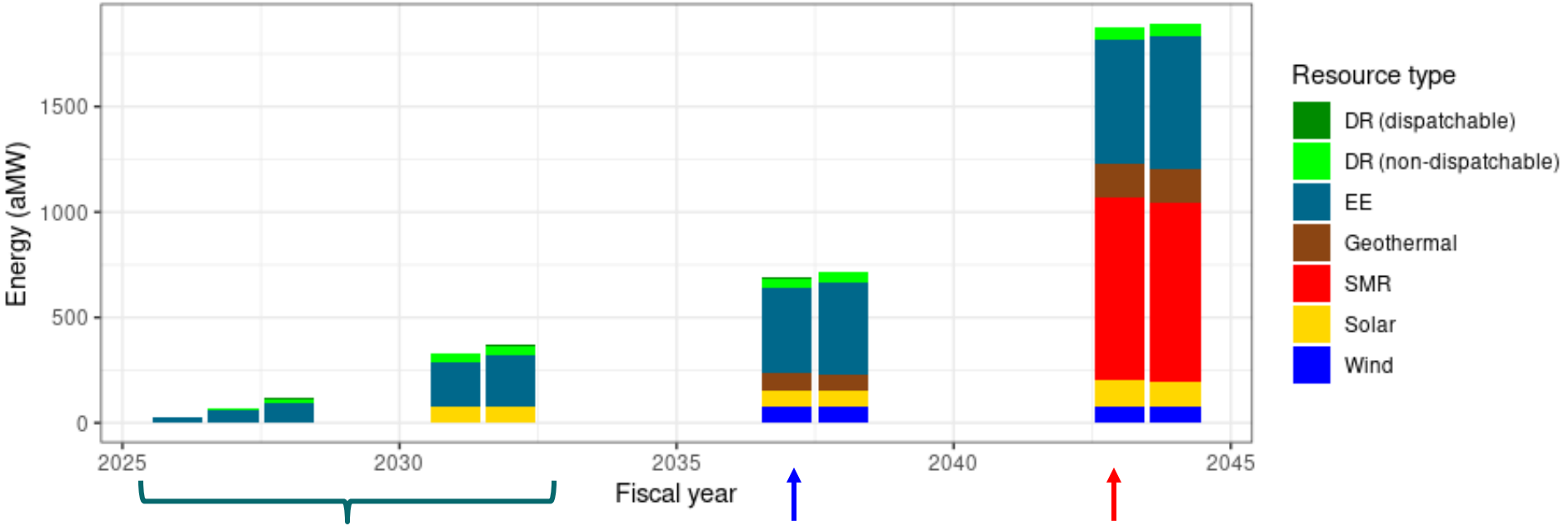


Months without enough resources to meet needs: Nov – Feb and April

‘Reducing market purchases to 0’ sensitivity: Mid-C annual aMW



Medium load adder: Mid-C annual aMW



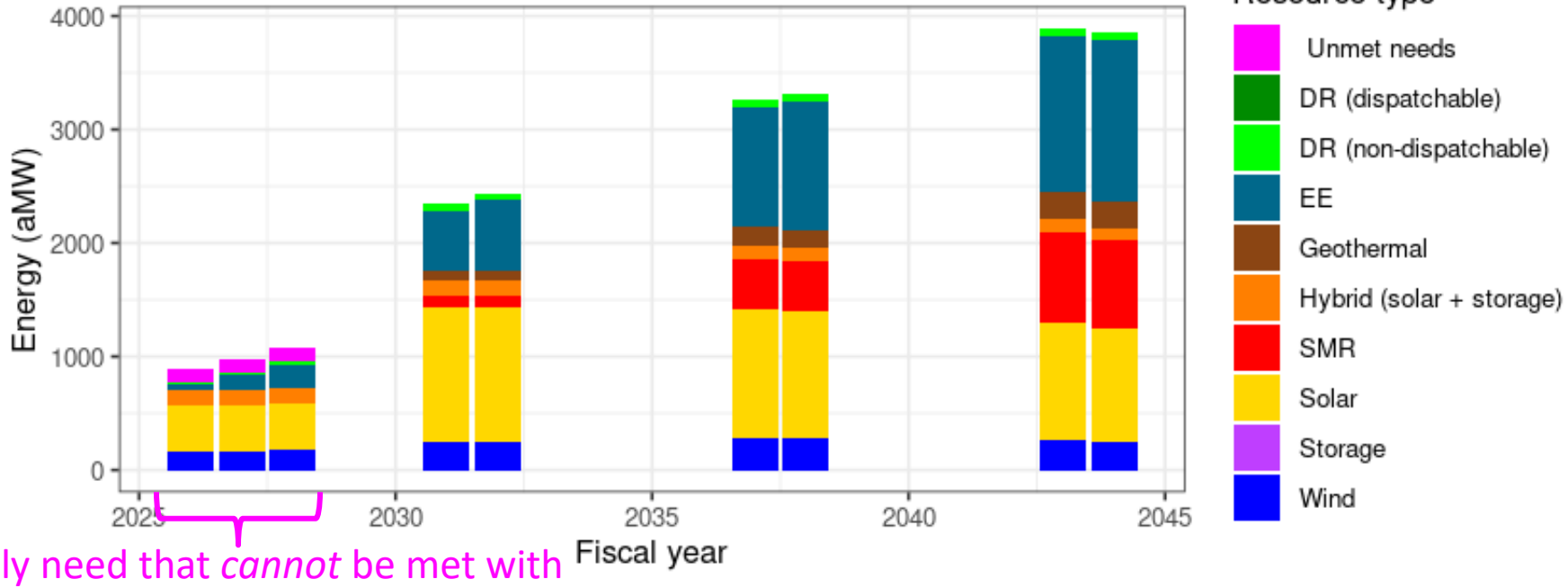
2026-2032 acquisitions same as Base Scenario

Wind and geothermal added in 2037

Most acquisitions happen in 2043

High load adder: Mid-C annual aMW

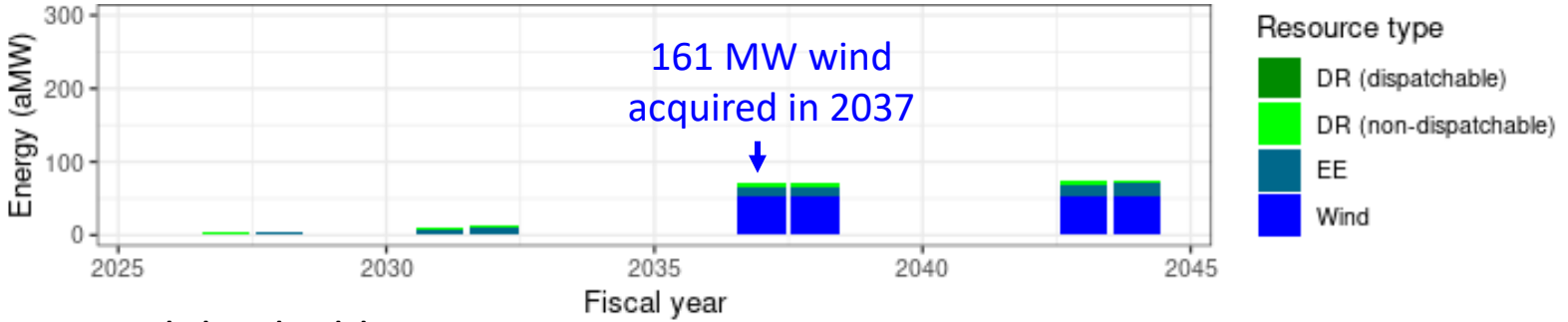
New, large acquisitions made in every available year
(i.e., 2026, 2031, 2037, and 2043)



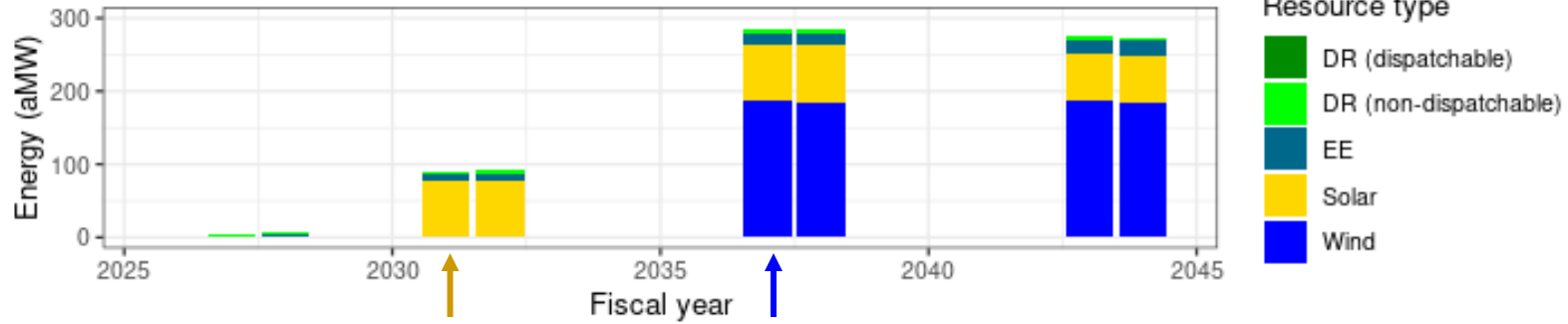
Only need that *cannot* be met with resources in the model: Apr '28 HLH

Load adders: SWEDE annual aMW

Medium load adder:



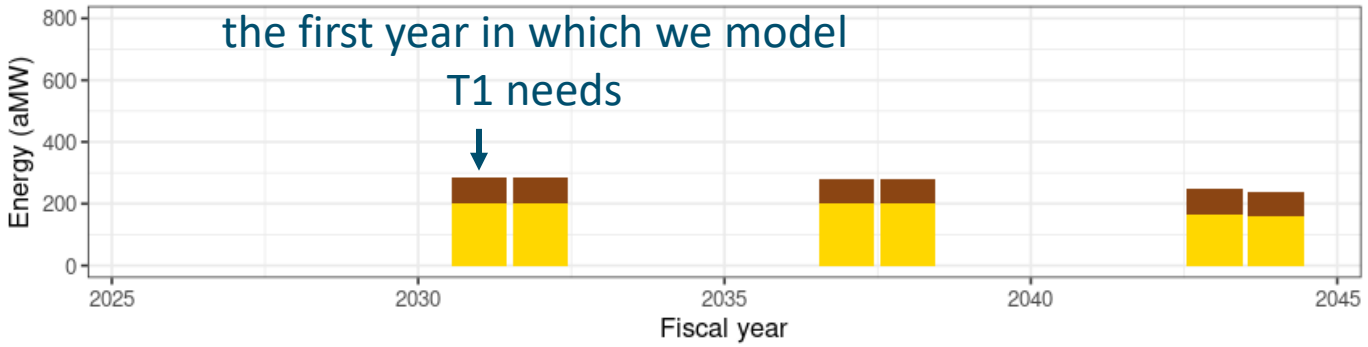
High load adder:



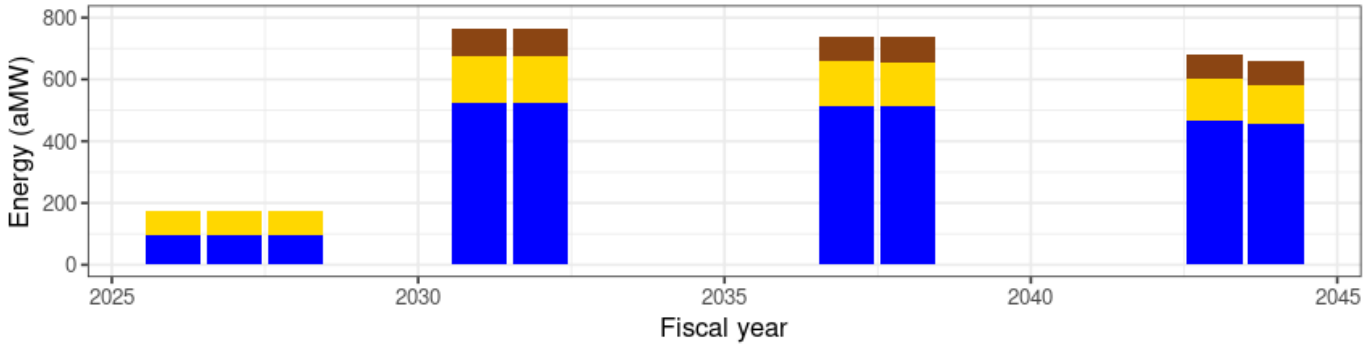
Tier 1 augmentation: annual aMW

MIDC:

Resources all acquired by 2031, the first year in which we model T1 needs



SWEDE:

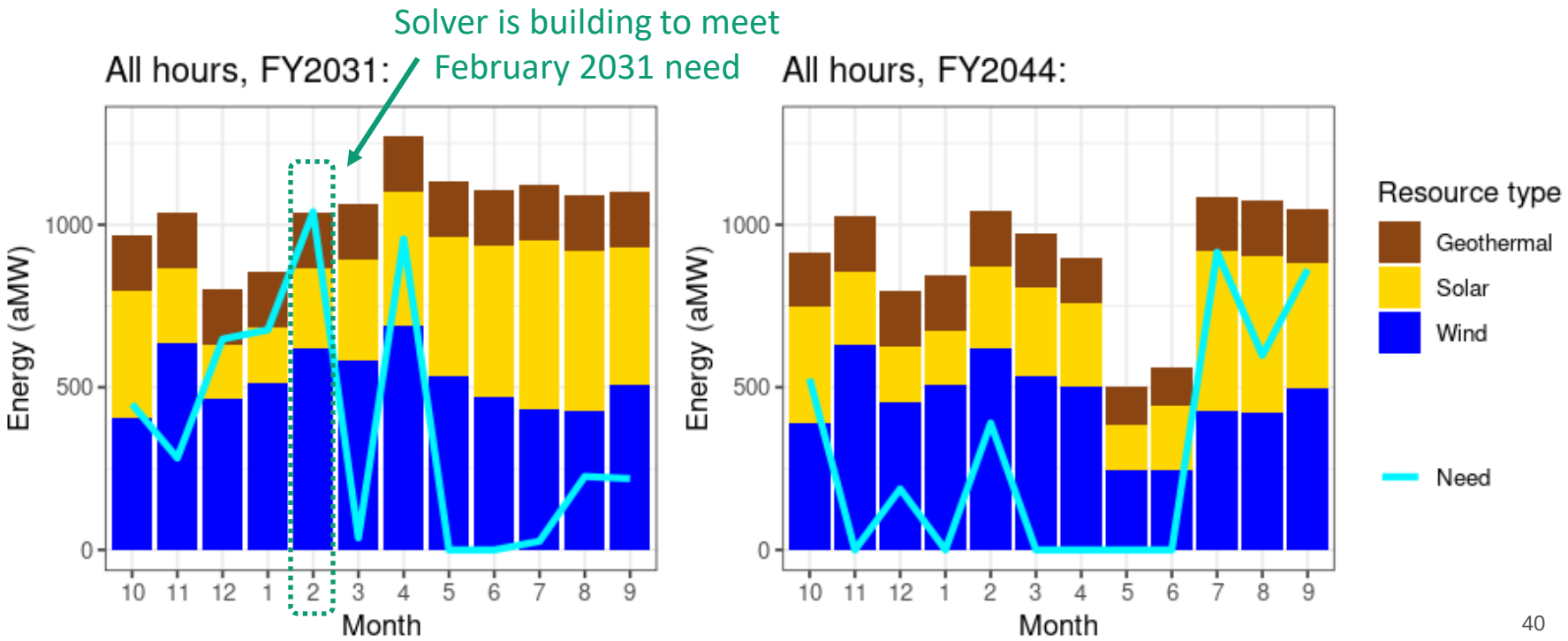


Resource type
Geothermal
Solar
Wind

Most of the energy is generated in SWEDE

Tier 1 augmentation: monthly aMW

In most months, generation is much greater than needs, even under P10 conditions



Natural Gas Assessment

	Base scenario	Market limits				High Mkt Price	Loads	
		Reduce 25%	Reduce 50%	Reduce 50% All	Path to 0		Med Load	High Load
2029-2034								
*2035-2040								
2041-2045								

	Not Selected
	Likely Selected if Available
	Likely Selected

*2035 is the earliest date we've assumed BPA could have a new resource online considering EIS, interconnection, and other necessary processes.

If BPA could get a NG resource online sooner, temporarily acquire output from an existing plant, or invest in NG resources that transition to zero emissions (through clean fuels or carbon sequestration), NG resources may help reduce costs of meeting needs under more sensitivities.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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 2-95:
Centralia Summary by TransAlta



Facts & Figures

Location:	**Centralia, WA**
Legacy Fuel:	**Coal**
Capacity (MW):	**670**
Ownership:	**100%**
Operator:	**Yes**
First on-stream:	**1971**
Revenue Source:	**LTC/Merchant**
Builder:	**No**

Facts & Figures	
Contract Expiry:	**Unit 1 - 2020; Unit 2 - 2025**

Back

Centralia

On December 31, 2020, TransAlta retired Unit 1 of our Centralia facility, decreasing the facility's capacity to 670 MW. Throughout its lifetime, Unit 1 provided a total net generation of just over 176,660,518 MWh with an average availability of 85.66 per cent. Unit 2 of the facility is set to retire at the end of 2025, as part of TransAlta's transition to a 100 per cent clean electricity future.

In **December 2025**, TransAlta Corporation's subsidiary, TransAlta Centralia Generation LLC, received an order (the Order) from the United States Department of Energy. The Order mandates that Centralia Unit 2 in Washington State, remain available for operation for a period of 90 days, until March 16, 2026. TransAlta is currently evaluating the Order and will work with the state and federal governments in relation thereto. The coal-to-gas conversion project, announced on December 9, 2025, remains a priority for TransAlta. Further information regarding the Order will be provided as it becomes available in due course.

The reliable and steady supply of power from the Centralia Coal Plant is essential for keeping the west-coast electrical grid stable. The facility is a merchant plant, which means that costs such as environmental upgrades cannot be passed on to customers. TransAlta has invested more than US$300 million in pollution control technology at Centralia Plant, including scrubbers and low nitrogen dioxide burners. Today, the facility is one of the cleanest coal-fired power plants in North America.

Fuel for Centralia Plant is delivered by train from the Powder River Basin in the U.S. Midwest. The plant's coal unloading facility is considered one of the most efficient and environmentally friendly in North America.

In preparation for the retirement of Unit 1 in 2020, and the upcoming retirement of Unit 2 in 2025, TransAlta has invested $55 million USD to support energy efficiency, economic and community development and education and retraining initiatives in Washington

State, $20 million USD of which is dedicated to the *Economic and Community Development Board,* which will fund education, retraining, economic development and community enhancement for those impacted by the units retirement.

Coal Combustion Residuals (CCR) rule compliance data and information

TransAlta is committed to providing information to the community about our facilities. The information below is intended to satisfy the requirement under the *CCR Rule 40 CFR 257.107* to maintain a publicly accessible internet site (CCR site) containing the required information. The required information will be posted when it is accomplished and is available.

Location restrictions

Unstable areas

Operating criteria

CCR fugitive dust control plan

Run-on and run-off control plan

Annual fugitive dust control report

Annual CCR Fugitive Dust Control Report – 2016

Annual CCR Fugitive Dust Control Report – 2017

Annual CCR Fugitive Dust Control Report – 2018

Annual CCR Fugitive Dust Control Report – 2019

Annual CCR Fugitive Dust Control Report – 2020

Annual CCR Fugitive Dust Control Report – 2021

Annual CCR Fugitive Dust Control Report – 2022

Annual CCR Fugitive Dust Control Report – 2023

Annual CCR Fugitive Dust Control Report – 2024

Annual CCR Fugitive Dust Control Report – 2025

Annual engineering inspection reports

CCR Annual Inspection January 11, 2016

CCR Annual Inspection January 5, 2017

CCR Annual Inspection January 4, 2018

CCR Annual Inspection January 3, 2019

CCR Annual Inspection January 7, 2020

CCR Annual Inspection January 6, 2021

CCR Annual Inspection January 5, 2022

CCR Annual Inspection January 5, 2023

CCR Annual Inspection January 5, 2024

CCR Annual Inspection January 15, 2025

Groundwater monitoring and corrective action

Annual groundwater monitoring and corrective action Report – 2024

Annual groundwater monitoring and corrective action Report – 2023

Annual groundwater monitoring and corrective action Report – 2022

Annual groundwater monitoring and corrective action Report – 2021

Annual groundwater monitoring and corrective action Report – 2020

Annual groundwater monitoring and corrective action Report – 2019

Alternative Source Demonstration Nov-2-2018

Annual groundwater monitoring and corrective action Report – 2018

Annual groundwater monitoring and corrective action Report – 2017

Addendum to 2017 Annual CCR Groundwater Monitoring Report

Groundwater monitoring system certification

Statistical method certification

Notification of assessment monitoring program

Notification of return to detection monitoring program

Notification of Appendix IV exceedances

Notification of corrective measures assessment

Corrective measures assessment

Semi-annual corrective action report

Notification of completion of corrective action

Closure and post-closure care

Closure plan

Time extensions for initiating closure

Time extensions for completing closure

Notification of intent to initiate closure

Notification of completion of closure

Notification of intent to comply with alternative closure requirements

Annual progress reports for alternative closure

Notification recording a notation on property deed

Post-closure care plan

Notification of completion of post-closure care

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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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 2-96:
MIT Article



Have a question?

Ask us!

ASK MIT CLIMATE

Why does burning coal generate more CO2 than oil or gas?

Listen with Speechify

0:00 2:43

Coal contains more carbon than oil or gas. When we burn these fuels, the higher amount of carbon in coal reacts to form CO_2,



by MIT Climate Portal Writing Team



featuring guest expert Gregory Stephanopoulos, MIT Professor of Chemical Engineering

while a higher proportion of hydrogen in oil and gas causes them to form H_2O along with CO



and guest expert Shuhei Ono, MIT Professor of Geochemistry

carbon-based molecules—so fossil fuels, which are made of once-living things, are as well. But coal "has a lot more carbon in it" than oil or gas, says Gregory Stephanopoulos, an MIT professor of chemical engineering. The "carbon-intensity" of each fuel determines how much CO_2, or carbon dioxide, each produces.

Coal, oil, and gas were created over millennia as buried organic material decayed.

Today's coal began as plants growing in and near swamps millions of years ago, which died and became covered with water. Cut off from oxygen, the plants slowly decomposed, and bacteria and chemicals in the water reacted to create a substance called peat.

As geology changed, water and sediment covered the peat, burying it under layers of earth and minerals, and applying pressure.

"When organic matter is buried in sediments, it gets cooked at higher temperatures," says Shuhei Ono, an MIT professor of geochemistry. This heat aided chemical reactions and broke down molecules, pushing out hydrogen and oxygen and leaving

MIT Department of Chemical Engineering

MIT Department of Earth Atmospheric and Planetary Sciences

More Resources for Learning

U.S. Energy Information Administration: "How much carbon dioxide is produced when different fuels are burned?"

U.S. Energy Information Administration: "Coal explained"

Smithsonian Ocean Portal: "What are fossil fuels?"

University of Calgary: "Coal formation"

behind higher percentages of carbon. Thus, peat became coal.[1]

Generally, the more pressure and heat coal experiences as it forms, the more carbon it contains—from younger "lignite" coal (about 25 percent carbon) to "anthracite" coal (up to 97 percent carbon).

Oil and gas formed not in swamps, but in the ocean, when small plants and animals called plankton died and sank to the ocean floor, mixing with other organic material. Like the peat in swamps, this material was buried and exposed to pressure and heat under the ocean floor, producing a material called kerogen. With increased temperature and pressure, the kerogen slowly lost its hydrogen atoms, shedding them first as long chains of carbon and hydrogen (oil), and finally as CH_4 (methane, or gas). Pure carbon is left underground, while the hydrogen-rich oil and gas can be extracted and burned as fuels.

In the end, says Ono, "methane contains only C-H bonds, and coals are [mostly] C-C. Oil is between the two."

When humans burn any of these fossil fuels, the chemical reaction releases energy in the form of heat. "This is the energy we use for power generation or moving cars, and doing all the things that we do with fossil fuels," says Stephanopoulos. As the fuels burn, oxygen in the air reacts either with carbon, forming CO_2, or with hydrogen, forming H_2O, or water vapor. When coal burns, its higher proportion of carbon molecules creates more CO_2 per unit of energy. For oil and gas, it's "mainly the

University of Calgary: "Oil formation"

Topics

ATMOSPHERE FOSSIL FUELS

hydrogens that will burn and generate energy, not the carbons," Stephanopoulos says.

Though burning coal is more carbon-intensive, both oil and gas still produce climate-warming CO_2. And natural gas is largely made up of CH_4, a short-lived climate pollutant that warms the planet even more than CO_2.

Thank you to Juan Manuel Alfonso of Argentina for the question. You can submit your own question to Ask MIT Climate here.

Read more Ask MIT Climate

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FOOTNOTES

[1] Coal formation also creates some natural gas, which is trapped in fractures in coal buried underground.

Keep exploring

Check out these related Explainers, written by scientists and experts from MIT and beyond.



EXPLAINER



EXPLAINER



EXPLAINER

Greenhouse Gases

Greenhouse gases are gases—like carbon dioxide, methane, and nitrous oxide—that keep the Earth warmer than it would be without them.

Hydrogen

Hydrogen is the most abundant chemical substance in the universe. It can be used as a fuel that does not produce greenhouse gases when burned.

Heating and Cooling

Heating and cooling is the biggest driver of energy use in homes and commercial buildings. Technology and building design can help keep us comfortable while reducing the impact of that energy use on the climate.

VIEW ALL

Related Pieces

What makes the climate of Venus so hot?

The planet's searing temperatures are sustained by a thick atmosphere full of carbon dioxide.

KEEP READING

When we remove carbon dioxide from the atmosphere, how long does it stay locked away?

In theory, we can remove CO2 from the air for thousands or even millions of years, which in terms of addressing climate change is effectively

KEEP READING

rbon removal can also fail.

When scientists reconstruct ancient climates from ice cores,

Are trucks and buses that burn natural gas better for the climate than diesel ones?

How do they create an accurate timeline?

How do these chemical analysis, computer models, and other tools to date these valuable climate archives.

KEEP READING

Fossil natural gas brings minor climate benefits, if any. In theory, methane from organic waste can do much ...y to mess up.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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Exhibit 2-97:
WECC Explainer

WECC

Electric Reliability and Security for the West

ODITY Threshold Interpretations

October 25, 2022

What is the ODITY Threshold?

In planning, "one day in ten years" (ODITY) represents the maximum acceptable amount of time electricity generation can be at risk of being short of demand and still be considered adequately reliable.

How is the ODITY Threshold measured?

Many utilities incorporate the ODITY threshold into their long term, integrated resource planning methods by bringing it down to an annual level of temporal granularity. One day in 10 years, or 24 hours in 10 years, is often averaged to a maximum of 2.4 hours of risk allowed per year for a portfolio of resources to be considered sufficiently reliable.

WECC takes the ODITY maximum down to the hourly level to set thresholds in its probabilistic assessments of resource adequacy. This interpretation yields a threshold for each hour needing to demonstrate sufficient resource availability to meet demand 99.8% of the time.

Why does WECC use the ODITY threshold on each hour?

WECC chooses to look at the ODITY threshold for each hour rather than averaged over each year:

- To accurately account for risk;
- To study variability hour to hour; and
- To improve assumptions of import availability.

ODITY in Probabilistic Assessments: Accounting for Risk

WECC uses hourly shaped, bell curve probability distributions of demand next to those of energy availability by resource type to measure reliability.

For each hour, the distributions are compared to determine the amount of "overlap" in the upper tail of the demand distribution with the lower tail of the generation availability distribution. The amount of overlap and the probabilities associated with each percentile of the distributions can then calculate as a loss of load probability (LOLP). This is the cumulative probability associated with the overlap.

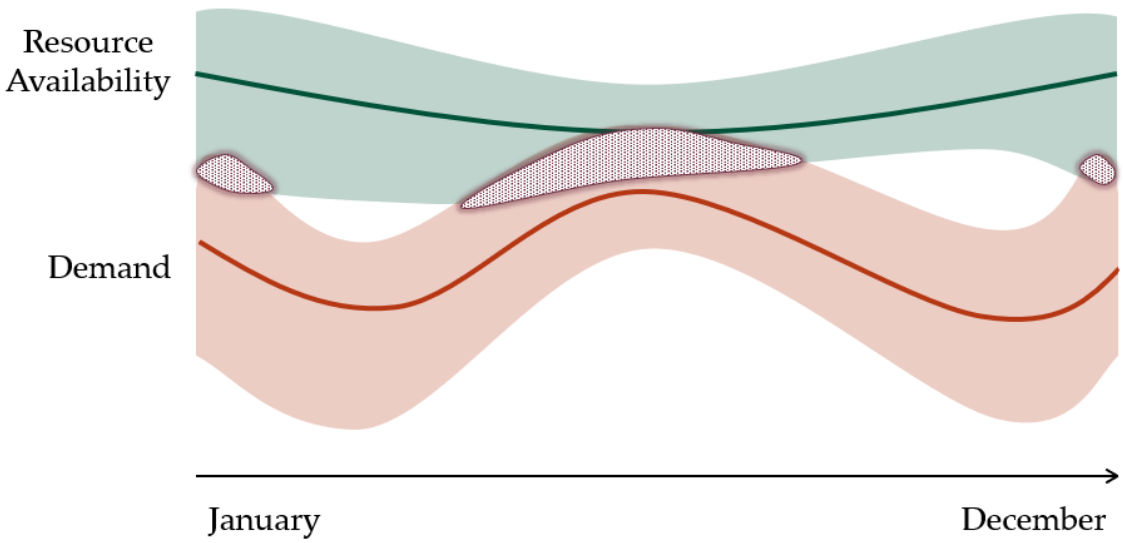


Figure 1: Annual Distribution Ranges of Demand and Resource Availability

If the probability of the resource availability falling below demand is greater than a certain threshold—in this case more than 0.02% for one of the hours—WECC notes there is a reliability shortfall in that area for that hour. A reliability threshold reserve margin (in megawatts) can be calculated to determine the shortfall in need of amelioration to maintain a level of LOLP at or less than the threshold.

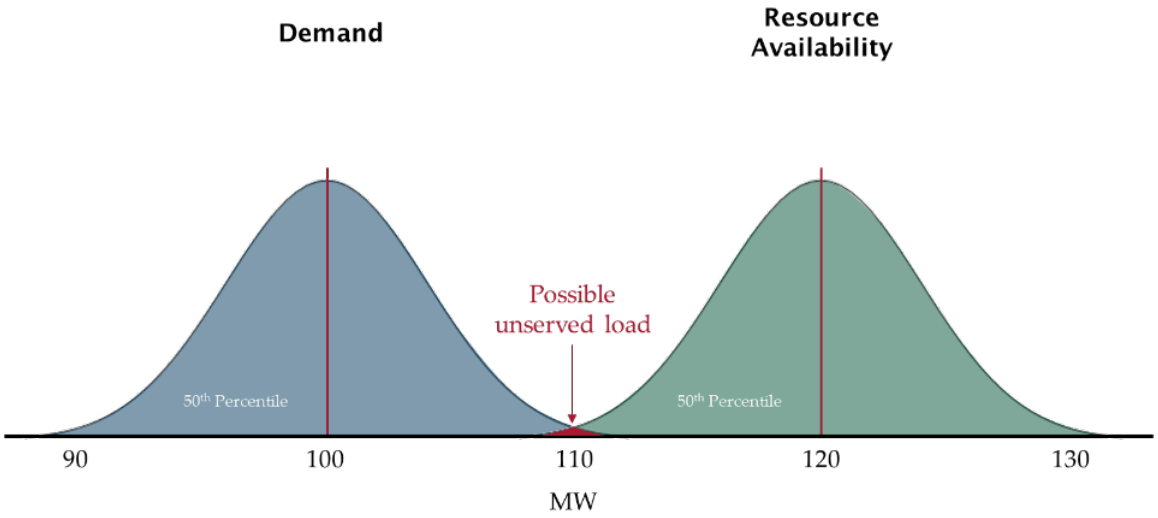


Figure 2: A Single Hour's View of the Probability Distributions of Demand and Resource Availability

Hourly Variability

Over 80% of new electricity capacity are renewables.[1] Concurrently, climate change is contributing to record peak demand by skewing the probability of previously rare weather, like widespread and long-lasting heat dome events.

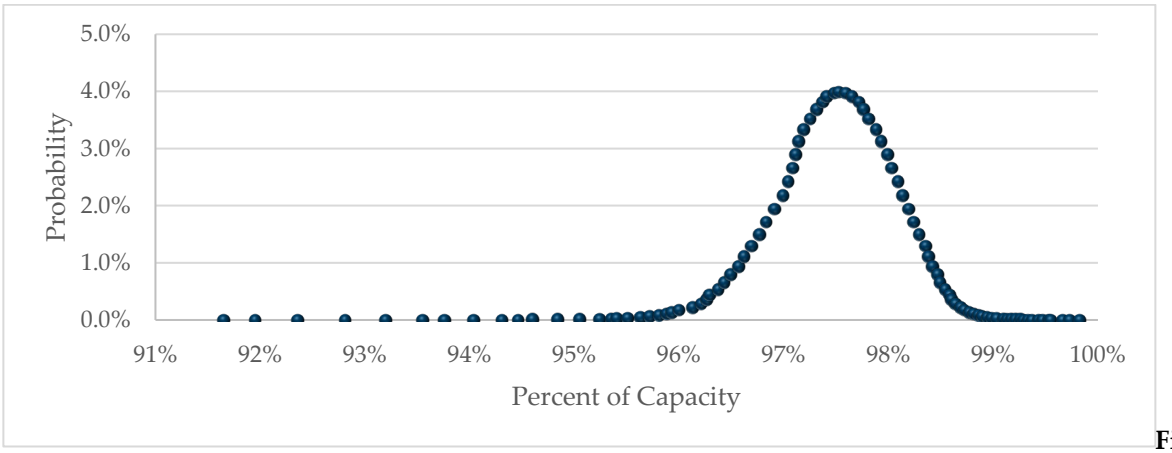


Figure 3: Baseload Availability Probability Distribution Example

Historically, electricity demand peaked on weekdays in the early evenings when many people get home from work. This timing typically coincides with a setting sun. So, just as electricity system operators are looking for resource availability to ramp up generation to meet the spiking demand, at least the solar resources' availabilities are dropping.

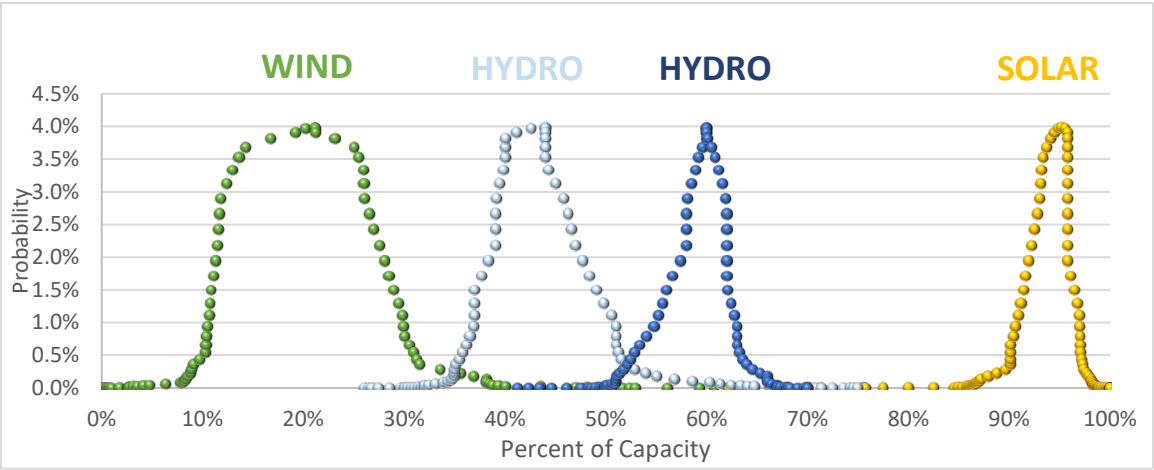


Figure 4: Renewables' Availability Probability Distributions Example

To combat the ramping risk, many planners are turning to long-term energy storage, either via hydro reservoirs, utility-scale batteries, or the incorporation of other new technologies like hydrogen, as well

1 Some good news on energy—The New York Times (nytimes.com) October 25, 2022

as the traditional use of natural gas peaker plants. The combinations of new and conventional resource types make new shapes of availability.

WECC is interested in looking at every hour so this aspect of a changing system is regularly analyzed to ensure reliability and spot potential issues years in advance.

Imports' Availability Assumptions

The West's system is large, and its diversity increases reliability because Balancing Authority Areas (BAA) can often rely on each other for imports. In planning, sometimes a limit is set for how many megawatts of imports will be available.

Since WECC collects loads and resources information from all of the BAAs throughout the West, and conducts probabilistic assessments of availability and demand, WECC can see when and where imports may not be sufficient to cover shortfalls of internal availability to meet demand.

Doing this analysis at the hourly level provides greater insights by identifying specific situational risk.

Conclusion

There are many ways to perform probabilistic studies, each with its strengths and weaknesses. The tool used to perform the probabilistic calculations depends on the system and the desired output that is being analyzed. In the Western Interconnection, a system that is geographically diverse and depends on transfer capabilities, WECC developed the Multiple Area Variable Resource Integration Convolution (MAVRIC) model to enhance its probabilistic capabilities. Using convolution techniques, Monte-Carlo simulations, and the ability to use transfers dynamically, MAVRIC can better model the overall reliability of the Western Interconnection while maintaining adequate run-time and computing capabilities.

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Exhibit 2-98:
NERC Emergency Operations

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-4**

3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

   4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

5. **Effective Date:** See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual Load shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) during an Emergency that accounts for each of the following:

1.2.5.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. Cold weather conditions; and

1.2.6.2. Extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has

been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. Capability and availability;

2.2.3.2. Fuel supply and inventory concerns;

2.2.3.3. Fuel switching capabilities; and

2.2.3.4. Environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load, and demand response;

2.2.8. Provisions for excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. Extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator;

evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator

communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

8.1. Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:

8.1.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

8.1.2. Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

8.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

8.1.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual

Load shed to situations where warranted by system conditions; and

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4.
- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
- The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
- The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner shall retain the current Load shedding plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R8.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.
R4	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Alert.
R7	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR more of those entities 60 days or more late.
R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by the NERC Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by the NERC Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
3	October 26, 2022	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094	
4	October 23, 2023	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
4	February 15, 2024	FERC Order issued approving EOP-011-4. Docket No. RD24-1-000	

Attachment 1-EOP-011-4
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**

   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**

   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

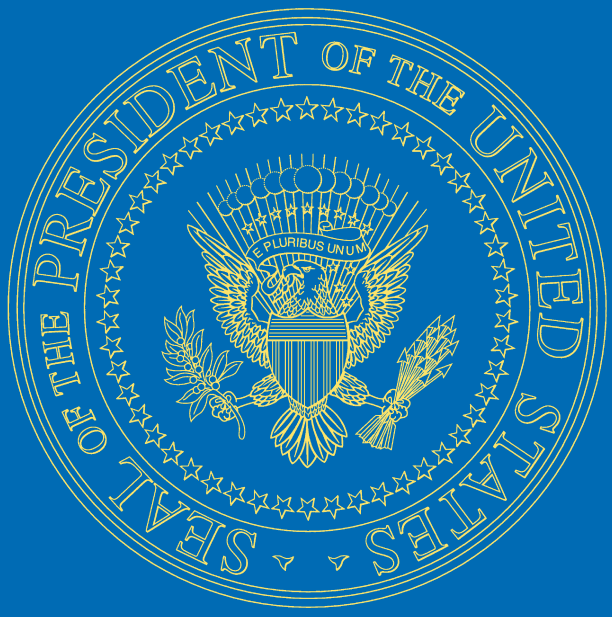
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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 2-99:
2001 National Energy Policy

National Energy Policy



Report of the
National Energy Policy Development Group

May 2001

Reliable, Affordable, and Environmentally Sound Energy for America's Future

Report of the

National Energy Policy Development Group

"America must have an energy policy that plans for the future, but meets the needs of today. I believe we can develop our natural resources and protect our environment."

— President George W. Bush

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THE VICE PRESIDENT

WASHINGTON

May 16, 2001

The Honorable George W. Bush
President of the United States
The White House
Washington, D.C. 20500

Dear Mr. President:

On behalf of the National Energy Policy Development Group, I submit for your consideration our National Energy Policy report. As you directed us at the outset of your Administration, we have developed a national energy policy designed to help bring together business, government, local communities and citizens to promote dependable, affordable and environmentally sound energy for the future.

The report reflects the requirements and philosophy you set out for our work. It envisions a comprehensive long-term strategy that uses leading edge technology to produce an integrated energy, environmental and economic policy. To achieve a 21st century quality of life -- enhanced by reliable energy and a clean environment -- we must modernize conservation, modernize our infrastructure, increase our energy supplies, including renewables, accelerate the protection and improvement of our environment, and increase our energy security.

We submit these recommendations with optimism. The tasks ahead are great but achievable. To meet our energy challenge, we must put to good use the resources around us and the talents within us. It summons the best of America and offers a healthier environment, a stronger economy and a brighter future for the American people.

Sincerely,

Dick Cheney

Enclosure

PRINTED ON RECYCLED PAPER

Members of the
National Energy Policy Development Group

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Appendix One
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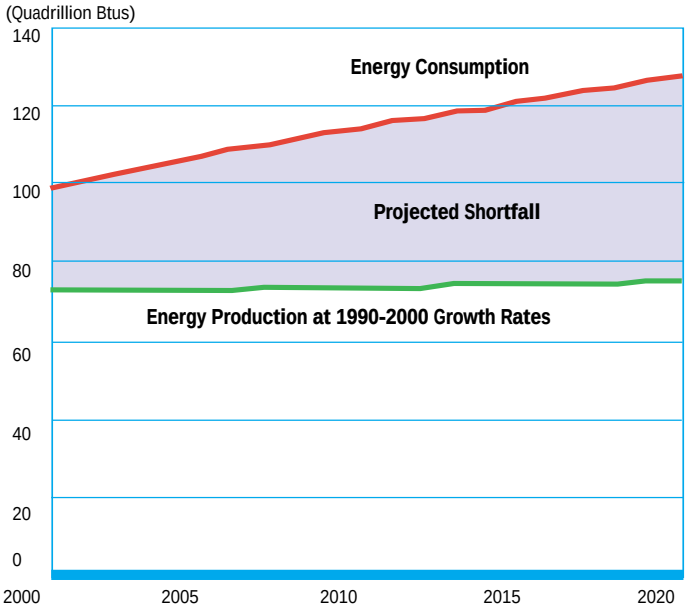
Overview

Reliable, Affordable, and Environmentally Sound Energy for America's Future

In his second week in office, President George W. Bush established the National Energy Policy Development Group, directing it to "develop a national energy policy designed to help the private sector, and, as necessary and appropriate, State and local governments, promote dependable, affordable, and environmentally sound production and distribution of energy for the future." This Overview sets forth the National Energy Policy Development (NEPD) Group's findings and key recommendations for a National Energy Policy.

Figure 1

Growth in U.S. Energy Consumption Is Outpacing Production



Over the next 20 years, growth in U.S. energy consumption will increasingly outpace U.S. energy production, if production only grows at the rate of the last 10 years.

Sources: Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.

America in the year 2001 faces the most serious energy shortage since the oil embargoes of the 1970s. The effects are already being felt nationwide. Many families face energy bills two to three times higher than they were a year ago. Millions of Americans find themselves dealing with rolling blackouts or brownouts; some employers must lay off workers or curtail production to absorb the rising cost of energy. Drivers across America are paying higher and higher gasoline prices.

Californians have felt these problems most acutely. California actually began the 1990s with a surplus of electricity generating capacity. Yet despite an economic boom, a rapidly growing population, and a corresponding increase in energy needs, California did not add a single new major electric power plant during the 1990s. The result is a demand for electricity that greatly succeeds the amount available.

A fundamental imbalance between supply and demand defines our nation's energy crisis. As the chart illustrates, if energy production increases at the same rate as during the last decade our projected energy needs will far outstrip expected levels of production.

This imbalance, if allowed to continue, will inevitably undermine our economy, our standard of living, and our national security. But it is not beyond our power to correct. America leads the world in scientific achievement, technical skill, and entrepreneurial drive. Within our country are abundant natural resources, unrivaled technology, and unlimited human creativity. With forward-looking leadership and sensible policies, we can meet our fu-



America's expanding economy, growing population, and rising standard of living will be sustained by our unmatched technological know-how.

ture energy demands and promote energy conservation, and do so in environmentally responsible ways that set a standard for the world.

The Challenge

America's energy challenge begins with our expanding economy, growing population, and rising standard of living. Our prosperity and way of life are sustained by energy use. America has the technological know-how and environmentally sound 21st century technologies needed to meet the principal energy challenges we face: promoting energy conservation, repairing and modernizing our energy infrastructure, and increasing our energy supplies in ways that protect and improve the environment. Meeting each of these challenges is critical to expanding our economy, meeting the needs of a growing population, and raising the American standard of living.

We are already working to meet the first challenge: using energy more wisely. Dramatic technological advances in energy efficiency have enabled us to make great strides in conservation, from the operation of farms and factories to the construction of buildings and automobiles. New technology allows us to go about our lives and work with less cost, less effort, and less burden on the natural environment. While such advances cannot alone solve America's energy problems, they can and will continue to play an important role in our energy future.

The second challenge is to repair and expand our energy infrastructure. Our current, outdated network of electric generators, transmission lines, pipelines, and refineries that convert raw materials into usable fuel has been allowed to deteriorate. Oil pipelines and refining capacity are in need of repair and expansion. Not a single major oil refinery has been built in the United States in nearly a generation, causing the kind of bottlenecks that lead to sudden spikes in the price of gasoline. Natural gas distribution, likewise, is hindered by an aging and inadequate network of pipelines. To match supply and demand will require some 38,000 miles of new gas pipelines, along with 255,000 miles of distribution lines. Similarly, an antiquated and inadequate transmission grid prevents us from routing electricity over long distances and thereby avoiding regional blackouts, such as California's.

"America must have an energy policy that plans for the future, but meets the needs of today. I believe we can develop our natural resources and protect our environment."

— President
George W. Bush

Increasing energy supplies while protecting the environment is the third challenge. Even with successful conservation efforts, America will need more energy.

Renewable and alternative fuels offer hope for America's energy future. But they supply only a small fraction of present energy needs. The day they fulfill the bulk of our needs is still years away. Until that day comes, we must continue meeting the nation's energy requirements by the means available to us.

Estimates indicate that over the next 20 years, U.S. oil consumption will increase by 33 percent, natural gas consumption by well over 50 percent, and demand for electricity will rise by 45 percent. If America's energy production grows at the same rate as it did in the 1990s we will face an ever-increasing gap.

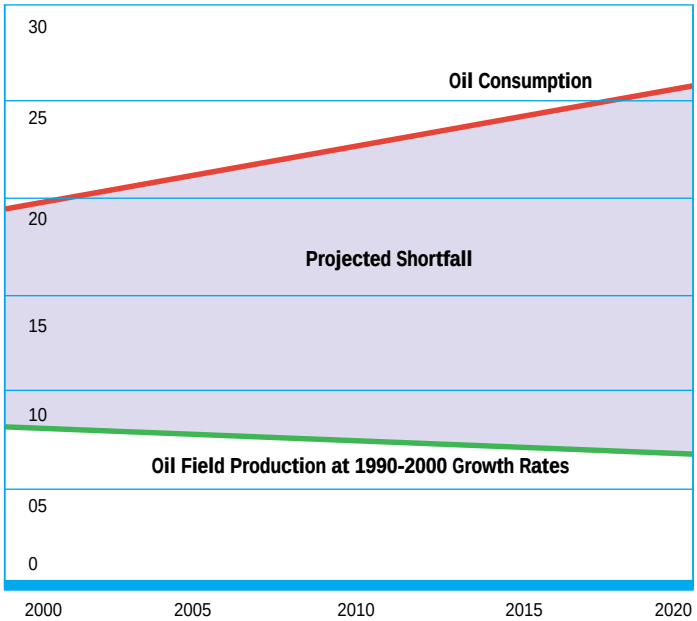
Increases on this scale will require preparation and action today. Yet America has not been bringing on line the necessary supplies and infrastructure.

Extraordinary advances in technology have transformed energy exploration and production. Yet we produce 39 percent less oil today than we did in 1970, leaving us ever more reliant on foreign suppliers. On our present course, America 20 years from now will import nearly two of every three barrels of oil – a condition of increased dependency on foreign powers that do not always have America's interests at heart. Our increasing demand for natural gas – one of the cleanest forms of energy – far exceeds the current rate of production. We should reconsider any regulatory restrictions that do not take technological advances into account.

Figure 2

U.S. Oil Consumption Will Continue to Exceed Production

(Millions of Barrels per Day)



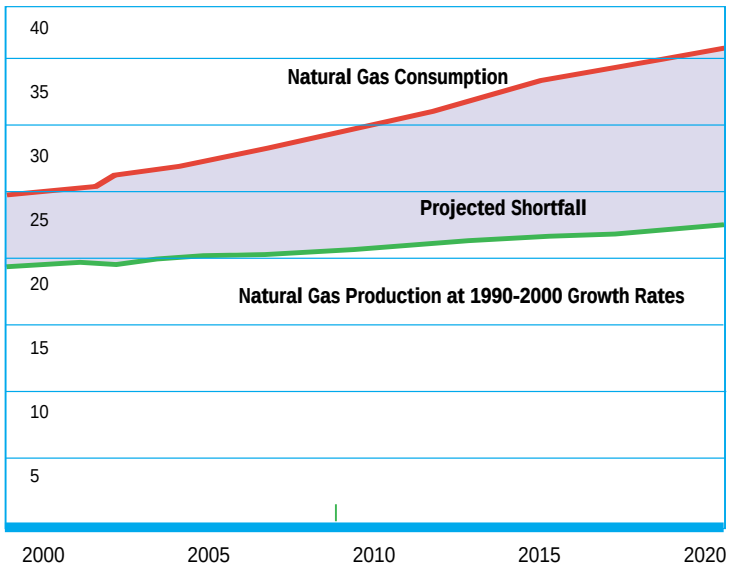
Over the next 20 years, U.S. oil consumption will grow by over 6 million barrels per day. If U.S. oil production follows the same historical pattern of the last 10 years, it will decline by 1.5 million barrels per day. To meet U.S. oil demand, oil and product imports would have to grow by a combined 7.5 million barrels per day. In 2020, U.S. oil production would supply less than 30 percent of U.S. oil needs.

Sources: Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.

Figure 3

U.S. Natural Gas Consumption Is Outpacing Production

(Trillion Cubic Feet)



Over the next 20 years, U.S. natural gas consumption will grow by over 50 percent. At the same time, U.S. natural gas production will grow by only 14 percent, if it grows at the rate of the last 10 years.

Sources: Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.

We have a similar opportunity to increase our supplies of electricity. To meet projected demand over the next two decades, America must have in place between 1,300 and 1,900 new electric plants. Much of this new generation will be fueled by natural gas. However, existing and new technologies offer us the opportunity to expand nuclear generation as well. Nuclear power today accounts for 20 percent of our country's electricity. This power source, which causes no greenhouse gas emissions, can play an expanding part in our energy future.

The recommendations of this report address the energy challenges facing America. Taken together, they offer the thorough and responsible energy plan our nation has long needed.

Components of the National Energy Policy

The National Energy Policy we propose follows three basic principles:

- The Policy is a long-term, comprehensive strategy. Our energy crisis has been years in the making, and will take years to put fully behind us.
- The Policy will advance new, environmentally friendly technologies to increase energy supplies and encourage cleaner, more efficient energy use.
- The Policy seeks to raise the living standards of the American people, recognizing that to do so our country must fully integrate its energy, environmental, and economic policies.

Applying these principles, we urge action to meet five specific national goals. America must modernize conservation, modernize our energy infrastructure, increase energy supplies, accelerate the protection and improvement of the environment, and increase our nation's energy security.

Modernize Conservation

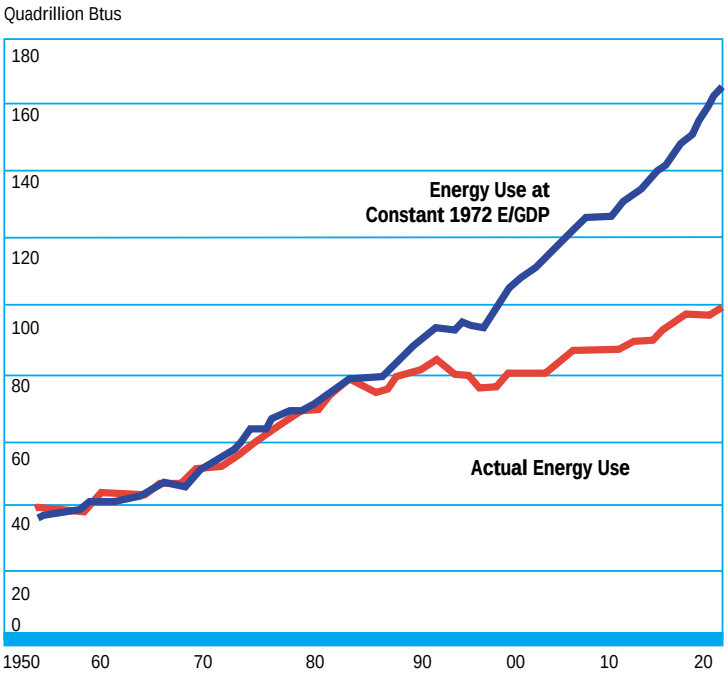
Americans share the goal of energy conservation. The best way of meeting this goal is to increase energy efficiency by applying new technology – raising productivity, reducing waste, and trimming costs. In addition, it holds out great hope for improving the quality of the environment. American families, communities, and businesses all depend upon reliable and affordable energy services for their well being and safety. From transportation to communication, from air conditioning to lighting, energy is critical to nearly everything we do in life and work. Public policy can and should encourage energy conservation.

Over the past three decades, America has made impressive gains in energy efficiency. Today's automobiles, for example, use about 60 percent of the gasoline they

"Here we aim to continue a path of uninterrupted progress in many fields... New technologies are proving that we can save energy without sacrificing our standard of living. And we're going to encourage it in every way possible."

— Vice President
Richard B. Cheney

Figure 4
U.S. Economy is More Energy Efficient (Energy Intensity)
Primary Energy Use



Improvements in energy efficiency since the 1970s have had a major impact in meeting national energy needs relative to new supply. If the intensity of U.S. energy use had remained constant since 1972, consumption would have been about 70 quadrillion Btus (74 percent) higher in 1999 than it actually was.

Source: U.S. Department of Energy, Energy Information Administration.

did in 1972, while new refrigerators require just one-third the electricity they did 30 years ago. As a result, since 1973, the U.S. economy has grown by 126 percent, while energy use has increased by only 30 percent. In the 1990s alone, manufacturing output expanded by 41 percent, while industrial electricity consumption grew by only 11 percent. We must build on this progress and strengthen America's commitment to energy efficiency and conservation.

The National Energy Policy builds on our nation's successful track record and will promote further improvements in the productive and efficient use of energy. This report includes recommendations to:

- Direct federal agencies to take appropriate actions to responsibly conserve energy use at their facilities, especially during periods of peak demand in regions where electricity shortages are possible, and to report to the President on actions taken.
- Increase funding for renewable energy and energy efficiency research and development programs that are performance-based and cost-shared.
- Create an income tax credit for the purchase of hybrid and fuel cell vehicles to promote fuel-efficient vehicles.
- Extend the Department of Energy's "Energy Star" efficiency program to include schools, retail buildings, health care facilities, and homes and extend the "Energy Star" labeling program to additional products and appliances.
- Fund the federal government's Intelligent Transportation Systems program, the fuel cell powered transit bus program, and the Clean Buses program.
- Provide a tax incentive and streamline permitting to accelerate the development of clean Combined Heat and Power technology.
- Direct the Secretary of Transportation to review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards with due consideration to the National Academy of Sciences study of CAFE standards to be released in July, 2001.

Modernize Our Energy Infrastructure

The energy we use passes through a vast nationwide network of generating facilities, transmission lines, pipelines, and refineries that converts raw resources into usable fuel and power. That system is deteriorating, and is now strained to capacity.

One reason for this is government regulation, often excessive and redundant. Regulation is needed in such a complex field, but it has become overly burdensome. Regulatory hurdles, delays in issuing permits, and economic uncertainty are limiting investment in new facilities, making our energy markets more vulnerable to transmission bottlenecks, price spikes and supply disruptions. America needs more environmentally-sound energy projects to connect supply sources to growing markets and to deliver energy to homes and business.

To reduce the incidence of electricity blackouts, we must greatly enhance our ability to transmit electric power between geographic regions, that is, sending power to where it is needed from where it is produced. Most of America's transmission lines, substations, and transformers were built when utilities were tightly regulated and provided service only within their assigned regions. The system is simply unequipped for large-scale swapping of power in the highly competitive market of the 21st century.

The National Energy Policy will modernize and expand our energy infrastructure in order to ensure that energy supplies can be safely, reliably, and affordably transported to homes and businesses. This report includes recommendations to:

- Direct agencies to improve pipeline safety and expedite pipeline permitting.
- Issue an Executive Order directing federal agencies to expedite permits and coordinate federal, state, and local actions necessary for energy-related project approvals on a national basis

"For the electricity we need, we must be ambitious. Transmission grids stand in need of repair, upgrading, and expansion. . . . If we put these connections in place, we'll go a long way toward avoiding future blackouts."

— Vice President
Richard B. Cheney

in an environmentally sound manner, and establish an interagency task force chaired by the Council on Environmental Quality. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state and local permitting activity in particular regions where increased activity is expected.

- Grant authority to obtain rights-of-way for electricity transmission lines with the goal of creating a reliable national transmission grid. Similar authority already exists for natural gas pipelines and highways.
- Enact comprehensive electricity legislation that promotes competition, encourages new generation, protects consumers, enhances reliability, and promotes renewable energy.
- Implement administrative and regulatory changes to improve the reliability of the interstate transmission system and enact legislation to provide for enforcement of electricity reliability standards.
- Expand the Energy Department's research and development on transmission reliability and superconductivity.

Increase Energy Supplies

A primary goal of the National Energy Policy is to add supply from diverse sources. This means domestic oil, gas, and coal. It also means hydropower and nuclear power. And it means making greater use of non-hydro renewable sources now available.

One aspect of the present crisis is an increased dependence, not only on foreign oil, but on a narrow range of energy options. For example, about 90 percent of all new electricity plants currently under construction will be fueled by natural gas. While natural gas has many advantages, an over-reliance on any one fuel source leaves consumers vulnerable to price spikes and supply disruptions. There are several other fuel sources available that can help meet our needs.

Currently, the U.S. has enough coal to last for another 250 years. Yet very few coal-powered electric plants are now under construction. Research into clean coal technologies may increase the attractiveness of coal as a source for new generation plants.

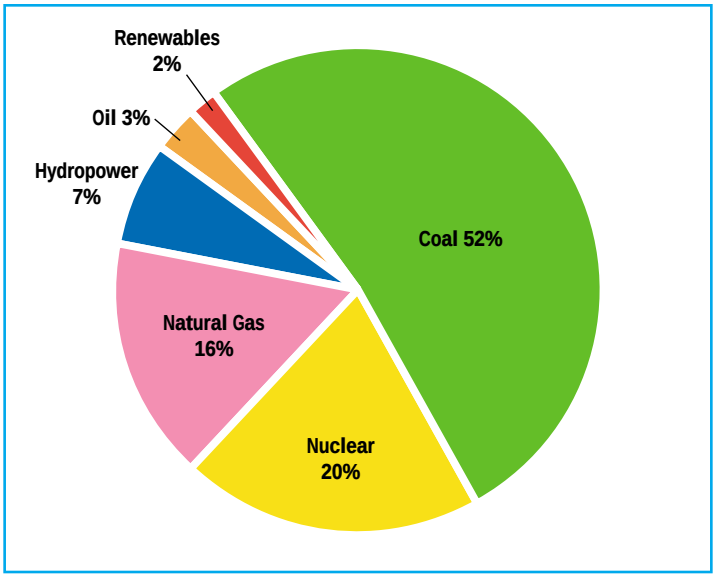
Nuclear power plants serve millions of American homes and businesses, have a dependable record for safety and efficiency, and discharge no greenhouse gases into the atmosphere. As noted earlier, these facilities currently generate 20 percent of all electricity in America, and more than 40 percent of electricity generated in 10 states in the Northeast, South, and Midwest. Other nations, such as Japan and France, generate a much higher percentage of their electricity from nuclear power. Yet the number of nuclear plants in America is actually projected to decline in coming years, as old plants close and none are built to replace them.

Enormous advances in technology have made oil and natural gas exploration and production both more efficient and more environmentally sound. Better technology means fewer rigs, more accurate drilling, greater resource recovery and envi-

"As a country, we have demanded more and more energy. But we have not brought on line the supplies needed to meet that demand.... We can explore for energy, we can produce energy and use it, and we can do so with a decent regard for the natural environment."

—Vice President
Richard B. Cheney

Figure 5
Fuel Sources for Electricity Generation in 2000



Electricity is a secondary source of energy, generated through the consumption of primary sources. Coal and nuclear energy account for nearly 75 percent of U.S. electricity generation.

Source: U.S. Department of Energy, Energy Information Administration

ronmentally friendly exploration. Drilling pads are 80 percent smaller than a generation ago. High-tech drilling allows us to access supplies five to six miles away from a single compact drilling site, leaving sensitive wetlands and wildlife habitats undisturbed. Yet the current regulatory structure fails to take sufficient account of these extraordinary advances, excessively restricting the environmentally safe production of energy from many known sources.

Our policy will increase and diversify our nation's sources of traditional and alternative fuels in order to furnish families and businesses with reliable and affordable energy, to enhance national security, and to improve the environment. This report includes recommendations to:

- Issue an Executive Order directing all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies a detailed statement on the energy impact of the proposed action.
- Open a small fraction of the Arctic National Wildlife Refuge to environmentally regulated exploration and production using leading-edge technology. Examine the potential for the regulated increase in oil and natural gas development on other federal lands.
- Earmark $1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR to fund research into alternative and renewable energy resources – including wind, solar, biomass, and geothermal.
- Enact legislation to expand existing alternative fuels tax incentives to include landfills that capture methane gas emissions for electricity generation and to electricity produced from wind and biomass. Extend the number of eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources.
- Provide $2 billion over 10 years to fund clean coal technology research and a new credit for electricity produced from biomass co-fired with coal.
- Direct federal agencies to streamline the hydropower relicensing process with proper regard given to environmental factors.
- Provide for the safe expansion of nuclear energy by establishing a national repository for nuclear waste, and by streamlining the licensing of nuclear power plants.

Accelerate Protection and Improvement of the Environment

America's commitment to environmental protection runs deep. We are all aware of past excesses in our use of the natural world and its resources. No one wishes to see them repeated. In the 21st century, the ethic of good stewardship is well established in American life and law.

We do not accept the false choice between environmental protection and energy production. An integrated approach to policy can yield a cleaner environment, a stronger economy, and a sufficient supply of energy for our future. The primary reason for that has been steady advances in the technology of locating, producing, and using energy. Since 1970, emissions of key air emissions are down 31 percent. Cars today emit 85 percent less carbon monoxide than 30 years ago. Lead emissions are down 90 percent. Lead levels in ambient air today are 98 percent lower than they were in 1970. America is using more, and polluting less.

One of the factors harming the environment today is the very lack of a comprehensive, long-term national energy policy. States confronting blackouts must take desperate measures, often at the expense of environmental standards, requesting waivers of environmental rules, and delaying the implementation of anti-pollution efforts. Shortfalls in electricity generating capacity and short-sighted policies have blocked construction of new, cleaner plants, leaving no choice but to rely on older, inefficient plants to meet demand. The increased use of emergency power sources, such as diesel generators, results in greater air pollution.

New anti-pollution technologies hold great promise for the environment. The same can be said of 21st century power generators that must soon replace older models; signifi-

"We will insist on protecting and enhancing the environment, showing consideration for the air and natural lands and watersheds of our country."

— Vice President
Richard B. Cheney

cant new resources for land conservation efforts; and continued research into renewable energy sources. All have a place in the National Energy Policy.

The National Energy Policy will build upon our nation's successful track record and will promote further improvements in the productive and efficient use of energy. This report includes recommendations to:

- Enact "multi-pollutant" legislation to establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators.
- Increase exports of environmentally friendly, market-ready U.S. technologies that generate a clean environment and increase energy efficiency.
- Establish a new "Royalties Conservation Fund" and earmark royalties from new, clean oil and gas exploration in ANWR to fund land conservation efforts.
- Implement new guidelines to reduce truck idling emissions at truck stops.

Increase Energy Security.

The National Energy Policy seeks to lessen the impact on Americans of energy price volatility and supply uncertainty. Such uncertainty increases as we reduce America's dependence on foreign sources of energy. At the same time, however, we recognize that a significant percentage of our resources will come from overseas. Energy security must be a priority of U.S. trade and foreign policy.

We must look beyond our borders and restore America's credibility with overseas suppliers. In addition, we must build strong relationships with energy-producing nations in our own hemisphere, improving the outlook for trade, investment, and reliable supplies.

Energy security also requires preparing our nation for supply emergencies, and assisting low-income Americans who are most vulnerable in times of supply disruption, price spikes, and extreme weather.

To ensure energy security for our nation and its families, our report includes these recommendations:

- Dedicate new funds to the Low Income Home Energy Assistance Program by funneling a portion of oil and gas royalty payments to LIHEAP when oil and natural gas prices exceed a certain amount.
- Double funding for the Department of Energy's Weatherization Assistance Program, increasing funding by $1.4 billion over 10 years.
- Direct the Federal Emergency Management Administration to prepare for potential energy-related emergencies.
- Support a North American Energy Framework to expand and accelerate cross-border energy investment, oil and gas pipelines, and electricity grid connections by streamlining and expediting permitting procedures with Mexico and Canada. Direct federal agencies to expedite necessary permits for a gas pipeline route from Alaska to the lower 48 states.

Looking Toward the Future

The President's goal of reliable, affordable, and environmentally sound energy supplies will not be reached overnight. It will call forth innovations in science, research, and engineering. It will require time and the best efforts of leaders in both political parties. It will require also that we deal with the facts as they are, meeting serious problems in a serious way. The complacency of the past decade must now give way to swift but well-considered action.

Present trends are not encouraging, but they are not immutable. They are among today's most urgent challenges, and well within our power to overcome. Our country has met many great tests. Some have imposed extreme hardship and sacrifice. Others have demanded only resolve, ingenuity, and clarity of purpose. Such is the case with energy today.

We submit these recommendations with optimism. We believe that the tasks ahead, while great, are achievable. The energy crisis is a call to put to good use the resources around us, and the talents within us. It summons the best of America, and offers the best of rewards – in new jobs, a healthier environment, a stronger economy, and a brighter future for our people.

"The goals of this strategy are clear: to ensure a steady supply of affordable energy for America's homes and businesses and industries."

— President
George W. Bush

Taking Stock

Energy Challenges Facing the United States



The U.S. economy depends on reliable and affordable energy. In the coming months, we face several serious long-term energy challenges: electricity shortages and disruptions in California and the West, dramatic increases in gasoline prices due to record-low inventories, a strained supply system, and continued dependence on foreign suppliers.

America's current energy challenges can be met with rapidly improving technology, dedicated leadership, and a comprehensive approach to our energy needs. Our challenge is clear—we must use technology to reduce demand for energy, repair and maintain our energy infrastructure, and increase energy supply. Today, the United States remains the world's undisputed technological leader; but recent events have demonstrated that we have yet to integrate 21st-century technology into an energy plan that is focused on wise energy use, production, efficiency, and conservation.

Prices today for gasoline, heating oil, and natural gas are dramatically higher than they were only a year ago. In California, homeowners, farmers, and businesses face soaring electricity prices, rolling blackouts, increasing financial turmoil, and an uncertain energy future. Our nation's dependence on foreign sources of oil is at an all-time high and is expected to grow. Current high energy prices and supply shortages are hurting U.S. consumers and businesses, as well as their prospects for continued economic growth.

Our national energy policy must be comprehensive in scope. It must protect our environment. It must also increase our supply of domestic oil, natural gas, coal, nuclear, and renewable energy sources. Our failure over the past several years to modernize our energy infrastructure—the network of transmission lines, gas pipelines, and oil refineries that transports our energy to consumers and converts raw materials into usable fuels—is a result of the lack of careful planning and lack of a comprehensive national energy plan. The United States faces serious energy challenges: electricity shortages and disruptions in California and elsewhere in the West, dramatic increases in gasoline prices due to record-low inventories, a strained supply system, and continued dependence on foreign suppliers. These challenges have developed from years of neglect and can only be addressed with the implementation of sound policy. There are no easy, short-term solutions.

Our increased dependence on foreign oil profoundly illustrates our nation's failure to establish an effective energy policy. Between 1991 and 2000, Americans used 17 percent more energy than in the previous decade, while during that same period, domestic energy production rose by only 2.3 percent. While U.S. production of coal, natural gas, nuclear energy, and renewable energy has increased somewhat in recent years, these increases have been largely offset by declines in domestic oil production. As a result, America has met almost all of its increased energy demand over the past ten years with increased imports.

U.S. energy consumption is projected to increase by about 32 percent by 2020. Unless a comprehensive national energy policy is adopted, Americans will continue to feel the effects of an inadequate electrical transmission grid, a pipeline system stretched to capacity, insufficient domestic energy supply, and a regional imbalance in supply sources. It is important that we meet these challenges with a comprehensive energy plan that takes a long-term approach to meeting our energy needs.

PHILADELPHIA CONVENTION & VISITORS BUREAU



California's Energy Challenge

Recent and looming electricity blackouts in California demonstrate the problem of neglecting energy supply. They also foretell the consequences of failing to implement a long-term energy plan for our nation as a whole. Though weather conditions and design flaws in California's electricity restructuring plan contributed, the California electricity crisis is at heart a supply crisis.

Since 1995, California's peak summer demand for electricity has risen by at least 5,500 megawatts (MW), while in-state generation has failed to keep pace. California's generation shortfall did not stem from a lack of interest in building capacity. Since 1997, power producers filed applications to build an additional 14,000 MW of new capacity in California.

In addition to a lack of new generation, a crucial transmission bottleneck in the middle of the state—called Path 15—prevents power in the south from being shipped to the north during emergencies.

This year, reduced hydropower availability due to low rainfall, higher than expected unplanned plant outages, and the financial problems of California's utilities exacerbated this growing supply–demand imbalance. As a result, California's supply problem turned into a crisis, resulting in soaring electricity bills for homes and businesses and rolling blackouts.

In part due to the interconnected nature of the western electricity grid, California's critical electricity shortages have helped to drive up electricity costs in the West.

Unfortunately, there are no short-term solutions to long-term neglect. It can take new power plants and transmission facilities years to site, permit, and construct. Despite expedited federal permitting, California's emergency efforts to increase new generation by 5,000 MW by July appear to be falling short. Less than 2,000 MW of new generation is expected to be in place by summer. Even with aggressive conservation measures, peak demand this summer is projected to outstrip supply by several thousand megawatts. The California grid operator expects more than 30 days of blackouts.

California officials have warned that the crisis may last several years. Though California's efforts to increase generation may not suffice to prevent blackouts this summer, if continued and strengthened, they promise to limit the duration of the crisis.

Recommendations:

★ The National Energy Policy Development (NEPD) Group recommends that the President issue an Executive Order to direct all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies, distribution, or use, a detailed statement on (1) the energy impact of the proposed action, (2) any adverse energy effects that cannot be avoided should the proposal be implemented, and (3) alternatives to the proposed action. The agencies would be directed to include this statement in all submissions to the Office of Management and Budget of proposed regulations covered by Executive Order 12866, as well as in all notices of proposed regulations published in the Federal Register.

★ The NEPD Group recommends that the President direct the executive agencies to work closely with Congress to implement the legislative components of a national energy policy.

Conservation and Energy Efficiency

Conservation and energy efficiency are crucial components of a national energy plan. Energy efficiency is the ability to use less energy to produce the same amount of useful work or services. Conservation is closely related and is simply using less energy. Improved energy efficiency and conservation reduces energy consumption and energy costs, while maintaining equivalent service in our homes, offices, factories, and automobiles. Greater energy

efficiency helps the United States reduce energy imports, the likelihood of energy shortages, emissions, and the volatility of energy prices.

Over the last three decades, the United States has significantly improved its energy efficiency by developing and expanding the use of energy efficient technologies. Although our economy has grown by 126 percent since 1973, our energy use has increased by only 30 percent. Had energy use kept pace with economic growth, the nation would have consumed 171 quadrillion British thermal units (Btus) last year instead of 99 quadrillion Btus.

About a third to a half of these savings resulted from shifts in the economy, such as the growth of the service sector. The other half to two-thirds resulted from greater energy efficiency. Technological improvements in energy efficiency allow consumers to enjoy more energy services without commensurate increases in energy demand. The rate at which these efficiency improvements are made varies over time, depending on the extent to which factors—such as energy policies, research and development, prices, and market regulations—encourage the development of new, efficient products and consumer investment in these products. An increased rate of improvement in energy efficiency can have a large impact on energy supply and infrastructure needs, reducing the need for new power plants and other energy resources, along with reduced stress on the energy supply infrastructure.

Load management is the ability to adjust energy loads to reflect immediate supply conditions. In the very short term, direct appeals for conservation can ease strained energy supply markets for a time. Over the longer run, the ability to adjust demand on an as-needed basis can be an important source of energy reserves, resulting in lower energy bills for participating customers.

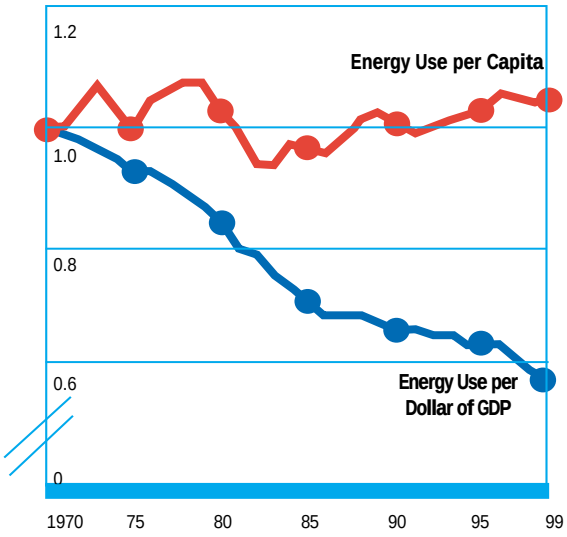
The impact that improvements in energy efficiency can have on energy supply markets grows over time. Electricity demand is projected to rise by 1.8 percent a year over the next 20 years, requiring the addition of some 393,000 MW of generation capacity. At the same time, energy efficiency is projected to continue to improve between 2000 and 2020. A decrease in demand from 1.8 percent to 1.5 percent would reduce the need for new generating capacity next year by about 2,000 MW. Extending that reduction over the next 20 years would reduce the need for new generation by 60,000 to 66,000 MW.

While this projection shows that conservation can help ensure the United States has adequate energy supplies for the future, it also shows that conservation alone is not the answer. Even with more conservation, the U.S. will need more energy supplies. Today, new technologies offer new opportunities to enhance our energy efficiency. As these technologies gain market acceptance, they will help ensure a reliable and affordable energy and electric power supply for the nation.

Energy Intensity

The energy intensity of the U.S. economy is measured by the amount of energy used to produce a dollar's worth of gross domestic product (GDP). It now takes only about 56 percent of the energy required in 1970 to produce a

Figure 1-1
U.S. Energy Use per Capita and per Dollar of GDP: 1970–1999
(Index: 1970 = 1)



The energy intensity of the U.S. economy is measured by the amount of energy used to produce a dollar's worth of gross domestic product (GDP). By that yardstick, U.S. energy intensity declined significantly between 1970 and 1985, and has continued to decline, albeit at a slower rate.

Source: U.S. Department of Energy, Energy Information Administration.

Measures of Electrical Power

A watt is a measure of the amount of energy that can be produced during a specific period of time.

1 kilowatt (KW)= 1,000 watts
1 megawatt (MW)=1million watts
1 gigawatt (GW)=1 billion watts
1 terawatt (TW)=1 trillion watts

U.S. Energy Efficiency Is Improving

- New home refrigerators now use about one-third less energy than they did in 1972.
- New commercial fluorescent lighting systems use less than half the energy they did during the 1980s.
- Federal buildings now use about 20 percent less energy per square foot since 1985.
- Industrial energy use per unit of output declined by 25 percent from 1980 to 1999.
- The chemical industry's energy use per unit of output has declined by roughly 40 percent in the past 25 years.
- The U.S. government has reduced its energy use in buildings by over 20 percent since 1985.
- The amount of energy required to generate 1 kilowatt-hour of electricity has declined by 10 percent since 1980.

What Causes Transmission Constraints?

When additional electricity flow from one area exceeds a circuit's capacity to carry that flow to another area, the overloaded circuit becomes congested and blocks a steady flow of power. To prevent transmission bottlenecks, system operators curtail transactions between areas or increase generation on the side of the constraint where the electricity is flowing and reduce generation on the opposite side. Transmission constraints result in price differences between regions that exceed differences due to line losses, because electricity can no longer flow freely to the affected area.

dollar of GDP today (Figure 1-1). This reduction is attributable to improved energy efficiency, as well as to structural changes in the economy, particularly the relative decline of energy-intensive industries.

The decline in the nation's energy intensity accelerated between 1999 and 2000, a period when nonenergy-intensive industries experienced rapid growth. Energy intensity is projected to continue to decline through 2020 at an average rate of 1.6 percent a year. This is a slower rate of decline than experienced in the 1970s and early 1980s, which was characterized by high energy prices and a shift to less energy-intensive industries, but is a more rapid rate of decline than experienced on average during the latter part of the 1980s and the 1990s.

Challenges Confronting Electricity Supply

Our nation's electricity supply has failed to keep pace with growing demand. This imbalance is projected to persist into the future. The adverse consequences have manifested themselves most severely in the West, where supply shortages have led to high prices and even blackouts. In other regions, inadequate supply threatens the reliability and affordability of electric power.

Large amounts of new generating capacity are slated for installation around the country from 2001 to 2004. However, there is a geographic mismatch between where we will generate energy and where it is needed. For example, little capacity is being added where it is most needed, such as in California and eastern New York.



A pressing long-term electricity challenge is to build enough new generation and transmission capacity to meet projected growth in demand.

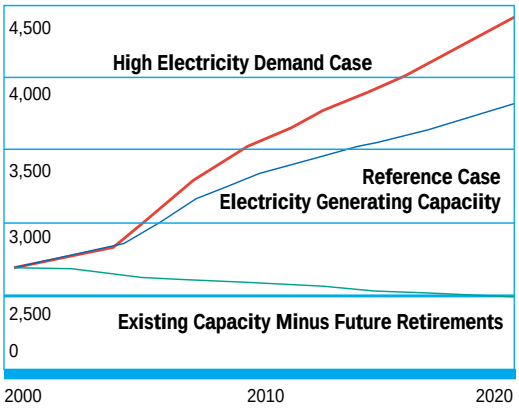
Electricity supply conditions in the Southeast are expected to be tight in the summer of 2001, much as they have been the previous two years. The Northeast may also face supply shortages. If the temperatures of the summer of 2000 had been normal rather than unseasonably cool, New York and New England would most likely have experienced electricity supply shortfalls and price spikes. Critical supply problems could arise if the weather in the summer of 2001 is unusually warm or if plant outages rise above average levels.

Our nation's most pressing long-term electricity challenge is to build enough new generation and transmission capacity to meet projected growth in demand. Across the country, we are seeing the same signs that California faced in the mid-1990s: significant economic regulatory uncertainty, which can result in inadequate supply. This level of uncertainty can vary across the country, depending on state and local regulations. Of the approximately 43,000 MW of new generating capacity that power companies planned in 1994 for construction from 1995 to 1999, only about 18,000 MW were actually built. Although plans have been announced to build more capacity than the country will need over the next five to seven years, this new construction assumes market and regulatory conditions that are not yet assured. Over the next twenty years, the United States will need 1,300 to 1,900 new power plants, which is the equivalent of 60 to 90 new power plants a year (Figure 1-2).

But even with adequate generating capacity, we do not have the infrastructure to ensure reliable supply of electricity. Investment in new transmission capacity has failed to keep pace with growth in demand and with changes in the industry's structure. Since 1989, electricity sales to consumers have increased by 2.1 percent annually, yet transmission capacity has increased by only 0.8 percent annually. As electricity markets become more regional, transmission constraints are impeding the movement of electricity both within and between regions.

The price spikes in the Midwest in the summer of 1998 were in part caused by trans-

Figure 1-2
The U.S. Needs More Power Plants



The nation is going to require significant new generation capacity in the next two decades. Depending on demand, the United States will need to build between 1,300 and 1,900 new power plants—or about one new power plant a week.

Source: U.S. Department of Energy, Energy Information Administration.

mission constraints, which limited the region's ability to import electricity from other regions at a time of high demand. Transmission bottlenecks contributed to the blackouts in California over the past year, and have been a persistent cause of price spikes in New York City during peak demand. Constraints on New England's ability to import low-cost power from Canada could raise electricity prices during periods of high demand.

Electricity is a secondary source of energy, generated through the consumption of primary sources (Figure 1-3). The largest source of U.S. electricity generation is coal, followed by nuclear energy, natural gas, hydropower, oil, and non-hydropower renewable energy.

Coal

Coal is America's most abundant fuel source. The United States has a 250-year supply of coal. Over 1 billion tons of coal were produced in 25 states in 2000. About 99.7 percent of U.S. coal production is consumed domestically, with electricity generation accounting for about 90 percent of coal consumption.

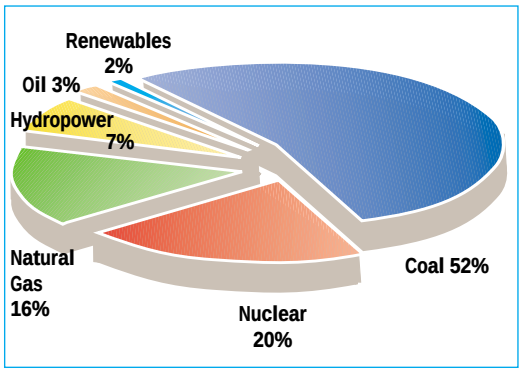
After peaking in 1982, coal prices have generally declined. This trend is projected to continue through 2020, reflecting an expanding shift into lower-cost western coal production and substantial increases in productivity. While coal is expected to remain the dominant fuel in meeting increasing U.S. electricity demand through 2020, energy policy goals must be carefully integrated with environmental policy goals. The Clean Air Act Amendments of 1990 and related state regulations require electricity generators to reduce emissions of sulfur dioxide and nitrogen oxide.

Nuclear Energy

Nuclear energy is the second-largest source (20 percent) of U.S. electricity generation. Nuclear power is used exclusively to generate electricity. Nuclear power has none of the emissions associated with coal and gas power plants, including nitrogen oxides, sulfur dioxide, mercury and carbon dioxide. Costs of electricity generation by nuclear plants compare favorably with the costs of generation by other sources.

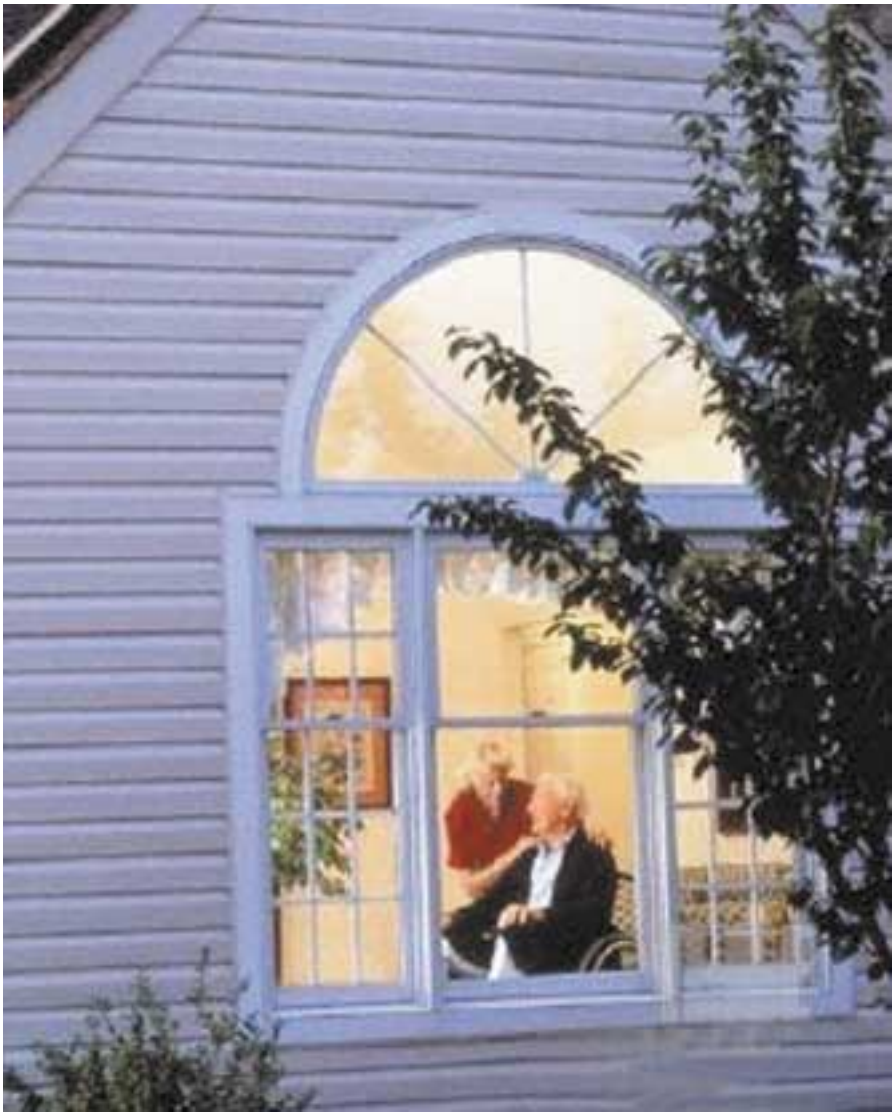
While the number of nuclear plants has declined due to retirements, nuclear electricity generation has steadily increased in recent years. Several factors have created a more favorable environment for nuclear energy: safe, standardized plant designs; an improved licensing process; effective safety oversight by the Nuclear Regulatory Commission (NRC); the advent of new technologies; and uncertain, volatile natural gas prices. This more favorable environment has resulted in increased re-licensing of nuclear plants and the consolidation of several plants in the hands of fewer, more experienced operators.

Figure 1-3
Fuel Sources for Electricity Generation in 2000



Electricity is a secondary source of energy, generated through the consumption of primary sources. Coal and nuclear energy account for over 70 percent of U.S. electricity generation.

Source: U.S. Department of Energy, Energy Information Administration.



Many Americans received high heating bills this winter as a result of sharp increases in natural gas prices.

The nuclear industry is closely regulated by the NRC, which provides oversight of the operation and maintenance of these plants. This oversight includes a comprehensive inspection program that focuses on the most significant potential risks of plant operations, and features full-time resident inspectors at each plant, as well as regional inspectors with specialized expertise. In addition to rigorous inspection criteria, the installation of new design features, improvements in operating experience, nuclear safety research, and operator training have all contributed to the nuclear industry's strong safety record.

An important challenge to the use of nuclear energy is the issue of safe and timely long-term storage of spent nuclear fuel and high- and low-level radioactive waste. Currently, no plans exist to construct any new nuclear plants. However, due to more favorable conditions, the decline in nuclear energy generation has not been as rapid as was predicted only a few years ago, as evidenced by increased re-licensing.

Natural Gas

Natural gas is the third-largest source of U.S. electricity generation, accounting for 16 percent of generation in 2000. Under existing policy, natural gas generating capacity is expected to constitute about 90 percent of the projected increase in electricity generation between 1999 and 2020. Electricity generated by natural gas is expected to grow to 33 percent in 2020—a growth driven by electricity restructuring and the economics of natural gas power plants. Lower capital costs, shorter construction lead times, higher efficiencies, and lower emissions give gas an advantage over coal and other fuels for new generation in most regions of the country.

However, natural gas is not just an electricity source. It is used in many different ways, including as vehicle fuel, as industrial fuel, and in our homes. In addition, natural gas is used as a feedstock during the manufacturing process of such products as chemicals, rubber, apparel, furniture, paper, clay, glass, and other petroleum and coal products. Overall, natural gas accounts for 24 percent of total U.S. energy consumed and for all purposes 27 percent of domestic energy produced.

Eighty-five percent of total U.S. natural gas consumption is produced domestically. The import share of consumption rose from 5 percent in 1987 to 15 percent in 2000, and net imports have comprised more than 50 percent of the growth in gas demand since 1990. Canada, with very large gas supplies and easy pipeline access to the lower 48 states, accounts for nearly all U.S. natural gas imports. Unlike oil, almost all natural gas is produced and sold within the same region. Therefore, prices are determined by regional, rather than global, markets.

In 2000, natural gas prices moved

sharply higher after fifteen years of generally flat prices. Futures prices surged by 320 percent in 2000 to an all-time high of $9.98 per million Btus in late December 2000—nearly five times higher than the $2.05 per million Btu average from 1991 to 1999. While prices have declined since the beginning of 2001, they remain much higher than recent levels.

Between 2000 and 2020, U.S. natural gas demand is projected by the Energy Information Administration to increse by more than 50 percent, from 22.8 to 34.7 trillion cubic feet. Others, such as Cambridge Energy Research Associates, expect gas consumption to increase by about 37 percent over that period. Growth is projected in all sectors—industrial, commercial, residential, transportation, and electric generation. More than half of the increase in overall gas consumption will result from rising demand for electricity generation.

Although high natural gas prices have negative effects on consumers, businesses, industries, and the economy as a whole, they also promote more rapid development and adoption of new energy efficient technologies, investment in distribution systems, and greater investment in exploration and development. Although these market responses do not occur rapidly enough to prevent near-term price spikes, over time, they help to hold down prices.

As a result of the sharp increase in natural gas prices, many consumers received historically high utility bills this winter. The price spike has had a particularly severe impact on low-income consumers who use natural gas for heating. In recent months, 5 million consumers have applied for federal and state assistance to pay their heating bills—an increase of 1 million consumers over last year.

The projected rise in domestic natural gas production—from 19.3 trillion cubic feet in 2000 to 29.0 trillion cubic feet in 2020—may not be high enough to meet projected demand. In the near term, incremental production of natural gas is expected to come primarily from unconventional sources in the Rocky Mountain, Gulf Coast, and mid-continent regions; the North Slope of Alaska; and the offshore Gulf of Mexico. Onshore federal lands currently contribute about 10 percent of U.S. production, and federal offshore production contributes about 26 percent.

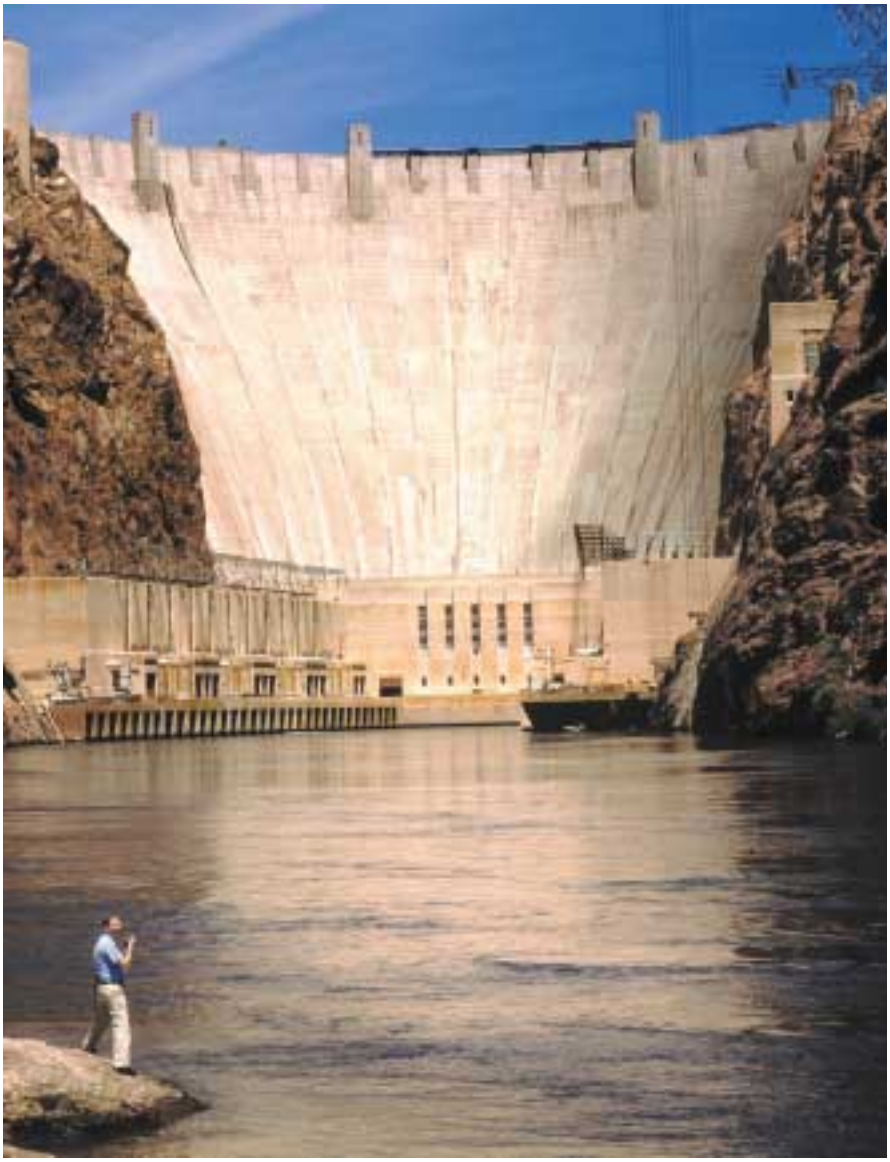
The most significant long-term challenge relating to natural gas is whether adequate supplies can be provided to meet sharply increased projected demand at reasonable prices. If supplies are not adequate, the high natural gas prices experienced over the past year could become a continuing problem, with consequent impacts on electricity prices, home heating bills, and the cost of industrial production. These concerns will redouble if policy decisions sharply reduce electricity generation by any other source, since it is doubtful that natural gas electricity generation could expand to the extent necessary to compensate for that loss of generation.

To meet this long-term challenge, the United States not only needs to boost production, but also must ensure that the natural gas pipeline network is expanded to the extent necessary. For example, although natural gas electricity generation in New England is projected to increase by 16,000 MW through 2000, bottlenecks may block the transmission of necessary supplies. Unless pipeline constraints are eliminated, they will contribute to supply shortages and high prices, and will impede growth in electricity generation.

Hydropower

Hydropower is the fourth-largest source of U.S. electricity generation, accounting for about 7 percent of total generation in 2000. In some regions of the country, such as the Northwest and New York, hydropower makes a much bigger contribution to electricity generation. Although the United States is second only to Canada in hydropower generation, hydropower generation has remained relatively flat in the United States for years.

Hydropower has significant environmental benefits. It is a form of low-cost electricity generation that produces no emissions, and it will continue to be an important source of U.S. energy for the future. Given the potential impacts on fish and wildlife, however, it is important to ef-



Hydropower is the fourth-largest source of U.S. electricity generation. The most significant challenge confronting this source of energy is regulatory uncertainty regarding the federal licensing process.

ficiently and effectively integrate national interests in both natural resource preservation and environmental protection with energy needs.

There are two categories of hydropower projects in the United States: (1) those operated by federal electric utilities, such as the federal power marketing administrations (Bonneville, Western, Southwestern, and Southeastern); and (2) the approximately 2,600 non-federal hydropower dams licensed or exempted by the Federal Energy Regulatory Commission (FERC). The federal utilities have large hydropower systems operated by the Bureau of Reclamation and Army Corps of Engineers, and play an important role meeting electricity demand, especially in the Northwest and the West. Hydropower projects operate with multiple purposes, such as electricity generation, flood control, navigation, and irrigation.

Although most potential for hydropower has already been developed, there is some undeveloped hydropower capacity in the United States. Much of this capacity could be expanded without constructing a new dam.

The most significant challenge confronting hydropower is regulatory uncertainty regarding the federal licensing process. The process is long and burdensome, and decision-making authority is spread across a range of federal and state agencies charged with promoting different public policy goals. Reforms can improve the hydropower licensing process, ensuring better public participation, ensuring that effective fish and wildlife conditions are adopted, and providing interagency resolution before conflicting mandatory license conditions are presented. The licensing process needs both administrative and legislative reforms. In addition, FERC should be encouraged to adopt appropriate deadlines for its own actions during the process.

Oil

Oil accounts for approximately 3 percent of electricity generation. Oil is used as a primary source to fire electricity generation plants in some regions. Specifically, oil is an important source of electricity in Hawaii, Florida, and some northeastern states. Oil can also be used an additional source of fuel for electricity generation in plants that can use either natural gas or oil. However, electricity generation from oil is projected to decline to about one-half of one percent of total electricity generation by 2020.

Renewable Energy: A Growing Resource

Renewable energy technologies tap natural flows of energy—such as water, wind, solar, geological, and biomass sources—to produce electricity, fuels, and heat. Non-hydropower renewable electricity generation is projected to grow at a faster rate

than all other generation sources, except natural gas. These sources of energy are continuously renewable, can be very clean, are domestically produced, and can generate income for farmers, landowners, and others. Although its production costs generally remain higher than other sources, renewable energy has not experienced the price volatility of other energy resources.

Non-hydropower renewable energy sources currently account for only about 4 percent of total energy consumption and 2 percent of total electricity generation. The sources of non-hydropower renewable electricity generation are biomass (the direct combustion of plant matter and organic residues, such as municipal solid waste use); geothermal (use of naturally occurring steam and hot water); wind; and solar. Biomass and geothermal account for most renewable electricity generation.

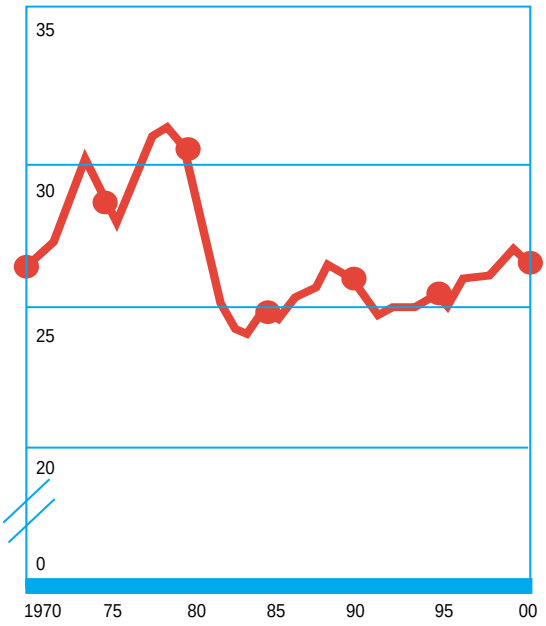
The most important long-term challenge facing renewable energy remains economic. Renewable energy costs are often greater than those of other energy sources. However, these costs have declined sharply in recent years, due to improved technology. If this trend continues, renewable energy growth will accelerate. By 2020, non-hydropower renewable energy is expected to account for 2.8 percent of total electricity generation.

Transportation Energy Needs

Oil is the nation's largest source of primary energy, serving almost 40 percent of U.S. energy needs. In 2000, the United States consumed an average of 19.5 million barrels of oil every day. Transportation fuels account for about two-thirds of our oil consumption, and the industrial sector for 25 percent. Residential and commercial uses, such as heating oil and propane—important fuels in the Northeast and Midwest—account for most of the rest.

The share of oil in U.S. energy supply has declined since the early 1970s, the result of growth in other fuels, particularly coal and nuclear. Per capita oil consumption, which reached a peak in 1978, has fallen by 20 percent from that level (Figure 1-4).

Figure 1-4
U.S. Per Capita Oil Consumption: 1970–2000



Per capita oil consumption reached a peak in 1978 of 31 barrels. it has fallen by 20 percent since then to 26 barrels per capita.

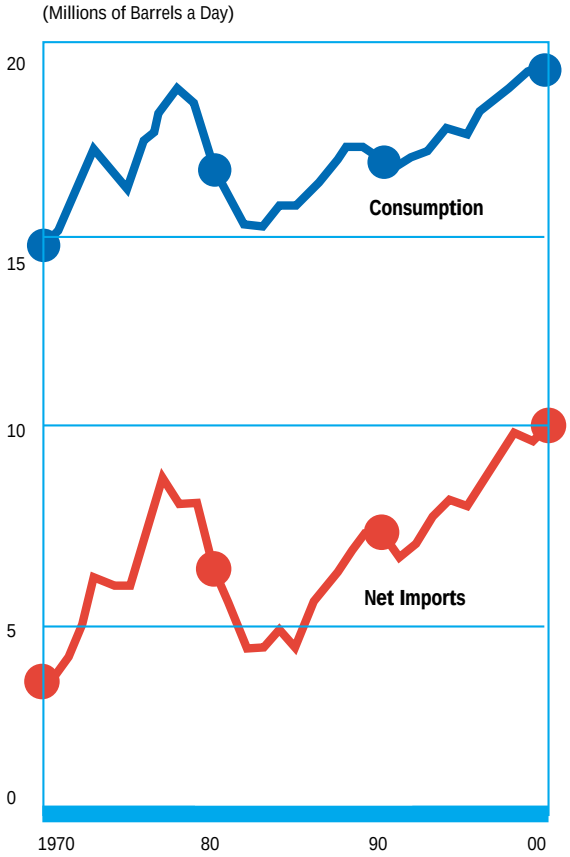
Source: U.S. Department of Energy, Energy Information Administration

Renewable energy technologies tap natural flows of energy to produce electricity, fuels, and heat.

U.S. Department of Energy, National Renewable Energy Laboratory



Figure 1-5
Dependence on Foreign Sources of Oil



U.S. dependence on oil imports is a serious long-term challenge. The economic security of our nation and our trading partners will remain closely tied to global oil market developments.

Source: U.S. Department of Energy, Energy Information Administration.

In 2020, oil is projected to account for roughly the same share of U.S. energy consumption as it does today.

The United States has been a net importer of energy since the 1950s, and U.S. dependence on imports has grown sharply since 1985 (Figure 1-5). Today, oil accounts for 89 percent of net U.S. energy imports. Net oil imports account for most of the rise in energy imports since the mid-1980s, and have grown from about 4.3 million barrels per day (bpd) in 1985 to 10 million bpd in 2000.

World oil prices have been marked by notable price volatility over the past several years. For example, the average initial purchase price of crude oil rose from $8.03 a barrel in December 1998 to $30.30 a barrel in November 2000. Spot prices rose even higher. This dramatic price swing was the product of several events. A series of production cuts by the Organization of Petroleum Exporting Countries (OPEC) in 1998 and 1999 sharply curtailed global oil supplies. At the same time, rebounding demand for oil in Asia following roughly two years of economic weakness, and rapid economic growth in the United States boosted oil consumption and squeezed supplies even further. By September 2000, oil prices peaked as markets faced limited supply of crude and petroleum products



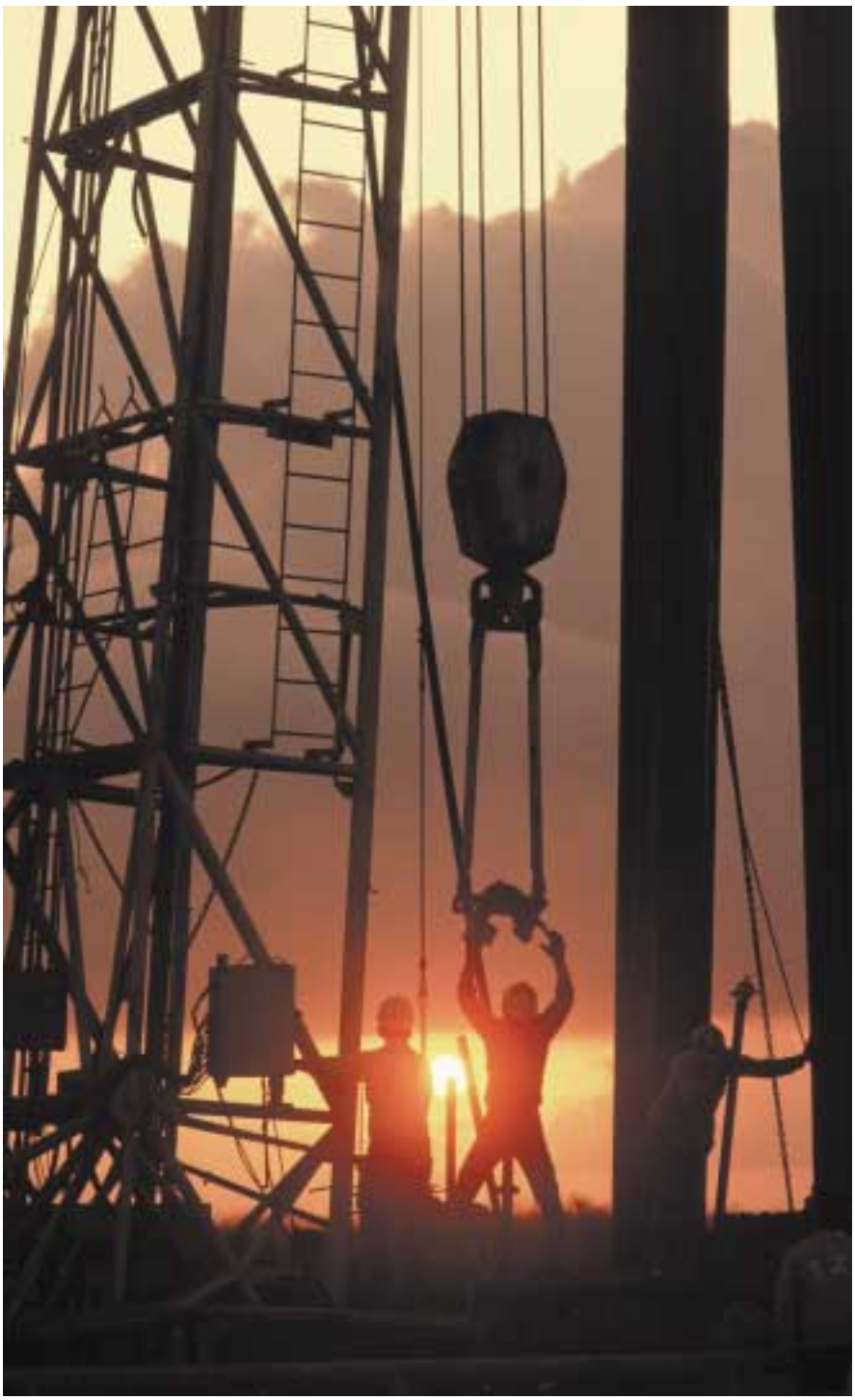
U.S. Department of Transportation

Domestic oil supply cannot be increased unless several access and infrastructure challenges are addressed. For example, U.S. refining and pipeline capacity has not kept pace with increasing demand for petroleum products.

ahead of the winter season, when demand is typically higher. In December 2000, oil prices fell after the market absorbed the impact of a series of OPEC production increases.

This recent price volatility illustrates the effect of intermittent market power exerted by cartel behavior in a global petroleum market. Moreover, prices are set in a market where supply is geographically concentrated. Almost two-thirds of world proven reserves are in the Middle East. Elsewhere, Central and South America account for 9 percent; Africa, 7 percent; North America, 5 percent; Eastern Europe and the former Soviet Union, 5 percent; the rest of Asia, 4 percent; and Western Europe, 2 percent. OPEC's huge oil reserves and production capacity and its periodic efforts to influence prices add to volatility in the market.

Oil prices are expected to remain high through 2002, affecting the cost of transportation, heating, electricity generation, and industrial production. High oil prices mean high prices for petroleum products, such as gasoline, diesel fuel, heating oil, propane, and jet fuel. The summer 2001 base case average gasoline price from the Department of Energy *Short-Term Energy Outlook* is $1.49 per gallon. However, prices have risen more rapidly than anticipated since the report's release, and a much higher summer average in the range of $1.50 to $1.65 per gallon is likely. Some areas have already experienced gasoline prices above $2.00 per gallon. Gasoline inventories going into the driving season are projected to be lower than last year, which could set the stage for regional supply problems that once again create significant price volatility in gasoline markets.



Because the United States is a mature oil-producing region, production costs are often higher than in foreign countries.

Price Volatility in Gasoline Markets

During the early summer of 2000, low inventories set the stage for a gasoline price run-up in the Midwest. Several pipeline and refinery problems sent marketers scrambling for limited supplies of both reformulated gasoline (RFG) and conventional gasoline, driving prices up rapidly. In Chicago, the spot price for blend stock for RFG, excluding ethanol, doubled in about six weeks, from 83 cents per gallon on April 25 to $1.65 on June 7. Spot prices then fell back over the next five weeks to 84 cents on July 12 as extra supply began arriving. Retail regular-grade RFG prices in the Midwest rose from $1.47 on April 24 to just over $2.00 per gallon on June 19, before falling back to $1.43 by July 24, showing the typical tendency of

retail prices to lag spot price changes.

Refiners face additional challenges as a result of various state and local clean fuel requirements for distinct gasoline blends ("boutique fuels"). These different requirements sometimes make it difficult, if not impossible, to draw on gasoline supplies from nearby areas or states to meet local needs when the normal supply is disrupted.

In 2000, very low inventories of gasoline and other refined products on the U.S. East and Gulf coasts increased the market's susceptibility to external shocks, such as operating problems in refineries or pipelines, or short-term surges in demand. Last winter, heating oil prices were at near-record levels. During 2000, the federal government reduced the vulnerability of the Northeast to heating oil shortages, such as those experienced in January 2000, by creating a 2-million-barrel heating oil reserve in New Jersey and Connecticut.

Because the United States is a mature oil-producing region, production costs are often higher than in foreign countries, particularly OPEC countries. In addition, access to promising domestic oil reserves is limited. U.S. oil production in the lower 48 states reached its peak in 1970 at 9.4 million bpd. A surge in Alaskan North Slope oil production beginning in the late 1970s helped postpone the decline in overall U.S. production, but Alaska's production peaked in 1988 at 2 million bpd, and fell to 1 million bpd by 2000. By then, U.S. total oil output had fallen to 5.8 million bpd, 39 percent below its peak.

By 2020, U.S. oil production is projected to decline from 5.8 to 5.1 million bpd under current policy. However, oil consumption is expected to rise to 25.8 million bpd by 2020, primarily due to growth in consumption of transportation fuels. Given existing law, production from offshore sources, particularly the Gulf of Mexico, is predicted to play an increasingly important role in the future, accounting for a projected high of 40 percent of domestic oil production by 2010, up from 27 percent today. Technological advances can mitigate the decline in U.S. oil production by enhancing recovery from domestic oil reserves and lowering production costs.

Our projected growing dependence on oil imports is a serious long-term challenge. U.S. economic security and that of our trading partners will remain closely tied to global oil market developments. Without a change in current policy, the share of U.S. oil demand met by net imports is projected to increase from 52 percent in 2000 to 64 percent in 2020. By 2020, the oil for nearly two of every three gallons of our gasoline and heating oil could come from foreign countries. The sources of this imported oil have changed considerably over the last thirty years, with more of our imports coming from the Western Hemisphere. Despite progress in diversifying our oil suppliers over the past two decades, the U.S. and global economies remain vulnerable to a major disruption of oil supplies.

The Strategic Petroleum Reserve (SPR), the federal government's major tool for responding to oil supply disruptions, has not kept pace with the growth in imports. The number of days of net oil import protection provided by the Reserve declined from 83 days of imports in 1992 to 54 days of imports today. Net domestic oil imports have increased significantly since 1992, while the SPR's oil inventory actually decreased.

Domestic oil supply cannot be increased unless several access and infrastructure challenges are addressed. U.S. refining and pipeline capacity has not kept pace with increasing demand for petroleum products. Unless changes take place, the net effect will likely be increased imports, regionally tight markets, and circumstances in which prices for gasoline, heating oil, and other products rise independently of oil prices.

Greater price volatility for gasoline, diesel fuel, heating oil, propane, and jet fuel is likely to become a larger problem over time, unless additional refining capacity and expanded distribution infrastructure can be developed at the same time cleaner products are required. Increasing domestic oil production and reducing demand, particularly for transportation fuels, will re-

quire adoption of a comprehensive national energy policy.

Alternative Transportation Fuels

Development of alternative fuels such as ethanol and other biofuels (liquid fuels derived from organic matter, such as crops), natural gas, and electricity, can help diversify the transportation sector that is so reliant on oil.

Ethanol, a biofuel based on starch crops such as corn, is already making a significant contribution to U.S. energy security, displacing more oil than any other alternative fuel. Other biofuels, such as biodiesel, which can be made from soybean, canola oils, animal fats, and vegetable oils, are making an increasingly important contribution

The success of the federal alternative fuels program has been limited, however. The program focuses on mandating that certain fleet operators purchase alternative fueled vehicles. The hope was that this vehicle purchase mandate would lead to expanded use of alternative fuels. That expectation has not been realized, since most fleet operators purchase dual-fueled vehicles that operate on petroleum motor fuels. Reforms to the federal alternative fuels program could promote alternative fuels use, such as expanding the development of an alternative fuels infrastructure.

Summary of Recommendations

Taking Stock: Energy Challenges Facing the United States

★ The NEPD Group recommends that the President issue an Executive Order to direct all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies, distribution, or use, a detailed statement on: (1) the energy impact of the proposed action, (2) any adverse energy effects that cannot be avoided should the proposal be implemented, and (3) alternatives to the proposed action. The agencies would be directed to include this statement in all submissions to the Office of Management and Budget of proposed regulations covered by Executive Order 12866, as well as in all notices of proposed regulations published in the Federal Register.

★ The NEPD Group recommends that the President direct the executive agencies to work closely with Congress to implement the legislative components of a national energy policy.

★ The NEPD Group recommends to the President that the NEPD Group continue to work and meet on the implementation of the National Energy Policy, and to explore other ways to advance dependable, affordable, and environmentally responsible production and distribution of energy.

Note: All recommendations in this report are subject to execution in accordance with applicable law. Legislation would be sought where needed. Also, any recommendations that involve foreign countries would be executed in accordance with the customs of international relations, including appropriate diplomatic consultation.

Regional U.S. Energy Challenges

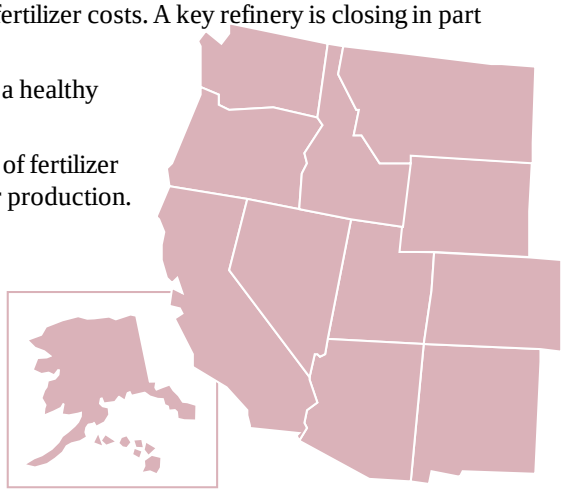
Midwest

Energy consumption in the Midwest is dominated by the industrial sector, the sector with the fastest-growing consumption rate through 2020. The transportation sector has the second-fastest consumption growth rate through 2020. States are affected by higher prices for natural gas, propane, and gasoline, and they expect gasoline price spikes this summer. Electricity supplies in some parts of the region may be tight during peak summer demand. High energy prices will drive up farm operating costs, particularly for fertilizer, irrigation, grain drying, and fuel for tractors.

Illinois consumers are reeling from high heating and cooling costs. Landlords are forced to pass on these costs in the form of higher rents. Farmers face low commodity prices, high fuel costs, and dramatically higher fertilizer costs. A key refinery is closing in part because of the cost of meeting cleaner-burning gasoline requirements.

Minnesota's residential electricity use has increased due to population growth and a healthy economy.

Iowa imports over 90 percent of its energy. Farmers are paying twice the 1999 price of fertilizer because of higher prices for natural gas, which is a major component in the fertilizer production.



West

Energy consumption in the West is dominated by the transportation sector, which is followed closely by the industrial sector. The region's drought emergency is exacerbating an already challenging energy picture. California is likely to experience more severe electricity blackouts this summer. The Pacific Northwest faces a major shortage of hydropower generation due to low water levels. Electricity prices will remain high in the West until more supply is added. Gasoline could be in short supply this summer in California and other states.

California's energy consumption has grown by about 7 percent a year, while production has remained flat. The point has been reached where demand is occasionally exceeding supply, which has caused rolling blackouts. The situation is likely to worsen this summer when demand will peak.

Oregon's lowest snow pack in history will result in the most severe short-term electricity problem in decades. The state will face high spot market prices and reports the highest gasoline prices in the country.

Washington businesses are closing down or cutting back on production. Electricity costs of $400 per unit compared to $35 a year ago contributed to the closure of a major paper plant employing 800 employees.

Colorado small business are suffering as well. A 169 percent jump in natural gas prices in one year may force small businesses to close.

Idaho utilities are offering to pay their irrigation customers to not farm portions of their fields to reduce electricity demand and make that saved power available for other local customers. The low snow pack has reduced water in river systems needed for hydropower generation.

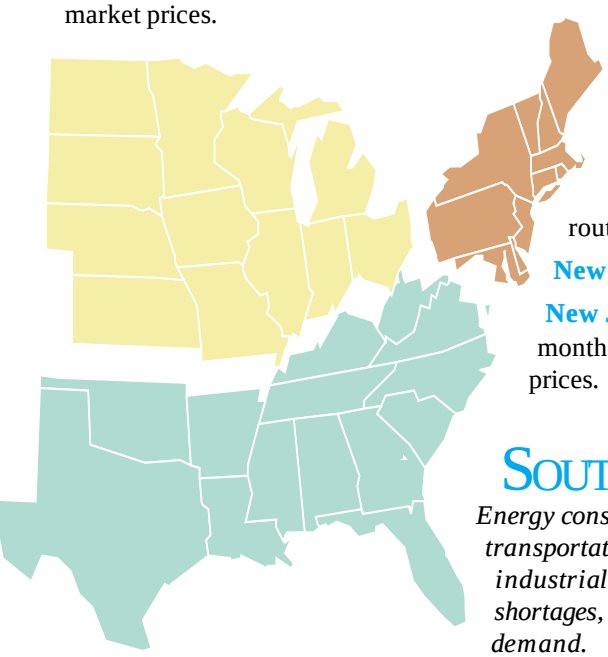
Hawaii's geographic isolation contributes to its many energy issues, such as importing 100 percent of its energy, its disproportionately high consumption of jet fuel and heavy reliance on tourism, and its dependence on imported oil for over 90 percent of its primary energy, the majority from sources in the Asia-Pacific region. Electricity is produced mainly from oil, including residuals and distillates from refineries and coal. Because the Islands' electric grids are not interconnected, electric utilities must operate with high reserve margins.

Nevada is covered in large part by federal lands that require federal approval for permitting new transmission and generation facilities. The permitting process can be protracted and cumbersome, despite efforts by federal agencies to streamline and coordinate. The desert climate requires both heating and cooling, the cost of which can be burdensome. While the desert climate is also conducive to geothermal, wind, and solar technologies, additional work is needed to make these technologies economically competitive.

NORTHEAST

Energy consumption in the Northeast is dominated by the transportation sector. Forecasts developed by the Energy Information Administration indicate that the transportation sector will also remain the dominant sector with the fastest-growing consumption rate through 2020. Northeast states' energy challenges include reducing vehicle pollution and interstate transport of power plant emissions. Heavy dependence on heating oil results in disproportionate impacts during cycles of high prices. Energy supplies in the region are limited by electric transmission and gas pipeline bottlenecks.

New York is rushing to complete 11 small natural gas turbines to avoid blackouts in New York City this summer, where customers pay market prices.



Delaware needs upgraded transmission lines to handle increasing loads. Traditional distributed generation using diesel generators may address these shortfalls, but could raise environmental problems.

Connecticut expects no power shortages this summer, but brownouts are possible if there is a prolonged spike in energy use while power plants are shut down for routine maintenance.

New Hampshire must conserve power on hot days to avoid summer blackouts.

New Jersey regulators have had to allow utilities to raise natural gas rates by 2 percent a month through July 2001 to make up for money lost during the winter due to high fuel prices.

SOUTH

Energy consumption in the South is dominated by the industrial sector, followed by the transportation sector. The transportation sector, however, is expected to grow faster than the industrial sector through 2020. While no state in the region anticipates summer power shortages, electricity supplies in parts of the region may be tight during peak summer demand.

Arkansas' costs of natural gas and propane have doubled and then tripled, contributing to employee layoffs.

Oklahoma's second-largest industry is the oil and gas industry. The volatility of oil and gas markets can severely affect Oklahomans and the state's economy.

Striking Home

The Impacts of High Energy Prices on Families, Communities, and Businesses

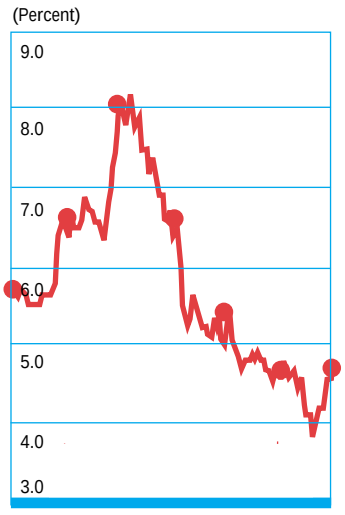
American families, communities, and businesses all depend on reliable and affordable energy for their health, safety, and livelihood. Energy is a critical component of nearly everything that affects our daily lives, from transportation to communication, from food production to medical services, and from air conditioning to heating. Americans expect these services to enhance our lives, and are keenly aware that each additional, unanticipated energy expense is a decrease in funds available for other needs.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to explore potential opportunities to develop educational programs related to energy development and use. This should include possible legislation to create public education awareness programs about energy. Such programs should be long-term in nature, should be funded and managed by the respective energy industries, and should include information on energy's compatibility with a clean environment.

Figure 2-1

Income Spent on Energy



Until recently, the share of disposable household income spent on energy steadily declined, falling to a low of 3.8 percent at the end of 1998. Higher prices for oil and other energy products and record cold temperatures in late 2000 bumped this share up to 4.8 percent in the fourth quarter.

Note: Plotted quarterly through the fourth quarter of 2000.

Source: U.S. Department of Commerce, Bureau of Economic Analysis.

Impacts of High Energy Prices on the Daily Lives of Americans

Many American families and businesses have already felt the strain of rising prices and unreliable energy supplies. Every time energy prices rise, American families have fewer dollars available to meet their needs. Low-income households, energy-intensive industries, and farmers generally find it difficult to make rapid adjustments to energy price increases.

Rising oil prices act like a tax by foreign oil exporters on Americans. Changing energy prices impose economic costs, such as forcing plants to change schedules, replace machinery, or even shut down. These costs can eventually impact economic growth. So far, increased capital investment by domestic energy producers has offset only a small part of the dampening effects of higher energy costs on consumer spending.

Families

Energy bills for the 74 million middle-class American households consist primarily of home and transportation related expenses. Heating and cooling expenses represent about 40 percent of household energy costs. Other energy expenses include costs for lighting, hot water, appliances, and transportation.

For almost twenty years, the share of household income that Americans spent on their energy needs steadily declined. However, between 1998 and the end of last year, family spending on energy rose by more than 26 percent, from 3.8 to 4.8 percent of after-tax income (Figure 2-1).

Last winter, heating bills for many families tripled. Roughly 50 percent of American families heat their homes with natural gas. Because the last two months of 2000 were particularly cold in some parts of the country, heating bills increased significantly relative to the previous winter. Last winter, average natural gas heating costs in the Midwest increased by 73 percent, from $540 to $933. New Englanders' heating bills rose by 27 percent, from $760 to $967.





Higher energy prices have forced some energy-intensive manufacturing industries to halt or scale back production and lay off workers.

Many working households can usually accommodate such increases in energy by cutting back on other needs. However, low-income households often have more difficult choices to make. Energy costs for an average low-income household could total 14 percent of family income during the winter of 2000–01, up from about 11 percent for the previous winter. In contrast, energy costs typically represent only about 4 percent of a middle-class family's household budget.

The Low Income Home Energy Assistance Program (LIHEAP) is a federal block grant program that helps low-income consumers pay their energy bills. Last winter, 1.2 million more American families applied for LIHEAP assistance to pay their heating bills, bringing the total close to 5 million American families—up by 26 percent over last year's 3.9 million applicants. As many as 3.6 million families in eighteen states and the District of Columbia risk being unable to pay their bills and having their energy cut off because of the effects of rapidly increasing energy costs.

Recommendations:

★ The NEPD Group recommends that the President take steps to mitigate impacts of high energy costs on low-income consumers. These steps would include:

- Strengthening the Low Income Home Energy Assistance Pro gram by making $1.7 billion available annually. This is an increase of $300 million over the regular FY 2001 appropriation.
- Directing the Secretaries of Interior and Health and Human Services to propose legislation to bolster LIHEAP funding by using a portion of oil and gas royalty payments.
- Redirecting royalties above a set trigger price to LIHEAP, whenever crude oil and natural gas prices exceed that trigger price, as determined by the responsible agencies.

★ The NEPD Group recommends that the President increase funding for the Weatherization Assistance Program by $1.2 billion over ten years. This will roughly double the spending during that period on weatherization. Consistent with that commitment, the FY 2002 Budget includes a $120 million increase over 2001. The Department of Energy will have the option of using a portion of those funds to test improved implementation approaches for the weatherization program.

★ The NEPD Group recommends that the President support legislation to allow funds dedicated for the Weatherization and State Energy Programs to be transferred to LIHEAP if the Department of Energy deems it appropriate.

The low-income elderly are particularly vulnerable to disruptions in energy supply. If they keep their homes at a reasonable temperature, the high cost of electricity may make it difficult for them to pay their higher electricity bills. This could further result in an elimination of service. Another summer of very hot weather and high energy bills could cause serious health problems for some Americans, particularly those sensitive to high temperatures.

The Department of Energy's Weatherization Assistance Program has reduced the heating and cooling costs of low-income households by weatherizing more than 5 million homes since its inception in 1976. The President has requested $1.2 billion in additional funding for this program over ten years, roughly double the current level of spending. Consistent with that commitment, the 2002 budget will include a $120 million increase over 2001.

The Department of Energy's Weatherization Assistance Program

The energy burden on low-income households, as a proportion of income, is four times greater than for other American households. The Weatherization Program provides grant funding for a network of all states and some 970 local weatherization agencies to provide insulation, duct system improvements, furnace upgrades, and other cost-effective, energy-saving improvements based on the energy needs of each home weatherized. Currently, each dollar spent on home weatherization generates $2.10 worth of energy savings over the life of the home; with additional economic, environmental, health, and safety benefits associated with the installations and resulting home improvements. Typical savings in heating bills, for a natural gas heated home, grew from about 18 percent in 1989 to 33 percent today.

Businesses

For businesses, higher energy prices and disruptions in energy supply may increase inflation and reduce profits, production, investment, and employment. The im-

pact of higher energy prices takes two forms: the higher costs of paying for the energy to run the business, and the higher costs when raw fuel sources are used in manufacturing.

In some energy-intensive industries, rising energy prices have had a significant effect on product prices and operations. For instance, while nonenergy producer prices at the intermediate stage of processing have risen by only 3.6 percent since December 1998, prices of industrial materials and plastic resins, which use petroleum inputs, are up 14 and 23 percent, respectively. DuPont, the leading U.S. producer of plastics, chemicals, and fibers derived from oil and natural gas, faced an increase of $1.3 billion in raw material costs last year, the largest increase in the industry in a decade. The company expects further disruptions this year due to high energy costs.

The Federal Reserve has reported that businesses have experienced higher energy costs for a number of months, but have been unable to pass these increases on to customers due to intense foreign and domestic competition and slowing demand. On March 7, 2001, the Federal Reserve reported that businesses across the country experienced higher fuel and other energy costs in February 2001, but most businesses were unwilling or unable to pass these costs on to consumers.

This absorption of much of the higher costs of energy has deteriorated the profit margins of many businesses. About one-quarter of the increase in total unit costs of nonfinancial, nonenergy corporations in the final quarter of last year reflected a rise in energy costs. A more moderate pace of consumer spending, due in part to higher energy prices (natural gas in particular) also contributed to the margin squeeze. The reduction in businesses' purchasing power has also constrained outlays for plants and equipment and most likely intensified the slowdown in business investment that occurred in the last half of 2000.

Energy-intensive manufacturing industries are very sensitive to changes in energy prices, and adjust their production accordingly. Some companies have been forced to halt or scale back production and lay off workers. Others have deemed it more profitable to sell their energy than to produce their products. In the Pacific Northwest, Georgia-Pacific's paper mill closed down and laid off 800 workers until diesel generators could be installed. In recent months, the company's average power costs soared from $1.2 million to $10 million.

For other industries, such as computer-driven service industries, energy is not an important component of the total cost. However, many such businesses require a high-quality, reliable source of power. Even a brief loss of power can impose significant costs on high-technology firms.

Energy supply disruptions also impose costs on firms when products or prod-



Disruptions in the supply of energy impose hardships on businesses when products or product inputs are damaged or destroyed, or when production runs are interrupted.



Many companies have been unable to pass higher energy costs on to their customers, which has sharply reduced their profit margins.



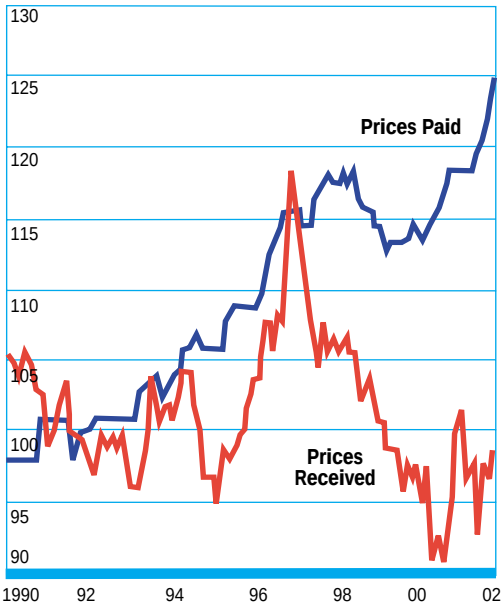
Farmers have been hit especially hard by higher fuel and oil prices, which accounted for over a third of the rise in the cost of running their farms.

uct inputs are damaged or destroyed, or when production runs are interrupted. For example, a survey of small businesses conducted by the National Federation of Independent Business in February, 2001, found that more than half of the firms surveyed that had experienced blackouts this year in California were forced to reduce or shut down business operations altogether during the blackouts. About one-third lost sales, almost 21 percent said materials were damaged or destroyed, and nearly 40 percent had to absorb wage costs for work that was not completed.

For businesses that seek to mitigate energy price volatility, an important factor is access to derivatives markets. Both exchange-traded futures and over-the-counter derivative contracts allow firms to substantially reduce their exposure to changes in energy prices. A wide variety of highly liquid futures contracts on energy products such as oil, natural gas, and electricity allow energy users and market participants to reduce or add financial exposure to energy prices. More sophisticated and customizable products are available in the over-the-counter derivative markets. As these markets become increasingly liquid and efficient, more firms will take advantage of these products, reducing the economy's sensitivity to shifts in energy prices. However, most small businesses currently lack the resources or sophistication to take advantage of these products, and will therefore remain vulnerable to rising energy costs. The U.S. government should continue to support the development of efficient derivatives markets.

Figure 2-2
Farmers Are Being Squeezed by Energy Prices

(Index: 1990–92 = 100)



Costs for fuel, fertilizer, and electricity have boosted total prices paid by farmers, while prices farmers receive for their products have remained weak.

Note: Prices paid are for goods, services, interest, taxes, and wages; prices received are for all farm products.

Source: U.S. Department of Agriculture.

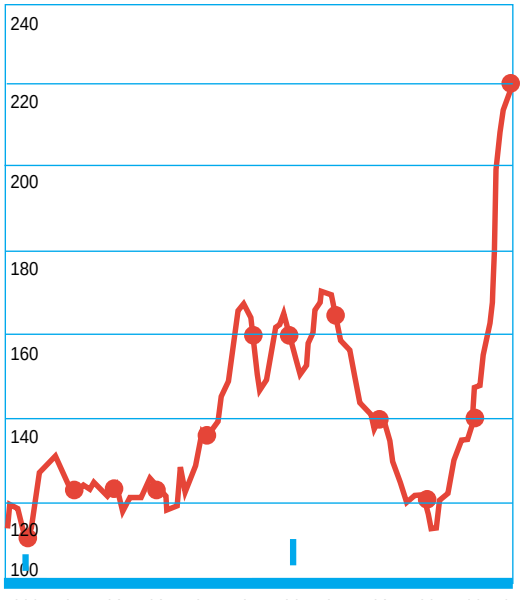
Agriculture

Farmers need ample, affordable energy to run their machinery and equipment. Today, farm production costs are rising sharply, while farm income remains low. Increasing oil prices and interest rates, along with higher prices for other production inputs (including hired labor), boosted farmers' production expenses by 4 percent, or $7.6 billion, in 2000. The rise in farm production expenses has occurred at a time of continued weakness in the prices farmers receive for their products (Figure 2-2).

Higher fuel and oil prices accounted for over one-third of the increase in farm

Figure 2-3
Farm Costs Are Increasing

(Index: December 1979 = 100)



Rising energy prices had a significant effect on product prices in some industries that are heavily dependent on energy inputs. The most dramatic example is the 90 percent increase in the price of nitrogenous fertilizer since December 1998.

Source: U.S. Department of Labor.

production costs. Retail diesel prices this past winter were $1.60 a gallon, compared to about $1.40 a year ago and only $1.00 two years ago. Propane prices were over $1.60 a gallon this winter, compared to $1.10 a year ago. And, natural gas prices hit $10.00 per million Btus in January, after averaging about $2.50 for most of 1998–99. Although natural gas prices have declined, they remain much higher than earlier levels.

Natural gas is an important component of farm production costs. For example, it is used to dry grain, heat farm buildings, and run food-processing equipment. Heating costs for poultry producers soared last winter, sharply reducing earnings.

Natural gas also is a major component in the production of fertilizers, pesticides, and other farm chemicals. It accounts for 70 to 90 percent of the cost of producing anhydrous ammonia, a key source of nitrogen fertilizer. Surging natural gas prices have boosted the price of nitrogenous fertilizer by 90 percent since 1998 (Figure 2-3). During last December and January, several nitrogen production plants shut down, and capacity utilization fell to 50 percent. Anhydrous ammonia recently sold for $330 a ton in the Midwest, compared to $210 a ton for all of 2000 and $160 to $170 a ton at the start of 2000.

Depending on the region of the country and type of farming enterprises, energy-related expenses range from 10 to 30 percent of operating costs for producing major crops. Farm operating costs are highest where fertilizer use is heaviest and natural gas is used for irrigation pumps, such as wheat, cotton, and corn farms in the West and southwestern plains states. Costs are high for greenhouse and nursery crops that use natural gas for heating. Perishable crops also face problems, as energy costs in processing are markedly higher.

Most of California's 9.5 million irrigated acres use electricity to pump water. In addition to higher bills, California farmers will likly face rolling blackouts this summer, which may disrupt farming and processing operations. Low stream flows in the West this year may lead to more pumping of ground water, which will add to irrigation costs in the West. As a result, the costs of California's agricultural products may rise significantly.

In 2001, farmers' total cash production expenses are forecast to increase by an additional $1.5 billion to a record $179.5 billion.

Farm production costs are rising sharply, while farmers' incomes remain low. Depending on the region of the country and type of farming enterprises, energy-related expenses range from 10 to 30 percent of operating costs for producing major crops



Even though total planted acreage is expected to fall this year, higher natural gas prices will raise expenses for nitrogen fertilizer. At the same time, net cash farm income is projected to decline from $56.4 billion in 2000 to under $51 billion in 2001, as production expenses continue to rise.

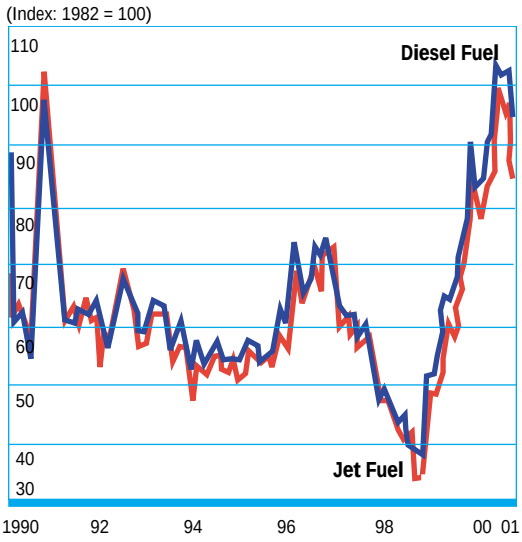
Taken together, fertilizer, fuel, and electricity costs for farmers are forecast to reach $24 billion for 2001, up by about 28 percent from $18.7 billion in 1999. This increase is about 9 percent of U.S. net cash farm income, and that share could be much higher for many individual commodities.

Transportation

The transportation sector accounts for nearly 30 percent of total U.S. energy consumption. The major transportation fuel sources are petroleum-based gasoline and diesel, jet, and marine-mode bunker fuels. Natural gas pipelines are used for product distribution, and electricity is the primary source of power for rail transit and liquid pipeline transmission and distribution.

During 2000, oil prices surged to a nine-year high, and gasoline prices skyrocketed. On average, fuel prices rose by 30 to 40 cents a gallon from 1999 prices, resulting in sharp increases for most modes of transportation, with nearly a 60 percent increase in railroad diesel fuel prices.

Figure 2-4
Transportation Costs Are on the Rise



The recent 140 percent rise in producer prices for intermediate diesel and airline fuels has affected the price of passenger and freight transport.

Note: Plotted through February 2001.
Source: U.S. Department of Labor.



A recent study by a San Francisco Bay business group concluded that blackouts could cost California as much as $16 billion annually, and $5 billion in the Bay area alone.

Price spikes have hit the travel and trucking industries particularly hard and have led to the closure of some operations. Trucking bankruptcies are currently at an all-time high. Over 3,500 motor carrier operations failed in 2000, a dramatic increase over the previous record high of 2,700 motor carrier failures in 1997. Producer prices for intermediate diesel fuel and aviation fuel each rose by about 140 percent from a low in December 1998, affecting passenger and freight transport in the highway, airline, rail, and other transportation sectors (Figure 2-4).

For most transport operations, energy-related expenses were 7 to 14 percent of total operating costs in 1998–99. This share was expected to jump to 10 to 25 percent in 2000. Excluding private auto travel, U.S. passenger and freight operations in 1999 generated about $600 billion in annual revenue and paid approximately $60 billion for fuel and power. If the volume stayed the same in 2000, the various increases in fuel costs for each mode of transportation would yield a fuel bill of

about $80 billion—an increase of one-third over the prior year's bill.

Economic Impacts of California's Energy Crunch

In California, 43 percent of small businesses surveyed in February, 2001, said the power problem had dimmed their views about California as an attractive place for doing business. When asked whether they agreed with the statement, "The electricity problem has forced me to take concrete steps exploring the possibility of moving my business out of California," 18.3 percent of small business respondents said they either agreed or strongly agreed with the statement. More than 31 percent said they will probably or definitely cut back on planned business investment, and almost 20 percent are exploring a move to another state. Half of these small businesses concluded that blackouts would reduce their earnings.

The Silicon Valley Manufacturing Group recently estimated that its nearly 200 members lost over $100 million dollars because of one day of rolling blackouts in June 2000. Countless more millions of dollars have been lost by interruptible commercial power users. Fontana-based California Steel Industries estimates it lost $2.4 million in a single day after its interruptible power was cut off twice for a total of about 12 hours. A recent study by a San Francisco Bay business group concluded that blackouts could cost California as much as $16 billion annually, and $5 billion in the Bay area alone.

The example of California's utilities illustrates the potentially severe negative effects on companies whose business is highly sensitive to energy prices. In this instance, rising energy costs coupled with an inability to pass those costs along to customers has created a sharp increase in short-term liabilities. Pacific Gas & Electric has been forced to file for bankruptcy as a result, and Southern California Edison, while avoiding bankruptcy for the time being, has seen its access to credit markets disappear and the value of its financial assets plummet. Resulting concerns about solvency have led to a withdrawal of bank-lending facilities and supplier credit.

The situation in California is of particular concern because of the major role the state plays in the regional and national economies. California's economy is equivalent to about 13 percent of U.S. gross domestic product (GDP), and it has accounted for an even larger share of U.S. GDP growth in recent years. Some businesses and consumers have been affected by production losses, lost wages, and higher energy bills resulting from rolling blackouts and higher natural gas prices.

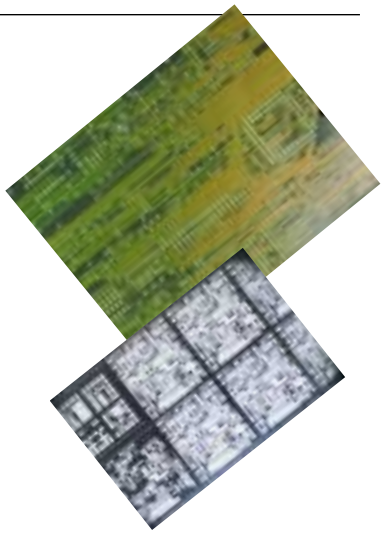
The power supply crunch in California and the West could affect the region's economy, as energy supply uncertainty could reduce investment in the region. California's troubles could also spill over to the national economy:

- California accounted for 11 percent of U.S. manufacturing output in 1998. Sectors in other regions that rely on those products, or that supply inputs to California manufacturers, may share any pain caused by the energy squeeze.
- Disruptions to California's economy could have negative impacts on our international trade. California accounts for over 16 percent of total U.S. commodity exports; nearly 25 percent of industrial equipment and computers, electronics, and instruments exports; and over 15 percent of farm commodity and food product exports.
- The credit problems of the California utilities have boosted commercial paper rates for all lower-rated borrowers, and liquidity in the commercial paper market has fallen. This will push some firms to seek other sources of financing, which can be more costly than commercial paper.

American consumers and businesses are best served when markets function freely. Free markets allow prices to reflect changes in demand and supply, and avoid subsidies, price caps, and other constraints.

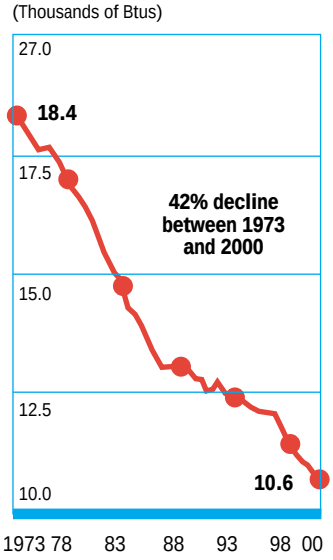
Improvements in Energy Efficiency Can Help

Improved energy efficiency strengthens energy security. The 42 percent decline in the intensity of U.S. energy use since the energy crisis in 1973 reflects a combination of technological advances, conservation ef-



The Silicon Valley Manufacturing Group recently estimated that its nearly 200 members lost over $100 million dollars because of only one day of rolling blackouts in California.

Figure 2-5
Conservation Through Higher Efficiency
Energy Consumption per Dollar of Real GDP



Energy intensity is the amount of energy used to produce a dollar's worth of gross domestic product (GDP). As a result of the 42 percent decline in energy intensity since the first energy crisis in 1973, the U.S. economy is far better prepared to day than it was in the 1970s to ad just to energy price or supply shocks.

Note: Real GDP in 1996 chained dollars.
Source: U.S. Department of Energy, Energy Information Administration.

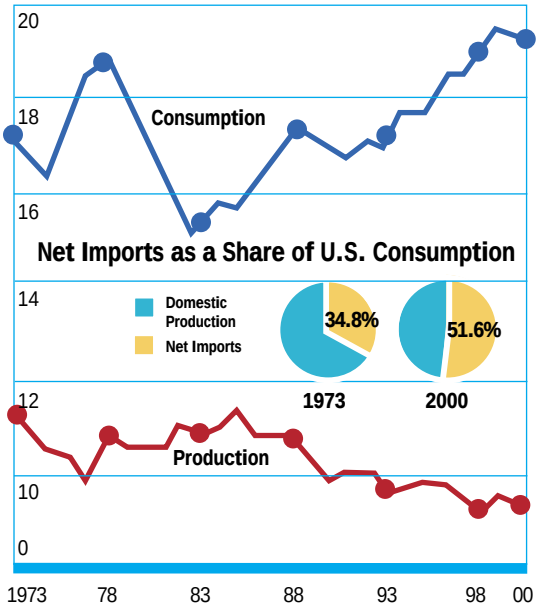
forts, regulatory action, market response, and a shift toward a service economy (Figure 2-5). Our improvements in energy efficiency have prevented our current energy problems from becoming worse.

The macroeconomic effects of a substantial rise in energy prices take two forms. First, to the extent that energy resources are imported, more U.S. dollars must be sent abroad to finance energy consumption, thus reducing funds available for investing in our own country. Second, higher prices cause dislocations among certain sectors of the economy, which could ultimately feed through to lower GDP growth and higher inflation.

Reliance on Foreign Energy

Between 1973 and 2000, U.S. dependence on foreign oil rose from about 35 percent to more than 52 percent of U.S. consumption (Figure 2-6). During the same period, the import share of natural gas consumption climbed from less than 5 percent to more than 15 percent and continues to rise.

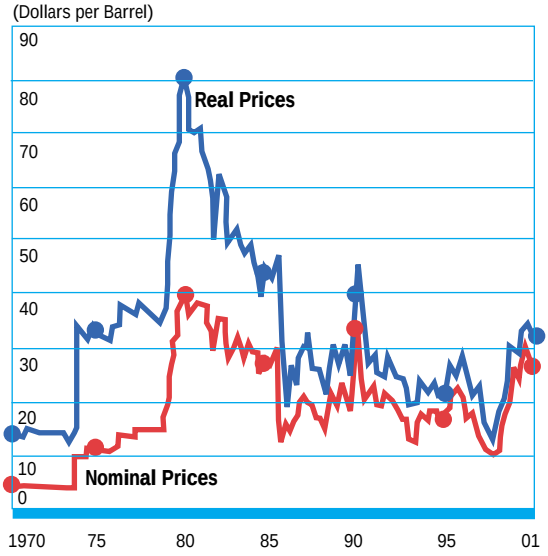
Figure 2-6
Dependence on Oil Imports Is Rising
(Millions of Barrels per Day)



Over the past few decades, U.S. consumption of oil and petroleum products has increasingly outpaced domestic production. Today the United States imports over half of the oil it consumes—up from about 35 percent in the early 1970s.

Note: Petroleum includes both crude oil and petroleum products.
Source: U.S. Department of Energy, Energy Information Administration.

Figure 2-7
Oil Prices Have Risen Sharply
Monthly Spot Price of West Texas Intermediate Crude Oil
(Dollars per Barrel)



Despite the sharp rise in crude oil prices since late 1998, real prices still remain lower than at any time from 1974 to 1985.

Note: Real prices in 2000 dollars. Prices deflated using the Consumer-Price Index–Urban (CPI–U) Research Series for all items linked to CPI–U–X1 prior to December 1977.
Sources: Wall Street Journal; U.S. Department of Labor, Bureau of Labor Statistics.

Imports of energy products make up nearly 11 percent of all U.S. imports. By contrast, U.S. energy exports are relatively small. The energy trade deficit relative to our GDP represents the share of U.S. income that must be exported to purchase foreign fuel to meet domestic energy needs. The U.S. energy trade deficit in 2000 was about $120 billion, most of which was spent on oil imports.

As a share of GDP, the energy trade deficit had fallen to as low as 0.4 percent at the beginning of 1999, when prices for imported crude oil were less than $10 a barrel. However, by the end of 2000, these prices had tripled to more than $30 a barrel (Figure 2-7). As a result of both the oil price spike and growing U.S. demand, the energy deficit deteriorated significantly to 1.3 percent of GDP by the fourth quarter of last year—the largest deficit relative to GDP since the mid-1980s (Figure 2-8). The rise in oil prices alone has added about 0.7 percent of GDP to the U.S. trade deficit, compared to 0.9 percent in the euro currency area, and 0.8 percent in Japan.



Financial markets react to energy costs and the effect those energy costs have on both individual firms and sectors of the market.

Figure 2-8
The U.S.Energy Trade Deficit Has Worsened



The energy trade deficit relative to GDP represents the share of domestic income that must be exported to sup port domestic energy needs. For the past several years, the United States has been a net importer of energy prod ucts. As a consequence, our energy trade balance has been in deficit. By the fourth quarter of 2000, the energy deficit had deteriorated significantly to 1.3 percent of GDP—the largest since the mid-1980s.

Note: Plotted quarterly through the fourth quarter of 2000.-
Source: U.S. Department of Commerce, Bureau of Economic Analysis.-

Net U.S. oil imports are 4 billion barrels a year, which means that each $1 increase in the price of imported crude oil boosts U.S. expenditures by about $4 billion. Given these guidelines, the $20 per barrel increase from early 1999 to late 2000 translates into an export of roughly $80 billion a year (0.9 percent of GDP) when measured from the low price prevailing at the end of 1998.

Impacts of Energy Prices on Financial Markets

An analysis of the financial impacts of higher energy prices can be divided into two parts: the effects on individual firms whose securities comprise the financial markets, and the macroeconomic impact on inflation and interest rates. Rising energy costs and greater volatility in energy prices can have a negative effect on both individual firms and the broader financial environment, generally producing lower asset prices and higher interest rates. The financial market impact to date of rising energy prices has been limited to firms with high sensitivity to energy costs and to those with significant exposure to the California crisis. The second broad effect of rising energy costs is an increase both in measured inflation

and in expectations for future inflation. Both factors have considerable impact on interest rates and, therefore, on the borrowing costs for businesses and consumers throughout the economy.

Inflation Expectations and Interest Rates

Measurable inflation, for both producers and consumers, is a primary concern of the Federal Reserve in conducting monetary policy. Energy costs represent roughly 16 percent of the producer price index for finished goods and 8 percent of the consumer price index. This means that sharply rising energy costs can have a substantial impact on the Federal Reserve's decision-making process. Additional impacts will come from the market's anticipating Federal Reserve actions and pushing short-term interest rates higher than they otherwise would have been. Higher short-term interest rates raise the nominal cost of borrowing for firms and individuals and can slow economic growth.

Rising energy prices can also raise the inflation expectations of lenders, which can result in higher interest rates for borrowing at longer maturities. Rising long-term interest rates can reduce long-term investment, limiting future economic growth and productivity gains. Such an outcome would carry negative consequences for growth-sensitive financial sectors, such as equity and high-yield debt markets.

More broadly, declining credit fundamentals for certain business sectors could raise borrowing costs for firms not directly affected by higher energy prices. For example, commercial paper rates for all lower-rated borrowers have been affected by the credit problems of the California utilities, and liquidity in the market has fallen. As a result, firms may need to seek other sources of financing, such as bank loans (if obtainable) or asset-backed loans, that can be more costly than traditional commercial paper issuance.

Global Financial Markets

The upward pressure on interest rates that may result from higher U.S. energy costs also affects markets beyond our borders. U.S. monetary policy and related movements in short-term interest rates can have a significant impact on other countries. While the effect varies from region to region, many emerging market economies, particularly in Latin America, are vulnerable to upward moves in U.S. interest rates.

Higher nominal interest rates in the developed countries tend to reduce the amount of capital flowing to emerging markets. To the extent that this reduces investment, economic activity may be further reduced. In addition, borrowing in dollars is a significant source of funding for sovereign and private-sector entities worldwide, particularly in the emerging markets. Rising U.S. interest rates will increase the interest expenses for these borrowers, diverting funds from more productive uses and reducing overall credit quality.

The global market for energy is highly fragmented and region-specific, with the exception of oil. Nevertheless, certain nations and regions are net importers of energy and are highly sensitive to changing prices. Japan, a major importer of oil and natural gas, is particularly vulnerable. Europe is a net importer of energy, with certain exceptions, while emerging market nations vary widely in their dependence on foreign energy sources.

At the macroeconomic level, rising energy prices will increase the current account deficit of energy-importing nations. Since current account deficits must be financed, these nations will most likely need to pay higher interest rates to attract the necessary capital. As noted, this will tend to reduce domestic investment and lower long-term growth. In some countries, such as the United States or Japan, changes in interest rates and growth expectations can have substantial global impact.

Central banks and monetary authorities vary in the degree to which they focus on inflation in setting monetary policy, making some countries more or less likely than others to raise interest rates in an environment of rising energy prices.

Although Japan maintains a current account surplus due to manufacturing exports, its role as an international creditor could diminish. This may have additional impacts on the global financial markets, since Japanese financial institutions are generally suppliers of global credit.

The impact of rising energy costs on the dollar is likely to be mixed. While slower U.S. growth generally reduces demand for dollars, rising oil prices are likely to increase demand, since oil contracts are usually denominated in dollars.

Summary of Recommendations

★ The NEPD Group recommends that the President direct the Secretary of Energy to explore potential opportunities to develop educational programs related to energy development and use. This should include possible legislation to create public education awareness programs about energy. Such programs should be long-term in nature, should be funded and managed by the respective energy industries, and should include information on energy's compatibility with a clean environment.

★ The NEPD Group recommends that the President take steps to mitigate impacts of high energy costs on low-income consumers. These steps would include:

- Strengthening the Low Income Home Energy Assistance Program by making $1.7 billion available annually. This is an increase of $300 million over the regular FY 2001 appropriation.
- Directing the Secretaries of Interior and Health and Human Services to propose legislation to bolster LIHEAP funding by using a portion of oil and gas royalty payments.
- Redirecting royalties above a set trigger price to LIHEAP, whenever crude oil and natural gas prices exceed that trigger price, as determined by the responsible agencies.

★ The NEPD Group recommends that the President increase funding for the Weatherization Assistance Program by $1.2 billion over ten years. This will roughly double the spending during that period on weatherization. Consistent with that commitment, the FY 2002 Budget includes a $120 million increase over 2001. The Department of Energy will have the option of using a portion of those funds to test improved implementation approaches for the weatherization program.

★ The NEPD Group recommends that the President support legislation to allow funds dedicated for the Weatherization and State Energy Programs to be transferred to LIHEAP if the Department of Energy deems it appropriate.

★ The NEPD Group recommends the President recognize unique regional energy concerns by working with the National Governors Association and regional governor associations to determine how to better serve the needs of diverse areas of the country.

★ The NEPD Group recommends the President direct FEMA to prepare for potential energy emergencies.

- -FEMA should work with states' Offices of Emergency Management as they expand existing emergency operations plans to identify potential problems and address consequences of the power shortages. FEMA should use its current Regional Incident Reporting System to identify any situations that might demand immediate attention.
- Using the structure of the already existing Federal Response Plan, FEMA should conduct Regional Interagency Steering Committee (RISC) meetings for states affected by the energy shortfalls. The RISC is a FEMA-led interagency committee comprised of agencies and departments that support the Federal Response Plan. Either an upcoming, scheduled RISC meeting or a special-focus RISC meeting can be held to identify the short-term energy outlook, as well as any expected consequences, in each of the states during the peak summer season.

Protecting America's Environment

Sustaining the Nation's Health and Environment

Over the last three decades, American ingenuity has led to a reduction in adverse environmental and public health impacts from energy development and use. Americans demand a reliable energy supply and a clean environment, and we can achieve both. Spurred by strong environmental concerns, competitive forces, and environmental regulations, businesses have developed innovative technologies and pollution-prevention techniques to protect the environment. However, more can be done.

As our energy needs continue to grow and our production and distribution system is strained to capacity, it is clear that the lack of a comprehensive energy policy has environmental costs. For example, to prevent blackouts, California officials must tolerate a large short-term increase in smog-forming nitrogen oxides emissions. In Los Angeles, older, dirtier power plants have had to run longer than expected. California is also rushing to use mid-sized "peaker power plants" and diesel-fired emergency backup generators to keep the lights on.

The short-term cost in increased pollutant emissions of these emergency measures has been stark. Preliminary figures from California's South Coast Air Quality Management District indicate emissions have doubled in the first three months of the year compared with last year. In addition to nitrogen oxides emissions, diesel-fired backup generators also emit toxic soot. But with many days of blackouts predicted in California this summer, these generators will most likely run for much longer than expected, and could greatly increase emissions.

In the longer term, penalties and technological improvements should offset the impact of these increased emissions. However, California's experience demonstrates the environmental costs of not building an adequate supply of clean energy.

Government's Role

The federal government has a unique role in facilitating energy development while simultaneously protecting the environment and conserving our country's natural resource legacy. Energy development initiatives will be successful only if they adequately address their impacts on natural resource values.

Federal, state, tribal, and local governments have the responsibility of protecting unique natural resources and environmental values. In fact, some environmental protections we enjoy today are often taken for granted. For example, lead levels in ambient air today are 98 percent lower than they were in 1970, largely because government regulations required that lead be removed from gasoline. The reduced number of children with IQs below 70 is attributed to reducing lead in our environment.

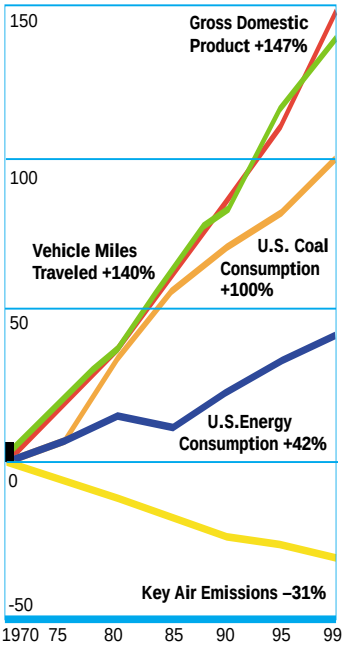
As U.S. energy needs grow, additional innovations will be necessary to continue improving environmental conditions and to meet new environmental challenges. As we improve the energy production and distribution system, all levels of government must ensure that regulatory systems protecting public health and the environment are rigorous and efficient, and encourage innovation and improvement.



Roughly 30 percent of our nation's electricity supply is now generated by nuclear, hydropower, and renewable sources, all of which have few air emissions.

Figure 3-1
Cleaner Air: Energy Consumption Has Risen While Emissions Have Declined

(Percent Change Since 1970)



Despite a marked increase in U.S. energy consumption, a combination of environmental regulations and technologies has decreased aggregate emissions of key air emissions: SO_2, NOx, mercury, CO, and volatile organic compounds.

Sources: U.S. Department of Energy, Energy Information Administration, and U.S. Environmental Protection Agency.

Air Quality

Regulatory Programs

Advances in technology and environmental regulations have decreased aggregate emissions of key air pollutants over the last three decades, despite a marked increase in energy consumption (Figure 3-1). Roughly 30 percent of our nation's electricity supply is now generated by nuclear, hydropower, and renewable sources, all of which have few air emissions.

Nonetheless, fossil fuel-fired power plants, other industrial sources, and vehicles remain significant sources of air pollution (Figure 3-2). These emissions can be associated with significant health problems, including respiratory and cardiopulmonary disease, cancer, and birth defects. In addition, they can be harmful to forests, water bodies, and fish, and can decrease visibility in scenic areas.

Environmental Protection Agency's (EPA) Acid Rain Program, enacted as part of the 1990 Clean Air Act Amendments, is the only program directed primarily at reducing air emissions from electric utilities.

Using flexible market-based incentives instead of technology-forcing standards, the program has reduced sulfur dioxide (SO_2) emissions from utilities faster than required by law for a fraction of the initial cost estimates. By 2010, EPA expects the program will reduce annual SO_2 emissions by 10 million tons from 1980 levels, thus avoiding significant health problems and the costs associated with those levels.

Federal and state regulatory programs also limit air pollution directly by restricting emissions from cars and trucks, and indirectly by setting criteria for the fuel for these vehicles. An individual car meeting 2004 federal requirements will emit 95 percent less carbon monoxide (CO), 94 percent fewer nitrogen oxides (NOx), and 98 percent fewer hydrocarbons than an average car did before laws limiting such vehicle pollution. Although individual cars and trucks are far cleaner today than they were in 1970, total emissions from the fleet of highway vehicles have remained relatively constant, because Americans drive twice as many miles today (2.5 trillion miles a year) as they did in 1970 (1.1 trillion miles a year).

Despite these and other achievements, further air quality improvements can be sought, as well as ways to address new problems identified by recent scientific findings. EPA has recently adopted new, more stringent standards to further reduce ozone and particulate matter. To meet public health and environmental challenges, power plants, industrial sources, and vehicles will need to produce fewer potentially harmful emissions.

Recommendation:

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to propose multi-pollutant legislation. The NEPD Group recommends that the President direct the EPA Administrator to work with Congress to propose legislation that would establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators. Such a program (with appropriate measures to address local concerns) would provide significant public health benefits even as we increase electricity supplies.

- Establish mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides, and mercury.
- Phase in reductions over a reasonable period of time, similar to the successful acid rain reduction program established by the 1990 amendments to the Clean Air Act.
- Provide regulatory certainty to allow utilities to make modifications to their plants without fear of new litigation.
- Provide market-based incentives, such as emissions-trading credits to help achieve the required reductions.

Cleaner, More Efficient Technologies

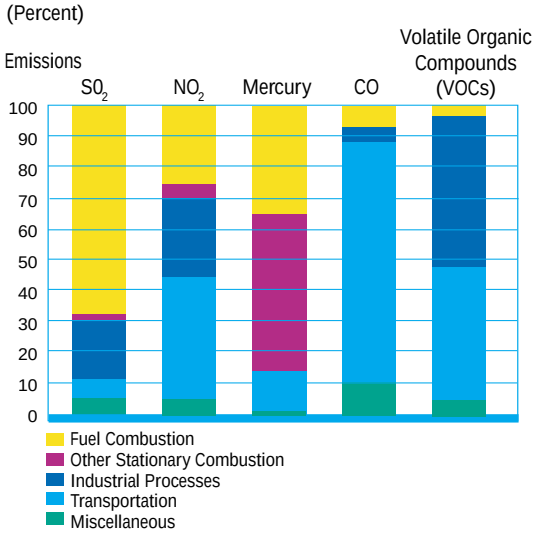
Emission control technologies and emission prevention not only decrease pollution but can also contribute to economic prosperity. Innovative emission control and prevention technology and increasingly efficient energy systems have developed at a brisk pace, increasing our ability to provide cleaner, cheaper energy. Besides reducing pollution, environmental technologies account for about $21.3 billion in U.S. exports, and support approximately 136,000 U.S. jobs.

The need to reduce emissions from cars and trucks has contributed to technological innovations that have transformed the domestic and global automotive industries. U.S. vehicle emission standards were the primary driving force for the original development of innovative technologies, many of which have become standard design features of today's high-tech vehicles: sophisticated three-way catalysts, on-board computers, oxygen sensors, and fuel-injection systems for cars and advanced fuel systems for trucks. Technologies such as these have allowed today's vehicles to be much cleaner, more efficient, higher performing, more reliable, and more durable than their counterparts of the 1960s and 1970s. Manufacturers are now working on developing state-of-the-art pollution control technology to further reduce emissions from motor vehicles. For optimal performance, this technology requires low-sulfur fuel that, consistent with applicable law, will be required in 2004 for gasoline and 2006 for diesel fuel. Some vehicles use alternative fuels (*e.g.*, natural gas, propane, ethanol, and electricity); others operate with a hybrid gasoline and electrical motor; and others are using fuel cells.

Cleaner Electricity

The source of energy used for power generation significantly affects the amount of air emissions. Clean energy can be generated from nuclear plants, hydropower facilities, wind farms, and solar energy systems with negligible (if any) air emissions. These sources today make up about 30 percent of our electricity supply. Solar and wind energy systems will continue to improve with advances in short-term weather and climate forecasting. Improved forecasting can also maximize hydropower efficiency.

Figure 3-2
Sources of Pollutants from Energy Generation and Use
(Percent)



Technology significantly reduces pollution from coal-fired power plants, which generate more electricity in the United States than any other source. For example, scrubbers can remove 95 percent of the SO_2 emissions from a coal-fired power plant. With the innovative, market-based SO_2 reduction requirements of the Clean Air Act Amendments of 1990, the estimated cost of using a scrubber on a coal-fired power plant to remove one ton of SO_2 has dropped approximately 40 percent in four years, from $474/ton in a 1993 estimate to $282/ton in a 1997 estimate, and continues to decline. Other existing control technologies for coal-fired plants can reduce NOx emissions by more than 90 percent.

A recently permitted state-of-the-art coal-fired unit, for example, at a Kansas City Power & Light facility, has 88 percent lower NOx, 99 percent lower particulate matter, and 92 percent lower SO_2 emissions than would an uncontrolled facility.

Recent research by the Department of Energy (DOE), EPA, and private companies suggests that existing technologies can also significantly reduce mercury emissions.

Technologies for Reducing SO_2 Emissions

Many power plants use flue-gas desulfurization, or scrubbers, to reduce SO_2 emissions from burning coal. The most common wet scrubber, the limestone forced-oxidation (LSFO) process, removes SO_2 from the flue gas by sorption and through chemical reactions with the limestone. LSFO technologies can remove up to 98 percent of SO_2 and significant amounts of mercury. The most common dry scrubber, the lime spray-drying process, is used for plants that burn lower-sulfur coals. A lime slurry mixes with the hot flue gas in a spray dryer and reacts with SO_2. By recapturing sorbent at the bottom of the spray dryer removed in a particulate control device, dry scrubbers can remove up to 96 percent of SO_2.

Clean Coal Technologies

New clean coal technologies are showing that air pollution can be reduced, and energy efficiency increased, by using America's abundant supply of coal.

Most conventional air emission control technologies installed on coal-fired electric-generating boilers have been designed to remove a specific pollutant from the stack flue gas. Because these technologies may not be the most cost effective means of reducing multiple pollutants, several companies are developing a single-control technology to reduce multiple air pollutants to levels equivalent to those achieved by conventional controls.

For example, a First Energy plant in New Hampshire recently pilot-tested state-of-the-art technology that has cut NOx emissions by 76 percent, SO_2 by 44 percent, total particulate matter by 99.94 percent, and mercury by 81 percent. The process uses electrically charged particles instead of catalysts to oxidize the air pollutants into products that are easily removed and can be converted to gypsum, fertilizer, and concentrated acids. American Electric Power is installing a wet scrubber system that it expects will remove up to 75 percent NOx and 90 percent mercury. It injects a phosphorus mixture into the hot flue gas, causing the release of ozone. The ozone then oxidizes the mercury into ionic mercury and the NOx into N_2, both of which are water-soluble and easily removed.

Using flexible market-based incentives, EPA's Acid Rain Program has reduced sulfur dioxide (SO_2) emissions from utilities faster than required by law for a fraction of the initial cost estimates.



Technologies for Improved Efficiencies

Two-thirds of the energy used in a conventional coal-fired power plant is wasted in the production of electricity. These losses can be minimized through a number of innovations, including installing high efficiency steam turbines, reducing steam leaks, and using software to optimize combustion efficiency. New coal-burning power plants can achieve efficiencies of over 40 percent using existing technology, and companies are developing even more efficient technologies. Wasted energy can also be recycled for use in industrial processes or for heating buildings.

A family of technologies known as combined heat and power (CHP) can achieve efficiencies of 80 percent or more. In addition to environmental benefits, CHP projects offer efficiency and cost savings in a variety of settings, including industrial boilers, energy systems, and small, building-scale applications. At industrial facilities alone, there is potential for an additional 124,000 megawatts (MW) of efficient power from gas-fired CHP, which could result in annual emission reductions of 614,000 tons of NOx emissions and 44 million metric tons of carbon equivalent. CHP is also one of a group of clean, highly reliable distributed energy technologies that reduce the amount of electricity lost in transmission while eliminating the need to construct expensive power lines to transmit power from large central power plants.

The U.S. Department of Energy, through its Clean Coal Technology Program, is working with utilities and scientists to develop even cleaner, more efficient electricity-generating systems using coal. One of the most promising new approaches to using coal for clean production of electricity is integrated gasification combined-cycle (IGCC) technology. IGCC power plants convert coal to a gaseous fuel, from which most

Clean Coal Technologies Up Close

The Wabash River Coal Gasification Project in Terre Haute, Indiana, is one of the cleanest, most efficient coal-burning facilities in the country. Partly funded by the Department of Energy (DOE) as part of its Clean Coal Technology Program, the 262-MW coal gasification facility is owned and operated by PSI Energy and Global Energy, Inc. Instead of being directly burned, the coal is gasified and then combusted in a combined-cycle gas turbine. This allows the coal to burn more efficiently—which means it gets more energy than a traditional plant out of the same amount of coal. The Wabash River Facility is over 20 percent more efficient than a typical coal-fired power plant.

The gasification process also allows many of the impurities in the coal to be removed before it is combusted to generate electricity. At the Wabash River project, over 99 percent of the sulfur is removed from the coal and marketed to industrial users of sulfur. Slag is also removed and is marketed to the construction industry. The plant's design allows it to burn other fuels, such as petroleum coke.

DOE is currently working with Global Energy and other industry partners to see if the plant could also be used to co-produce chemical feedstocks and transportation fuels. Additionally, DOE and its partners are studying lessons learned from the project to design a less expensive, more efficient coal gasification facility that would be ready for commercial deployment by 2005.

of the impurities are removed prior to combustion, and then use the gaseous fuel in a combustion turbine to produce electricity. Waste heat from the turbine is used to generate steam and drive a steam turbine, to produce more electricity.

Coal gasification plants offer the flexibility to burn other fuels, such as petroleum coke, and to make other products in addition to electricity, such as chemical feedstocks and transportation fuels. Hydrogen, which is produced directly in the coal gasifier, can be used in fuel cell-equipped vehicles. Methane, hydrogen, and other gasified coal products can be recombined into more traditional fuels, such as methanol, gasoline, or diesel fuel. Because these fuels would contain essentially no sulfur, they would easily meet EPA's sulfur standards for transportation fuels, and they would be usable in fuel cell-equipped vehicles designed for these fuels.

Two plants demonstrating coal gasification technology have already been built in the United States and have achieved over 98 percent SO_2 reduction, 90 percent NOx reduction, particulate emissions below detectable levels, and approximately 38 percent efficiency. EPA believes that lessons learned will enable the next plant of this design to achieve 42 percent efficiency, and the research goal is to achieve 60 percent efficiency for plants introduced after 2015.

A modern gas-fired power plant has virtually no SO_2 or mercury emissions and emits 97 percent less NOx and 50 percent less carbon dioxide (CO_2) than a traditional coal-fired plant. Natural gas as a source of electricity generation is on the rise, in part because it can help generators meet increasingly stringent clean air requirements.

Conservation and Environmental Protection

Conserving energy minimizes adverse environmental effects. Government partnerships with businesses and consumers are improving the energy efficiency of homes, office buildings, transportation sources, and industrial sites throughout the country. EPA's voluntary conservation and energy efficiency programs include Energy Star products labeling; Energy Star Residential programs for both new homes and home improvement; Energy Star Buildings, principally for commercial buildings; and new Energy Star for Industry, which focuses on manufacturers. In 2000, business participation in EPA's voluntary energy efficiency

programs reduced NOx emissions by more than 160,000 tons.

Through EPA's and the Department of Transportation's Commuter Choice Leadership Initiative, private-public employers are offering employees a variety of commuting options, which encourage commuting patterns that save fuel and energy while reducing emissions. For example, a 10 percent reduction in the rate of growth in vehicle miles traveled can result in annual savings of 38 million barrels of gasoline (82 million barrels of oil) by 2005, and can remove 45,000 metric tons of NOx, 37,000 metric tons of hydrocarbons, and 4.8 million metric tons of carbon-equivalent emissions.

Energy efficiency and conservation in the home are also important factors. Examples include EPA's home improvement program, which involves efficient appliances, duct work to prevent air conditioners from leaking, efficient windows, programmable thermostats, and efficient residential lighting.

Federal and state regulators are working with businesses and communities to mitigate adverse environmental impacts by requiring developers and operators to choose more environmentally friendly sites, infrastructure routes, and operational criteria; fostering the use of technologies that both protect the environment and still meet energy production goals; and requiring reclamation and mitigation of any environmental damage.



Water Quality

Oil, gas, and coal extraction processes can degrade water quality through their discharges. Energy generation and use can also degrade water quality by directly discharging pollutants into water bodies; changing the temperature, timing, and flow characteristics of water bodies; and emitting pollutants into the air that are ultimately deposited in water. Leaking storage tanks and pipelines release petroleum and fuel additives that can contaminate surface water and ground water, including drinking-water supplies.

Federal and state regulators are working with businesses and communities to mitigate these adverse impacts by requiring developers and operators to choose more environmentally friendly sites, infrastructure routes, and operational criteria; fostering the use of technologies that both protect the environment and meet energy production goals; and requiring reclamation and mitigation of any environmental damage. For example, as a result of an analysis under the National Environmental Policy Act of the impacts of a new power plant in California, the company building the plant agreed to change the design to use a dry cooling method. This change reduced ground-water consumption by 95 percent and eliminated both cooling tower "blowdown" water and particulate emissions, while still achieving the desired energy production. Adverse impacts to aquatic life from cooling-water intakes, thermal discharges, and hydropower intakes can be minimized with proper design and environmental controls. A cooperative government, industry, and community-based approach during project siting and design will help ensure full consideration of the effects upon fish and aquatic resources.

Programs to reduce air pollution also help clean up water bodies. For example, reducing electric utilities' air emissions of NOx and SO_2 and vehicles' NOx emissions reduces eutrophication and acid deposition in estuaries, both of which can harm fish populations and threaten commercial and recreational yields. For example, roughly 25 percent of nitrogen (which contributes to

eutrophication) entering Chesapeake Bay is from air emissions. And by significantly reducing SO_2 air emissions, the Acid Rain Program has helped reduce the acidification of water bodies.

Airborne mercury emitted by coal-fired power plants has been deposited into thousands of water bodies, and humans can be exposed to toxic methyl mercury when they eat fish from these waters. The Bush Administration will propose legislation adding mercury to the list of pollutant emissions from power plants that will be subject to mandatory limits.

Fish, Wildlife, and Their Habitat

Ecosystems provide food, shelter, and critical breeding and spawning grounds for fish and wildlife, and support commercial and recreational fishing, tourism, and other activities that contribute billions of dollars to the U.S. economy every year. Oil and gas exploration and production, hydropower dams, power plants, pipelines, and other energy-related projects can potentially affect fish, wildlife, and habitat. However, technological advances, a strong commitment to environmental protection, and the use of appropriate regulatory tools can enable proper energy development to go forward in an environmentally sensitive manner. It is important to recognize and to continue the progress in this area.

When energy development is proposed, the federal government has the dual responsibilities of facilitating such energy development *and* conserving our natural resource legacy.

Special efforts are often necessary to ensure that proposed energy projects do not diminish the vitality of these unique resources. Working together, the public, businesses, and federal, state, tribal, and local governments can ensure that environmental impacts are carefully evaluated when considering energy exploration and production activities. For example, such precautions have been important for the exploration and production that is already allowed today in 42 National Wildlife Refuges.

Recommendation:Ä

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress to create the "Royalties Conservation Fund."

- This fund will earmark potentially billions of dollars in royalties from new oil and gas prodution in ANWR to fund land conservation efforts.
- This fund will also be used to eliminate the maintenance and improvements backlog on federal lands.



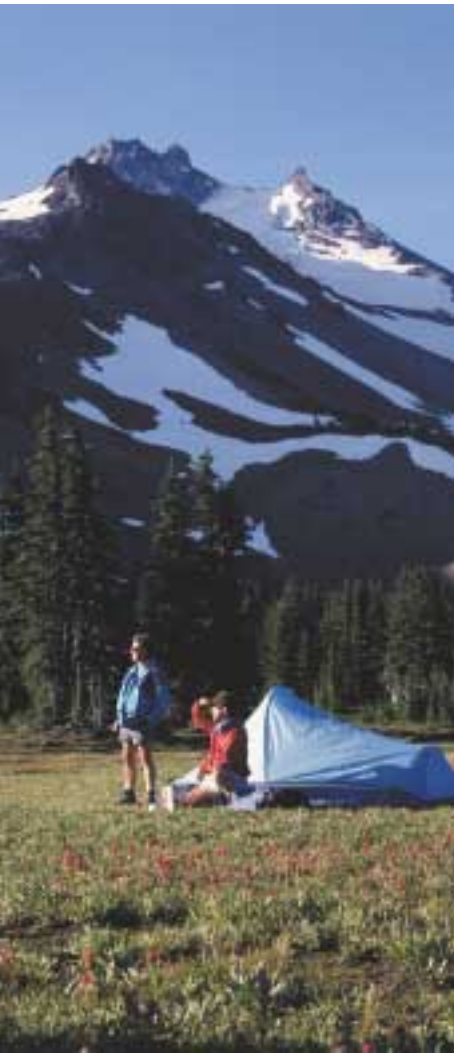
Technological advances and a strong commitment to environmental protection are enabling the healthy coexistence of our nation's diverse ecosystems with the development of energy resources.

Hydropower Generation

Hydropower, although a clean energy source, does present environmental challenges. Unless properly designed and operated, hydropower dams can injure or kill fish, such as salmon, by blocking their passage to upstream spawning pools. Innovations in fish ladders, screens, and hatcheries are helping to mitigate these adverse impacts. Ongoing dam relicensing efforts are resulting in community involvement and the industry's application of the latest technologies to ensure the maintenance of downstream flows and the upstream passage of fish. These efforts also have been successful in identifying and removing older, nonfunctioning dams and other impediments to fish movements.



Ecosystems provide food, shelter, and critical breeding and spawning grounds for fish and wildlife, and support commercial and recreational fishing, tourism, enhance our quality of life,and other activities that contribute billions of dollars to the U.S. economy every year.



Some natural resource areas are to be protected from any exploration. In other areas, energy development can proceed using the most advanced designs and technologies to ensure that proposed energy projects do not diminish the vitality and diversity of these unique resources.

An example of such successful collaboration involves the Wanapum Dam on the Columbia River. In coordination with the National Marine Fisheries Service, the Grant County Public Utility District No. 2 installed spillway deflectors that effectively reduced concentrations of total dissolved gas that can harm fish and other aquatic life. Furthermore, through the unique collaboration on this project, the cost for the spillway deflectors was a fraction of that for deflectors installed at other hydropower projects.

Coal, Oil, and Gas Exploration and Production

Certain exploration and production activities can pose environmental impacts to wildlife habitat, unless conducted in a way that protects the environment. In sensitive areas, these effects can often be avoided or minimized by timing exploration and operation activities in light of migration, nesting, and other critical time periods for wildlife. In addition, new technologies designed to lessen these and other impacts can be used, such as double-walled pipes to reduce the risk of oil spills.

Surface impacts from coal mining and oil exploration can temporarily damage habitats during the operation phases until reclamation is complete. To mitigate impacts during mining, for example, stormwater runoff and discharge into undisturbed environments are controlled. After mining is complete, reclamation efforts required by the Surface Mining Control and Reclamation Act restore viable habitats through careful reconstruction of physical and botanical resources. For instance, in the Powder River Basin, as part of reclamation, coal companies strategically place large boulders and other rock material to create wildlife cover and denning habitat. Restoration of wildlife habitat on these reclaimed areas has been quite successful.

In Alaska's Arctic—home to such animals as polar bears, musk oxen, caribou, wolves, and arctic fox—the bitterly cold winters have proven to be beneficial for environmentally responsible energy development. For example, when the North Slope is frozen and snow-covered, seismic trains can travel across it to gather geophysical information. Furthermore, companies have adopted innovative techniques to reduce the possible impacts of exploration and development. In Alaska's National Petroleum Reserve, the "footprint" from most exploratory wells on federal lands is short-lived and has minimal impact due to the use of ice roads and ice pads that melt with the spring thaw. Advances in extended-reach drilling technologies have also served to minimize environmental effects during energy production activities.

A lengthy 1999 Department of Energy study examined the environmental benefits of new exploration and production technologies and concluded that "improvements over the past 40 years have dramatically reduced industry's footprint on the fragile tundra, have minimized waste produced, and have protected the land for resident and migrating wildlife." The same study concluded that "it is important to tell this remarkable story of environmental progress in E&P [exploration and production] technology. Greater awareness of the industry's achievements in environmental protection will provide the context for effective policy, and for informed decision-making by both the private and public sectors."

Waste Management

Vigilant management and careful disposal of waste from energy extraction and production can prevent the contamination of our air, land, and water. Federal and state authorities are working to ensure that energy projects maintain sound programs to safely handle wastes from mining, drilling, generation and transmission.

Nuclear power plants present waste management challenges unique among energy-generating technologies. They generate spent fuel, as well as other radioactive waste, which must be isolated from ecosystems and human contact for long periods of time. Currently, spent fuel is stored at reactor sites in a number of states, although capacity is limited. Newer technologies have been developed to reduce the volume and

increase the manageability of spent fuel, but such spent fuel will still require safe handling and long-term isolation.

While the federal government has the responsibility to address such high-level wastes, states have the responsibility to address low-level wastes from nuclear plants, such as clothing and equipment. Disposal options for this type of radioactive waste are limited, because siting these facilities has been controversial. In fact, there are only three disposal facilities active in the United States.

Accidental Releases

Since the passage of the Oil Pollution Act in 1990, which, among other things, required double-hulled vessels and improved industry readiness, oil spilled in coastal zone waters has decreased from almost 8 million gallons in 1990 to just over 1 million gallons in 1999. Most energy production facilities implement comprehensive risk-management plans, which reduce the potential for accidents and help local officials prepare for accidents that may arise.

In contrast, inland oil spills do not appear to be decreasing at the same rate as coastal spills. The federal government receives many more inland oil spill notifications (9,000 notifications a year in the early 1990s versus 10,000 to 12,000 a year in the late 1990s), and many very large inland oil spills occur each year (over 100,000 gallons). The continued problem with inland oil spills may be due to aging pipelines, storage tanks, and other infrastructure components.

Since the advent of commercial nuclear power generation, there have been no radiation-related injuries or deaths associated with the operation of a commercial nuclear power plant in the United States. The most significant incident from a nuclear plant in the United States, at Three Mile Island in 1979, prompted improved safety regulation of nuclear plants. New nuclear reactor designs promise even higher safety levels than the reactors currently operating in this country.

Radiation exposure from nuclear facilities is extremely rare. In fact, roughly 82 percent of human exposure to radiation comes from natural sources: radon gas; the human body, which contains radioactive elements; outer space; and rocks and soil. Radon accounts for about 55 percent of our exposure to natural sources of radiation; radioactive elements in our own bodies account for 11 percent; rocks and soil account for 11 percent; and outer space, including the sun, accounts for 8 percent. The remaining 18 percent of average human radiation exposure comes from man-made sources, primarily medical and dental X-rays and consumer products.

The safety of U.S. nuclear energy plants has improved sharply in recent years. A safe nuclear energy plant is one that runs well, experiences few unplanned outages, and has a well-disciplined work force that follows procedures and avoids accidents. The safety of a U.S. nuclear energy plant is typically gauged by monitoring indicators of its performance in these areas: unplanned automatic reactor shutdowns, the annual percentage of possible power generated, and the industrial safety accident rate for plant workers.

In 2000, for the fourth year in a row, the number of unscheduled reactor shutdowns was zero. The industry generated 91.1 percent of its potential maximum output, breaking its 1999 record of 88.7 percent, far better than the typical 80 percent number of ten years ago.

Today, U.S. nuclear plants are more efficient and safer than ever. In the increasingly deregulated marketplace, competition has forced improvements in plant operations that have benefited safety performance as much as economic performance.

Climate Change

Energy-related activities are the primary sources of U.S. man-made greenhouse gas emissions, representing about 85 percent of the U.S. man-made total carbon-equivalent emissions in 1998.

Scientists continue to learn more about global climate change, its causes, potential impacts, and possible solutions.

The United States recognizes the seriousness of this global issue as scientists attempt to learn more about climate change. The United States is making progress in reducing emissions of greenhouse gases. Recent data show that the rate of growth in U.S. greenhouse gas emissions has begun to decline, even as the U.S. economy has been growing at an unprecedented rate. For example, historically U.S. CO_2 emissions have grown at roughly half the rate of GDP. In recent years, however, very robust growth in the nation's GDP has been accompanied by a slowdown in the growth of greenhouse gas emissions. In both 1998 and 1999, U.S. GDP grew by more than 4 percent a year, while CO_2 emissions grew by less than 1.5 percent a year. In addition, the carbon intensity of the U.S. economy—the amount of CO_2 emitted per unit of GDP—declined by 15 percent during the 1990s.

The United States has reduced greenhouse gas emissions by promoting energy efficiency and the broader use of renewable energy through a wide range of public-private partnership programs. These programs save energy, cut energy bills, enhance economic growth, and reduce emissions of conventional air pollutants as well as greenhouse gases.

The U.S. government, businesses, and nongovernmental organizations are sequestering carbon, at home and abroad. For example, working with the U.S. Fish and Wildlife Service Research, Illinova Generating Company has voluntarily committed to reforesting 100,000 acres of bottomland hardwood forests on National Wildlife Refuges in the Lower Mississippi River Valley. It is projected that this project will sequester approximately 13.5 million tons of carbon, improve fish and wildlife populations by restoring the natural forest wetland habitats, and enhance the Gulf of Mexico's near-shore aquatic environment by restoring natural forested wetland filters to the Mississippi River floodplain.

Industry and the federal government are researching various new technologies that will reduce greenhouse gas emissions or sequester those emissions, in geologic formations, oceans, and elsewhere.



Forests can absorb carbon dioxide, which accounts for the largest share of greenhouse gas emissions. Working with the U.S. Fish and Wildlife Service Research, Illinova Generating Company has voluntarily committed to reforesting 100,000 acres of bottomland hardwood forests on National Wildlife Refuges in the Lower Mississippi River Valley.

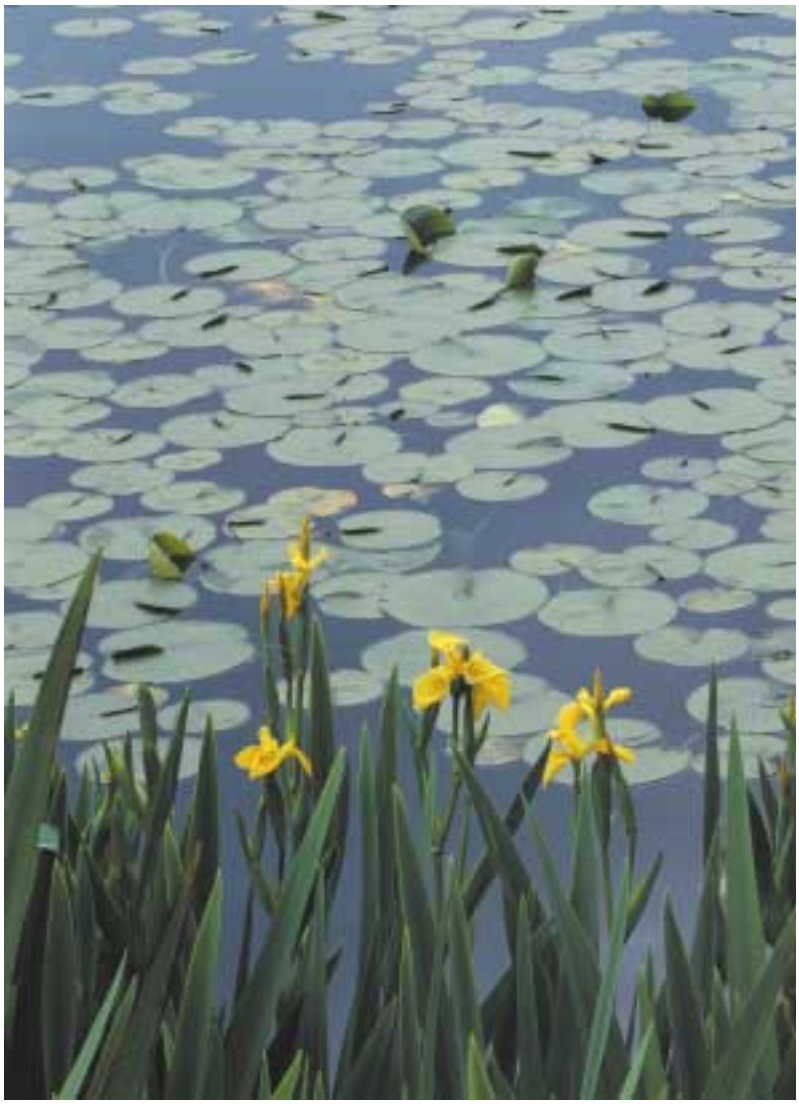
Regulatory Structure

The United States has adopted many regulatory protections to limit the environmental damage and public health consequences of the exploration, extraction, production, and use of energy. Most environmental controls are implemented through state or federal permitting or review systems, which often require time for agency review and public participation. Facilities may need several different permits or reviews from different agencies, and they may also need to meet local licensing or zoning laws. Businesses have an interest in moving expeditiously to respond to consumers' needs. The public also has an interest in participating in the system to ensure that appropriate health and environmental precautions will be taken.

Regulatory requirements are not static. New scientific information and new control technologies result in new regulations and modifications to existing regulations over time. However, some level of certainty in the regulatory environment is important for all parties. Businesses can plan more effectively in such an environment, and regulators can focus on ensuring that the desired outcomes are in fact achieved consistently. For example, studies have shown that if electricity generators knew today what their emission requirements for several emissions would be for a defined time period, they would most likely control emissions more cost effectively and sooner than if their emission requirements were decided upon one gas at a time.

Traditional permit and regulatory programs may not always be the most effective and efficient way to protect the environment. Increasingly, regulatory programs are considering approaches that include market-based incentives. These types of incentives offer advantages over traditional forms of regulation because they set high performance standards and then allow market forces to determine the most effective way to meet them. While not appropriate for every situation, market-based incentives can control pollution at a lower cost to society than traditional regulation, stimulate technological improvements, and be structured to achieve larger reductions in pollution than would result from traditional regulations.

A good example of a U.S. market-based program is the Acid Rain Program, which has reduced SO_2 air emissions from utilities at a fraction of the initial cost estimates. Other emerging market-based environmental protection mechanisms include effluent trading, wetland mitigation banks, tradable development rights, easement purchases, off-site mitigation, and leasing or purchasing of water rights. These programs can reduce mitigation or pollution control costs, increase business flexibility, and provide transparency and environmental protection for the public.



The environmental review process can also be made more open, understandable, predictable, and coordinated among federal agencies and with state and local agencies. It can be improved by providing greater information to clarify expectations for energy developers, facilitating concurrent reviews by federal agencies by standardizing certain information needs, sharing information received by project applicants, and seeking opportunities to integrate required environmental processes and reviews.

Recommendation:

★ The NEPD Group recommends that the President issue an Executive Order to rationalize permitting for energy production in an environmentally sound manner by directing federal agencies to expedite permits and other federal actions necessary for energy-related project approvals on a national basis. This order would establish an interagency task force chaired by the Council on Environmental Quality to ensure that federal agencies responsible for permitting energy-related facilities are coordinating their efforts. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state, tribal, and local permitting activity in particular regions where increased activity is expected.

Summary of Recommendations

Protecting America's Environment: Sustaining the Nation's Health and Environment

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to propose multi-pollutant legislation. The NEPD Group recommends that the President direct the EPA Administrator to work with Congress to propose legislation that would establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators. Such a program (with appropriate measures to address local concerns) would provide significant public health benefits even as we increase electricity supplies.

- Establish mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides, and mercury.
- Phase in reductions over a reasonable period of time, similar to the successful acid rain reduction program established by the 1990 amendments to the Clean Air Act.
- Provide regulatory certainty to allow utilities to make modifications to their plants without fear of new litigation.
- Provide market-based incentives, such as emissions trading credits to help achieve the required reductions.

★ The NEPD Group recommends the President direct the Secretary of the Interior to work with Congress to create the "Royalties Conservation Fund."

- This fund will earmark potentially billions of dollars in royalties from new oil and gas production in ANWR to fund land conservation efforts.
- This fund will also be used to eliminate the maintenance and improvements backlog on federal lands.

★ The NEPD Group recommends the President issue an Executive Order to rationalize permitting for energy production in an environmentally sound manner by directing federal agencies to expedite permits and other federal actions necessary for energy-related project approvals on a national basis. This order would establish an interagency task force chaired by the Council on Environmental Quality to ensure that federal agencies responsible for permitting energy-related facilities are coordinating their efforts. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state, tribal, and local permitting activity in particular regions where increased activity is expected.

Using Energy Wisely

Increasing Energy Conservation and Efficiency

The Department of Energy has installed two low-sulfur light bulbs as a test at its Forrestal Building headquarters in Washington, D.C. The two golf ball-sized bulbs, like those on the opposite page, are at each end of a 240-foot, 10-inch-wide reflective plastic "light pipe."
U.S. DEPARTMENTOF ENERGY



U.S. DEPARTMENTOF ENERGY

Energy efficiency is the ability to use less energy to produce the same amount of lighting, heating, transportation, and other energy services. For a family or business, conserving energy means lower energy bills. For the country as a whole, greater energy efficiency helps us make the most of U.S. energy resources, reduces energy shortages, lowers our reliance on energy imports, mitigates the impact of high energy prices, and reduces pollution. Improvements in efficiency can be particularly effective in reducing energy demand when energy is most expensive.

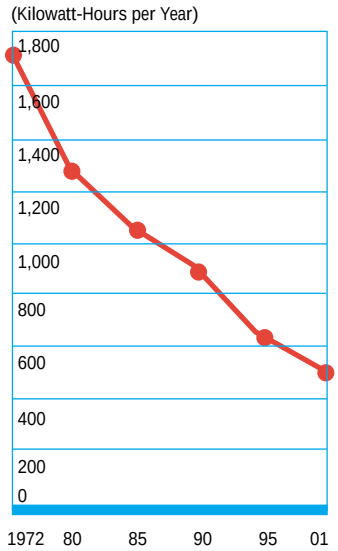
Conservation and energy efficiency are important elements of a sound energy policy. Improved energy efficiency is the result of many decisions, including those of individual consumers; manufacturers of cars and appliances; home builders; and state, federal, and local government officials. The federal government can promote energy efficiency and conservation by including the dissemination of timely and accurate information regarding the energy use of consumers' purchases, setting standards for more energy efficient products, and encouraging industry to develop more efficient products. The federal government can also promote energy efficiency and conservation through programs like the Energy Star program, and search for more innovative technologies that improve efficiency and conservation through research and development.

Since 1973, the U.S. economy has grown nearly five times faster than energy use (126 percent versus 26 percent). Had Americans continued to use energy as intensively as in 1970, the U.S. would have consumed about 177 quadrillion Btus of energy last year, compared to about 99 quadrillion Btus actually consumed.

British Thermal Unit (Btu)
A British thermal unit is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit at sea level. Put another way, it is approximately the same amount of energy contained in a wooden match head.



Figure 4-1
New Refrigerator-Freezers are Using Less Energy
Consumption per Unit for New Shipments



Over the last thirty years, the energy efficiency of refrigerator-freezer appliances has increased by approximately 70 percent.

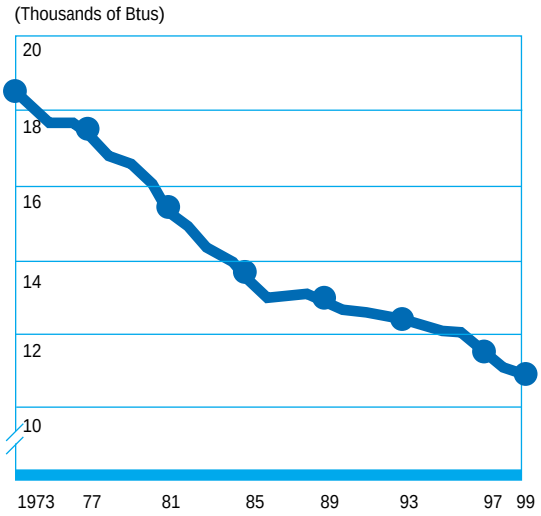
Sources: AHAM 2000 Major Home Industry Fact Book and BTS appliance standard.

Improving Efficiency through Innovative Technologies

One measure of energy efficiency is energy intensity—the amount of energy it takes to produce a dollar of gross domestic product (GDP). While about half of the long-term decline in energy intensity can be attributed to changes in the economy, especially the shift from manufacturing to services, the other half reflects improved energy efficiency. Gains in energy efficiency over the last three decades were built on a combination of technological improvements, better management practices, and learning to put these technologies and practices to their best use in automobiles, homes, offices, factories, and farms. In many areas the results have been quite impressive. New home refrigerators use about one-third of the electricity they used in 1972 (Figure 4-1). Compact fluorescent lights use about 25 percent of the electricity of the incandescent bulbs they replace. Automobiles use roughly 60 percent of the gasoline they did in 1972 per mile driven. These individual technological improvements have resulted in significant reductions in energy use (Figure 4-2).

Several new and innovative technologies offer expanded opportunities to improve our energy efficiency. For example, advanced sensors and controls enable more efficient operation of buildings and factories, and allow equipment and lights to be turned off or dimmed when not in use. Hybrid vehicles use power electronics and battery storage to get more out of every gallon of gasoline consumed, and provide the ability to double vehicle mileage. Cogeneration of electricity and heat and combined heat and power allow for the productive use of much of the waste heat from electricity production, which accounts for about two-thirds of the energy used to produce electricity.

Figure 4-2
The U.S. Economy Has Become More Energy Efficient



The amount of energy used by the United States in relation to its economic output has steadily declined since the early 1970s.

Source: U.S. Department of Energy, Energy Information Administration.

District Energy St. Paul—A Combined Heat and Power Plant

District Energy St. Paul, Inc., is a combined heat and power plant that can operate on natural gas, oil, or clean-burning coal that is mixed with wood chips. These wood wastes come from downed trees, trimmings, and branches. District Energy has been able to keep its rates stable because it is able to rely on a diverse fuel supply. District Energy serves about 75 percent of all building space in the city. Nearly 150 large buildings and 3,200 residential units use the system. It is the largest system of its kind in the nation.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of energy efficiency research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

Consumer Choices

The two most important factors in consumers' decisions about purchasing an energy efficient product are price and the life of the product. When energy prices are high, consumers tend to weigh energy efficiency more heavily. Unless consumers are informed about the price of energy, they may not have the incentive to select the most energy efficient product.

Consumers do not receive timely signals about rising electricity costs in order to make adjustments to their energy use and efficiency. When consumers' peak costs are averaged with off-peak costs, the higher cost of peak electricity supplies is masked. As a result, consumers may not recognize the benefits of investing in technologies that best target peak consumption.

Some energy efficiency improvements are easiest and most cost effective to undertake when first building new factories, cars, equipment, appliances, and buildings. Some energy-using equipment, like computers, are used for only a few years before being replaced. Other equipment is used from five to twenty years, such as home appliances, home electronics, and lighting systems. Some capital stock, such as buildings and boilers, can last a half a century or more.

The average car now lasts fourteen years, and newer cars have even more longevity. Vehicle efficiency improvements require significant technological changes. Development of new-car production models requires at least three to four years, which limits the rate at which new technologies can enter the market. Making fundamental changes, such as switching to the use of a fuel cell, would take even longer. Once those new vehicles are in the showroom, it then takes several more years before they constitute any sizable percentage of total vehicles.

In a typical U.S. home, appliances are responsible for about 20 percent of the energy bills. Refrigerators, freezers, clothes washers, dryers, dishwashers, and ranges and ovens are the primary energy-using appliances in most households. Taking steps to save energy while using these appliances, and replacing old inefficient appliances with modern ones can save money.



Some efficiency improvements are easiest and most cost-effective to undertake when first building new factories, cars, equipment, appliances and buildings.

The federal government established a mandatory program in the 1970s requiring that certain types of new appliances bear a label to help consumers compare the energy efficiency of various products. Under this program, all refrigerators, freezers, clothes washers, and dishwashers are sold with yellow Energy Guide labels to indicate their energy efficiency. These labels provide an estimated annual operating cost of the appliance, and also indicate the cost of operating the models with the highest annual operating cost and the lowest annual operating cost. By comparing a model's annual operating cost with the operating cost of the most efficient model, you can compare their efficiencies. This labeling program ensures that consumers have the information they need to make the right decisions when they purchase major home appliances. However, Energy Guide labels are not currently required for some products, such as kitchen ranges, microwave ovens, clothes dryers, on–demand water heaters, portable space heaters, and lights.

The federal government not only ensures consumers have information on the energy efficiency of major home appliances. It also promotes the most energy efficient products through the Energy Star program, a joint program run by the Department of Energy and the Environmental Protection



In April 2001, the Sustainable Buildings Industry Council showcased a net-zero-energy home featuring passive solar design strategies, an integrated photovoltaic system, domestic solar hot water, high-efficiency lights and appliances, and a host of sustainable, market-ready components and systems.
Sustainable Buildings Industry Council



A 48-story skyscraper at the corner of Broadway and 42nd Street in New York City has a photovoltaic skin that uses thin-film PV panels to replace traditional glass cladding material. The PV curtain wall extends from the 35th to the 48th floors on the south and east walls of the tower, making it a highly visible part of the New York City skyline.
U.S. Department of Energy, National Renewable Energy Laboratory

Agency. Energy Star is only awarded to appliances that significantly exceed minimum energy efficiency standards. The Energy Star program does not extend to all products. Energy efficiency would be further promoted if the Energy Star program were expanded to a broader range of products.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to promote greater energy efficiency.

- Expand the Energy Star program beyond office buildings to include schools, retail buildings, health care facilities, and homes.
- Extend the Energy Star labeling program to additional products, appliances, and services.
- Strengthen Department of Energy public education programs relating to energy efficiency.

Energy efficiency can also be improved by the establishment of minimum energy efficiency standards. Congress enacted legislation in 1987 and 1988 to establish minimum energy efficiency standards for many major appliances. These standards apply to manufacturers, not consumers. Appliance manufacturers must produce products that meet the minimum level of energy efficiency. These rules do not affect the marketing of products manufactured before the standards went into effect, and any products made beforehand can be sold. The new standards will stimulate energy savings that benefit the consumer, and reduce fossil fuel consumption, thus reducing air emissions.

These laws established minimum energy efficiency standards for many appliances, including refrigerators, refrigerator-freezers, freezers, room air conditioners, fluorescent lamp ballasts, and incandescent reflector lamps, clothes dryers, clothes washers, dishwashers, kitchen ranges, and ovens, pool heaters, and water heaters. The Energy Policy Act of 1992 added standards for fluorescent and incandescent reflector lamps, plumbing products, electric motors, and commercial water heaters, and heating, ventilation, and air conditioning systems. Under current law, the Department of Energy can raise the minimum energy efficiency standards for these appliances if certain criteria are met, such as cost, technological feasibility, and the impact on competition among appliance manufacturers. In addition, the Department can set energy efficiency standards for appliances not covered by these laws.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to take steps to improve the energy efficiency of appliances.

- Support appliance standards program for covered products, setting higher standards where technologically feasible and economically justified.
- Expand the scope of the appliance standard program, setting standards for additional appliances where technologically feasible and economically justified.

Energy Efficiency

Government Agencies

As the largest energy consumer in the nation, the U.S. government's cost- and energy-saving opportunity is enormous. In 1999, the government consumed nearly 1.1 percent of all U.S. energy and spent nearly $8 billion for its vehicles, operations, and its nearly 500,000 buildings.

The federal government has reduced its energy use in buildings by about 30 percent from 1990 levels, largely by installing energy efficient technologies (Figure 4-3). It has reduced its energy use for vehicles and equipment by 35 percent. Some of these improvements are attributable to the Department of Energy, whose Federal Energy Management Program helps government agencies reduce their energy and water use, manage their utility costs, and promote renewable energy.

Recommendations:

★ The NEPD Group recommends that the President direct heads of executive departments and agencies to take appropriate actions to conserve energy use at their facilities to the maximum extent consistent with the effective discharge of public responsibilities. Agencies located in regions where electricity shortages are possible should conserve especially during periods of peak demand.

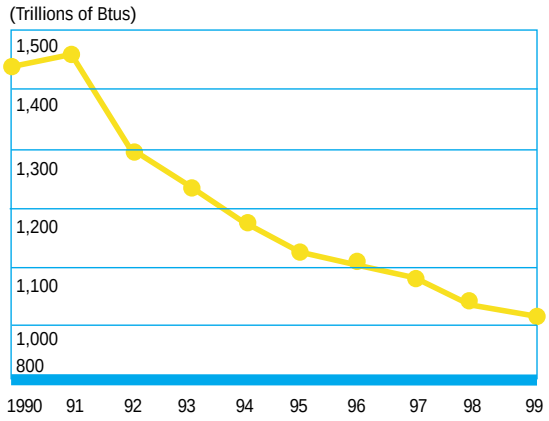
- Agencies should report to the President, through the Secretary of Energy, within 30 days of the conservation actions taken.

State and local governments have unique opportunities for energy savings in schools, transportation, state buildings, and building codes. For example, the Texas School Energy Management Program could save school districts as much as $100 million in energy costs every year by helping school districts evaluate their energy needs and resources. Similarly, Wisconsin's Energy Initiative is working with utilities to make basic changes to public buildings. By installing new lighting fixtures and taking other steps, Wisconsin estimates that it will save $60 million in state spending on energy over ten years.

Residential and Commercial Buildings

There are significant opportunities to improve the energy efficiency of buildings and homes through technologies and better practices. For existing homes, immediate options for improving efficiency include reducing air infiltration with caulking and weather stripping, installing modern thermostats, sealing ductwork, and adding insulation. These steps can reduce the 40 percent share of residential energy bills that

Figure 4-3
The U.S. Government is Reducing Its Energy Consumption



During the 1990s, energy use in federal buildings decreased by about 30 percent.

Source: U.S. Department of Energy, Energy Information Administration.



Pulte Homes

Building America—Pulte Homes

Pulte Homes Southwest Division has used technical assistance from the Department of Energy's Building America program to create what one residential expert calls "the best production house in the world," which won the 2001 National Association of Home Builders' Energy Value Award. In Tucson, Phoenix, and Las Vegas, Pulte Homes has worked with the Department of Energy to redesign the energy features of its basic models.

Using advanced insulation techniques, highly efficient equipment and windows, and right-sized heating and cooling systems, the homes look the same, but perform so well they use half the energy for heating and cooling at virtually no increase in construction costs.

The whole building/systems engineering approach used in the Building America program allows builders to add more insulation and more efficient windows while reducing the size of the heating and cooling equipment. The trade-off means no added cost to the builder, better value for the buyer, reduced electric load for the utility, and improved affordability.

go toward heating and cooling. Additional savings are possible when efficient appliances are purchased or major home renovations are undertaken. Installing a new, more efficient gas furnace can save up to 20 percent annually on natural gas. New buildings offer the greatest energy efficiency opportunities and can be designed to be both more comfortable and more efficient, cutting heating and cooling costs by close to 50 percent.

In commercial buildings, typically the quickest, most cost effective way to increase energy efficiency is to replace the lighting systems. Sensors help to avoid 24-hour operation of lights and equipment that are only used for a portion of the day. As with homes, advances in windows, heating and air conditioning systems, overall building designs, and equipment and appliances present significant energy saving opportunities.

Many families and businesses can face obstacles to realizing energy cost reductions.

Insufficient Information

Monthly energy bills generally report only total electricity or natural gas used, leaving families and businesses unsure about which energy services are most responsible for their energy use, and which investments could best help them reduce their costs. In addition, consumers may be unsure about the credibility of the energy-saving claims of individual manufacturers, salesmen, and designers. This incomplete information causes imperfections in the marketplace that hinder purchases of efficient technologies that would actually save families and businesses money.

Lack of Availability

Frequently, the most energy efficient products cost more and are not widely available, especially in smaller communities. Builders who would like to construct more efficient homes and businesses face the same problem at the wholesale level. For example, to keep costs down, builders are less likely to install top-of-the-line,

highly efficient products. The less expensive and generally less efficient products are heavily stocked and deeply discounted due to volume ordering. The decisions made about the energy efficiency of buildings and homes are not usually made by the consumer who will ultimately pay the energy bills. The incentive is for the builders to choose the material that poses the least cost to the builder, which is not necessarily the most energy efficient choice.

Lack of Automation

People often walk out of their offices and homes with the lights on and the air conditioner running. Turning off unused appliances, electronics, and lights is not always easy. Lack of automation (e.g., daylight sensors) means that conservation mostly depends on people turning off switches. Some appliances and electronics, such as stereos, video tape players, and televisions, continue to use electricity even after they are turned off.

Higher Initial Costs

Efficient products often cost more than less efficient versions, especially when they are first introduced to the market. Unless consumers can verify the resulting savings, they may be reluctant to pay the additional costs. Businesses that adopt labeling programs that spell out energy savings may be more successful in selling a more efficient, yet initially more expensive product. Higher initial costs can be particularly difficult for the purchaser or builder of a new home or office building.

Industry and Agriculture

Six industries consume three-quarters of all industrial energy: lumber and paper; chemicals; petroleum refining; primary metals; food processing; and stone, clay, and glass. Improved energy efficiency in these energy-intensive industries yields even larger improvements in overall productivity, product quality, safety, and pollution prevention. Manufacturing companies generally obtain their largest savings from improved efficiency of motors (motors account for 54 percent of electricity use in manufacturing) and from improved steam and hot-water systems. Many companies can reduce energy needs further by cogenerating their electricity and heat for steam.



High energy prices during the 1970s and early 1980s caused many farmers to find ways to reduce their energy costs, such as by switching from gasoline-powered to more fuel efficient diesel-powered engines and by adopting conservation tillage practices.

Energy use for U.S. agriculture grew during the 1960s and 1970s, peaking in 1978. High energy prices during the 1970s and early 1980s caused many farmers to find ways to reduce their energy costs, such as by switching from gasoline-powered to more fuel-efficient diesel-powered engines, adopting conservation tillage practices, shifting to larger multiprocessor machines, and using energy saving methods for drying and irrigating crops. These measures helped farmers reduce their energy use by 41 percent from 1978 to 1998, while agricultural output grew by about 40 percent over the same period.

Farmers can reap additional energy savings as they replace old machinery with more energy efficient equipment. Furthermore, farmers can adopt more advanced practices, such as precision farming, that optimize the use of machines, chemicals, and fertilizers to achieve energy savings. New seed varieties can also reduce energy-intensive chemical requirements.

Despite the opportunity for increased energy efficiency, the industrial and agricultural sectors face several obstacles. Because many manufacturing and farming operations are highly specialized, they need specific information on energy-saving opportunities to effectively respond to energy price signals and supply problems.

Cogeneration

In 1998, Malden Mills Industries, a textile manufacturer employing 2,300 workers in Lawrence, Massachusetts, installed a state-of-the-art combined heat and power (CHP) facility. The system uses two 4.3 MW industrial gas turbines, retrofitted with ceramic combustion liners, that were developed as part of the Department of Energy's Advanced Turbine Systems program, and that enable higher operating temperatures and lower emissions. The CHP system saves Malden Mills more than $1 million annually. The liners have accumulated more than 9,500 hours of successful operation and have cut emissions of nitrogen oxides and carbon monoxide to less than 15 parts per million.



In order for manufacturing or agriculture to switch to more efficient energy products and practices, significant costs are incurred due to production delays, waste and spoilage, and labor costs. As a result, manufacturers and farmers tend to use readily available and reliable equipment when upgrading, instead of untested, newer products and approaches.

Because of their large needs for both heat and electricity, businesses find combined heat and power (CHP) systems particularly attractive. However, replacing old, inefficient boilers with highly efficient CHP systems may add a number of new regulatory requirements (such as air permits), but does not offer the same tax depreciation incentives the tax code grants to power plants.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with the Congress on legislation to encourage increased energy efficiency through combined heat and power (CHP) projects by shortening the depreciation life for CHP projects or providing an investment tax credit.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to work with local and state governments to promote the use of well-designed CHP and other clean power generation at brownfield sites, consistent with the local communities' interests. EPA will also work to clarify liability issues if they are raised at a particular site.

★ The NEPD Group recommends that the President direct the EPA Administrator to promote CHP through flexibility in environmental permitting.

Conservation can be improved by car pooling, telecommuting, increasing public transit choices, and pricing highway use during periods of peak demand.

Transportation

Transportation plays a key role in a growing U.S. economy, comprising 16 percent of GDP in 1998, 10.5 percent of total employment, and 27 percent of total U.S. energy consumption. Trucks and automobiles account for over three-fourths of the sector's petroleum use, with the remainder attributable to rail, ship, air, and pipeline systems. Mass transit ridership has increased by 21 percent since 1996. Automobiles today use roughly 60 percent of the gasoline they did in 1972 per mile driven, due in part to new technology, such as better engine and design controls, improved transmission, weight reduction, and improved aerodynamics. Despite the adoption of more efficient transportation technologies, average fuel economy for passenger vehicles has remained relatively flat for ten years and is, in fact, at a twenty-year low, in large part due to the growth and popularity of low-fuel-economy pickup trucks, vans, and sport utility vehicles (Figure 4-4).

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Transportation to:

- Review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards with due consideration of the National Academy of Sciences study to be released in July 2001. Responsibly crafted CAFE standards should increase efficiency without negatively impacting the U.S. automotive industry. The determination of future fuel economy standards must therefore be addressed analytically and based on sound science.
- Consider passenger safety, economic concerns, and disparate impact on the U.S. versus foreign fleet of automobiles.
- Look at other market-based approaches to increasing the national average fuel economy of new motor vehicles.

Opportunities for reducing oil demand in the transportation sector include increasing conservation, vehicle efficiency, and alternative fuels. Conservation can be improved by car pooling, telecommuting, and increasing transit choices. For example, an increase in the average fuel economy of the on-road vehicle fleet by three miles per gallon would save one million barrels of oil a day, or about half of the global shortfall between supply and demand that triggered the oil price increases since 1998. In addition, fuel conservation can be further improved by technologies to reduce congestion.

A recent analysis indicates that the fuel economy of a typical automobile could be enhanced by 60 percent by increasing engine and transmission efficiency and reducing vehicle mass by about 15 percent. Several promising efficiency technologies are being presented to the U.S. market. For example, some automobile manufacturers have already introduced hybrid vehicles, and others have announced that they will introduce hybrid vehicles within the next several years. Advanced lightweight materials offer up to 6 percent improvement in mileage for each 10 percent reduction in body weight. Although promising, it may be many years before hybrids become a substantial part of the automotive fleet.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of Transportation to review and promote congestion mitigation technologies and strategies and to work with the Congress on legislation to implement these strategies.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to increase energy efficiency with a tax credit for fuel-efficient vehicles. The NEPD Group recommends that a temporary, efficiency-based income tax credit be available for purchase of new hybrid or fuel cell vehicles between 2002 and 2007.

Higher Initial Production Costs

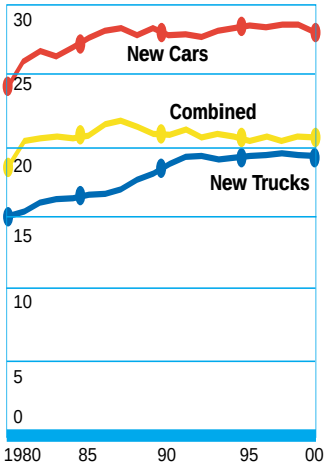
Because of the large economies of scale in automobile manufacturing, new technologies with limited early production runs often enter the market at higher initial costs. In this highly competitive international market, higher initial production costs can be a significant impediment to the introduction of new technologies. Unless U.S. automakers can remain competitive with their overseas counterparts, it is unlikely they will invest in new, more efficient technologies. Vehicle efficiency technologies, such as advanced engines, fuel cells, and cutting-edge electronic drive-train technologies, will become widely available only when component costs are reduced or demand is increased.

Hybrid Vehicles

The engine of a conventional gasoline vehicle is typically sized for the small amount of time the driver spends accelerating to enter the freeway, to pass another car, or to climb a hill. Most of the time it operates at less than 20 percent efficiency. An attractive alternative is to use a hybrid system that allows the engine to operate at peak efficiency, and get a boost from a battery when entering the freeway or climbing a hill. Not only does this system allow improved performance from a smaller engine, but the energy usually lost in stopping the car can be recovered and stored in the battery.

What does this mean to the average American? Significantly improved fuel economy and reduced emissions.

Figure 4-4
Fuel Efficiency of Light Vehicles Has Remained Flat
(Miles per Gallon)



Despite the adoption of more efficient transportation technologies, U.S. average fuel economy has been flat for 10 years. In large part, this is due to the growth of low-fuel-economy pickup trucks, vans, and sport utility vehicles.

Source: U.S. Department of Energy, Energy Information Administration.

Summary of Recommendations

Using Energy Wisely: Increasing Energy Conservation and Efficiency

★ The NEPD Group recommends that the President direct the Office of Science and Technology Policy and the President's Council of Advisors on Science and Technology to review and make recommendations on using the nation's energy resources more efficiently.

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of energy efficiency research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

★ The NEPD Group recommends that the President direct the Secretary of Energy to promote greater energy efficiency.

- Expand the Energy Star program beyond office buildings to include schools, retail buildings, health care facilities, and homes.
- Extend the Energy Star labeling program to additional products, appliances, and services.
- Strengthen Department of Energy public education programs relating to energy efficiency.

★ The NEPD Group recommends that the President direct the Secretary of Energy to improve the energy efficiency of appliances.

- Support the appliance standards program for covered products, setting higher standards where technologically feasible and economically justified.
- Expand the scope of the appliance standards program, setting standards for additional appliances where technologically feasible and economically justified.

★ The NEPD Group recommends that the President direct heads of executive departments and agencies to take appropriate actions to conserve energy use at their facilities to the maximum extent consistent with the effective discharge of public responsibilities. Agencies located in regions where electricity shortages are possible should conserve especially during periods of peak demand. Agencies should report to the President, through the Secretary of Energy, within 30 days on the conservation actions taken.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to encourage increased energy efficiency through combined heat and power (CHP) projects by shortening the depreciation life for CHP projects or providing an investment tax credit.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to work with local and state governments to promote the use of well-designed CHP and other clean power generation at brownfields sites, consistent with the local communities' interests. EPA will also work to clarify liability issues if they are raised at a particular site.

★ The NEPD Group recommends that the President direct the EPA Administrator to promote CHP through flexibility in environmental permitting.

★ The NEPD Group recommends that the President direct the Secretary of Transportation to:

- Review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards with due consideration of the National Academy of Sciences study to be released in July 2001. Responsibly

crafted CAFE standards should increase efficiency without negatively impacting the U.S. automotive industry. The determination of future fuel economy standards must therefore be addressed analytically and based on sound science.
- Consider passenger safety, economic concerns, and disparate impact on the U.S. versus foreign fleet of automobiles.
- Look at other market-based approaches to increasing the national average fuel economy of new motor vehicles.

★ The new NEPD Group recommends that the President direct the Secretary of Transportation to review and promote congestion mitigation technologies and strategies and work with Congress on legislation to implement these strategies.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to increase energy efficiency with a tax credit for fuel-efficient vehicles. The NEPD Group recommends that a temporary, efficiency-based income tax credit be available for purchase of new hybrid fuel cell vehicles between 2002 and 2007.

★ The NEPD Group recommends that the President direct all agencies to use technological advances to better protect our environment.
- The Administration remains committed to investing in Intelligent Transportation Systems (ITS) and encourages the private sector to invest in ITS applications. This Department of Transportation (DOT) program funds the development of improved transportation infrastructure that will reduce congestion, such as traveler information/navigation systems, freeway management, and electronic toll collection. ITS applications reduce fuel associated with travel.
- The Administration remains committed to the DOT's fuel-cell-powered transit bus program, authored by the Transportation Equity Act for the 21st Century (TEA-21). This program demonstrates the viability of fuel-cell power plants for transit bus applications.
- The Administration remains committed to the Clean Buses program. TEA-21 establishes a new clean fuel formula grant program, which provides an opportunity to accelerate the introduction of advanced bus propulsion technologies into the mainstream of the nation's transit fleet.

★ The NEPD Group recommends that the President direct the EPA and DOT to develop ways to reduce demand for petroleum transportation fuels by working with the trucking industry to establish a program to reduce emissions and fuel consumption from long-haul trucks at truck stops by implementing alternatives to idling, such as electrification and auxiliary power units at truck stops along interstate highways. EPA and DOT will develop partnership agreements with trucking fleets, truck stops, and manufacturers of idle-reducing technologies (*e.g.*, portable auxiliary packs, electrification) to install and use low-emission-idling technologies.

★ The NEPD Group recommends that the President direct the Secretary of Energy to establish a national priority for improving energy efficiency. The priority would be to improve the energy intensity of the U.S. economy as measured by the amount of energy required for each dollar of economic productivity. This increased efficiency should be pursued through the combined efforts of industry, consumers, and federal, state, and local governments.

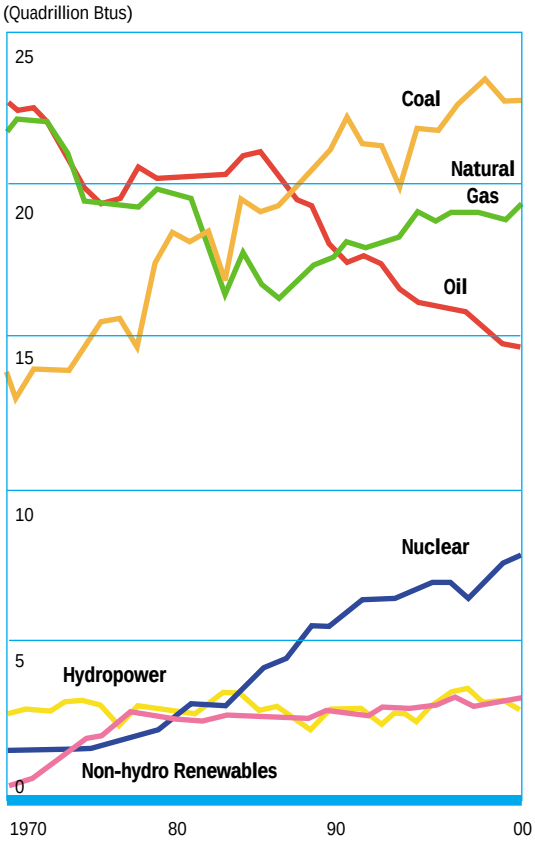
★ The NEPD Group recommends that the President direct the EPA Administrator to develop and implement a strategy to increase public awareness of the sizable savings that energy efficiency offers to homeowners across the country. Typical homeowners can save about 30 percent (about $400) a year on their home energy bill by using Energy Star-labeled products.

Energy for a New Century

Increasing Domestic Energy Supplies

America's energy strength lies in the abundance and diversity of its energy resources, and in its technological leadership in developing and efficiently using these resources. Our nation has rich deposits of coal, oil, and natural gas. The United States is the third-largest oil-producing nation in the world, despite a thirty-year decline in domestic production. While our economy runs primarily on fossil fuels, we also have long experience with hydropower and nuclear energy. We are pursuing the ability to further capture the energy of sunlight, the heat of the earth, and the power of wind.

Figure 5-1
U.S. Energy Production: 1970–2000



Production of coal, the nation's most abundant fuel source, exceeded 1 billion tons in 2000. Electricity generation accounted for about 90 percent of U.S. coal consumption last year.

Source: U.S. Department of Energy, Energy Information Administration.

Economic factors will help determine the future development of our nation's energy sources. These factors will be shaped not only by conservation, energy demand, and the cost of energy development, but also by the regulations that federal, state, and local governments put in place to balance energy needs with legitimate competing aims, including the protection of the environment. A number of factors will make it difficult to increase domestic energy production in response to the growing demand for energy: economic and technological factors associated with depletion of the fossil fuel resource base in the U.S.; regulatory uncertainty; limitations on access to federal lands with high potential for new discoveries; infrastructure constraints, such as electricity transmission and gas pipeline bottlenecks; and conflicts with legitimate land use, environmental, and other public policy goals.

The United States has significant domestic energy resources, and remains a major energy producer. Between 1986 and 2000, production of coal, natural gas, nuclear energy, and renewable energy increased. However, these increases have been largely offset by declines in oil production (Figure 5-1).

U.S. Department of the Interior, Minerals Management Service



Even with improved energy efficiency, the United States will need more energy supply. U.S. energy demand is projected to rise to 127 quadrillion Btus by 2020, even with significantly improved energy efficiency. However, domestic production is expected to rise to only 86 quadrillion Btus by 2020. The shortfall between projected energy supply and demand in 2020 is nearly 50 percent. That shortfall can be made up in only three ways: import more energy; improve energy efficiency even more than expected; and increase domestic energy supply.

The challenge for our nation is to use technology to maintain and enhance the diversity of our supplies, thus providing a reliable and affordable source of energy for Americans. These goals can and must be accomplished while maintaining our commitment to environmental protection.

Oil and Natural Gas

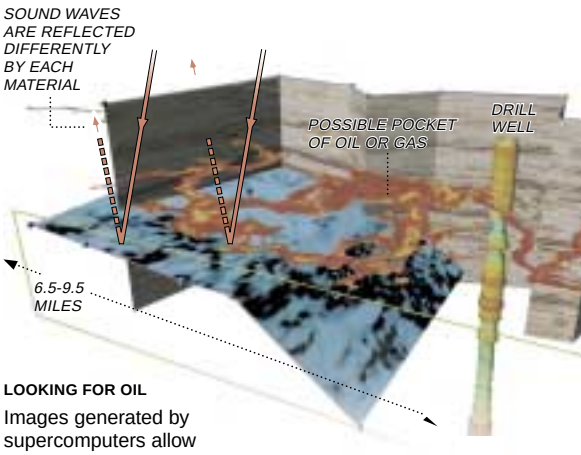
Oil and natural gas are the dominant fuels in the U.S. economy, providing 62 percent of the nation's energy and almost 100 percent of its transportation fuels. By 2020, the Energy Information Administration expects the United States will need about 50 percent more natural gas and one-third more oil to meet demand.

U.S. oil production is expected to decline over the next two decades. Over the same period, demand for natural gas will most likely continue to outpace domestic production. As a result, the United States will rely increasingly on imports of both natural gas and oil from Canada, and imports of oil and liquefied natural gas from producers across the globe.

21st Century Technology

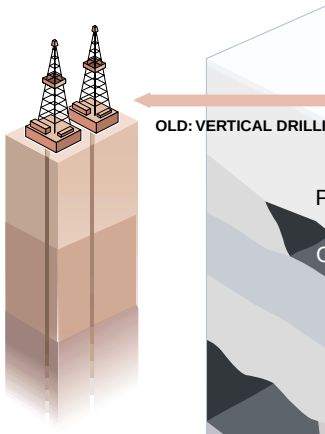
Remaining U.S. oil reserves are becoming increasingly costly to produce because much of the lower-cost oil has already been largely recovered. The remaining resources have higher exploration and production costs and greater technical challenges, because they are located in geologically complex reservoirs, (*e.g.*, deep water

Figure 5-2



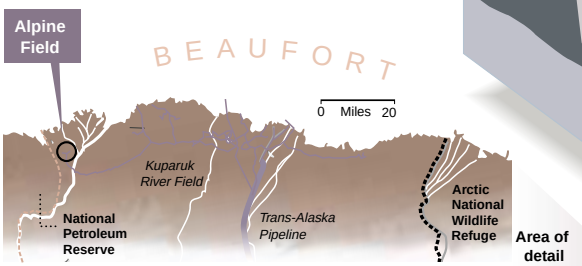
LOOKING FOR OIL

Images generated by supercomputers allow geologists to locate small pockets of oil or gas.



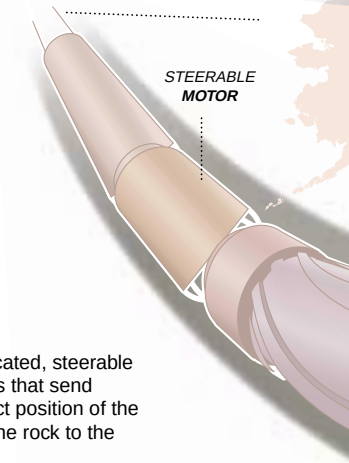
DRILLING TECHNOLOGY

Old drills were limited to a single vertical well, but newer wells can drill horizontally or spread in different directions to tap small pockets of oil.



TRANSPORTING THE OIL

A 14-inch pipeline connects the Alpine field to the Trans-Alaska Pipeline about 60 miles west of the Arctic National Wildlife Refuge, a site proposed for new drilling.



TRANSPORTING THE OIL

Today's drills are sophisticated, steerable machines with instruments that send information about the exact position of the drill bit and properties of the rock to the drilling team.

Sources: Phillips Petroleum Company, Chevron Corporation, BP Amoco, Magic Earth, Arctic Connections.

***DRILL BIT**: MADE OF STEEL AND/OR TUNGSTEN*

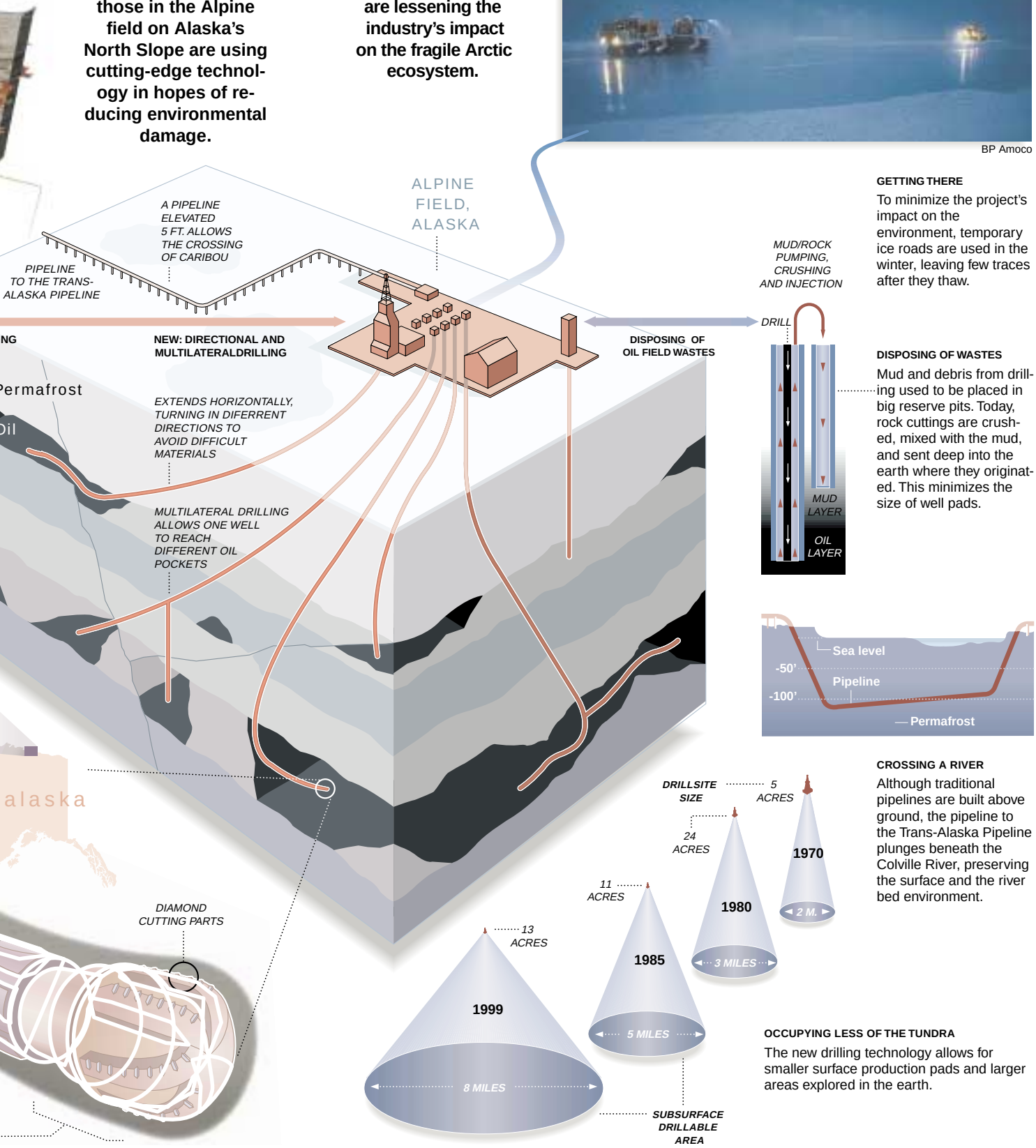
Using the Latest Drilling Technology to Reduce Environmental Damage

Oil drilling sites like those in the Alpine field on Alaska's North Slope are using cutting-edge technology in hopes of reducing environmental damage.

Recent advances are lessening the industry's impact on the fragile Arctic ecosystem.



BP Amoco



GETTING THERE

To minimize the project's impact on the environment, temporary ice roads are used in the winter, leaving few traces after they thaw.

DISPOSING OF WASTES

Mud and debris from drilling used to be placed in big reserve pits. Today, rock cuttings are crushed, mixed with the mud, and sent deep into the earth where they originated. This minimizes the size of well pads.

CROSSING A RIVER

Although traditional pipelines are built above ground, the pipeline to the Trans-Alaska Pipeline plunges beneath the Colville River, preserving the surface and the river bed environment.

OCCUPYING LESS OF THE TUNDRA

The new drilling technology allows for smaller surface production pads and larger areas explored in the earth.

Source: New York Times News Service

21st Century Technology: The Key to Environmental Protection and New Energy Production

Producing oil and gas from geologically challenging areas while protecting the environment is important to Americans and to the future of our nation's energy security. New technology and management techniques allow for sophisticated energy production as well as enhanced environmental protection. A technology evolution has occurred in the way oil and natural gas are found. The computer, three dimensional seismic technology, and other technologies have transformed the process from one based on "feel," to one highly dependent on the most advanced and sophisticated technology available. These technologies reduce cost and protect the environment.

Today's oil and gas exploration technology, for example, is boosting the success rate of pinpointing new resources. The results: fewer dry holes, reduced waste volumes, and a cleaner environment. Smaller, lighter drilling rigs coupled with advances in directional and extended-reach drilling significantly increase protection of the environment.

- Advanced, more energy efficient drilling and production methods:
  - — reduce emissions;
  - — practically eliminate spills from offshore platforms; and
  - — enhance worker safety, lower risk of blowouts, and provide better protection of groundwater resources.
- With each improvement in operational performance and efficiency, more oil and gas resources can be recovered with fewer wells drilled, resulting in smaller volumes of:
  - — cuttings;
  - — drilling muds and fluids; and
  - — produced waters.
- Modular drilling rigs, "slimhole" drilling, directional drilling, and other advances enable:
  - — production of oil and gas with increased protection to wetlands and other sensitive environments;
  - — reduced greenhouse gas emissions;
    and worker safety through the use of innovative best management practices.

Other examples of advanced technology include:

- 3-D seismic technology that enables geologists to use computers to determine the location of oil and gas before drilling begins, dramatically improving the exploration success rate;
- deep-water drilling technology that enables exploration and production of oil and gas at depths over two miles beneath the ocean's surface;
- high-powered lasers that may one day be used for drilling for oil and gas; and
- highly sophisticated directional drilling that enables wells to be drilled long horizontal distances from the drilling site.

:

and harsh environments).

While the resource base that supplies today's natural gas is vast, U.S. conventional production is projected to peak as early as 2015. Increasingly, the nation will have to rely on natural gas from unconventional resources, such as tight sands, deep formations, deep water, and gas hydrates. Also, many resources are in environmentally sensitive areas that require use of less intrusive technologies.

New technologies are being developed to reduce both the environmental effects and the economic costs of exploration for oil and gas. These exciting new technologies, like horizontal drilling and three-dimensional seismic technology allow for much greater precision and significantly less impact on the environment (Figure 5-2).

Small independent businesses account for 50 and 65 percent, respectively, of domestic petroleum and natural gas production in the lower 48 states. However, even when new technology is available, independent producers can lack the investment capital needed to apply the technology and be unable to cope with the increased economic and technical risks associated with harder-to-recover resources.

For example, most new gas wells drilled in the United States will require hydraulic fracturing. This is a common procedure used by producers to complete gas wells by stimulating the well's ability to flow increased volumes of gas from the reservoir rock into the wellbore. During a fracture procedure, fluid and a propping agent (usually sand) are pumped into the reservoir rock, widening natural fractures to provide paths for the gas to migrate to the wellbore. In certain formations, it has been demonstrated that the gas flow rate may be increased as much as twenty-fold by hydraulic fracturing. Each year nearly 25,000 oil and gas wells are hydraulically fractured.

The use of hydraulic fracturing in natural gas production from coal seams is one of the fastest-growing sources of gas production. This source will most likely face added controls, and costs to ensure that disposal (by re-injection or discharge) of production waters is done in an environmentally sensitive manner.

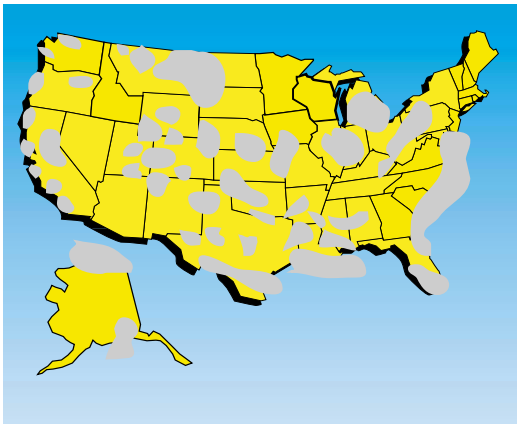
For each of these issues, opportunities exist to better coordinate, improve performance, and meet America's energy, public health, safety and environmental goals.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Energy and the Interior to promote enhanced oil and gas recovery from existing wells through new technology.

Anywhere from 30 to 70 percent of oil, and 10 to 20 percent of natural gas, is not recovered in field development. It is estimated that enhanced oil recovery projects, including development of new recovery techniques, could add about 60 billion barrels of oil nationwide through increased use of existing fields (Figure 5-3).

Figure 5-3
Major U.S. Oil and Gas Fields



The United States is the most mature oil-producing region in the world, and much of our easy-to-find resource base has been delpeted. Advanced exploration and production technologies of the past two decades have played a key role in recovering additional oil and natural gas from existing fields.

Source: U.S. Department of Energy, Energy Information Administration.

Public Lands Leasing

The federal government owns about 31 percent of the nation's land, so it can have a major role in increasing energy production in appropriate places. A large portion of U.S. energy resources are contained in these federal lands and offshore areas. Public lands provide nearly 30 percent of

Small independent businesses account for 50 and 65 percent, respectively, of domestic petroleum and natural gas production in the lower 48 states.

annual national energy production, and are estimated to contain a substantial majority of the nation's undiscovered domestic energy resources.

Portions of federal onshore and offshore lands are off-limits to oil and gas exploration and development. Access is restricted for a variety of reasons, including administrative land withdrawals for competing land uses, such as national defense or water projects; and stipulations affecting surface occupancy, use, and timing for environmental compatibility.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to examine land status and lease stipulation impediments to federal oil and gas leasing, and review and modify those where opportunities exist (consistent with the law, good environmental practice, and balanced use of other resources).

- Expedite the ongoing Energy Policy and Conservation Act study of impediments to federal oil and gas exploration and development.
- Review public lands withdrawals and lease stipulations, with full public consultation, especially with the people in the region, to consider modifications where appropriate.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider economic incentives for environmentally sound offshore oil and gas development where warranted by specific circumstances: explore opportunities for royalty reductions, consistent with ensuring a fair return to the public where warranted for enhanced oil and gas recovery; for reduction of risk associated with production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic.

Offshore

Congress has designated about 610 million acres off limits to leasing on the Outer Continental Shelf (OCS), which contains large amounts of recoverable oil and gas resources. These Congressional moratoria have been expanded by Presidential action through 2012, effectively confining the federal OCS leasing program to the central and western Gulf of Mexico, a small portion of the eastern Gulf, existing leases off California's shore, and areas off of Alaska.

Concerns over the potential impacts of oil spills have been a major factor behind imposition of the OCS moratoria. For areas that are available for possible development, it is projected that with advanced technology, we could recover 59 billion barrels of oil and 300 trillion cubic feet of natural gas. This type of exploration and production from the OCS has an impressive environmental record. For example, since 1985, OCS operators have produced over 6.3 billion barrels of oil, and have spilled only 0.001 percent of production. Naturally occurring oil seeps add about 150 times as much oil to the oceans. Additionally, about 62 percent of OCS energy production is natural gas, which poses little risk of pollution.

For those areas that are available for potential coastal zone and OCS exploration and production activity, businesses must comply with a variety of federal and state statutes, regulations, and executive orders. Aspects of these, under the Coastal Zone Management Act and the Outer Continental Shelf Lands Act and their regulations, attempt to provide for responsible development while considering important environmental resources. However, effectiveness is sometimes lost through a lack of clearly defined requirements and information needs from federal and state entities, as well as uncertain deadlines during the process. These delays and uncertainties can hinder proper energy exploration and production projects.

The Deep Water Royalty Relief Act of 1995, granting variable royalty reductions for new leases in deep water, contributed to a significant increase in deep-water leasing in the central and western Gulf over the last five years. The opportunities created in deep water help spur the development of new

technologies and infrastructure for this frontier area. However, substantial economic risks remain to investment in deep water and continued incentives could help draw investment in other countries. Similar incentives could spur development in other technological frontiers, such as deep gas, or make possible continued production from both offshore and onshore fields near the end of their economic life.

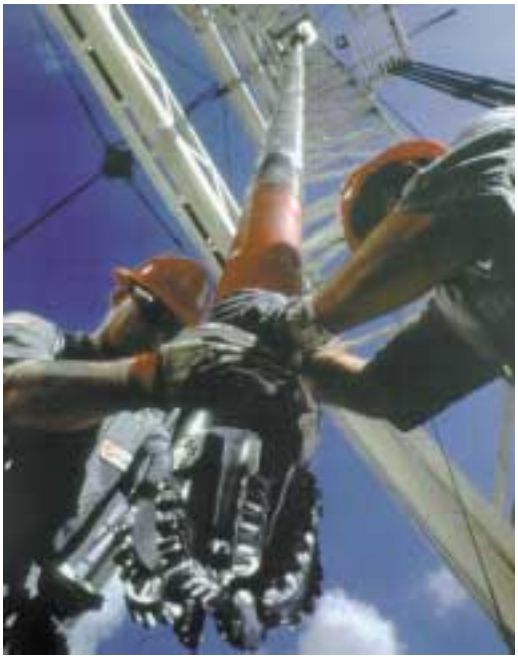
Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Interior to re-examine the current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the Outer Continental Shelf (OCS).

Arctic Outer Continental Shelf

It is estimated there are significant undiscovered resources in the two planning areas of the Arctic OCS. Geologists estimate that there are approximately 22.5 billion barrels of oil and 92 trillion cubic feet of natural gas in the Arctic OCS. The Beaufort Sea Planning Area encompasses approximately 65 million acres. Active leases within the Beaufort Sea Planning Area represent only 0.4 percent of the total acreage, and only 5 percent of the leased acreage is being actively pursued for development and production. The Chukchi Sea Planning Area encompasses approximately 63.7 million acres, none of which is currently leased.

Lease offerings totaling 58 million acres over the past twenty years have resulted in 34 exploratory wells. Two oil discoveries are now moving toward production, but economic factors have delayed several others. These discoveries have estimated recoverable reserves of more than 260 million barrels of oil. This is another area where periodic, well-scheduled lease sales can help contribute to national energy production.



The high-technology oil industry requires an educated, technologically sophisticated work force. Many workers left the industry in the mid-1980s because of job insecurity caused by price volatility. The lack of an experienced work force today may limit the amount and increase the cost of future exploration and production activity.

U.S. Department of Energy

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior continue OCS oil and gas leasing and approval of exploration and development plans on predictable schedules.

Onshore

North Slope Oil and Gas

The Alaska North Slope is a promising area for discovery of additional reserves to increase our domestic production of oil and natural gas. Currently, state lands on Alaska's North Slope provide about 17 percent of U.S. oil production. Oil and gas development in the Arctic, however, needs to be done in an environmentally responsible manner, using new technology and relying upon on the best available scientific information. Such technology is making it possible to explore and develop oil and gas with significantly less impact on the environment. Areas with potential for oil and gas development are the National Petroleum Reserve–Alaska (NPR–A), the Arctic Outer Continental Shelf, and the Arctic National Wildlife Refuge (ANWR).

National Petroleum Reserve–Alaska

The National Petroleum Reserve–Alaska lies between the Brooks Range and the Arctic Ocean. The U.S. Geological Survey (USGS) estimates a high potential for oil and gas resources in the NPR–A, with a mean estimate of 2.1 billion barrels of oil and 8.5 trillion cubic feet of gas. A leasing program was designed and initiated in 1999 for the northeast sector of NPR–A, resulting in the award of 133 leases covering 900,000 acres. Eight exploratory wells have been completed in the past two years, and additional exploratory wells are expected this coming winter.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider additional environmentally responsible oil and gas development, based on sound science and the best available technology, through further lease sales in the National Petroleum Reserve-Alaska. Such consideration should include areas not currently leased within the Northeast corner of the Reserve.

Arctic National Wildlife Refuge

The Alaska National Interest Lands Conservation Act expanded ANWR from 9 million acres to 19 million acres, and designated 8 million acres as wilderness. Congress specifically left open the question of management of a 1.5-million-acre Arctic Coastal Plain area of ANWR because of the likelihood that it contains significant oil and gas resources. Section 1002 of the Act directed the Department of the Interior to conduct geological and biological studies of the Arctic Coastal Plain, "the 1002 Area," and to provide to Congress the results of those studies with recommendations on future management of the area. Section 1003 of the Act prohibits leasing of the 1002 Area until authorized by an act of Congress.

In 1987, after more than five years of biological baseline studies, surface geological studies, and two seasons of seismic exploration surveys, the Department of the Interior recommended to Congress that the 1002 Area be leased for oil and gas exploration and production in an environmentally sensitive manner. In 1995, both the Senate and the House passed legislation containing a provision to authorize leasing in the 1002 Area, but the legislation was vetoed.

In May 1998, the USGS issued revised estimates of oil and gas resources in the 1002 Area. The 1998 USGS assessment shows an overall increase in estimated oil resources when compared to all previous government estimates. The estimate reaffirms the 1002 Area's potential as the single most promising prospect in the United States. The total quantity of recoverable oil within the entire assessment area is estimated to be between 5.7 and 16 billion barrels (95 percent and 5 percent probability range) with a mean value of 10.4 billion barrels. The mean estimate of 10.4 billion barrels is just below the amount produced to date from North America's largest field, Prudhoe Bay, since production began 23 years ago. Peak production from ANWR could to be between 1 and 1.3 million barrels a day and account for more than 20 percent of all U.S. oil production. ANWR production could equal 46 years of current oil imports from Iraq.

Technological improvements over the past 40 years have dramatically reduced industry's footprint on the tundra, minimized waste produced, and protected the land for resident and migratory wildlife. These advances include the use of ice roads and drilling pads, low-impact exploration approaches such as winter-only exploration activities, and extended reach and through-tubing rotary drilling. These technologies have significantly reduced the size of production-related facilities on the North Slope. Estimates indicate that no more than 2,000 acres will be disturbed if the 1002 Area of ANWR is developed. For purposes of comparison, ANWR is about the size of the state of South Carolina, whereas the developed area is estimated to be less than one-fifth the size of Washington D.C.'s Dulles International Airport.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress to authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR. Congress should require the use of the best available technology and should require that activities will result in no significant adverse impact to the surrounding environment.

Other Onshore Restrictions

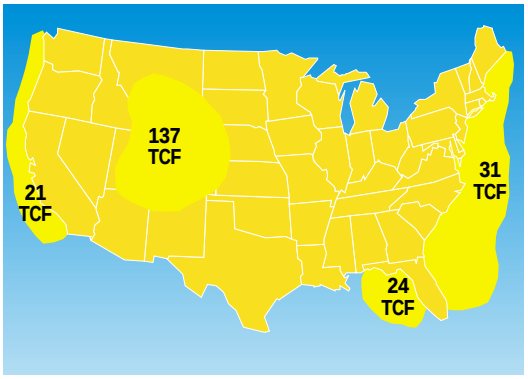
There is a significant potential for oil and gas resources on federal land in the lower 48 states as well. According to the most recent estimates from the USGS and the Minerals Management Service, oil resources underlying federal lands in the lower 48 states are estimated to be 4.1 billion barrels, and natural gas reserves are estimated to be 167 trillion cubic feet (Figure 5-4). Much of these potential resources have been placed off-limits or are subject to significant restrictions. For example, about 40 percent of the natural gas resources on federal land in the Rocky Mountain region have been placed off-limits.

The Department of the Interior initiated a study to examine the energy potential and restrictions on development on federal lands in the lower 48 states. In many cases, limits on oil and gas development are appropriate. However, improved technology has helped to reduce the impact of oil and gas development on the environment.

Exploration and Production

To meet increased natural gas demand in the coming decades, total wells drilled annually will need to double the 1999 level by 2020. Very few new onshore rigs have been built since the mid-1980s, because the oil field supply and service sectors have been hit especially hard by price volatility. Major additions to the offshore rig fleet will also be needed just to develop existing leases. The lack of an experienced work force may limit the speed and increase the cost of exploration and production activity.

Figure 5-4
Restricted Natural Gas Resource Areas in the U.S. Lower 48



Much of the nation's oil and gas resource base resides on federal lands or in federal waters. A large portion of this is not open to exploration and development. For example, an estimated 40 percent or 137 trillion cubic feet of potential natural gas resource in the Rockies is either closed to exploration (29 tcf) or is open to development under restrictive provisions (108 tcf).

Source: U.S.Department of Energy, Energy Information Administration.

Electricity

Electricity is an essential part of modern life. When supply fails to keep pace with demand, costs to consumers and businesses rise and reliability falls. The California experience demonstrates the crippling effect that electricity shortages and blackouts can have on a state or region. This summer, the possibility exists for more intense electricity shortfalls in the West, with additional problems possible in New York City and on Long Island.

Electricity demand is projected to grow sharply over the next twenty years. Based on current estimates, the United States will need about 393,000 MW of new generating capacity by 2020 to meet the growing demand. If the U.S. electricity demand continues to grow at the high rate it has recently, we will need even more generating capacity. To meet that future demand, the United States will have to build between 1,300 to 1,900 new power plants; that averages out to be more than 60 to 90 plants a year, or more than one a week.

Over the next few years, if the demand for electricity continues to grow as predicted, and if we fail to implement a

comprehensive energy plan that recognizes the need to increase capacity, we can expect our electricity shortage problems to grow. The result will be higher costs and lower reliability.

Electricity Restructuring

One of the most important energy issues facing the Administration and Congress is electricity restructuring. The electricity industry is going through a period of dramatic change. To provide ample electricity supplies at reasonable prices, states are opening their retail markets to competition. This is the most recent step in a long transition from reliance on regulation to reliance on competitive forces.

Changes in Wholesale Electricity Market

This transition from regulation to competition began in 1978 with enactment of the Public Utility Regulatory Policies Act, which promoted independent electricity generation. Open-access transmission policies adopted by the Federal Energy Regulatory Commission (FERC) in the late 1980s further promoted competition in wholesale power markets. Congress largely ratified these policies with enactment of the Energy Policy Act of 1992, which further promoted non-utility generation. FERC took another large step to promote competition with its open-access rule in 1996, which provided greater access to the transmission grid, the highway for interstate commerce in electricity.

Electricity demand is projected to rise sharply over the next twenty years. If we fail to build the 1,300–1,900 new power plants needed to increase generation and transmission capacity, current electricity shortages will become more frequent and more widespread.
U.S. Department of Energy



Changes in the Retail Electricity Market

Increased competition in wholesale power markets encourages states to open retail electricity markets. Under current law, FERC has jurisdiction over the wholesale power market, while states have jurisdiction over retail markets. Beginning in 1996, states began opening their retail markets to competition in order to lower electricity prices. Twenty-five states have opted to open their retail electricity markets to competition.

Most new electricity generation is being built not by regulated utilities, but by independent power producers. These companies assume the financial risk of investment in new generation, and their success rides on their ability to generate electricity at a low cost.

These dramatic changes affecting the industry led to important structural changes. Independent power producers, which were once infant industries, now dwarf many utilities. Utility mergers, which were once rare, are now commonplace. U.S. utilities have been purchased by foreign companies, and U.S. utilities have in turn purchased utilities abroad. While utilities had service areas that were limited to a single state or region, independent power producers are international companies that can build power plants across the globe. Many utilities that were once vertically integrated divested themselves of generation, either voluntarily or because of state law.

Pending Congressional Action

Since 1995, Congress has been grappling with electricity competition legislation. Initial efforts sought to require states to open their retail markets by a date certain. Subsequent efforts focused on promoting competition in electricity markets and complementing state retail competition plans. Under this

approach, federal legislation focused on core federal issues, including:

- regulation of interstate commerce;
- assuring open access to the interstate and international transmission system;
- enhancing reliability of the grid;
- lowering barriers to entry;
- reforming outdated federal electricity laws, such as the Public Utility Holding Company Act and Public Utility Regulatory Policies Act of 1978;
- reforming the role of federal electric utilities in competitive markets;
- protecting consumers; and
- clarifying federal and state regulatory jurisdictions.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of Energy to propose comprehensive electricity legislation that promotes competition, protects consumers, enhances reliability, improves efficiency, promotes renewable energy, repeals the Public Utility Holding Company Act, and reforms the Public Utility Regulatory Policies Act.

★ The NEPD Group recommends the President encourage FERC to use its existing statutory authority to promote competition and encourage investment in transmission facilities.

California Electricity Crisis

The California electricity crisis is not a test of the merits of competition in electricity markets. Instead, it demonstrates that a poorly designed state retail competition plan can have disastrous results if electricity supply does not keep pace with increased demand. At heart, the California electricity crisis is a supply crisis. California allowed demand to outstrip supply, and did little to lower barriers to entry through reform of an inflexible siting process. The risk that the California experience will repeat itself is low, since other states have not modeled their retail competition plans on California's plan.

The California crisis also shows that state electricity markets do not stay neatly confined within legal and jurisdictional bounds. Due to regional interconnection, disastrous mistakes made by the State of California have dire effects on the entire West. California's failure to reform flawed regulatory rules affecting the market drove up wholesale prices. Actions such as forcing utilities to purchase all their power through volatile spot markets, imposing a single-price auction system, and barring bilateral contracts all contributed to the problems that California now faces.

Lessons Learned from Successful Deregulation

As stated previously, 25 states have decided to open their retail electricity markets. A comparison of the different approaches taken by California and other states demonstrates that competition will benefit consumers if implemented effectively. A better gauge of the potential for retail competition to lower prices can be found in Pennsylvania, where electricity prices have fallen significantly as a result of competition. There is also reason to believe that the plan in Texas will have similar success.

A major difference between the California experience and the approaches taken by Pennsylvania and Texas is that the latter states ensured they had adequate electricity supplies. Pennsylvania and Texas took steps to ensure that procedures for adding new power plants were efficient. Unlike California, which imports 25 percent of its electricity, Pennsylvania is a net exporter of power, and Texas imports almost no power from other states. For these reasons, Pennsylvania and Texas have ample electricity supply to meet demand, while California is confronting a serious supply shortage.

In addition, California required its utilities to divest themselves of much of their generation, unlike Pennsylvania and Texas. This action forced California utilities to rely much more heavily on buying power, at ever-increasing prices, instead of generating power themselves.

Another major difference is that Pennsylvania and Texas did not require their utilities to purchase electricity through volatile spot markets. This requirement, combined with frozen retail rates imposed by the State, forced California utilities to purchase power at much higher costs than could be passed along to the consumer. As a result, the California regulatory plan resulted in unreliable service, destroyed the financial health of the State's utilities, and drove one utility into bankruptcy.

The federal government does not site power plants; that is a responsibility of the states. For that reason, delays relating to the construction of new power plants are usually the result of state action. A number of federal agencies, such as the Environmental Protection Agency, the Department of Commerce, and the Department of the Interior, do issue air and other permits for generation facilities. Some of the concerns about permitting or review delays in other states can be similarly addressed by expediting processes. These agencies, pursuant to President Bush's Executive Order, have expedited permit-processing applications for energy production in California.

Some of the concerns about permitting or review delays in other states can be similarly addressed by expediting processes.For example, in 1999–2000, the time for issuing air permits (including the time for public participation) for turbines was reduced to three to four months (compared to the twelve months allowed by the regulations) for the majority of permit applications.

Fuels for Electricity Generation

Electricity is not a primary source of energy. It is generated by the use of primary energy sources (Figure 5-5). Coal, nuclear energy, natural gas and hydropower account for about 95 percent of total electricity generation, with oil and renewable energy contributing the remainder. Despite this healthy diversity of energy sources, each type of electricity resource is faced with constraints to maintaining or expanding its contribution to electricity production.

Coal

Coal is used almost exclusively to generate electricity. Coal power plants account for over 50 percent of all U.S. electricity generation, and over 80 percent of generation in twelve states in the Midwest, Southeast, and West. Coal electricity generation costs are low, and coal prices have proved remarkably stable. In 1999, the United States produced 1.1 billion tons of coal. Production of coal from federal and tribal lands, which has increased substantially in the past decade, accounted for 38 percent of this total.

Although coal is the nation's most abundant fossil energy source, production and market issues can affect the adequacy of supply. Production issues include the protection of public health, safety, property, and the environment, and the effectiveness of federal and state agencies implementing various laws governing coal mining. These issues have resulted in some coal resources becoming uneconomical to produce. Statutory, regulatory, and administrative difficulties also may limit or prevent the production of some coal resources. However, technological advances in cleaner coal technology have allowed for significant progress toward reducing these barriers. There are also opportunities to protect the environment while lowering costs through further improvements in technology.

Over the past decade, greater efficiencies, lower capital costs, fewer emissions and quicker start-up times have made power plants fueled by natural gas a more attractive choice for new coal generation. Recently, however, rising natural gas prices have renewed interest in building coal power plants.

Uncertainty about future environmental controls is of particular concern for companies that operate existing coal power plants. Regulations under development include a variety of measures requiring reductions in emissions of nitrogen oxide, sulfur dioxide, and mercury. In addition, rules related to discharges to streams and cooling-water intake structures, possible regulation of large-volume wastes as hazardous wastes,

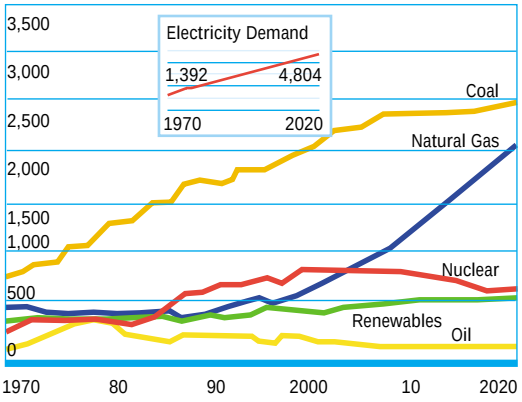
uncertainty over rules requiring air permits for certain modifications to power plants, and uncertainty over global and domestic efforts to reduce carbon dioxide emissions also play a role. This regulatory uncertainty discourages power producers from building coal power plants and is one reason the Unites States is relying so heavily on natural gas power generation to meet growing electricity demand.

Much of the current uncertainty has resulted because regulators do not weigh the cumulative impacts of their proposals. Compliance decisions by businesses concerning each new regulation must often be made without the benefit of clear information regarding additional requirements that may be imposed. More effective and economical compliance strategies are possible if companies know the full range of requirements with which they must comply.

If rising U.S. electricity demand is to be met, then coal must play a significant role. Under current policies, in the next two decades, nuclear electricity generation and hydropower are projected to decline. Natural gas electricity generation is projected to increase from about 16 to 36 percent of total generation, which would require the tripling of natural gas used for electricity generation. Significantly, this projected increase in natural gas generation assumes that coal electricity generation will continue to account for about 50 percent of U.S. electricity generation. If policies are adopted that sharply lower coal electricity generation, then the likely result is an even greater dependence on natural gas generation. This creates concern about the adequacy of natural gas supplies and policies.

Figure 5-5
Electricity Generation by Fuel: Current Trends

(Billions of Kilowatt-Hours)



Source: U.S. Department of Energy, Energy Information Administration

Clean Coal Technology

Technology has been and will continue to be a key to achieving our energy, economic, and environmental goals. In recent years, technological advancements through efforts of both the public and private sectors have led to substantial reductions in the cost of controlling sulfur dioxide and nitrogen oxide emissions, while the effectiveness of control systems increased significantly. The Department of Energy, through its Clean Coal Technology Program, has worked to provide effective control technologies. These nitrogen oxide and sulfur dioxide control technologies have moved into the utility marketplace and now provide a means to achieve cost effective regulatory compliance.

For example, most power plants that can use low nitrogen oxide burners have now installed them, and about 25 percent of all coal power plants have either ordered or installed selective catalytic reduction technology, which reduces nitrogen oxide emissions.

Technologies like fluidized-bed combustion and integrated gasification combined cycle have been developed that further reduce emissions. Fluidized-bed combustion is a low-emitting nitrogen oxide combustion technology that allows the use of fuels, such as coal pile washer waste, that were not formerly usable. Integrated gasification combined cycle is a relatively new technology that uses refinery waste as fuel.

Future coal electricity generation will need to meet new challenges to reduce emissions even further, especially mercury emissions. The Department of Energy is supporting efforts to develop more cost effective control technology. Indeed, the goal

Clean Coal Technology

Clean Coal Technology describes a category of technologies that allow for the use of coal to generate electricity while meeting environmental regulations at low cost.

- In the short term, the goal of the program is to meet existing and emerging environmental regulations, which will dramatically reduce compliance costs for controlled mercury, NOx, SO_2, and fine particulate at new and existing coal power plants.
- In the mid-term, the goal of the program is to develop low-cost, super-clean coal power plants, with efficiencies 50 percent higher than today's average. The higher efficiencies will reduce emissions at minimal costs.
- In the long term, the goal of the program is to develop low-cost, zero-emission power plants with efficiencies close to double that of today's fleet.

of these research, development, and demonstration programs is to develop and demonstrate coal power systems with near zero environmental emissions, while maintaining low production costs.

Recommendations:

★ The NEPD Group recognizes the importance of looking to technology to help us meet the goals of increasing electricity generation while protecting our environment. To that end, the NEPD Group recommends that the President direct the Department of Energy to continue to develop advanced clean coal technology by:

- Investing $2 billion over 10 years to fund research in clean coal technologies.
- Supporting a permanent extension of the existing R&D tax credit.
- Directing agencies to explore regulatory approaches that will encourage advancements in environmental technology.

★ The NEPD Group recommends that the President direct federal agencies to provide greater regulatory certainty relating to coal electricity generation through clear policies that are easily applied to business decisions.

Nuclear Energy

Nuclear energy accounts for 20 percent of all U.S. electricity generation, and more than 40 percent of the electricity generation in ten states in the Northeast, the South, and the Midwest. Despite the closure of several less efficient plants during the 1990s, the 103 U.S. nuclear energy plants currently operating produce more electricity today than at any time in history.

There are a number of reasons why nuclear energy expansion halted in the 1980s. Regulatory changes implemented after the Three Mile Island incident in 1979 lengthened the licensing period to an average of fourteen years, resulting in large cost overruns. Increased public concern about the safety of nuclear energy after the accident often resulted in active opposition to proposed plants. As a result, the last completed nuclear energy plant in the United States was ordered in 1973.

Since the 1980s, the performance of nuclear energy plant operations has substantially improved. While U.S. nuclear energy plants once generated electricity only around 70 percent of the time, the average plant today is generating electricity close to 90 percent. This improved performance has lowered the cost of nuclear generation, which is now competitive with other sources of electricity (Figure 5-6).

There is potential for even greater generation from existing nuclear energy plants. Experts estimate that 2,000 MW could be added from existing nuclear power plants by increasing operating performance to 92 percent. In addition, about 12,000 MW of additional nuclear electricity generation could be derived from uprating U.S. nuclear power plants, a process that uses new technologies and methods to increase rated power levels without decreasing safety. However, modifications to uprate plants can be expensive and require extensive licensing review and approval by the Nuclear Regulatory Commission (NRC). Another way to increase nuclear generation from existing plants is through license renewal. Many nuclear utilities are planning to extend the operating license of existing nuclear plants by twenty years, and the licenses of as many as 90 percent of the currently operating nuclear plants may be renewed.

The nuclear energy industry is closely regulated by the NRC, which provides rigorous oversight of the operation and maintenance of these plants. This oversight includes a comprehensive inspection program that focuses on the most significant potential risks of plant operations and features full-time resident inspectors at each plant, as well as regional inspectors with specialized expertise. The NRC has made great strides to provide greater regulatory certainty while maintaining high safety standards.

The installation of new design features, improvements in operating experience, nuclear safety research, and operator training have all contributed to the strong safety record of the nuclear energy industry. Since the Three Mile Island incident in 1979, the nuclear industry's safety record has significantly improved. This safety record has been achieved through a defense-in-depth philosophy accomplished by way of engineering design, quality construction, safe operation, and emergency planning. This philosophy provides for diverse and redundant systems to prevent accidents from occurring, as well as multiple safety barriers to mitigate the effects of accidents in the highly unlikely event they do occur.

Over the last several years, utilities have begun purchasing nuclear plants from other operators as the industry undergoes consolidation. Several nuclear utilities have merged, creating management teams with extensive expertise in running and maintaining nuclear plants. These mergers are impeded by tax rules relating to the transfer of decommissioning funds.

Utilities are also considering nuclear energy as an option for new generation. The NRC has certified three standardized nuclear power plant designs, and Congress enacted legislation in 1992 to reform the nuclear licensing process. Under this process, a utility can apply for a combined construction and operating license for one of these standardized designs in a streamlined process. This reformed licensing process provides for site permits—a way to resolve siting issues early in the process. Building new generators on existing sites avoids many complex issues associated with building plants on new sites. Many U.S. nuclear plant sites were designed to host four to six reactors, and most operate only two or three; many sites across the country could host additional plants.

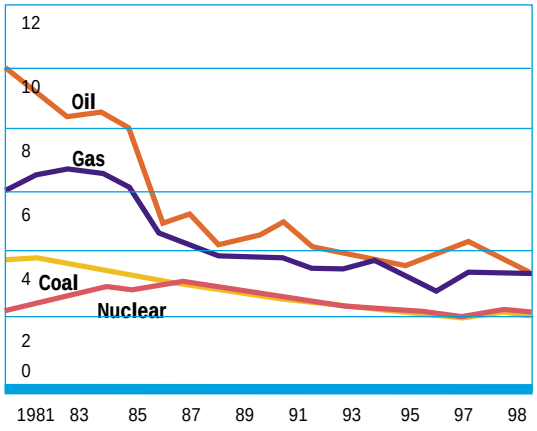
Advanced reactor technology promises to improve nuclear safety. One example of an advanced reactor design is the gas-cooled, pebble-bed reactor, which has inherent safety features. The industry has an interest in this and other advanced reactor designs.

The federal government must also provide for the safe disposal of nuclear waste. At present, nuclear waste continues to be stored at local plant sites. The Department of Energy is over a decade behind schedule for accepting nuclear waste from utilities, but has made progress toward characterization of the Yucca Mountain, Nevada site. Construction of an exploratory studies facility has been completed, a viability assessment was published, and recently scientists placed their extensive research about Yucca Mountain on the record for public scrutiny. However, key regulatory standards to protect public health and the environment at the repository have not been issued.

The Administration will continue to study the science to determine whether to proceed with the consideration of this site as the location for the repository. If the Administration decides to proceed, the Department of Energy must file a license application with the NRC. No waste will be sent to any location until the NRC determines it to be safe.

Other countries have developed different approaches for nuclear waste disposal. For example, the French, British and Japanese rely on reprocessing, an in-

Figure 5-6
Nuclear Generation is Competitively Priced
(1998 Cents per Kilowatt-Hour)



Note: Fuel costs are included.é
Source: Utility Data Institute via the Nuclear Energy Institute.é



Calvert Cliffs is the first U.S. nuclear plant to receive a renewed license from the Nuclear Regulatory Commission. The renewal will allow the plant to continue producing environmentally sound electricity for an additional twenty years.
CONSTELLATION ENERGY GROUP

dustrial approach that separates nuclear waste into usable fuel and highly concentrated waste. While this approach does not obviate the need for geologic disposal of nuclear waste, it could significantly optimize the use of a geologic repository. There is growing interest in new technology known as accelerator transmutation, which could be used in combination with reprocessing to reduce the quantity and toxicity of nuclear waste.

Recommendations:

★ The NEPD Group recommends that the President support the expansion of nuclear energy in the United States as a major component of our national energy policy. Following are specific components of the recommendation:

- Encourage the Nuclear Regulatory Commission (NRC) to ensure that safety and environmental protection are high priorities as they prepare to evaluate and expedite applications for licensing new advanced-technology nuclear reactors.
- Encourage the NRC to facilitate efforts by utilities to expand nuclear energy generation in the United States by uprating existing nuclear plants safely.
- Encourage the NRC to relicense existing nuclear plants that meet or exceed safety standards.
- Direct the Secretary of Energy and the Administrator of the Environmental Protection Agency to assess the potential of nuclear energy to improve air quality.
- Increase resources as necessary for nuclear safety enforcement in light of the potential increase in generation.
- Use the best science to provide a deep geologic repository for nuclear waste.
- Support legislation clarifying that qualified funds set aside by plant owners for eventual decommissioning will not be taxed as part of the transaction.
- Support legislation to extend the Price–Anderson Act.

★ The NEPD Group recommends that, in the context of developing advanced nuclear fuel cycles and next generation technologies for nuclear energy, the United States should reexamine its policies to allow for research, development and deployment of fuel conditioning methods (such as pyroprocessing) that reduce waste streams and enhance proliferation resistance. In doing so, the United States will continue to discourage the accumulation of separated plutonium, worldwide.

★ The United States should also consider technologies, in collaboration with international partners with highly developed fuel cycles and a record of close cooperation, to develop reprocessing and fuel treatment technologies that are cleaner, more efficient, less waste-intensive, and more proliferation-resistant.

Hydropower

Although hydropower generation accounts for only about 7 percent of overall U.S. electricity generation, the following states depend heavily on this source of energy: Idaho, Washington, Oregon, Maine, South Dakota, California, Montana, and New York.

Hydropower generation has remained relatively flat for years. The most significant constraint on expansion of U.S. hydropower generation is physical; most of the best locations for hydropower generation have already been developed. Potential does remain for some increases in hydropower generation, and capacity can be optimized by adding additional turbines and increasing efficiency at existing facilities.

Also, the amount of hydropower generation depends upon the quantity of available water. A drought can have a devastating effect on a region that depends on hydropower. In fact, this year's water availability has been a contributing factor in California's electricity supply shortages. The amount of hydropower generation depends upon the quantity of available water. A drought can have a devastating effect on a region that depends on hydropower. In fact, this year's water availability has been a contributing factor in California's electricity supply shortages.

The Federal Energy Regulatory Commission is required to incorporate mandatory conditions proposed by different state and federal resource agencies into hydropower licenses. Decision-making authority in the licensing process is diffused among a host of federal and state agencies, all of which are pursuing different statutory missions. The hydropower licensing process is prolonged, costly, and poses regulatory uncertainty. The challenge is to efficiently and effectively balance national interests in natural resource and environmental preservation with energy needs.

Recommendation:

★ The NEPD Group recognizes there is a need to reduce the time and cost of the hydropower licensing process. The NEPD Group recommends that the President encourage the Federal Energy Regulatory Commission (FERC) and direct federal resource agencies to make the licensing process more clear and efficient, while preserving environmental goals. In addition, the NEPD Group recognizes the importance of optimizing the efficiency and reliability of existing hydropower facilities, and will encourage the Administration to adopt efforts toward that end.

- Support administrative and legislative reform of the hydropower licensing process.
- Direct federal resource agencies to reach interagency agreement on conflicting mandatory license conditions before they submit their conditions to FERC for inclusion in a license.
- Encourage FERC to adopt appropriate deadlines for its own actions during the licensing process.

Natural Gas

Currently, natural gas provides about 16 percent of U.S. electricity generation. Seven states obtain over one-third of their generation from natural gas (Rhode Island, new York, Delaware, Louisiana, Texas, California, and Alaska). Perhaps more importantly, natural gas-fired electricity is projected to constitute about 90 percent of capacity additions between 1999 and 2020. The amount of natural gas used in electricity generation is projected to triple by 2020.

Ensuring the long-term availability of adequate, reasonably priced natural gas supplies is a challenge. Low gas prices in 1998 and 1999 caused the industry to scale back gas exploration and production activity. Since 2000, the North American natural gas market has remained tight due to strong demand and diminished supplies. Last year, natural gas prices quadrupled, which resulted in substantially higher prices for electricity generated with natural gas.

While the largest barriers to expanded natural gas electricity generation relate to production and pipeline constraints, there are several other barriers. Environmental regulations affect the use of gas for electricity generation. Although natural gas electric plants produce fewer emissions than coal-fired power plants, they still emit nitrogen oxides, carbon dioxide and small amounts of toxic air emissions.

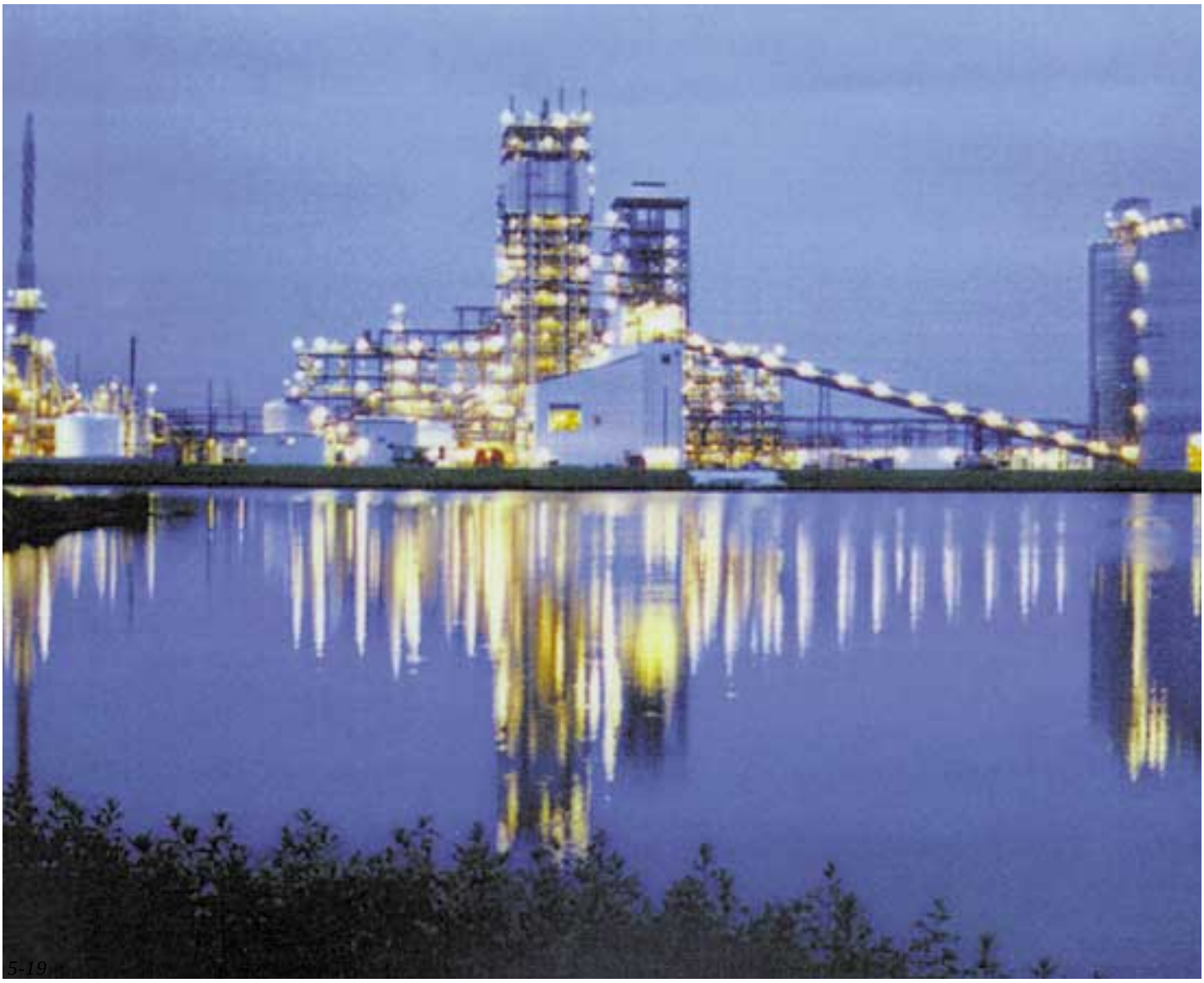
Oil

While oil fuels only about 3 percent of total U.S. electricity generation, it is the dominant source of electricity generation in Hawaii, and provides over 20 percent of the generation in Massachusetts, Connecticut, Delaware, Maine, and Florida. Over the next twenty years, market conditions are expected to reduce today's level of oil electricity generation by about 80 percent.

Renewable Energy

Hydropower is, to date, the most successful form of renewable energy. However, some forms of renewable energy generation—wind, geothermal, and biomass—have the potential to make more significant contributions in coming years, and the cost of most forms of renewable energy has declined sharply in recent years. The most important barrier to increased renewable energy production remains economic; nonhydropower renewable energy generation costs are greater than other traditional energy sources. The following chapter discusses renewable and alternative energy in greater detail.

High-tech power plants, like this combined cycle plant, are signaling a new age in electric power generation. The capability to co-produce electricity and a slate of fuels and chemicals makes the technology economically attractive to a broad range of industrial applications.
Tampa Electric Company



Summary of Recommendations
Energy for a New Century: Increasing Domestic Energy Supplies

★ The NEPD Group recommends that the President direct the Secretaries of Energy and the Interior to promote enhanced oil and gas recovery from existing wells through new technology.

★ The NEPD Group recommends that the President direct the Secretary of Energy to improve oil and gas exploration technology through continued partnership with public and private entities.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to examine land status and lease stipulation impediments to federal oil and gas leasing, and review and modify those where opportunities exist (consistent with the law, good environmental practice, and balanced use of other resources).

- Expedite the ongoing Energy Policy and Conservation Act study of impediments to federal oil and gas exploration and development.
- Review public lands withdrawals and lease stipulations, with full public consultation, especially with the people in the region, to consider modifications where appropriate.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider economic incentives for environmentally sound offshore oil and gas development where warranted by specific circumstances: explore opportunities for royalty reductions, consistent with ensuring a fair return to the public where warranted for enhanced oil and gas recovery; for reduction of risk associated with production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Interior to re-examine the current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the Outer Continental Shelf (OCS).

★ The NEPD Group recommends that the President direct the Secretary of the Interior continue OCS oil and gas leasing and approval of exploration and development plans on predictable schedules.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider additional environmentally responsible oil and gas development, based on sound science and the best available technology, through further lease sales in the National Petroleum Reserve-Alaska. Such consideration should include areas not currently leased within the Northeast corner of the Reserve.

★ The NEPD Group recommends that the President direct the Secretary of the Interior work with Congress to authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR. Congress should require the use of the best available technology and should require that activities will result in no significant adverse impact to the surrounding environment.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaska Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

★ The NEPD Group recommends that the President direct the Secretary of Energy to propose comprehensive electricity legislation that promotes competition, protects consumers, enhances reliability, promotes renewable energy, improves efficiency repeals the Public Utility Holding Company Act, and reforms the Public Utility Regulatory Policies Act.

★ The NEPD Group recommends that the President encourage FERC to use its existing statutory authority to promote competition and encourage investment in transmission facilities.

★ The NEPD Group recognizes the importance of looking to technology to help us meet the goals of increasing electricity generation while protecting our environment. To that end, the NEPD Group recommends that the President direct the Department of Energy to continue to develop advanced clean coal technology by:

- Investing $2 billion over 10 years to fund research in clean coal technologies.
- Supporting a permanent extension of the existing research and development tax credit.
- Directing federal agencies to explore regulatory approaches that will encourage advancements in environmental technology.

★ The NEPD Group recommends that the President direct federal agencies to provide greater regulatory certainty relating to coal electricity generation through clear policies that are easily applied to business decisions.

★ The NEPD Group recommends that the President support the expansion of nuclear energy in the United States as a major component of our national energy policy. Following are specific components of the recommendation:

- Encourage the Nuclear Regulatory Commission (NRC) to ensure that safety and environmental protection are high priorities as they prepare to evaluate and expedite applications for licensing new advanced-technology nuclear reactors.
- Encourage the NRC to facilitate efforts by utilities to expand nuclear energy generation in the United States by uprating existing nuclear plants safely.
- Encourage the NRC to relicense existing nuclear plants that meet or exceed safety standards.
- Direct the Secretary of Energy and the Administrator of the Environmental Protection Agency to assess the potential of nuclear energy to improve air quality.
- Increase resources as necessary for nuclear safety enforcement in light of the potential increase in generation.
- Use the best science to provide a deep geologic repository for nuclear waste.
- Support legislation clarifying that qualified funds set aside by plant owners for eventual decommissioning will not be taxed as part of the transaction.
- Support legislation to extend the Price–Anderson Act.

★ The NEPD Group recommends that, in the context of developing advanced nuclear fuel cycles and next generation technologies for nuclear energy, the United States should reexamine its policies to allow for research, development and deployment of fuel conditioning methods (such as pyroprocessing) that reduce waste streams and enhance proliferation resistance. In doing so, the United States will continue to discourage the accumulation of separated plutonium, worldwide.

★ The United States should also consider technologies (in collaboration with international partners with highly developed fuel cycles and a record of close cooperation) to develop reprocessing and fuel treatment technologies that are cleaner, more efficient, less waste-intensive, and more proliferation-resistant.

★ The NEPD Group recognizes there is a need to reduce the time and cost of the hydropower licensing process. The NEPD Group recommends that the President encourage the Federal Energy Regulatory Commission (FERC) and direct federal resource agencies to make the licensing process more clear and efficient, while preserving environmental goals. In addition, the NEPD Group recognizes the importance of optimizing the efficiency and reliability of existing hydropower facilities and will encourage the Administration to adopt efforts toward that end.

- Support administrative and legislative reform of the hydropower licensing process.
- Direct federal resource agencies to reach interagency agreement on conflicting mandatory license conditions before they submit their conditions to FERC for inclusion in a license.
- Encourage FERC to adopt appropriate deadlines for its own actions during the licensing process.

Nature's Power

Increasing America's Use of Renewable and Alternative Energy

A sound national energy policy should encourage a clean and diverse portfolio of domestic energy supplies. Such diversity helps to ensure that future generations of Americans will have access to the energy they need.

Renewable energy can help provide for our future needs by harnessing abundant, naturally occurring sources of energy, such as the sun, the wind, geothermal heat, and biomass. Effectively harnessing these renewable resources requires careful planning and advanced technology. Through improved technology, we can ensure that America will lead the world in the development of clean, natural, renewable and alternative energy supplies.

Renewable and alternative energy supplies not only help diversify our energy portfolio; they do so with few adverse environmental impacts. While the current contribution of renewable and alternative energy resources to America's total electricity supply is relatively small—only 9 percent—the renewable and alternative energy sectors are among the fastest growing in the United States. Non-hydropower only account for 2 percent of our electricity needs. However, electricity generation from non-hydropower renewable energy grew by nearly 30 percent in the 1990s. Continued growth of renewable energy will continue to be important in delivering larger supplies of clean, domestic power for America's growing economy.

Renewable energy resources tap naturally occurring flows of energy to produce electricity, fuel, heat, or a combination of these energy types. One type of renewable energy, hydropower, has long provided a significant contribution to the U.S. energy supply and today is competitive with other forms of conventional electricity. However, there is limited growth potential for hydropower. Non-hydropower renewable energy is generated from four sources: biomass, geothermal, wind, and solar (Figure 6-1). The United States has significant potential for renewable resource development. These nondepletable sources of energy are domestically abundant and often have less impact on the environment than conventional sources. They can provide a reliable source of energy at a stable price, and they can also generate income for farmers, landowners, and others who harness them.

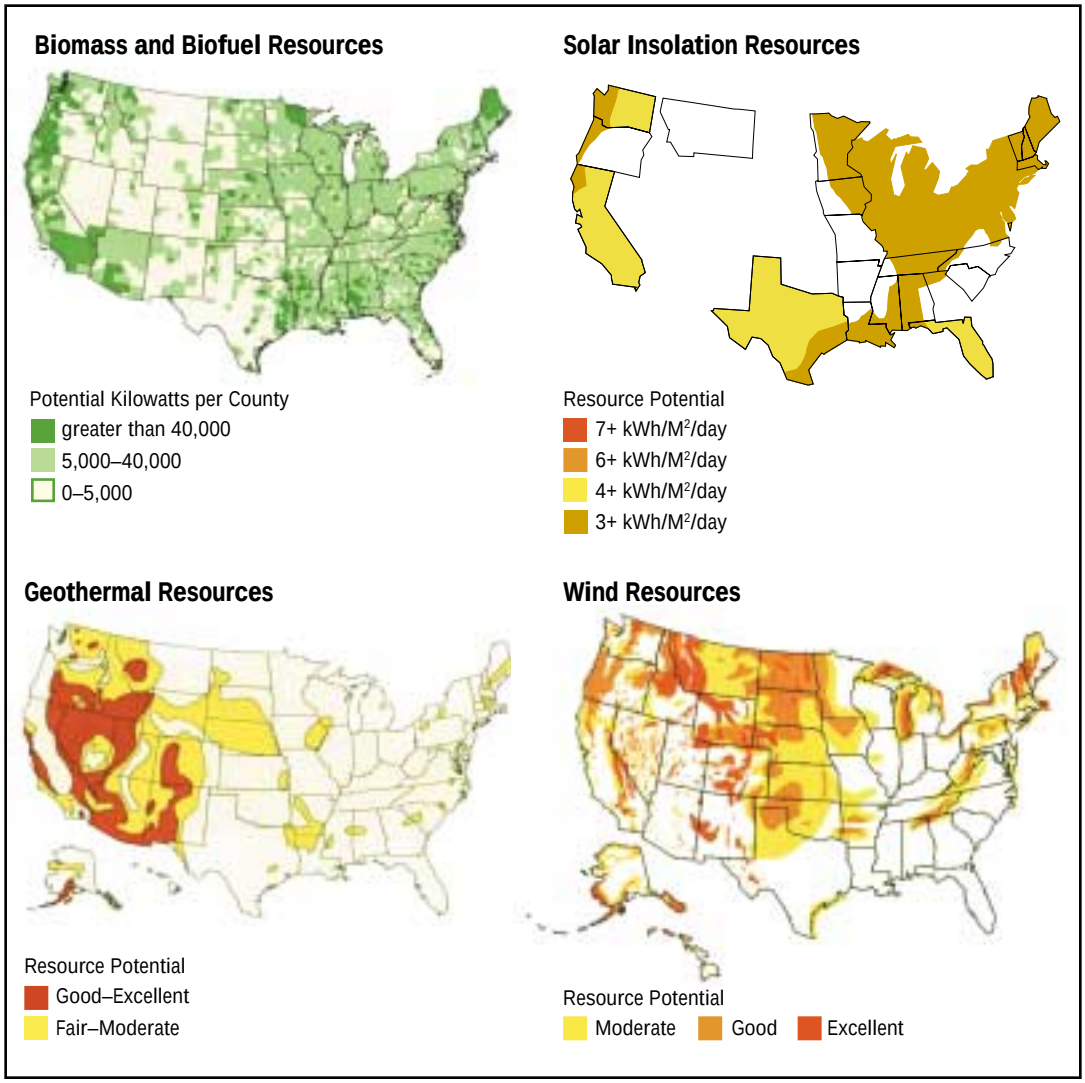


Renewable hydropower has long provided a significant contribution to the U.S. energy supply. Today, hydropower is competitive with other forms of conventionally generated electricity.



Figure 6-1

U.S. Resource Potential for Renewable Energy



Almost every state has the potential for wind energy and for biomass and biofuel production. The Southwest has the greatest potential for solar energy, and geothermal energy resources are most abundant in the West.

Source: U.S. Department of Energy, National Renewable Energy Laboratory.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to re-evaluate access limitations to federal lands in order to increase renewable-energy production, such as biomass, wind, geothermal, and solar.

Alternative energy includes: alternative fuels that are transportation fuels other than gasoline and diesel, even when the type of energy, such as natural gas, is traditional; the use of traditional energy sources, such as natural gas, in untraditional ways, such as for distributed energy at the point of use through microturbines or fuel cells; and future energy sources, such as hydrogen and fusion.

Both renewable and alternative energy resources can be produced centrally or on a distributed basis near their point of use. Providing electricity, light, heat, or mechanical energy at the point of use diminishes the

need for some transmission lines and pipe lines, reducing associated energy delivery losses and increasing energy efficiency. Dis tributed energy resources may be renew able resources, such as biomass cogenera tion in the lumber and paper industry or rooftop solar photovoltaic systems on homes, or they may be alternative uses of traditional energy, such as natural gas microturbines.

Recommendations:

★ The NEPD Group supports the increase of $39.2 million in the FY 2002 budget amendment for the Department of Energy's Energy Supply account that would provide increased support for research and development of renewable energy resources.

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic perfor mance of renewable energy and alternative energy research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

Microturbines

Microturbines are small combustion turbines approximately the size of a refrigerator with outputs of 25 to 500 kilowatts. Microturbines can be used to power a home or small business. This technology has evolved largely from automotive and truck turbochargers, auxiliary power units for airplanes, and small jet engines.

Compared to other technologies for small-scale power generation, microturbines offer a number of significant advantages, including a small number of moving parts; compact size; lightweight, optimal effi ciency; lower emissions and electricity costs; and opportunities to use waste fuels. For these reasons, microturbines could easily capture a significant share of the distributed generation market.

Renewable Energy Technologies

Biomass

Biomass is organic matter that can be used to provide heat, make fuel, and gener ate electricity. Wood, the largest source of biomass, has been used to provide heat for thousands of years. Many other types of biomass are also used as an energy source, such as plants, residue from agriculture or forestry, and the organic component of mu nicipal and industrial wastes. Landfill gas is also considered a biomass source. Biomass resources can be replenished through culti- vation of what are known as energy crops, such as fast-growing trees and grasses.

Unlike other renewable energy sources, biomass can be converted directly into liquid fuels, called biofuels, to meet our transportation needs. The two most com mon biofuels are ethanol and biodiesel. Ethanol is made by fermenting any biomass that is rich in carbohydrates, such as corn. It is mostly used as a fuel additive to reduce a vehicle's emissions. Biodiesel is made us ing vegetable oils, animal fats, algae, or even recycled cooking greases. It can be used as a diesel additive to reduce emissions or in its pure form to fuel a vehicle. Beyond en ergy benefits, development of biomass ben efits rural economies that produce crops used for biomass, particularly ethanol and biomass electricity generation.



Biomass, like corn, that is rich in carbohydrates can be converted directly into biofuels to meet our transportation needs. The biofuel ethanol is mostly used as a fuel additive to reduce vehicles' smog-causing emissions. In June 1992, the Greater Peoria Mass Transit District began operating fourteen ethanol-powered buses along regular city routes.
U.S. Department of Energy

Biomass is also used to generate electricity. This is accomplished through the direct combustion of wood, municipal solid waste, and other organic materials; co-firing with coal in high efficiency boilers; or combustion of biomass that has been chemically converted into fuel oil. In the lumber and paper industries, wood scraps are sometimes directly fed into boilers to produce steam for their manufacturing processes or to heat their buildings. For that reason, renewable energy offers a particular advantage to the lumber and paper industry, and many analysts project the industry may soon become a net seller of electricity. Co-firing coal power plants with biomass has environmental benefits, since co firing can significantly reduce emissions. Biomass accounts for 76 percent of renewable electricity generation and 1.6 percent of total U.S. electricity supply.

Even gas for generating electricity can be produced from biomass. Gasification systems use high temperatures to convert biomass into a gas that is used to fuel a turbine. The decay of biomass in landfills also produces methane, a gas that can be captured and burned in a boiler to produce steam for electricity generation or for industrial processes. Using methane emissions increases electricity supplies, reduces pollution from landfills and reduces greenhouse gas emissions. The technologies to collect and use landfill methane to generate electricity are already in the market. However, they have not been successfully integrated at present due to the perceived higher risk of new technologies.

The Geysers in northern California is the world's largest producer of renewable geothermal power. The dry-steam field has successfully produced power since the early 1960s, when Pacific Gas & Electric installed the first 11-megawatt plant. Today, nearly 2,000 megawatts are on line – enough energy to supply the electricity needs of San Francisco and Oakland.
Pacific Gas & Electric



Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Treasury, to work with Congress on legislation to expand the section 29 tax credit to make it available for new landfill methane projects. The credit could be tiered, depending on whether a landfill is already required by federal law to collect and flare its methane emissions due to local air pollution concerns.

Geothermal

Geothermal energy is the use of steam and hot water generated by heat from the Earth to perform work. Some geothermal power plants use steam or hot water from a natural underground reservoir to power a generator. Others use hot water to provide direct heat for residential and other buildings, and for other applications.

The most readily accessible resources for geothermal power generation in the United States are located in the West, Alaska, and Hawaii. A wide array of high technology geological, geochemical, and geophysical techniques are used to locate geothermal resources. In large measure, the technology for developing these resources has been adapted from the oil industry. Improvements in drill bits, drilling techniques, advanced instruments, and other technological advances have made energy production from geothermal resources increasingly efficient.

Geothermal accounts for 17 percent of renewable electricity generation and 0.3 percent of total U.S. electricity supply. However, the net installed capacity of U.S. geothermal power plants has increased significantly, from 500 MW in 1973 to 2,800 MW today.

Hot water near the surface of the Earth can also be used directly for heat. These direct-use applications include heat

ing buildings, growing plants in green houses, drying crops, heating water at fish farms, and several industrial processes, such as pasteurizing milk.

In addition, individual homeowners, farmers, and businesses can tap into geo thermal energy through geothermal heat pumps to heat and cool buildings. A geo thermal heat pump system consists of a heat pump, an air delivery system, a heat exchanger, and a system of pipes buried in the shallow ground near the building. In the winter, a heat pump removes heat from the heat exchanger and pumps that heat into the indoor air delivery system. In the sum mer, the process is reversed, and the heat pump moves heat from the indoor air into the heat exchanger. The heat removed from the indoor air during the summer can also be used to provide a free source of hot water. Geothermal heat pumps can be used almost anywhere in the United States, and can sig nificantly increase system efficiencies.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to determine ways to reduce the delays in geothermal lease process ing as part of the permitting review process.

Wind Energy

Wind energy has been used since at least 200 B.C. for grinding grain and pump ing water. By 1900, windmills were used on farms and ranches in the United States to pump water and, eventually, to produce electricity. Windmills developed into mod ern-day wind turbines.

Wind turbines are used for several ap plications. Wind power uses the naturally occurring energy of the wind for practical purposes like generating electricity, charg ing batteries, or pumping water. Large, modern wind turbines operate together in wind farms to produce electricity for utili ties. Small turbines are used by homeowners, farmers, and remote villages to help meet localized energy needs.

Wind turbines capture energy by using propeller-like blades that are mounted on a rotor. These blades are placed on top of high towers, in order to take advantage of the stronger winds at 100 feet or more above the ground. The wind causes the pro pellers to turn, which then turn the attached shaft to generate electricity. Wind can be used as a stand-alone source of energy or in conjunction with other renewable energy systems. Wind and natural gas hybrid sys tems are a promising approach that offers clean power to consumers.

Wind energy accounts for 6 percent of renewable electricity generation and 0.1 percent of total electricity supply. However, advances by research labs, universities, utilities, and wind energy developers have helped cut wind energy's costs by more than 80 percent during the last twenty years. The industry is poised for growth. In some parts of the country, electricity from wind power can be produced at prices that are comparable to other conventional en ergy technologies. The United States has many areas with abundant wind energy po tential, namely in the West, the Great Plains and New England.



In 1996, the National Association of Home Builders constructed advanced townhouses featuring standing-seam roofs and other energy efficient materials and systems. The townhouse on the right differs from the others in that it has an integrated photovoltaic standing-seam roof that also produces electricity.
Tim Ellison, Energy Conversion Devices

Solar

Sunlight, or solar energy, can be used to generate electricity; heat water; and heat, cool, and light buildings. Photovoltaic (so lar cell) systems use semiconductor materi als similar to those used in computer chips to capture the energy in sunlight and to convert it directly into electricity. Photovol taic cells have been used in everything from

the solar cells in calculators to the space station Freedom.

Another technology for harnessing the sun's energy is a concentrating solar power system, which uses the sun's heat to gener ate electricity. The sunlight is collected and focused with mirrors to create a high inten sity heat source that in turn can be used to generate electricity through a steam turbine or a heat engine.

Solar hot water systems use the sun to heat water for domestic or industrial use. Many large commercial buildings also use solar collectors for heat. A solar ventilation system can be used in cold climates to pre heat air as it enters a building. The heat from a solar collector can even be used to provide energy for cooling a building.

Some architects are using careful de sign and new optical materials to use sun light to reduce the need for traditional light ing and to cut down on heating and cooling costs. For example, materials that absorb and store the sun's heat can be built into the sunlit floors and walls. The floors and walls will store heat during the day and slowly re lease heat at night.

While solar energy technologies have undergone technological and cost improve ments and are well established in high value markets like remote power, satellites, communications, and navigational aids, continued research is needed to reduce costs and improve performance. Solar en ergy accounts for 1 percent of renewable electricity generation and 0.02 percent of total U.S. electricity supply.

Alternative Energy

Alternative Transportation Fuels

Alternative fuels are any transporta tion fuels made from a nontraditional source, including ethanol, biodiesel, and other biofuels. These can be made from biomass resources, including liquid fuels (e.g., ethanol, methanol, biodiesel) and gas eous fuels (e.g., hydrogen and methane). Biofuels are primarily used to fuel vehicles, but can also fuel engines or fuel cells for electricity generation. Alternative fuels also

Recommendations:

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to develop a new renewable energy partnership program to help companies more easily buy renewable energy, as well as receive recognition for the environmental benefits of their purchase, and help consumers by promoting consumer choice programs that increase their knowledge about the environmental benefits of purchasing renewable energy.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to extend and expand tax credits for electricity produced using renewable technology, such as wind and biomass. The President's budget request extends the present 1.7 cents per kilowatt hour tax credit for electricity produced from wind and biomass; expands eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources; and allows a credit for electricity produced from biomass co-fired with coal.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to provide a new 15 percent tax credit for residential solar energy property, up to a maximum credit of $2,000.

★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to work with Congress on legislation to use an estimated $1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR for funding research into alternative and renewable energy resources, including wind, solar, geothermal, and biomass.

Alternative Fuel Vehicles

Alternative fuel vehicles (AFVs) can run on methanol, ethanol, compressed natural gas, liquefied natural gas, propane, hydrogen, electricity, biodiesel, and natural gas. Today, more than 450,000 alternative vehicles are operating in the United States. Some of the barriers to using AFVs include:

Cost—For example, a Ford Crown Victoria that runs on compressed natural gas costs about $4,000 more than its gasoline counterpart.

Refueling Infrastructure—Refueling infrastructure is limited, which can make refueling inconvenient and travel options difficult.

Travel Distance—Ability to travel a long distance on a single volume of fuel. Al ternative fuels have an energy content lower than that of gasoline, which means that AFVs cannot travel as far as traditional vehicles on a single tank of fuel.

In the short term, natural gas and propane offer the greatest potential for market growth, especially in niche markets where lower fuel costs make them attractive, such as transit buses, school buses, shuttles, and other heavy-duty vehicles. Ethanol vehicles offer tremendous potential if ethanol production can be expanded. Electric vehicles could reach large numbers in the future if technology breakthroughs help bring costs down and increase driving distance. Fuel cell vehicles operating on com pressed hydrogen offer long-term potential. Compressed natural gas offers a distribu tion stepping-stone to a hydrogen-refueling infrastructure.

include traditional energy sources, such as natural gas and liquid propane that are tra ditionally not used as a transportation fuel.

Currently, there are approximately 450,000 alternative fuel vehicles in the United States, and more than 1.5 million flexible-fuel vehicles that can use gasoline or a mixture of ethanol and gasoline. Etha nol is made by converting the carbohydrate portion of biomass into sugar, which is then converted into ethanol through a fermenta tion process. Ethanol is the most widely used biofuel, and its production has in creased sharply since 1980, rising from 200 million gallons a year to 1.9 billion gallons. Today, many states are considering phasing out the use of MTBE (methyl tertiary butyl ether), an oxygenate additive for gasoline. If they do so, that will likely spur greater re liance on ethanol.

Each year, approximately 65 percent of the oil consumed in the United States is used for transportation. As a result, vehicle emissions have become the leading source of U.S. air pollution. However, recent ad vances in fuels and vehicle design are help ing increase fuel efficiency and reduce toxic substances discharged into the air.

Changes in the composition of trans portation fuels, such as gasoline and diesel fuels, are one way to improve vehicle per formance while reducing emissions and lowering oil consumption. Reformulated gasoline contains fuel additives such as ethanol to increase oxygen content, which reduces harmful emissions such as carbon monoxide. Low-sulfur gasoline reduces sul fur oxide emissions. New diesel fuels, some of which have lower sulfur contents or are produced from clean-burning natural gas, can help vehicles with diesel engines achieve lower emissions.

In addition to advanced transportation fuels, alternative fuels are being developed, such as biodiesel, electricity, ethanol, hydro gen, methanol, natural gas, and propane. These alternative fuels not only reduce de pendence on petroleum transportation fu els. They reduce or entirely eliminate harm ful emissions as well. With the exception of natural gas and propane, these fuels also have the potential of being generated from renewable resources, such as ethanol from corn. The federal government has promoted development of alternative fuels for many years and this program has helped to reduce U.S. reliance on oil-based fuels.

The evolution toward more efficient,

environmentally friendly transportation fu els has been mirrored by improvements in vehicle design, components, and materials. Alternative fuel vehicles, which can either switch between two fuels or run on a mix ture of two fuels such as gasoline and etha nol, are now available. Recent developments in both alternative fuel vehicles and petro leum-based vehicles, such as advances in engines, drive trains, and emission-control technologies, may double or triple the effi ciency of current vehicles. Some of these new technologies include hybrid electric ve hicles, which combine an engine with an electric motor, and fuel cells, which produce electricity by converting a fuel, generally hy drogen and oxygen, into water.

A number of issues drive the research and marketability of advanced alternative fuel vehicles and petroleum-based vehicles in the United States. The goal of reducing U.S. dependence on imported oil, combined with the link between vehicle emissions and air pollution, have prompted the develop ment of emissions and fuel economy stan dards for car manufacturers. In addition, federal, state, and local governments have enacted regulations, laws, and incentives de signed to reduce the number of vehicle miles traveled and to encourage businesses and individuals to purchase alternative fuel vehicles.

The success of the federal alternative fuels program has been limited, however. The current program focuses on mandating certain fleet operators to purchase alterna tive fueled vehicles. The hope was that this vehicle purchase mandate would lead to ex panded use of alternative fuels. That expec tation has not been realized, since most fleet operators purchase dual-fueled vehicles that operate on petroleum motor fuels. The Clean Air Act required the use of oxygen ates, such as MTBE (methyl tertiary butyl ether) and ethanol in fuel. These oxygenates account for 92 percent of alternative fuel use. Reforms to the federal alternative fuels program could promote alternative fuels use instead of mandating purchase of vehicles that ultimately run on petroleum fuels.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Treasury to work with Congress to continue the ethanol excise tax exemption.

Distributed Energy

Untapped opportunities for reducing energy demand loads could be realized by better integrating electricity supply systems and customers. Improved integration can produce a variety of benefits for tight en ergy markets, including reducing peak de mand loads, bypassing congested areas of transmission by placing new generating ca pacity closer to the consumer, and thus achieving greater overall system efficien cies.

Current electricity load management efforts are typically limited to cutting off in terruptible or nonfirm customers, appeals to the public to conserve, and brownouts. Some utilities are incorporating current generation metering, sensor, and control technologies to take the next step: selective reduction of individual energy-using appli ances. In some areas, residents can reduce their monthly bills by allowing the utility to electronically turn off selected appliances, such as water heaters, on a rotating basis. If this option is well managed, consumers are unaware of the temporary loss service, and critical systems continue to run unimpeded. Advanced integrated supply-and-demand load management controls also allow for widespread “demand auctions,” in which consumers can decide which energy ser vices to forego on which days.

Distributed energy resources describe a variety of smaller electricity-generating options well suited for placement in homes, offices, and factories, or near these facili ties. Distributed energy systems have the distinct advantage of being brought on line faster than new central power plants. While natural gas microturbines and solar roof panels are the most familiar types of distrib uted energy, other distributed energy re sources include: combined heat and power, stationary fuel cells, generation of

bioenergy from landfill methane recovery, and small wind systems. Photovoltaic solar distributed energy is a particularly valuable energy generation source during times of peak use of power.

Efficiency gains from distributed en ergy come from three sources. First, trans mission and distribution line losses (about 5 percent) are reduced because the energy is generally used near the source. Second, the co-location with consumption makes it more feasible to use waste heat, displacing otherwise needed natural gas or electricity for heating purposes. And, third, the co-lo cation with consumption allows for the in tegration of on-site energy efficiency and generating capabilities. For example, in the residential market, distributed energy appli cations can make possible the concept of the "net zero energy home," in which the overall level of energy produced at the home equals or exceeds the amount of en ergy used in the home.

Despite these advantages, a number of impediments and competing policy ob jectives discourage the wider application of integrated electricity supply and demand solutions, many of which reflect the relative newness and lack of familiarity with these technologies.

For example, the lack of standards governing interconnection of distributed energy to the grid impedes development. The lack of standards prevents a uniformly effective means of getting excess distrib uted energy to the grid.

In addition, current air quality regula tions do not take into account the additional energy savings from many distributed en ergy technologies. Likewise, distributed en ergy systems purchased by consumers may receive different tax rates than those pur chased by traditional electricity producers.

Although distributed energy can alle viate distribution constraints, these systems often cannot be sited and permitted in a timely manner. For instance, land-use zon ing codes may not allow generating equip ment in association with residential or com mercial land uses, and building code offi cials may not know enough about solar roof systems to provide timely building permits.

As with energy efficiency equipment, load management integrating systems, both controls and distributed energy, have higher first costs associated with lower future en ergy bills.

Another barrier to development of dis tributed energy is the need for net metering, which enables consumers to install a small electricity project at their homes and sell the excess to the local utility, offsetting their purchases from the utility at other times. Net metering can lower the cost to consumers of distributed energy projects. Some consumers are reluctant to install dis tributed renewable energy resources be cause many regions do not have the regula tory framework under which consumers can sell energy back to the grid under a net metering system.

Future Energy Sources

As we look to the long-term future of alternative energy technologies, there is sig nificant promise in these technologies to meet an ever-growing portion of our nation's energy needs.

Hydrogen

In the long run, alternative energy technologies such as hydrogen show great promise. Hydrogen is the most common ele ment in the universe and can be made from water. Converting hydrogen into energy is compatible with existing energy technolo gies, such as fuel cells, engines, and com bustion turbines. The energy for extracting hydrogen could come from existing, tradi tional fuels, or it could be derived from re newable energy sources, such as solar, nuclear, and fossil, to achieve the cleanest possible energy cycle. Hydrogen can be converted into useful energy forms effi ciently and without detrimental environ mental effects. Unlike other energy sources, its production by-product is water.

In the future, hydrogen may be able to be used in furnaces and as a transportation fuel for automobiles, buses, trains, ships and airplanes. Hydrogen could also be con verted directly into electricity by fuel cells. Combustion of hydrogen with oxygen re sults in pure steam, which has many appli-



There is a significant promise in renewable technologies to meet an ever-growing portion of our nation's energy needs. Wind power has significant growth potential. The principal challenges to achieving this level of renewable energy generation are cost and market acceptance of renewable power technologies.
U.S. Department of Energy, National Renewable Energy Laboratory

cations in industrial processes and space heating. Moreover, hydrogen is an important industrial gas and raw material in numerous industries, such as computer, metallurgical, chemical, pharmaceutical, fertilizer and food industries.

An energy infrastructure that relies on hydrogen could enable much greater use of distributed energy systems. These systems are small, modular electricity generators that can be placed right where they are needed for heating, cooling, and powering offices, factories, and residences. Hydrogen fuel cells are a promising type of distributed energy system that can provide the exacting reliability needed for the high-tech industry.

Fuel cells can produce electricity and heat from hydrogen, natural gas, and petroleum fuels, and fuel gases derived from coal and biomass. What makes fuel cells unique is that they can use fuels without combustion, simply by chemical reactions, making them extremely clean and efficient.

Fuel cells were developed by the National Aeronautics and Space Administration to generate electricity, heat, and water in space vehicles. The first-generation fuel cells for stationary power applications entered the commercial market in 1995. This type of fuel cell is used to generate very high-quality electricity and heat with negligible emissions in commercial and industrial settings. It is most likely to be used in cases where users are willing to pay a premium for cleaner, more reliable power than is available from the commercial grid.

The second generation of stationary fuel cells is currently in the demonstration phase, including a combined fuel cell–turbine hybrid. These fuel cells are expected to be more efficient and cost less when used in similar distributed energy systems. Smaller fuel cells for residential units are also being developed, and some are in the demonstration phase.

Despite technical progress, high costs remain the main deterrent to widespread fuel cell use. Significant cost reductions must be achieved before fuel cells will be competitive with internal combustion engines, and the size and weight of fuel cell systems must be reduced even more to accommodate vehicle packaging requirements.

The primary challenge to using more hydrogen in our energy systems is the cost of producing, storing, and transporting it. A serious challenge confronting a move toward distributed energy is the transition away from centralized energy systems of supply and production. These challenges are not expected to be resolved overnight, but progress made in the last few years has already far surpassed the expectations of just a decade ago.

A significant amount of promising research and development has already been completed. The automobile industry is aggressively exploring the fuel cell as the future of the industry. Moreover, a new first generation class of distributed energy technologies are already hitting the market.

Fusion

Fusion—the energy source of the sun—has the long-range potential to serve as an abundant and clean source of energy. The basic fuels, deuterium (a heavy form of hydrogen) and lithium, are abundantly available to all nations for thousands of years. There are no emissions from fusion, and the radioactive wastes from fusion are short lived, only requiring burial and oversight for about 100 years. In addition, there is no risk of a melt-down accident because only a small amount of fuel is present in the system at any time. Finally, there is little risk of nuclear proliferation because special nuclear materials, such as uranium and plutonium, are not required for fusion energy. Fusion systems could power an energy supply chain based on hydrogen and fuel cells, as well as provide electricity directly.

Although still in its early stages of development, fusion research has made some advances. In the early 1970s, fusion research achieved the milestone of producing 1/10 of one watt of fusion power, for 1/100 of a second. Today the energy produced from fusion is 10 billion times greater, and has been demonstrated in the laboratory at powers over 10 million watts in the range of a second.

Internationally, an effort is underway in Europe, Japan, and Russia to develop plans for constructing a large-scale fusion science and engineering test facility. This test facility may someday be capable of steady operation with fusion power in the range of hundreds of megawatts.

Both hydrogen and fusion must make significant progress before they can be come viable sources of energy. However, the technological advances experienced over the last decade and the advances yet to come will hopefully transform the en ergy sources of the distant future.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to develop next-generation technology—including hydrogen and fusion.

- Develop an education campaign that communicates the benefits of alternative forms of energy, including hydrogen and fusion.
- Focus research and development efforts on integrating current pro grams regarding hydrogen, fuel cells, and distributed energy.

Current Markets for Renewable and Alternative Energy

Advances in Technology

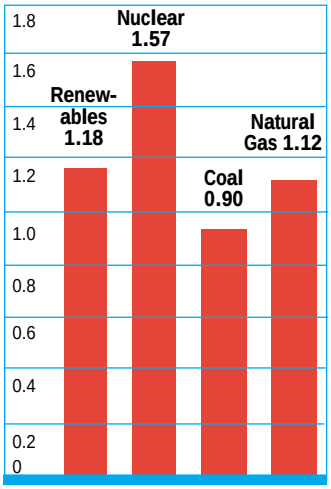
Non-hydropower renewable energy accounts for about 4 percent of current U.S. energy production, divided evenly be tween electricity generation and transpor tation fuels such as ethanol. Between 1990 and 1999, renewable energy generation grew by 29 percent, and renewable energy is projected to continue to grow (Figure 6-1). Renewable fuel consumption, includ ing ethanol for gasoline blending, is pro jected to grow at an average rate of 1.1 per cent a year through 2020. In 2020, 55 per cent of renewables are projected to be used for electricity generation and the rest for dispersed heating, industrial uses, and fuel blending.

The success of renewables is, in part, the result of over twenty years of research, development, and demonstration conducted by the public and private sectors. This work has dramatically improved these technolo gies and has reduced their costs by as much as 90 percent. For example:

- The Department of Energy (DOE), the National Renewable Energy Laboratory (NREL), and Alstom Energy Systems jointly created Advanced Direct-Contact Condens ers, which improve the efficiency and gener ating capacity of electric power plants by providing the best surface area for condens ing spent steam. This technological ad vance, tested in geothermal applications in California, can improve the efficiency of electricity production by 5 percent and capacity by 17 percent.
- United Solar Systems in Michigan pioneered the first commercial use of solar photovoltics as a building material. The triple-junction, thin-film technology is now sold as flexible solar panels, solar shingles for building roofs, and a peel-and-stick-on variety for standing seam metal roofs. United Solar is now building a larger manu facturing plant in Michigan that is five times the size of its existing manufacturing facil ity. DOE collaborates with United Solar on research and development helping over come hurdles in manufacturing. As a result, United Solar is able to provide unique solar electric products using a unique roll-to-roll manufacturing process.
- In partnership with DOE, NREL, Battelle Lab, Burlington Electric and others, Future Energy Resources Corporation of Norcross, Georgia, was able to build, test, and operate the world's first biomass gasifi cation system. The McNeil Plant, located in Burlington, Vermont, gasifies rather than combusts wood chips to power a gas boiler. The technology has shown itself to be com mercially viable, and is being considered worldwide by industries as a way of upgrad ing existing inefficient and aging boilers.

Improved renewable and alternative energy technologies are becoming increas ingly attractive to a number of energy com panies seeking to build new business oppor tunities for the future (Figure 6-3). Follow ing are a few examples:

Figure 6-1
Increases in U.S. Energy Production: 1990–1999



During the last decade, renewable energy sources contributed substantially to the growth in U.S. energy production, outpacing all fuel sources except for nuclear energy.

Source: U.S. Department of Energy, Energy Information Administration.

Table 6-2

Electricity Generated by Renewable Energy Sources: 1999

	Solar	Wind	Geothermal	Biomass	Hydropower
Current net summer capacity (MW)	350	2,600	2,870	6,170	79,130
Annual generation (millions of kWh)	940	4,460	13,070	36,570	312,000
Expected growth in generation (%)	PV: 19.3 Thermal: 21	5.3	3.3	3.0	-0.1
Cost (cents/kWh)	20	4–6	5–8	6–20	2–6

Renewable energy has become a significant source of electric power in the United States.

Note: Capacity, generation, and growth data do not include off-grid electricity, thermal, or other nonelectricity energy production, municipal solid waste, or methane from landfills.

Sources: U.S. Department of Energy, Energy Information Administration and Office of Power Technologies.

• FPL Group announced in January 2001 the construction of two major wind farms: a 300 MW facility on the Washington–Oregon border, and a 25.5 MW facility in Wisconsin. The company now has more than 1,000 MW of wind generating capacity in operation or under construction in seven states.

• CalEnergy Company has made renewable and alternative energy generation a central focus of its power portfolio. The company operates 1,300 MW of geothermal, natural gas, hydropower, and other power facilities in the U.S. and abroad, with another 750 MW currently under construction.

• General Motors, Ford, DaimlerChrysler, Texaco, BP/Amoco, and Shell are collectively spending between $500 million and $1 billion dollars a year on fuel cells, hydrogen storage, and infrastructure development for passenger vehicles. Ongoing bus demonstrations in the United States and Europe are expected to commercialize fuel cell power hydrogen buses in the next five years.

Because alternative and renewable energy resources can be used in so many different ways throughout the economy to produce so many combinations of energy types, their total use is often difficult to measure precisely. As of 1996, California alone had over 10 MW of installed distributed energy, a large increase in generating capacity during a period of otherwise limited growth in generation (Figure 6-3). In 1999, several types of renewable energy were used to produce electricity (Table 6-2).

On the transportation side, there are approximately 450,000 alternative fuel vehicles in the United States. Additionally, there are more than 1.5 million flexible-fuel vehicles that can use gasoline or a high mixture of ethanol and gasoline. These include the Ford Taurus, the DaimlerChrysler Caravan, and the General Motors S10 pickup. Ethanol is the most widely used biofuel, and its production is currently 1.9 billion gallons a year, representing a nearly ten-fold growth from about 200 million gallons a year in 1980.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to develop legislation to provide for a temporary income tax credit available for the purchase of new hybrid or fuel-cell vehicles.

Hybrid Electric Vehicles

Hybrid electric vehicles (HEVs) combine the internal combustion engine of a conventional engine with the battery and electric motor of an electric vehicle, resulting in twice the fuel economy of conventional vehicles. This combination offers the extended range and rapid refueling that consumers expect from a conventional vehicle, with a significant portion of the energy and environmental benefits of an electric vehicle. The practical benefits of HEVs include improved fuel economy and lower emissions compared to conventional vehicles. The car's flexibility will mean convenient use for individuals as well as businesses.

Removing Barriers to Renewable and Alternative Energy Growth

Perhaps the greatest barrier to growth of renewable energy is cost. Currently, the cost of renewable energy generation fre

quently exceeds the costs of conventional electricity generation. In recent years, though, the costs of renewable energy have declined substantially. For example, the cost of wind energy has declined by more than 80 percent over the past twenty years and is increasingly competitive with con ventional electricity generation sources. Wind, biomass, and geothermal are all in creasingly competitive with conventional electricity generation.

The ability of these technologies to meet specific market needs is another fac tor in how quickly their market share will grow. These technologies and energy sources provide multiple benefits to the en ergy producer and the consumer. For ex ample, many of these technologies are modular and can be constructed rapidly, adding an immediate source of new power in areas that otherwise might face a short fall. Distributed renewable energy re sources can enhance the reliability and quality of power.

Cogeneration uses of waste products and heat can increase profits by reducing purchased electricity costs, as well as costs for process steam and heating or cooling. Several sectors, including lumber and paper, steel, and chemical manufacturing, are ex ploring the increased use of cogeneration. With the technological development of biom ass gasification, the lumber and paper indus try could become a seller of electricity.

Recommendation:

★ The NEPD Group recommends that the President direct the Adminis trator of the Environmental Protec tion Agency to issue guidance to encourage the development of well designed combined heat and power (CHP) units that are both highly efficient and have low emissions. The goal of this guidance would be to shorten the time needed to obtain each permit, provide certainty to industry by ensuring consistent implementation across the country, and encourage the use of these cleaner, more efficient technologies.

Renewable technologies can help pro vide insurance against price volatility. In ad dition, many renewable technologies can help industry achieve compliance with the Clean Air Act and other environmental regu lations. In some cases, renewables can be more readily located in urban areas whose air quality does not meet regulatory require ments.

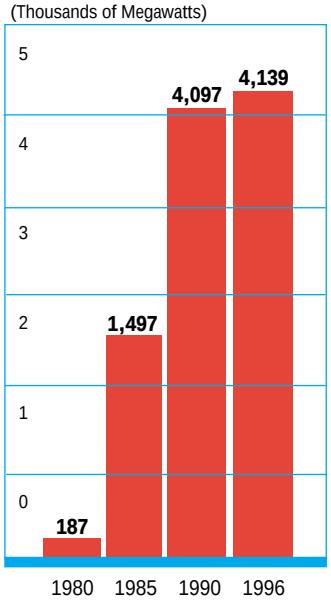
With the growth rate for non-hydro power renewable electricity generation more than doubling the expected growth in overall electricity capacity, these energy sources will play a more significant role in electricity markets in the next two decades. However, the extent to which these domes tic resources are successfully tapped will depend in large part on continued techno logical development.

For renewable and alternative energy to play a greater role in meeting our energy de mands, these sources of generation must be able to integrate into our existing distribution system. The tools that form the necessary in terface between distributed energy systems and the grid need to be less expensive, faster, more reliable, and more compact.

Promising technologies exist that will improve the transmission, storage, and reli ability of renewable energy. An example of recent technological success that will allow for increased access to all forms of energy, including renewable energy, is the high-tem perature superconducting underground power transmission cables that the Depart ment of Energy is developing in partnership with industry. These cables will allow a 300 percent increase in capacity without exca vation to lay new transmission lines. This summer, Detroit Edison is demonstrating this commercially viable high-temperature superconducting cable system in an applica tion that serves 14,000 customers.

Renewable and alternative energy technologies, such as wind energy and com bined heat and power could be significantly expanded, given today's technologies. They could be further expanded with added in vestment in technology. For example, wind energy could be developed that could be adapted to sites with lower wind speeds than is feasible today. Combined heat and

Figure 6-3
Growth in California's Renewable Energy Capacity



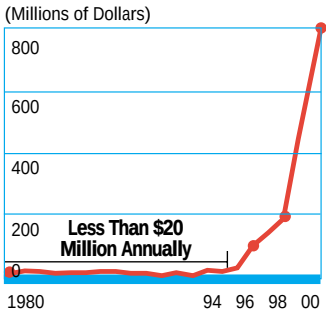
Source: U.S. Department of Energy, Energy Information Administration.



While solar energy technologies have undergone technological and cost improvements, and are well established in high value markets like remote power, satellites, communications, and navigational aids continued research is needed to reduce costs and improve performance.

U.S. Department of Energy

Figure 6-4
Investors Are Betting on Distributed Energy



In the last few years, surging venture capital investments showed strong support for distributed energy technologies.

Note: Data for 2000 are projected investments.
Source: Nth Power via the Economist, August 5, 2000.

power in buildings offers great potential for increased system efficiencies and lower costs. New developments in microturbine and fuel cell technologies are also highly promising. Performance improvements of other technologies, such as photovoltaic systems, would facilitate much wider use. In addition to technological performance, attention to several key market and regula tory constraints would accelerate the devel opment and use of renewable and alterna tive energy in the marketplace.

Because many renewable and alterna tive energy technologies do not fit into tra ditional regulatory categories, they are of ten subjected to competing regulatory re quirements or to requirements that were never designed to address them. For ex ample, much of the current Clean Air Act does not specifically address the use of new, more efficient renewable energy tech nologies. Consequently, the Act does not provide significant incentives for the devel opment of such technologies.

The lack of interconnection standards or guidelines for electricity supply and loads impedes the use of distributed energy tech nologies. As a result, developers of small re newable energy projects must negotiate in terconnection agreements on a site-by-site basis with local distribution companies that are often opposed to distributed energy projects because of the increased competi tion. Although a few states have established interconnection standards, there is no na tional standard to facilitate development of distributed energy (Figure 6-4).

New combined heat and power facili ties may face air permitting hurdles when they replace marginally dirty boilers. The Clean Air Act does not recognize the pollu tion prevention benefits of the increased ef ficiency of combined heat and power units. At the same time, these combined heat and power investments are taxed at the industry's tax rate, not at the rate they would receive if they were considered part of the utility sector for tax purposes.

In addition, modifications to permitting and siting requirements may be necessary to fa cilitate the incorporation of these technolo gies into buildings.

The infrastructure needed for increas ing the use of renewable and alternative en ergy varies considerably. In particular, the alternative fuels infrastructure lags far be hind the existing infrastructure for conven tional fuels. The lack of infrastructure for al ternative fuels is a major obstacle to con sumer acceptance of alternative fuels and the purchase of alternative fuel vehicles. It is also one of the main reasons why most al ternative fuel vehicles actually operate on petroleum fuels, such as gasoline and diesel. In addition, a considerable enlargement of ethanol production and distribution capac ity would be required to expand beyond their current base in the Midwest in order to increase use of ethanol-blended fuels.

The use of natural gas or electricity for vehicles requires enhancements to these distribution systems, such as compression stations for natural gas. While many alterna tive fuels can be shipped by pipeline, they may require separation within the pipeline to avoid mixing different energy products. Geographically dispersed renewable energy plants often face significant transmission barriers, including unfavorable grid sched ule policies and increased embedded costs.

Uncertainty regarding the tax treat ment of these technologies and energy sources can discourage long-term invest ment. Though existing tax credits provide an incentive for investing in some types of renewable energy, the limited scope of the credit and its frequent expiration discour ages investment.

Summary of Recommendations

Nature's Power: Increasing America's Use of Renewable and Alternative Energy

★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to re-evaluate access limitations to federal lands in order to increase renewable energy production, such as biomass, wind, geothermal, and solar.

★ The NEPD Group supports the increase of $39.2 million in the FY 2002 budget amendment for the Department of Energy's Energy Supply account that would provide increased support for research and development of renewable energy re sources.

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of renewable energy and alternative energy research and development programs in light of the recommen dations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to expand the section 29 tax credit to make it available for new landfill methane projects. The credit could be tiered, depending on whether a landfill is already required by federal law to collect and flare its methane emissions due to local air pollution concerns.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to determine ways to reduce the delays in geothermal lease processing as part of the permitting review process.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to develop a new renewable energy partnership program to help companies more easily buy renewable energy, as well as receive recognition for the environmental benefits of their purchase, and help consumers by promoting consumer choice programs that increase their knowledge about the environmental benefits of purchasing renewable energy.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to extend and expand tax credits for electricity produced using wind and biomass. The President's budget request extends the present 1.7 cents per kilowatt hour tax credit for electricity produced from wind and biomass; expands eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources; and allows a credit for electricity produced from biomass co-fired with coal.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to provide a new 15 percent tax credit for residential solar energy property, up to a maximum credit of $2,000.

★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to work with Congress on legislation to use an estimated $1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR for funding research into alternative and renewable energy resources, including wind, solar, geothermal, and biomass.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to continue the ethanol excise tax exemption.

★ The NEPD Group recommends that the President direct the Secretary of Energy to develop next-generation technology—including hydrogen and fusion.
• Develop an education campaign that communicates the benefits of alternative forms of energy, including hydrogen and fusion.
• Focus research and development efforts on integrating current programs regarding hydrogen, fuel cells, and distributed energy.
• Support legislation reauthorizing the Hydrogen Energy Act.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to develop legislation to provide for a temporary income tax credit available for the purchase of new hybrid or fuel-cell vehicles be tween 2002 and 2007.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to issue guidance to encourage the development of well-designed combined heat and power (CHP) units that are both highly efficient and have low emissions. The goal of this guidance would be to shorten the time needed to obtain each permit, provide certainty to industry by ensuring consistent implementa tion across the country, and encourage the use of these cleaner, more efficient tech nologies.

America's Energy Infrastructure

A Comprehensive Delivery System

One of the greatest energy challenges facing America is the need to use 21st- century technology to improve America's aging energy infrastructure. Americans need a comprehensive, long-term solution to deliver energy to industry and consumers in a reliable and safe manner.

Our energy infrastructure is comprised of many components, such as the physical network of pipes for oil and natural gas, electricity transmission lines and other means for transporting energy to consumers. This infrastructure also includes facilities that turn raw natural resources into useful energy products. The rail network, truck lines, and marine transportation are also key components of America's energy infrastructure.

The energy industry has undergone major changes in the last two decades, and more are expected. These changes affect how our energy infrastructure operates. For example, while the electricity industry was once vertically integrated, it is increasingly separated into three isolated segments: generation, transmission, and distribution.

Our energy infrastructure has failed to keep pace with the changing requirements of our energy system. Domestic refining capacity has not matched increases in demand, requiring the United States to import refined products. Natural gas pipelines have not expanded sufficiently to meet demand. The electricity transmission system is constrained by insufficient capacity. Rail capacity was significantly increased during the 1970s when rail facilities were improved to move more coal. Since then, however, few additions to the coal transportation rail network have been built.

The United States needs to modernize its energy infrastructure. One sign of a lack of an energy policy in recent years has been the failure to maintain the infrastructure needed to move energy where it is needed most.

Electricity

The electricity infrastructure includes a nationwide power grid of long-distance transmission lines that move electricity from region to region, as well as the local distribution lines that carry electricity to homes and businesses. Electricity originates at power plants, which are primarily fueled by coal, nuclear, natural gas, water and, to a lesser extent, oil. Coal, natural gas and oil powered plants require a dependable transportation infrastructure to deliver the fuels necessary for the production of electricity. A transportation network for waste disposal is also necessary for power plants that create by products.

Restructuring

The electricity industry has undergone considerable changes in the last two decades. These changes affect how our electricity infrastructure operates. Major industry restructuring has separated once vertically integrated electric utilities that supplied generation, transmission, and distribution services into distinct entities. To facilitate competition at the wholesale level, in 1996, the Federal Energy Regulatory Commission (FERC) required transmission-owning utilities to "unbundle" their transmission and power marketing functions, and provide nondiscriminatory, open access to their transmission systems by other utilities

U.S. DEPARTMENT OF ENERGY



FIGURE 7-1
North American Transmission Lines

About 204,000 miles of long-distance transmission lines move power from region to region. The four integrated transmission grids serving North America are the Western Interconnection, Eastern Interconnection, Electric Reliability Council of Texas, and Province of Quebec.

Source: PA Consulting Group




Eastern
Interconnect
Legend
Below 230kv
230kv - 344kv
345kv - 499kv
500kv - 734kv
735kv - 999kv
AC-DC-AC Tie
DC Line
Dashed lines indicate proposed transmission lines.
Prepared using RDI PowerMap data. Information on this map is believed to be accurate but is not guaranteed.

and independent power producers. At the retail level, some states have required utilities to divest their generation assets as part of restructuring. These utilities currently supply only transmission and distribution services for customers who purchase electricity (i.e., generation services) from other firms. In addition, power marketers—who often do not own generation, transmission, or distribution facilities—buy and sell power on wholesale markets and market electricity directly to customers.

Electricity competition has led to significant changes in the operation of the bulk power grid, which are the power plants and high-voltage transmission facilities that make up the wholesale power market. More electricity is being shipped longer distances over a transmission system that was initially designed only to provide limited power and reserve sharing among neighboring utilities. Electric utilities that were once solely responsible for ensuring that adequate generation was available to meet demand now purchase a substantial amount of the power they need from the wholesale market, relying on independent power producers to build and operate plants.

Electricity Generation

There are roughly 5,000 power plants in the United States, and they have a total generating capacity of nearly 800,000 megawatts. Over the past few years, there has been an explosion of "merchant" power plants proposed by independent power producers seeking to sell into wholesale markets. In spite of this interest, a number of regions of the country are experiencing capacity shortages as a result of wholesale market design problems and barriers to siting and building new power plants.

Over the next ten years, demand for electric power is expected to increase by about 25 percent, and more than 200,000 megawatts of new capacity will be required. However, under current plans electric transmission capacity will increase by only 4 percent. This shortage could lead to serious transmission congestion and reliability problems.

Transmission Grid

The United States does not have a national transmission grid. Instead, there are four integrated transmission grids serving North America: the Western Interconnection, Eastern Interconnection, Electric Reliability of Council of Texas, and the Province of Quebec (Figure 7-1). These regional grids themselves are international, encompassing the United States, Canada, and part of Mexico.

Transactions between the four integrated transmission grids are very limited because they are interconnected at only a few locations through interties, so for all practical purposes they can be viewed as separate transmission grids. The four integrated transmission grids break down into a series of smaller regions, largely defined by transmission constraints. Altogether, 204,000 miles of transmission lines in North America move power from the point of generation to where electricity is needed. There are 157,810 miles of transmission lines in the United States. Transmission grid expansions are expected to be slow over the next ten years, with additions totaling only 7,000 miles.

The transmission system is the highway system for interstate commerce in electricity. Transmission allows the sale of electricity between regions. In a particular region, transmission can be a substitute for generation, allowing that region to import power that otherwise would have to be generated within that region. In some cases, transmission expansion may be more cost effective than generation additions, allowing a region better access to lower-cost generation.

Transmission constraints limit these power flows, and result in consumers paying higher prices for electricity. The electricity price spikes in the Midwest in the summer of 1998 were caused in part by transmission constraints limiting the ability of the region to import electricity from other regions of the country that had available electricity. During the summer of 2000, transmission constraints limited the ability to sell low-cost power from the Midwest to the South during a period of peak demand,

resulting in higher prices for consumers. Transmission capacity limits could result in price pressures and reliability problems this summer in California, Long Island, the Great Lakes, the Southeast, and New En gland (Figure 7-2).

Regional shortages of generating ca pacity and transmission constraints com bine to reduce the overall reliability of elec tric supply in the country and are reducing the quality of power delivered to end users. Power quality is becoming an increasingly important issue as our digital economy con tinues to grow.

One factor limiting reliability is the lack of enforceable reliability standards. Since 1968, the reliability of the U.S. trans mission grid has depended entirely on vol untary compliance with reliability stan dards. There is a broad recognition that vol untary adherence with reliability standards is no longer a viable approach in an increas ingly competitive electricity market. There is a need to provide for enforcement of mandatory reliability standards. Broad sup port has emerged for development of these standards by a self-regulating organization overseen by FERC.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of Energy to work with FERC to improve the reliability of the interstate trans mission system and to develop legisla tion providing for enforcement by a self-regulatory organization subject to FERC oversight.

★ The NEPD Group recommends that the President direct the Secretary of Energy to expand the Department's research and development on trans mission reliability and superconduc tivity.

Transmission constraints were also a primary factor in blackouts in northern California, which imports power from both the Northwest and southern California. When resources are not available in the Northwest, electricity supply must come from southern California's Path 15 transmis sion route. Path 15 does not have sufficient capacity to provide all of the power needed in northern California.

Figure 7-2

Current Electric Power Bottlenecks



Transmission capacity limits could result in price pressures and reliability problems this summer in California, Long Island, the Great Lakes, the Southeast, and New England. The arrows in this figure de-pict the locations and directions of current transmission congestion.

Source: North American Electric Reliability Council.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to authorize the Western Area Power Administration to explore relieving the "Path 15" bottleneck through transmission expansion financed by nonfederal contributions.

Transmission constraints have been a persistent cause of price spikes in New York City in recent years. The New York Indepen dent System Operator (the grid operator in that state) estimates that the city will be short about 400 MW below their desired re serve margin of power during the summer peak. To fill this gap, the New York Power Authority is trying to install additional gen eration capacity in the city. Market-oriented approaches could also be used to create ad ditional capacity and alleviate some of the potential problems.

If transmission constraints are not re moved, the result can be higher prices and

lower reliability. There are various reasons why transmission constraints exist. One is the lack of sufficient investment in trans mission. Transmission investment has lagged dramatically over the past decade (Figure 7-3). There is a need to ensure that transmission rates create incentives for ad equate investment in the transmission sys tem, especially as restructuring leads to the creation of transmission companies whose only business is operation of transmission facilities. FERC recognizes this need and has expressed a willingness to consider in novative transmission pricing proposals.

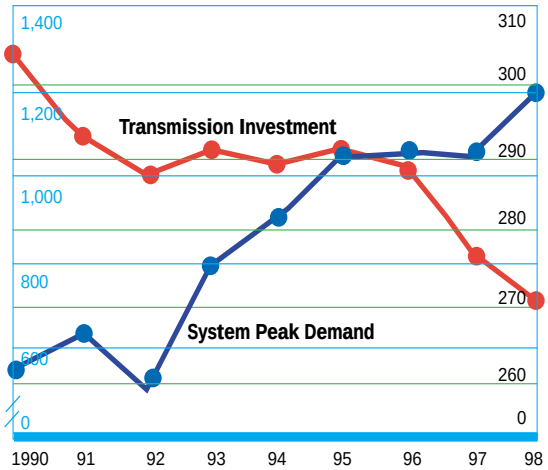
Another cause of transmission con straints is the siting process. Under current law, siting of transmission facilities is a re sponsibility of state governments, not the federal government, even though the trans mission system is not only interstate but also international, extending into both Canada and Mexico. This stands in stark contrast to siting of other interstate facili ties, such as natural gas pipelines, oil pipe lines, railroads, and interstate highways.

Federal law governing the responsibil ity for siting transmission facilities was written in 1935, nearly 80 years ago. At the time, transmission facilities were not inter-

Figure 7-3

U.S. Investment in New Electric Power Transmission

(Millions of 1990 Dollars)



Growth in peak demand for electricity has far outstripped investment in transmission capacity. As a result, transmission constraints could aggravate already limited supplies of power and could result in high prices in some areas of the country.

Source: PA Consulting Group, based on data from the UDI data base.

state, and there was virtually no interstate commerce in electricity. Congress did not anticipate the development of an interstate and international transmission system.

State decisions on where to locate transmission lines often do not recognize the importance of proposed transmission fa cilities to the interstate grid. For example, a recent decision by regulators in Connecticut to block a proposed transmission line to Long Island did not recognize the need for electricity on Long Island. Some state siting laws require that the benefits of a proposed transmission facility accrue to the indi vidual state, resulting in the rejection of transmission proposals that benefit an en tire region, rather than a single state.

Much has changed since 1935. The transmission system is the highway for in terstate commerce in electricity. Transmis sion constraints are resulting in higher prices for consumers and lower reliability. The siting process must be changed to re flect the interstate nature of the transmis sion system.

Recommendations:

★ The NEPD Group recommends that the President direct the appropriate federal agencies to take actions to re move constraints on the interstate transmission grid and allow our nation's electricity supply to meet the growing needs of our economy.

- Direct the Secretary of Energy, by December 31, 2001, to examine the benefits of establishing a national grid, identify transmission bottle necks, and identify measures to re move transmission bottlenecks.
- Direct the Secretary of Energy to work with FERC to relieve trans mission constraints by encouraging the use of incentive rate-making proposals.
- Direct the federal utilities to deter mine whether transmission expan sions are necessary to remove con straints. The Administration should review the Bonneville Power Administration's (BPA's) capital and



financing requirements in the context of its membership in a regional RTO, and if additional Treasury financing appears warranted or necessary in the future, the Administration should seek an increase in BPA's borrowing authority at that time.

- Direct the Secretary of Energy, in consultation with appropriate federal agencies and state and local government officials, to develop legislation to grant authority to obtain rights-of-way for electricity transmission lines, with the goal of creating a reliable national transmission grid. Similar authority already exists for natural gas pipelines in recognition of their role in interstate commerce.

Another cause of transmission constraints is limited access to federal lands. The federal government is the largest land owner in the United States and owns most of the land in some western states. Limited access to federal lands can block needed transmission expansion. A case in point is a transmission line being built from West Virginia to Virginia. Five years ago, the Department of Energy identified that line as critical to the reliability of the transmission system on the East Coast. Five years later, the line is still not complete. Improved access to federal land can help remove transmission constraints.

Rights-of-Way on Federal Lands

The Bureau of Land Management (BLM) estimates that 90 percent of the oil and natural gas pipeline and electric transmission rights-of-way in the western United States cross federal lands. These lands are principally lands managed by either the BLM or the U.S. Forest Service. Rights-of-way are authorized through an approval process that allows the public to comment on proposals to locate infrastructure items, like utility poles, on these rights-of way. As part of this process, proposals are examined for resource and other use conflicts, and a national interest test is applied prior to approval.

The BLM administers 85,000 rights-of-way, including 23,000 for oil and gas pipelines and 12,000 for electric transmission lines. It processes over 1,200 pipeline and electric system right-of-way applications a year, with an increase in applications of

The electric power infrastructure includes a nationwide "power grid" of long-distance transmission lines that move electricity from the point of generation to where the electricity is needed. Over the next ten years, U.S. demand for electric power is expected to increase by 25 percent, while transmission capacity is expected to increase by only 4 percent.



Virtually all natural gas in the United States is moved via pipeline. The current domestic natural gas transmission capacity of approximately 23 trillion cubic feet (tcf) will be insufficient to meet the projected 50 percent increase in U.S. consumption projected for 2020.

over 10 percent a year in recent years. The demand for additional energy and electric ity is expected to increase the need for rights-of-way across federal lands.

Other federal entities also deal with rights-of-way, each approaching the issue from a unique perspective. The National Park Service is authorized to grant leases and permits, but discourages rights-of-way corridors unless there are no practical alter natives. The U.S. Fish and Wildlife Service manages National Wildlife Refuge lands for wildlife and habitat values, and allows corri dors where they were pre-existing or are de termined to be compatible with the pur poses for which a refuge was established. The Bureau of Reclamation is authorized to grant rights-of-way over lands acquired or withdrawn for reclamation purposes, if compatible with authorized project pur poses. The Bureau of Indian Affairs and tribal governments are authorized to grant rights-of-way across both tribal and indi vidually owned Indian lands.

Pipelines

After being pumped from the ground in domestic oil fields, oil travels through gathering lines to pipelines, which bring it to refineries, where it is transformed into petroleum products like gasoline, diesel fuel, or heating oil. These products then travel through pipelines and tanker trucks to distribution outlets for purchase by con sumers. Natural gas must similarly travel from gas fields through gathering lines to processing facilities, and then into pipelines and local distribution lines to its final desti nation. These pipeline systems involve a complex infrastructure of their own, includ ing pump stations or compressor stations, and control systems that open and close valves and switch product flow through pipes, often with the use of computer tech nology.

Oil Pipelines

The two million miles of oil pipelines in the United States are the principal mode for transporting oil and petroleum products such as gasoline. They account for about 66 percent of domestic product movements (Figure 7-4). Increases in the demand for oil and changes in where it is supplied will lead to the need for more pipeline capacity.

Pipelines are less flexible than other forms of oil transport, because they are fixed assets that cannot be easily adjusted to changes in supply and demand. Once built, they are an efficient way to move pe troleum and petroleum products. A modest sized pipeline carries the equivalent of 750 tanker truckloads a day—the equivalent of a truckload leaving every two minutes, 24 hours a day, 7 days a week. Replacing the same pipeline with a railroad train of tank cars, carrying 2,000 barrels each, would re quire a 75-car train to arrive and be un loaded every day. Pipelines are relatively in expensive to operate and are generally quiet and safe. Ensuring pipeline safety requires careful management, as multiple products move through a single pipeline system at the same time.

Insufficient domestic pipeline capacity has caused peak-load problems in moving oil and petroleum products such as gasoline from one region of the country to another. For example, many energy analysts fore casted the possibility of a shortage last win ter in the upper Midwest of liquefied petro leum gas used for heating and for drying crops. Others were concerned about pos sible shortages of heating oil in New En gland.

Energy supply shortages can create operational difficulties for the pipelines themselves. The complex interrelationship

of our energy infrastructure is evident, since pipelines have been shut down for varying time periods due to regional elec tricity shortages.

For example, fuel supplies to Las Ve gas and Phoenix became dangerously low when blackouts in California shut down the main pipeline serving those areas. The Cali fornia Public Utilities Commission (CPUC) has granted a waiver of penalties to oil pipelines that have interruptible contracts for electricity to help ensure the uninter rupted flow of motor fuel supplies to Cali fornia. The California Energy Commission asked the CPUC to grant the waiver in or der to minimize the threat to public health due to disruptions of fossil fuel supplies. While the waiver of penalties does not guar antee that disruptions of power to petro leum product pipelines will not occur, it di minishes the threat by allowing disruptions to occur only when they are coordinated with the entire petroleum product delivery system, from refiner to pipeline to termi nals. Both Phoenix and Las Vegas would benefit from this decision because refiner ies and pipelines from California supply the two cities.

Much of the existing oil pipeline infra structure is old, requiring regular safety and environmental reviews to ensure its reliabil ity. The potential risk of pipeline accidents to human health and safety is of grave con cern. In June 1999, a petroleum product pipeline ruptured and caught fire in Bellingham, Washington. In addition to tragic loss of life, the pipeline's 18-month shutdown caused an economic hardship to the Seattle–Tacoma Airport and other local businesses that relied on the pipeline for aviation and diesel fuels. To avoid similar crises, the Department of Transportation, which has responsibility for pipeline safety, has adopted regulations and other risk man agement approaches to ensure safety in pipeline design, construction, testing, operation, maintenance, and emergency response.

Recommendation:

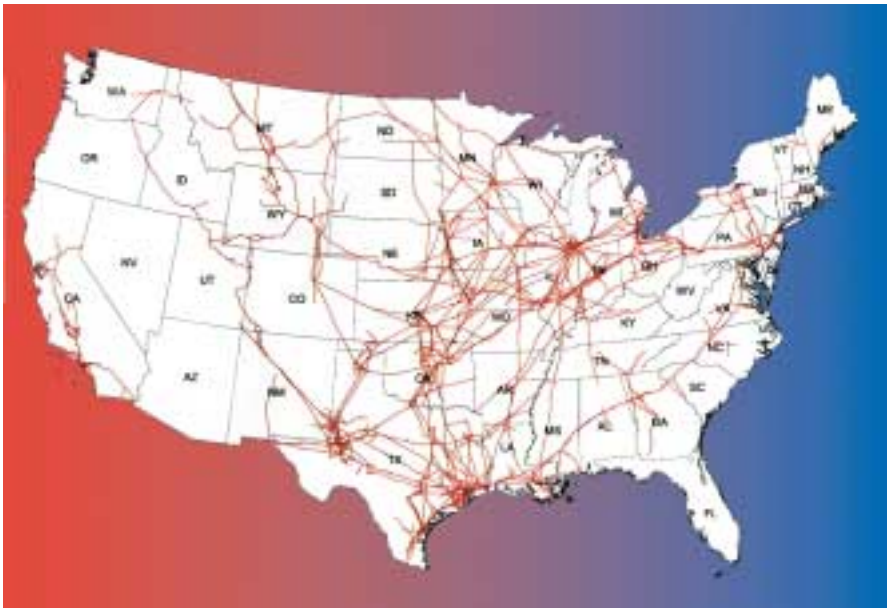
★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaskan Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

The Trans-Alaska Pipeline System is the single most important crude oil pipeline in the United States, and is perhaps the most regulated oil pipeline in the world. The pipeline system has carried nearly one-fifth of all domestically produced oil for the last two decades. Since beginning operations in 1977, it has transported more than 13 billion barrels of oil from Alaska's North Slope across 800 miles to the Port of Valdez. Since the pipeline began operation, only 0.00014 percent of the total amount of oil trans ported through it has been spilled.

The pipeline's federal grant and state lease for right-of-way expires in 2004 and will require renewal. That process will in-

Figure 7-4

U.S. Oil Pipelines



The two million miles of oil pipelines in the United States are the principal mode for transporting crude oil and refined products. They account for about 66 percent of domestic product movements.

Source: U.S. Department of Transportation, Office of Pipeline Safety.



Several federal agencies are authorized to grant rights-of-way for oil and gas pipeline and electric transmission systems on federal lands, and each approaches the issue from a unique perspective. Authorizing agencies include the Bureau of Land Management, the U.S. Forest Service the National Park Service, the U.S. Fish and Wildlife Service, the Bureau of Reclamation, and the Bureau of Indian Affairs.

volve a thorough review of compliance with federal laws and regulations, including those related to safety and environmental impacts. Because nearly 50 percent of the right-of-way is owned by the State of Alaska, they must also renew the applicable state permits. To commence the formal portion of the federal renewal process, regulations require a renewal application to be filed with the Alaska Office of the BLM of the Department of the Interior. To the extent possible, a single, joint federal/state approach should be considered.

Natural Gas Pipelines

Virtually all natural gas in the United States is moved via pipeline (Figure 7-5). The current domestic natural gas transmission capacity of approximately 23 trillion cubic feet (tcf) will be insufficient to meet the projected 50 percent increase in U.S. consumption projected for 2020.

Some parts of the country, such as California and New England, already face capacity shortages. Several pipeline operators have applied for permits to increase their delivery of natural gas to California, but right-of-way issues and local permitting delays have constrained the ability to transport natural gas to California, contributing to high prices. In addition, the natural gas pipeline connections from Canada are near capacity, so any greater U.S. reliance on Canadian natural gas will require increased pipeline capacity.

One of the largest known reserves of natural gas in the United States has been found in the Arctic, associated with the development of oil at Alaska's Prudhoe Bay. These known gas reserves, over 35 tcf, would make a significant long-term contribution to the nation's energy supplies if delivered to the lower 48 states. It is estimated there may be an additional 100 tcf on the North Slope of Alaska. Recently, as the energy supply situation has changed, interest has renewed in tapping into Alaska's natural gas supplies. Over the past year, the Alaska North Slope gas producers have been reviewing whether projected market conditions will make transportation of this natural gas economically feasible. The North Slope gas producers are scheduled to complete that review by the end of 2001.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

America needs the energy that Alaska's North Slope natural gas can provide. The Administration seeks to expedite the construction of a pipeline to deliver this natural gas to the lower 48 states.

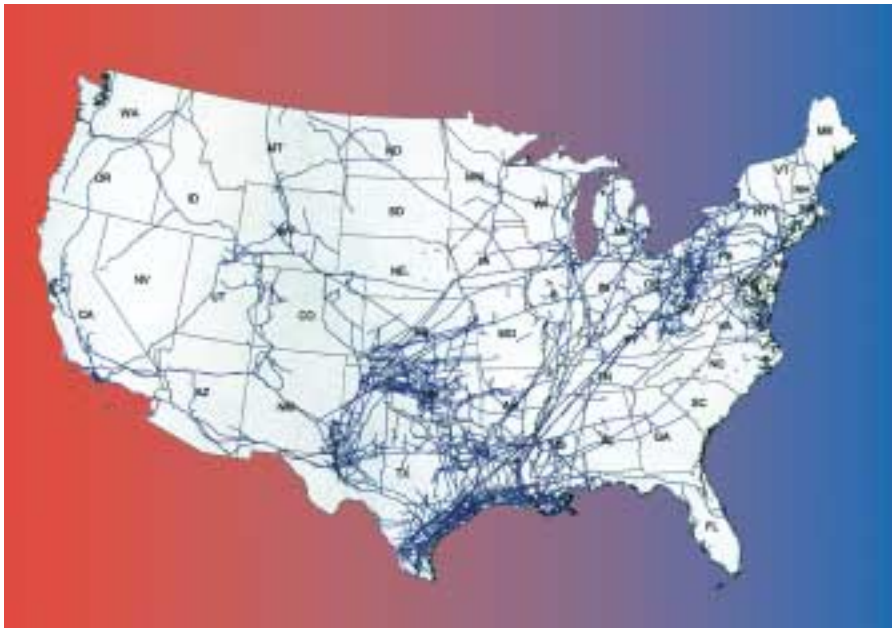
In addition to shortfalls in capacity, sources of natural gas have shifted from the Southwest to the deep water of the Gulf of Mexico, the Rocky Mountains, western Canada, and the Canadian Atlantic. At the same time, demand has shifted from the in dustrial Midwest to the growing population centers in the South and the West. An addi tional 263,000 miles of distribution pipe lines and 38,000 miles of new transmission pipelines will be necessary to meet in creased consumption and the new geo graphic realities of supply and demand.

Several factors complicate efforts to meet the need for increased pipeline capac ity, including encroachment on existing rights-of-way and heightened community resistance to pipeline construction. Cur rently it takes an average of four years to obtain approvals to construct a new natural gas pipeline. In some cases it can take much longer.

The projected growth in energy de mand has called into question whether regulatory actions and permitting processes can keep pace with the necessary construc tion of new facilities for storage and deliv ery. Consistent federal, state, and local gov ernment policies, and faster, more predict able regulatory decisions on permitting for oil and natural gas pipelines are needed to enable timely and cost-effective infrastruc ture development. The permitting process has a positive role in protecting the environ ment, public health, and safety by allowing all interested parties an opportunity to par ticipate effectively and fully in the delibera tions prior to the permit issuance.

Recent pipeline ruptures involving a natural gas pipeline near Carlsbad, New Mexico, and an underground natural gas storage facility near Hutchinson, Kansas, highlight the need to develop technologies and policies that protect people, environ ment, and the safety of the nation's energy infrastructure. The federal government has an important role in ensuring and improv ing the safety of these gas pipelines. New technologies need to be developed to im prove monitoring and assessment of system integrity, improve data quality for system planning, extend the serviceability and life of the national natural gas transmission and dis tribution network, provide safer transport of energy products, and lessen the impacts of the energy infrastructure on the environ ment.

Figure 7-5
U.S. Natural Gas Transmission Pipelines



Virtually all natural gas in the United States is moved via pipeline. The forecast of a doubling in the number of new natural gas wells drilled annually and an 80 percent increase in the number of active drilling rigs will require new pipelines.

Source: U.S. Department of Transportation, Office of Pipeline Safety.

Recommendations:

★ The NEPD Group recommends that the President support legislation to im prove the safety of natural gas pipelines, protect the environment, strengthen emergency preparedness and inspec tions and bolster enforcement.

★ The NEPD Group recommends that the President direct agencies to con tinue their interagency efforts to im prove pipeline safety and expedite pipe line permitting in an environmentally sound manner and encourage the Fed eral Energy Regulatory Commission to consider improvements in the regulatory process governing approval of interstate natural gas pipeline projects.



U.S. demand for refined petroleum products currently exceeds its domestic capacity to produce them. The refinery industry is now running at nearly 100 percent of capacity during the peak gasoline consumption season.

Oil Refineries

U.S. demand for refined petroleum products, such as gasoline and heating oil, currently exceeds our domestic capacity to produce them. The refinery industry is now running at nearly 100 percent of capacity during the peak gasoline consumption sea son and is producing record levels of needed products at other times. The excess demand has recently been met by increased imports.

The U.S. refining industry has experi enced a decade of low profitability and rates of return on investment. This has dis couraged investment in new refineries. In fact, almost 50 U.S. refineries closed over the last ten years, and no major refineries have been built in the last twenty-five years.

During the last ten years, overall refin ing capacity grew by about 1 to 2 percent a year as a result of expansion in the capacity of existing, larger refineries. Although there was a significant, sustained improvement in margins during 2000, those gains arose out of a very tight supply situation and high, vola tile prices. Industry consolidation has been a key response to this poor profitability.

The U.S. refining industry is also fac ing major infrastructure problems. While the industry expanded steadily through the 1970s, it went through a period of consoli dation after the oil shocks of 1973 and 1978. Ongoing industry consolidation, in an effort to improve profitability, inevitably leads to the sale or closure of redundant facilities by the new combined ownership. This has been particularly true of terminal facilities, which can lead to reductions in inventory and system flexibility. While excess capac ity may have deterred some new capacity investments in the past, more recently, other factors, such as regulations, have de terred investments.

Refiners are subject to significant en vironmental regulation and face several new clean air requirements over the next de cade. Refiners will face many clean fuel pro duction standards, which require the pro duction of many different kinds of gasoline and diesel fuel for different parts of the country. New Environmental Protection Agency rules will require refiners to pro duce gasoline and diesel fuel with signifi cantly lower sulfur content. New clean air requirements will benefit the environment, but will also require substantial capital in vestments and additional government per mits. The proliferation of distinct regional and state gasoline and diesel product stan dards, the significant permitting needed, and the downtime to make the needed physical and operational changes will chal lenge refiners and governments to effec tively coordinate in order to reduce the like lihood of supply shortfalls and price spikes.

Recommendation:

★ The NEPD Group recommends that the President direct the Administrator of the EPA to study opportunities to maintain or improve the environmen tal benefits of state and local "bou tique" clean fuel programs while ex ploring ways to increase the flexibility of the fuels distribution infrastructure, improve fungibility, and provide added gasoline market liquidity. In conclud ing this study, the Administrator shall consult with the Departments of En ergy and Agriculture, and other agen cies as needed.

Since 1990, refiners have met growing demand by increasing the use of existing equipment and increasing the efficiency and capacity of existing plants. Even with these efforts, however, refining capacity has be gun to lag behind peak summer demand. Price volatility and the cyclical nature of oil markets inhibit investment in supply infra structure. While investors can withstand market fluctuations for some commodities, large investments in oil exploration and de velopment—such as for drilling required to maintain a steady supply and the pipelines needed to bring supply to market—are of ten curtailed during times of low oil prices. The outcome of this lack of steady invest ment is less supply, higher prices, and the abandonment of marginal oil resources that may never be recovered.

Recommendations:-

★ The NEPD Group recommends that- the President direct the Administrator- of the Environmental Protection- Agency and the Secretary of Energy to- take steps to ensure America has ad - equate refining capacity to meet the- needs of consumers.-

- Provide more regulatory certainty to refinery owners and streamline the permitting process where pos sible to ensure that regulatory over lap is limited.
- Adopt comprehensive regulations (covering more than one pollutant and requirement) and consider the rules' cumulative impacts and benefits.

★ The NEPD Group recommends that the President to direct the Administra tor of the Environmental Protection Agency, in consultation with the Secre tary of Energy and other relevant agencies, to review New Source Re view regulations, including administra tive interpretation and implementa tion, and report to the President within 90 days on the impact of the regula tions on investment in new utility and refinery generation capacity, energy ef ficiency, and environmental protec tion.

- The NEPD Group recommends that the President direct the Attorney General to review existing enforce ment actions regarding New Source Review to ensure that the enforce ment actions are consistent with the Clean Air Act and its regula tions.

Energy Transportation Infrastructure

The infrastructure used to transport energy products includes ocean tankers; in land barges; specialized trucks for oil and refined products, such as gasoline and heat ing oil; railroad tank cars and coal cars; and the waterways, highways, and railroads upon which they travel. There is also a sub stantial inventory of river and oceanside port facilities that are used for moving en ergy materials.

Marine Transportation

Marine transportation of oil and re fined products accounts for nearly one-third of domestic shipments. Approximately 3.3 billion barrels of oil and petroleum products and 229 million short tons of coal move through the nation's ports and waterways every year.

There are three kinds of ship trans ports of domestic energy products. Tankers



Double-hulled tank barges provide distribution of petroleum products.

Nicole Leigh Reinauer and RTC 135

primarily carry Alaskan oil to the West Coast. Product tankers transport refined products from the Gulf of Mexico to the At lantic Coast, from the Gulf to the West Coast, and between ports within the West Coast. Tank barges provide coastwise distri bution of refined product imports, distribu tion from pipeline terminals, and inland dis tribution. In addition, 477 foreign tankers and 64 U.S. flag tankers deliver oil and pe troleum products to the United States. They deliver approximately 2.1 million barrels a day, for a total of 770 million barrels a year.

Ships are also used to import liquefied natural gas (LNG). With increasing demand for natural gas for electricity generation, there is a potential for substantial growth in the demand for LNG imports. From 1998 to 1999, the number of LNG carrier arrivals in Boston increased by 350 percent. In addi-- tion, mothballed terminals at Elba Island,- Georgia, and Cove Point, Maryland, may- reinitiate LNG imports by 2002.-

Winter storms, extended darkness, and ice formation disrupt barge and tanker movements. The U.S. Coast Guard's fleet of ice breakers has become an important component of the energy infrastructure for the New England, Mid-Atlantic, and Great Lakes regions.
U.S. Coast Guard



Unlike pipelines, water transportation requires the positioning of vessels to where cargoes are located. For example, it can take three weeks to move a tanker from the Gulf of Mexico to the West Coast. Conse quently, tanker markets do not respond quickly to temporary surges in demand, which typically result in price spikes.

Safety

In accordance with the Oil Pollution Act of 1990, a timeline has been established to replace all single-hulled vessels with double-hulled vessels. Many have already been replaced. Modern navigation and port services also help to prevent maritime oil spills. Spill-response technologies and coor dinated response plans are key to minimiz ing damage to property and the environ ment. Oil spill technology has improved dur ing the last decade and will continue to do so. Risk assessments, preparedness drills, and cleanup strategies are all necessary safeguards for transporting energy goods. As maritime transportation grows, port and waterway infrastructure, as well as the availability of accurate and timely naviga tion information, will continue to be impor tant for the safe, efficient delivery of energy.

New England's Dependence on Marine Transportation

New England has no refineries, and its small oil pipeline system is not connected to the interstate pipeline system. As a result, New England must rely on tanker and barge shipments of petroleum products from the south as well as direct imports from over seas. There is some question as to whether this distribution system is sufficient to meet the future needs of the region and, if not, what steps need to be taken to ensure fu ture economical, reliable energy supplies.

In recent years, lower national inven tories, market forces, and other factors have combined to create much lower inventories for petroleum products such as heating oil in the Northeast. A supply system with less capacity in reserve is more vulnerable to variations in product delivery, and is less ca pable of absorbing the disruptions in barge and tanker movements that inevitably come

with winter storms, extended darkness, and ice formation. A rapid change to colder weather affects both supply and demand: households need more fuel at the same time that harbors and rivers experience severe ice conditions.

For the New England and Mid-Atlantic seaboards, U.S. Coast Guard icebreakers have become an important component of the infrastructure necessary to provide energy to the region.

The Department of Energy established the Northeast Heating Oil Reserve to ensure heating oil supplies in the region. This emergency buffer can support a shortage for approximately ten days, which is the time required for ships to carry heating oil from the Gulf of Mexico to New York Harbor.

Even with the Reserve in place, marine transportation remains the only source of heating oil for the New England's winter months.

Recommendation:

★ The NEPD Group supports the President's budget proposal to provide $8 million to maintain the two-million-barrel Northeast Heating Oil Reserve. Operated by the private sector, the Reserve helps ensure adequate supplies of heating oil in the event that colder than normal winters occur in the Northeast United States.

Rail Transportation

Coal, which provides about 52 percent of America's electricity, is the most important single commodity carried by rail. Over the past ten years, the rail share of coal transportation has increased, primarily as a result of increases in low-sulfur western coal, which moves long distances over rail. In 1999, domestic railroads carried 68 percent of the nation's coal, and in 2000, they transported an average of 14.4 million tons of coal a week.

Transportation costs account for 30 to 50 percent of the final delivered price of coal to utilities. About 74 percent of U.S. low-sulfur coal reserves are located in Montana and Wyoming. Demand for clean coal from Wyoming's Powder River Basin is expected to increase because of its environmental benefits. However, rail capacity problems in the Powder River Basin have created a bottleneck in the coal transportation system.

With little excess capacity in the rail lines supporting the Powder River Basin, expected increases in demand could result in capacity shortfalls and delays in providing coal to power plants that are relying increasingly on "just-in-time" shipments to reduce inventory costs. Additionally, delays in other parts of the rail network, such as at key rail facilities, can undermine the efficiency and reliability of the system. There is a need to eliminate bottlenecks in the coal transportation system.

Infrastructure Security

The energy infrastructure is vulnerable to physical and cyber disruption that could threaten its integrity and safety. Disruptions could come from natural events, like geomagnetic storms and earthquakes, or could come from accidents, equipment failures, or deliberate sabotage. In addition, the nation's transportation and power infrastructures have grown increasingly complex and interdependent. Consequently, any disruption can have extensive consequences.

Transportation facilities have weathered relatively short interruptions in power as a result of natural disasters and accidents, with varying degrees of impact. In a few instances, they have experienced intermittent, lengthy outages that have affected not only primary systems, but integrated services as well, such as voice, data, Internet, and wireless networks that may be used to transmit control information. The growing reliance on computer technologies, automated monitoring and control systems, and electronic commerce makes the system more efficient and vibrant, but also requires a greater level of diligence and use of safeguards.

Accurate weather and climate forecasting can prevent millions of dollars in

damage to U.S. energy infrastructure. For example, the interaction of geomagnetic storms with the Earth's magnetic field can cause additional current to enter transmis sion lines, which at times has caused re gional grid collapse and has destroyed power plant electrical transformers. Given sufficient warning, the industry can initiate protective countermeasures, such as when several northeastern power plants shed 20 percent of their load during a July 2000 geo magnetic storm.

Improvements in forecasting can fur ther assist in the management of energy re sources and materials, can prevent power outages in many cases, and can accelerate restoration of power after outages that do occur. Also, data from extreme weather events can be used to design and build infra structure, such as transmission lines, pipe lines, and hydropower dams.

Summary of Recommendations

America's Energy Infrastructure: A Comprehensive Delivery System

★ The NEPD Group recommends that the President direct the Secretary of Energy to work with the Federal Energy Regulatory Commission (FERC) to improve the reliability of the interstate transmission system and to develop legislation provid ing for enforcement by a self-regulatory organization subject to FERC oversight.

★ The NEPD Group recommends that the President direct the Secretary of Energy to expand the Department's research and development on transmission re liability and superconductivity.

★ The NEPD Group recommends that the President direct the Secretary of Energy to authorize the Western Area Power Administration to explore relieving the "Path 15" bottleneck through transmission expansion financed by nonfederal contributions.

★ The NEPD Group recommends that the President direct the appropriate federal agencies to take actions to remove constraints on the interstate transmission grid and allow our nation's electricity supply to meet the growing needs of our economy.

- Direct the Secretary of Energy, by December 31, 2001, to examine the benefits of establishing a national grid, identify transmission bottlenecks, and identify mea sures to remove transmission bottlenecks.
- Direct the Secretary of Energy to work with FERC to relieve transmission con straints by encouraging the use of incentive rate-making proposals.
- Direct the federal utilities to determine whether transmission expansions are necessary to remove constraints. The Administration should review the Bonneville Power Administration's (BPA's) capital and financing requirements in the context of its membership in a regional RTO, and if additional Treasury fi nancing appears warranted or necessary in the future, the Administration should seek an increase in BPA's borrowing authority at that time.
- Direct the Secretary of Energy, in consultation with appropriate federal agencies and state and local government officials, to develop legislation to grant author ity to obtain rights-of-way for electricity transmission lines, with the goal of cre ating a reliable national transmission grid. Similar authority already exists for natural gas pipelines in recognition of their role in interstate commerce.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaskan Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

★ The NEPD Group recommends that the President support legislation to improve the safety of natural gas pipelines, protect the environment, strengthen emergency preparedness and inspections and bolster enforcement.

★ The NEPD Group recommends that the President direct agencies to continue their interagency efforts to improve pipeline safety and expedite pipeline permitting in an environmentally sound manner and encourage FERC to consider improvements in the regulatory process governing approval of interstate natural gas pipeline projects.

★ The NEPD Group recommends that the President direct the Administrator of the EPA to study opportunities to maintain or improve the environmental benefits of state and local "boutique" clean fuel programs while exploring ways to increase the flexibility of the fuels distribution infrastructure, improve fungibility, and provide added gasoline market liquidity. In concluding this study, the Administrator shall consult with the Departments of Energy and Agriculture, and other agencies as needed.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency and the Secretary of Energy to take steps to ensure America has adequate refining capacity to meet the needs of consumers.

- Provide more regulatory certainty to refinery owners and streamline the permitting process where possible to ensure that regulatory overlap is limited.
- Adopt comprehensive regulations (covering more than one pollutant and requirement) and consider the rules' cumulative impacts and benefits.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency, in consultation with the Secretary of Energy and other relevant agencies, to review New Source Review regulations, including administrative interpretation and implementation, and report to the President within 90 days on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection.

★ The NEPD Group recommends that the President direct the Attorney General to review existing enforcement actions regarding New Source Review to ensure that the enforcement actions are consistent with the Clean Air Act and its regulations.

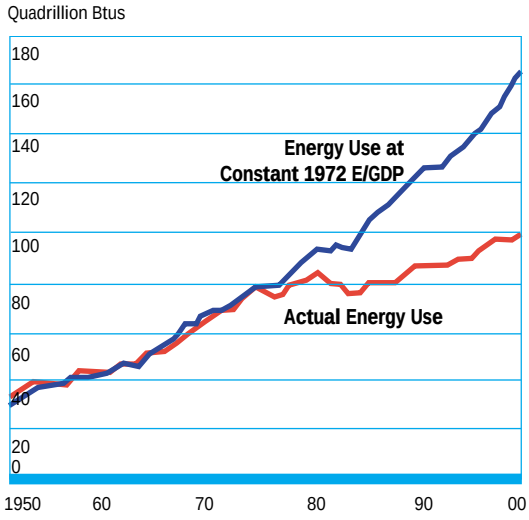
★ The NEPD Group supports the President's budget proposal to provide $8 million to maintain the two-million-barrel Northeast Heating Oil Reserve. Operated by the private sector, the Reserve helps ensure adequate supplies of heating oil in the event that colder than normal winters occur in the Northeast United States.

Strengthening Global Alliances

Enhancing National Energy Security and International Relationships

U.S. national energy security depends on sufficient energy supplies to support U.S. and global economic growth. Energy policies that have emphasized reliance on market forces have led to major energy security gains over the past two decades. Major improvements in exploration and production technology, as well as the trend toward opening new areas around the globe for exploration and development, have yielded significant dividends:

Figure 8-1
The U.S. Economy is More Energy Efficient (Energy Intensity)
Primary Energy Use



Improvements in energy efficiency since the 1970s have had a major impact in meeting national energy needs relative to new supply. If the intensity of U.S. energy use had remained constant since 1972, consumption would have been about 70 quadrillion Btus (74 percent) higher in 1999 than it actually was.

Source: U.S. Department of Energy, Energy Information Administration.

- The U.S. and world economies have diversified their sources of oil supplies, largely through increased production in the Western Hemisphere, the North Sea, and Africa.
- The world's fuel mix is also more diverse, primarily because of greater reliance on natural gas and nuclear power.
- The rate of growth in U.S. oil demand has slowed significantly since the first oil shocks of the 1970s because of more energy-efficient industries, structural changes in the economy, and greater efficiencies in vehicles, appliances, and buildings.

Since 1970, as the economy has shifted toward greater use of more efficient technologies, U.S. energy intensity (the amount of energy it takes to produce a dollar of GDP) has declined by 30 percent (Figure 8-1). However, energy use per person in the United States is expected to rise as is overall demand for energy.

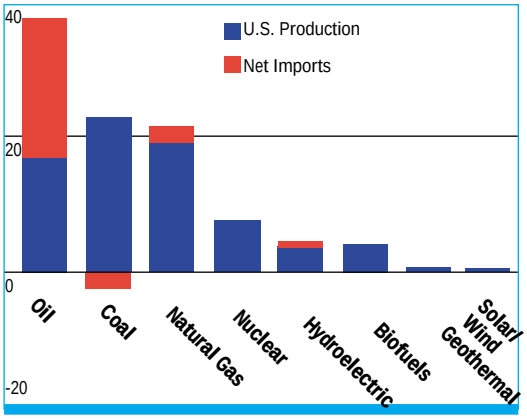
Measures to enhance U.S. energy security by meeting this increased demand must begin at home. The first step toward a sound international energy policy is to use our own capability to produce, process, and transport the energy resources we need in an efficient and environmentally sustainable manner. Market solutions to limit the growth in our oil imports would reduce oil consumption for our economy and increase our economic flexibility in responding to any domestic or international disruption of oil or other energy supplies. The United States produces 72 of the 99 quadrillion British thermal snits (Btus) of



Figure 8-2

Sources of U.S. Fuel Consumption in 1999

(Quadrillion Btus)



The United States produced 72 of the 98 quadrillion Btus of energy that it consumed in 1999. We are self-sufficient in vir tually all our energy resources, except oil, of which we import 52 percent of our net requirements, and natural gas, of which we import 15–16 percent net, primarily from Canada.

Source: U.S. Department of Energy, Energy Information Administration.

energy that it consumes (Figure 8-2). We are self-sufficient in virtually all our energy resources except oil, of which we import 52 percent of our net requirements, and natu ral gas, of which we import 15 to 16 percent of our net requirements, primarily from Canada.

We should not, however, look at en ergy security in isolation from the rest of the world. In a global energy marketplace, U.S. energy and economic security are di rectly linked not only to our domestic and international energy supplies, but to those of our trading partners as well. A significant disruption in world oil supplies could ad versely affect our economy and our ability to promote key foreign and economic policy objectives, regardless of the level of U.S. dependence on oil imports.

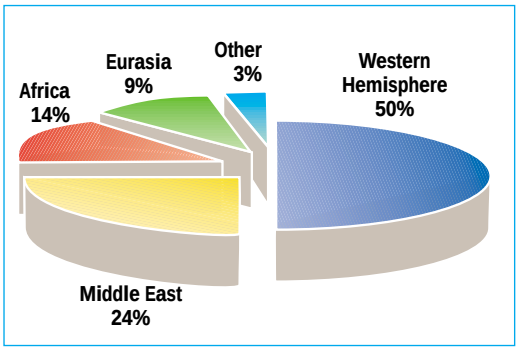
Our energy security also depends on an efficient domestic and international in frastructure to support all segments of the energy supply chain. We can strengthen our own energy security and the shared pros perity of the global economy by working cooperatively with key countries and insti tutions to expand the sources and types of global energy supplies. We can also ad vance these goals by increasing the effi ciency of energy consumption, enhancing the transparency and efficient operation of energy markets, and strengthening our ca pacity to respond to disruptions of oil sup plies. Energy is fundamental to economic growth, and we believe that economic growth and environmental protection can be mutually achieved.

We need to strengthen our trade alli ances, to deepen our dialogue with major oil producers, and to work for greater oil pro duction in the Western Hemisphere, Africa, the Caspian, and other regions with abun dant oil resources. Greater cooperation with our allies in addressing the growth in oil de mand in the transportation sector is particu larly important, given the growing demand for oil and other energy resources. Signifi cant economic and environmental benefits can be realized from increased energy effi ciency and from the use of clean energy technologies. We need to ensure that our partners in the International Energy Agency (IEA) continue to meet their obligations for emergency supply reserves. Finally, we must continue to work with the IEA, the Asia-Pacific Economic Cooperation (APEC) forum, and others to encourage other large importers to consider measures to augment their oil reserves

Oil Imports and Global Reserves

The U.S. influence on overall world markets is substantial in terms of produc tion and consumption. The United States is the world's second largest natural gas pro ducer and its third largest oil producer. The United States consumes over 25 percent of the oil produced worldwide, slightly more than half of which it imports. Nevertheless, because the price of our domestic and im ported oil is determined by a world market, our energy security interests transcend the source of our physical energy supplies (Fig ure 8-3). Given the large and projected growing volume of U.S. oil imports, our en ergy and economic security will increase if we take the steps necessary to realize America's potential as a major world oil and natural gas producer.

Figure 8-3
Regional Sources of U.S. Oil Imports in 2000



Slightly over half of the oil the United States imports every day comes from the Western Hemisphere. Canada, Venezuela, and Mexico account for the bulk (41%) of these imports.

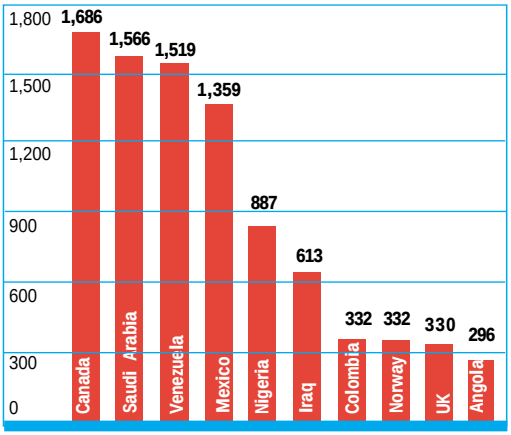
Source: US. Department of Energy, Energy Information Administration.

Recommendation:

★ The NEPD Group recommends- that the President make energy secu - rity a priority of our trade and foreign- policy.-

In 2000, nearly 55 percent of U.S. gross oil imports came from four countries: 15 percent from Canada, 14 percent each from Saudi Arabia and Venezuela, and 12 percent from Mexico (Figure 8-4). The se curity of U.S. energy supply is enhanced by several factors characterizing our diplo matic and economic relationships with our four top suppliers. These factors range from geographic proximity and free trade agree ments to integrated pipeline networks, re ciprocal energy-sector investments, shared security commitments, and, in all cases, long-term reliable supply relationships (Fig ure 8-5).

Figure 8-4
Top 10 Suppliers of U.S.Oil Imports in 2000



In 2000, nearly 55 percent of gross U.S. oil imports came from four leading suppliers: Canada (15%), Saudi Arabia (14%), Venezuela (14%), and Mexico (12%).

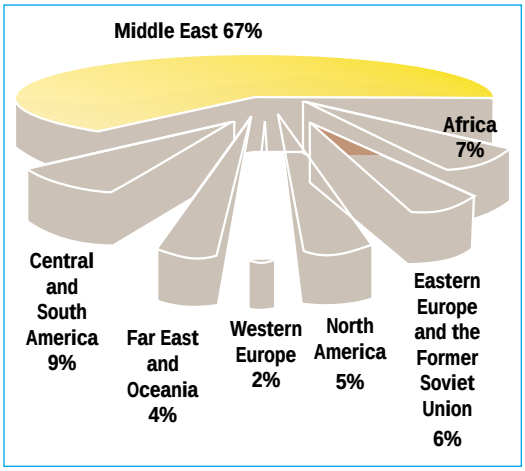
Source: U.S.Department of Energy, Energy Information Administration.-

Saudi Arabia and the Middle East Oil Supplies

By 2020, Gulf oil producers are pro jected to supply between 54 and 67 percent of the world's oil. Thus, the global economy will almost certainly continue to depend on the supply of oil from Organization of Petro leum Exporting Countries (OPEC) mem bers, particularly in the Gulf. This region will remain vital to U.S. interests. Saudi Arabia, the world's largest oil exporter, has been a linchpin of supply reliability to world oil markets.

Saudi Arabia has pursued a policy of investing in spare oil production capacity, diversifying export routes to both of its coasts, and providing effective assurances that it will use its capacity to mitigate the

Figure 8-5
Proven World Oil Reserves in January 2000



The world's proven crude oil reserves remain relatively concen trated. The Middle East holds 664 billion barrels, or roughly two-thirds of the world's conventional oil reserves, followed by the Western Hemisphere (14%) and Africa (7%).

Source: U.S. Department of Energy, Energy Information Administration.

Saudi Arabia has pursued a policy of investing in spare oil production capacity, diversifying export routes to both of its coasts, and providing effective assurances that it will use its capacity to mitigate the impact of oil supply disruptions in any region.
ARAMCO

impact of oil supply disruptions in any re gion (Figure 8-6). Algeria, Kuwait, Oman, Qatar, Saudi Arabia, the United Arab Emir ates (UAE), Yemen, and other states in the region with which we maintain diplomatic relations have all, to some extent, opened their energy sectors to international invest - ment. This development provides an impor - tant opportunity to further encourage for - eign investment in these important energy - producing countries, thereby broadening our shared commercial and strategic inter - ests. By any estimation, Middle East oil pro - ducers will remain central to world oil secu - rity. The Gulf will be a primary focus of U.S. international energy policy, but our engage ment will be global, spotlighting existing and emerging regions that will have a major impact on the global energy balance.



Figure 8-6
Saudi Arabia Export Pipelines



Saudi Arabia, the world's largest oil supplier, maintains major oil export ports and storage capacity on both the Gulf and the Red Sea.

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Recommendation:

★ The NEPD Group recommends that the President support initiatives by Saudi Arabia, Kuwait, Algeria, Qatar, the UAE, and other suppliers to open up areas of their energy sectors to for - eign investment.

Improving Market Transparency

The United States must work with oil producers to improve the transparency, timeliness, and accuracy of the data that guide global oil markets. A lack of timely and accurate data relating to both oil pro duction and inventory levels has contrib uted to the price volatility witnessed in 2000. Discussions among the major oil pro ducers and consumer countries should be designed to improve the transparency, accu racy, and timeliness of data that guide the market. In turn, enhanced data quality and increased data transparency will improve market efficiency. Refocusing that dialogue beyond short-term market developments to long-term issues of world economic growth, improving data quality, and addressing en ergy infrastructure is needed to maintain a smooth flow of energy from the wellhead to the consumer.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of State, Energy and Commerce work to improve dialogue among energy pro - ducing and consuming nations.

Promoting International Trade and Investment

Longstanding U.S. policy supports a liberalized global energy sector that is open to international trade and investment. The United States benefits from international in vestments at home that have increased our

energy sector's capacity and its infrastruc ture. Both producers and consumers will benefit from ensuring that the global energy infrastructure is sufficient and flexible to meet growing global demand.

American energy firms remain world leaders, and their investments in energy producing countries enhance efficiencies and market linkages while increasing envi ronmental protections. Expanded trade and investment between oil importing and ex porting nations can increase shared inter ests while enhancing global energy and eco nomic security. Promoting such investment will be a core element of our engagement with major foreign oil producers.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce and Energy to con tinue supporting American energy firms competing in markets abroad and use our membership in multilat eral organizations, such as the Asia-Pacific Economic Cooperation (APEC) forum, the Organization for Economic Cooperation and Develop ment (OECD), the World Trade Orga nization (WTO) Energy Services Ne gotiations, the Free Trade Area of the Americas (FTAA), and our bilateral relationships to implement a system of clear, open, and transparent rules and procedures governing foreign in vestment; to level the playing field for U.S. companies overseas; and to re duce barriers to trade and investment.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Energy, and the U.S. Trade Representative, to support a sectoral trade initiative to expand in vestment and trade in energy-related goods and services that will enhance exploration, production, and refining, as well as the development of new technologies.

Reviewing and Reforming Sanctions

Economic sanctions include U.S. uni lateral sanctions as well as multilateral sanctions, such as United Nations (UN) Se curity Council Resolutions. Sanctions can advance important national and global se curity objectives and can be an important foreign policy tool, especially against na tions that support terrorism or seek to ac quire weapons of mass destruction. Never theless, sanctions should be periodically re viewed to ensure their continued effective ness and to minimize their costs on U.S. citizens and interests.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of State, Treasury, and Commerce to ini tiate a comprehensive review of sanc tions. Energy security should be one of the factors considered in such a re view.

Diversity of Supply

Concentration of world oil production in any one region of the world is a potential contributor to market instability, benefiting neither oil producers nor consumers. Peri odic efforts by OPEC to maintain oil prices above levels dictated by market forces have increased price volatility and prices paid by consumers, and have worked against the shared interests of both producers and con sumers in greater oil market stability. This remains a policy challenge, which we will meet over the longer term through a com prehensive energy policy that addresses both supply and demand, as well as through increased engagement with all our major suppliers. Greater diversity of world oil pro duction remains important.

Encouraging greater diversity of oil production and, as appropriate, transporta tion, within and among geographic regions has obvious benefits to all market partici pants. Technological advances will enable the United States to accelerate the diversifi cation of oil supplies, notably through deep-



The United States is helping developing countries use energy efficient technologies. Photovoltaic-powered pumps are being used in many wells throughout rural India for collecting potable water.

U.S. Department of Energy, National Renewable Energy Laboratory

water offshore exploration and production in the Atlantic Basin, stretching from off shore Canada to the Caribbean, Brazil, and West Africa. The Caspian Sea can also be a rapidly growing new area of supply.

The ongoing development of so-called "heavy oil" reserves in the Western Hemi sphere is an important factor that promises to significantly enhance global oil reserves and production diversity. Recent Canadian and Venezuelan success in making heavy oil deposits commercially viable suggests that they will contribute substantially to the di versity of global energy supply, and to our own energy supply mix over the medium to long term. Leading non-OPEC oil exporters, such as Mexico and Norway, remain critical to the diversity of global energy supply.

Growing levels of conventional and heavy oil production and exports from the Western Hemisphere, the Caspian, and Af rica are important factors that can lessen the impact of a supply disruption on the U.S. and world economies. Overall U.S. policies in each of these high-priority re gions will focus on improving the invest ment climate and facilitating the flow of needed investment and technology.

Bilateral energy working groups, such as the U.S.-Kazakhstan Oil, Gas and Com mercial Energy Working Group and the U.S.-Russian Oil and Gas Working Group, can improve the trade climate in high-prior ity countries. In addition to seeking new sources of oil, the United States is helping developing countries use energy efficient technologies to mitigate the environmental impacts of energy use, and to improve ac cess to energy resources.

WTO members are beginning to exam ine global trade in energy services. The United States has called on WTO members to open markets eligible for private partici pation in the entire range of energy ser vices, from exploration to the final cus tomer. The energy service proposal would attempt to ensure nondiscriminatory access to foreign providers of energy services. Equally important, the U.S. proposal sug gests that WTO members consider how to best create a pro-competitive regulatory en-

Figure 8-7

Canada–U.S. Natural Gas Pipelines: 2001



Canada–U.S. Oil Pipelines: 2001

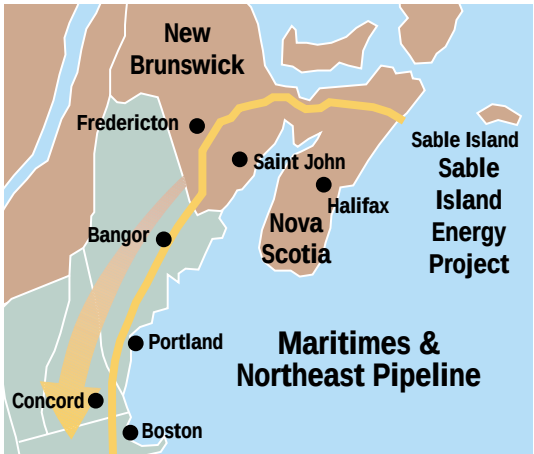


An integrated network of oil and gas pipelines demonstrates the seamless nature of North American energy trade.

Sources: Lakehead Pipe Line Company, Inc., and Canadian Association of Petroleum Producers.

Figure 8-8

Maritimes and Northeast Pipeline: 2000



New England's geography made it the "last stop" for natural gas pipelines stretching thousands of miles across the continent from the South and the West. Consequently, the region became the most oil-dependent area in the country, particularly for home heating and electricity. With the January 1, 2000, inauguration of Atlantic Canada's Maritimes and Northeast Pipeline, New England is now at the beginning of the line for natural gas flowing across the border from Canada at Calais, Maine. Overall, the region's fuel mix is becoming increasingly diversified, with natural gas demand slated to increase by 2.4 percent a year through 2020.

Source: Maritimes and NorthEast Pipeline.

vironment for energy services, so that opaque or discriminatory regulatory prac tices do not undermine commitments to open their domestic markets to foreign ser vice providers. Such objectives can also be pursued in the FTAA and APEC.

Toward a North American Energy Framework

Increased U.S., Canadian, and Mexi can energy production and cooperation would enhance energy security and, through our economic links in the North America Free Trade Agreement (NAFTA) economy, fundamentally advance each country's economic security. As state and federal governments consider energy re forms, there will be a need to ensure com patible regulatory frameworks with our neighbors while recognizing differences in jurisdictions.

Canada

Canada's deregulated energy sector has become America's largest overall en ergy trading partner, and our leading for eign supplier of natural gas, oil, and elec tricity. Canada's sustainable development based energy strategies contribute to the health of the NAFTA economy and of our shared environment.

Canada provided 14 percent of U.S. natural gas supply last year. An integrated network of pipelines demonstrates the seamless nature of North American energy trade (Figure 8-7). Estimated natural gas deposits in Alaska and Northwest Canada exceed 70 trillion cubic feet, representing over three years of total U.S. consumption at present levels.

To advance shared economic and en vironmental objectives, the private sector is poised to develop the continent's northern gas reserves, with pipeline linkages be tween both countries. To the east, recent development of Canada's Atlantic offshore energy reserves has made significant strides, with major offshore natural gas and oil production now available. Canada's At lantic energy development is now providing previously untapped sources of clean-burn ing natural gas not only to Nova Scotia and New Brunswick but also to heating oil-de pendent New England (Figure 8-8).



Offshore oil platform near Campeche, Mexico. Mexico's large crude oil reserves—approximately 25 percent larger than our own proven reserves—makes it a likely source of increased oil production over the next decade.

U.S. Embassy, Mexico City

Our large cross-border electricity trade flows in each direction. Our electric ity imports from Canada are derived largely from hydropower produced in eastern Canada, Canadian and American hydro power projects in the Pacific Northwest op erating pursuant to the Columbia River Treaty, and a nuclear power plant in New Brunswick. All of these sources provide im portant trade and clean air benefits, while allowing both countries to benefit from load sharing and integration. The reliability of the North American electricity grid can be enhanced yet further through closer coordi nation and compatible regulatory and juris dictional approaches.

Canada's oil trade, responding to mar ket signals, increased 4 percent worldwide and 10 percent with the United States last year. Estimates of Canada's recoverable heavy oil sands reserves are substantial, and new technologies are being deployed to de velop their potential. Production from these promising areas now approaches 600,000 barrels a day. Their continued development can be a pillar of sustained North American energy and economic security.

Mexico

Our energy relationship with Mexico reflects the increasingly interrelated charac ter of NAFTA economies and our contigu ous border. U.S. natural gas reserves, pipe-

Figure 8-9

Mexican Oil and Gas Resources: 2001



Mexico's large oil reserves—approximately 25 percent larger than U.S. proven reserves—make it a likely source of increased oil production over the next decade.

Source: U.S. Central Intelligence Agency.

lines, and industries are closer to the grow ing border area than some of Mexico's re serves. The United States is a net exporter of refined petroleum products and natural gas to Mexico, primarily through pipeline connections to northern Mexico. Mexico is a leading and reliable source of imported oil, and its large reserve base, approxi mately 25 percent larger than our own proven reserves, makes Mexico a likely source of increased oil production over the next decade (Figure 8- 9).

Mexico began exporting 50 megawatts of electricity from Baja to California in Janu ary 2001. However, the transmission infra structure on both sides of the border is in sufficient for greater flows of energy in ei ther direction without expansion. In the United States, our process for "Presidential Permitting" of cross-border infrastructure linkages needs to be updated and stream lined.

Mexico will make its own sovereign decisions on the breadth, pace, and extent to which it will expand and reform its electric ity and oil and gas capacities. Where the country has opened its energy sector to pri vate investment, such as in natural gas trans mission, distribution, and storage, invest ments have been made to our mutual ben efit. To the extent Mexico seeks to attract additional foreign investment consistent with its Constitution, which reserves explo ration and production rights to the Mexican government, the United States should ac tively encourage the U.S. private sector to consider market-based investments.

A carrier transports liquefied natural gas (LNG) from Trinidad and Tobago—our largest LNG supplier—to Boston harbor. LNG currently represents 16 percent of New England's natural gas supply.
CABOT LNG



Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to en gage in a dialogue through the North American Energy Working Group to develop closer energy integration among Canada, Mexico, and the United States and identify areas of co operation, fully consistent with the countries' respective sovereignties.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, in consultation with the Federal Energy Regulatory Com mission, to review their respective oil, natural gas, and electricity cross boundary "Presidential Permitting" authorities, and to propose reforms as necessary in order to make their own regulatory regimes more compatible for cross-border trade.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commis sion, to work closely with Canada, the State of Alaska, and all other inter ested parties to expedite the construc tion of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transporta tion Act of 1976 that may be required.

South America: Latin America and the Caribbean

Latin America and the Caribbean are growing not only as major producing re gions, but also as major consumers of oil and natural gas. Trinidad and Tobago's pro gressive investment code has made it the hemisphere's largest exporter of LNG and the largest supplier of LNG to the United States in 2000. Unprecedented development of Central and South America's vast natural gas reserves—222.7 trillion cubic feet as of January 2000, illustrated by transcontinen tal pipelines linking Bolivia, Brazil, Argen tina, Chile, Paraguay, and Uruguay—in crease regional self-reliance, affirm eco nomic integration, aid the environment, and stem the growth in oil demand. Colombia has also become an important supplier of oil to the United States.

The United States, with Venezuela, is a co-coordinator of the Hemispheric En ergy Initiative process. In March 2001, a Summit of the Americas Hemispheric En ergy Ministerial meeting was hosted by the Government of Mexico. At the meeting, the region's energy ministers pledged to sup port integration and sustainable develop ment in the hemisphere, recognizing the need to foster stable and transparent regu latory frameworks. In April 2001, the thirty four democratically elected leaders of the Western Hemisphere met in Quebec City for the Third Summit of the Americas. They called for a renewed effort to strengthen the hemisphere's energy cooperation and integration.



U.S. Secretary of Energy Spencer Abraham listens to his colleagues at the Summit of the Ameri-cas Hemispheric Energy Ministerial meeting in Mexico City on March 9, 2001.

U.S. Embassy, Mexico City

Venezuela is the world's fifth largest oil exporter, and the third largest oil sup plier to the United States. Its energy indus try is increasingly integrated into the U.S. marketplace. Venezuela's downstream in vestments in the United States make it a leading refiner and gasoline marketer here. Growing U.S. and international investments in Venezuela's energy sector, particularly in its resource-rich heavy oil sector, are en hancing the country's ability to meet its de velopment goals and to keep pace with a growing world energy marketplace. Venezu ela is also moving to liberalize its natural gas sector, which will increase opportuni ties for foreign investment to expand Ven ezuelan natural gas production. These posi tive steps along with conclusion of a Bilat eral Investment Treaty, which is now being negotiated, would provide investors from both the United States and Venezuela incen tives for increased investment.

Brazil has long been a pioneer in the development of deep-water offshore oil and gas resources. Its world-class oil industry is now moving to become a partner with U.S. and international investors to more fully de velop its prolific offshore oil reserves. This welcome development will enhance hemi spheric energy production from well-estab lished sedimentary basins.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State and Commerce to conclude ne gotiations with Venezuela on a Bilat eral Investment Treaty, and propose formal energy consultations with Bra zil, to improve the energy investment climate for the growing level of energy investment flows between the United States and each of these countries.

★ The NEPD Group recommends that the President direct the Secretaries of Energy, Commerce, and State to work through the Summit of the Americas Hemispheric Energy Initiative to de velop effective and stable regulatory frameworks and foster reliable supply sources of all fuels within the region.

Africa

Sub-Saharan Africa holds 7 percent of world oil reserves and comprises 11 percent of world oil production. Along with Latin America, West Africa is expected to be one of fastest-growing sources of oil and gas for the American market. African oil tends to be of high quality and low in sulfur, making it suitable for stringent refined product re quirements, and giving it a growing market share for refining centers on the East Coast of the United States.

In 2000, OPEC member Nigeria ex ported an average of 900,000 barrels of oil per day to the United States, out of its total production of 2.1 million barrels of oil per day. Nigeria, in partnership with the private sector, has set ambitious production goals as high as 5 million barrels of oil per day over the coming decade.

Angola's growing offshore oil indus try, with participation by U.S. and interna tional oil firms, is also a major source of growth. In 2000, Angola exported 300,000 barrels of oil per day out of its 750,000 bar rels of oil per day of total production to the United States, and is thought to have the potential to double its exports over the next ten years. Other significant exporters to the United States included Gabon and the Congo-Brazzaville.

The World Bank has supported Chad's efforts to begin ambitious oil development. This year an international consortium that includes U.S. firms began investing $3.5 bil lion in this pipeline from Chad to Cameroon, the largest infrastructure project in Africa to day. When complete, the pipeline will allow Chad to export up to 250,000 barrels of oil per day.

The U.S. Agency for International De velopment (USAID) has provided technical assistance in support of a West Africa Power Pool and associated pipeline project involving a number of U.S. oil companies, and is providing assistance for the creation of a regional regulatory framework that will enable Ghana and Nigeria to become major exporters of natural gas and electricity.

The West Africa Gas Pipeline is a 161 mile (1,000-kilometer), $400 million on shore/offshore natural gas pipeline connect ing Nigeria with Benin, Togo, and Ghana. The pipeline is being built by a consortium of companies, and includes financing by the U.S. Export-Import Bank.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Energy, and Commerce to rein vigorate the U.S.-Africa Trade and Economic Cooperation Forum and the U.S.-African Energy Ministerial pro cess; deepen bilateral and multilateral engagement to promote a more recep tive environment for U.S. oil and gas trade, investment, and operations; and promote geographic diversification of energy supplies, addressing such is sues as transparency, sanctity of con tracts, and security.

★ The NEPD Group recommends that the President direct the Secretaries of State, Energy, and Commerce to re cast the Joint Economic Partnership Committee with Nigeria to improve the climate for U.S. oil and gas trade, investment, and operations and to ad vance our shared energy interests.

★ The NEPD Group recommends that the President direct the Secretaries of

State, Energy, and Commerce to support more transparent, accountable, and responsible use of oil resources in African producer countries to enhance the stability and security of trade and investment environments.

The Caspian

Proven oil reserves in Azerbaijan and Kazakhstan are about 20 billion barrels, a little more than the North Sea and slightly less than the United States. Exploration, however, is continuing, and proven reserves are expected to increase significantly.

For example, initial results of the exploration well at Kazakhstan's Kashagan field indicate the find is one of the most important in thirty years, and is comparable to Prudhoe Bay in size. Current exports from the region are only about 800,000 barrels of oil per day, in part due to limited export route options. However, potential exports could increase by 1.8 million barrels of oil per day by 2005, as the United States works closely with private companies and countries in the region to develop commercially viable export routes, such as the Baku-Tbilisi-Ceyhan (BTC) and Caspian Pipeline Consortium oil pipelines (Figure 8 10). Moreover, there is considerable optimism that exports could grow even more substantially in subsequent years because of positive prospects for new oil and gas finds as additional geologic structures undergo exploration, and the development of new export routes.

Foreign investors and technology are critical to rapid development of new commercially viable export routes. Such development will ensure that rising Caspian oil production is effectively integrated into world oil trade. U.S.-supported East–West pipeline routes will add substantial new oil transportation capacity to allow continued expansion of production and exports. Overland routes via pipeline, such as the planned BTC oil pipeline, will also help mitigate maritime risks in the crowded Bosporus Straits. To help countries prepare for increased oil production within the region, the United States is working with Black Sea and Caspian Sea border states to ensure that they develop adequate oil spill response capabilities.

Figure 8-10

Caspian Energy Export Pipelines: 2001



Several oil and natural gas pipeline projects are proposed for the Caspian area.

Source: U.S. Central Intelligence Agency.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the BTC oil pipeline as it demonstrates its commercial viability.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to continue working with relevant companies and countries to establish the commercial conditions that will allow oil companies operating in Kazakhstan the option of exporting their oil via the BTC pipeline.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the efforts of private investors and regional governments to develop the Shah Deniz gas pipeline as a way to help Turkey and Georgia diversify their natural gas supplies and help Azerbaijan export its gas via a pipeline that will continue diversification of secure energy supply routes.

★ The NEPD Group recommends that the President direct appropriate federal agencies to complete the current cycle of oil spill response readiness workshops and to consider further appropriate steps to ensure the implementation of the workshops' recommendations.

★ The NEPD Group recommends that the President direct the Secretary of State to encourage Greece and Turkey to link their gas pipeline systems to allow European consumers to diversify their gas supplies by purchasing Caspian gas.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, Energy, and State to deepen their commercial dialogue with Kazakhstan, Azerbaijan, and other Caspian states to provide a strong, transparent, and stable business climate for energy and related infrastructure projects.

Russia

Russia has about 5 percent of the world's proven oil reserves. In 2000, Russia produced an average of 6.7 million barrels of oil and natural gas liquids per day, making it both the world's third largest producer and second largest exporter at 4.2 million barrels of oil per day. Russia's oil production in 2000 represented an increase of 7 percent over 1999, the first increase since the dissolution of the Soviet Union. A similar rate of increase is projected for 2001. New fields are being developed, including those with U.S. and other foreign investors.

Nevertheless, substantial infrastructure investment is still needed, as well as legislation and a stable and reliable regime of contracting to finalize the Production Sharing Agreement (PSA) mechanism for private-sector participation and actions to improve the general investment climate. Russian oil firms are increasingly active on a global scale, with upstream and downstream investments in the Caspian, the United States, Africa, South Asia, and Europe, enhancing Russia's ability to develop its own and international oil reserves.

Russia holds 33 percent of the world's natural gas reserves, exporting a full 35 percent of its production to Europe and Central Asia in 1999. Russian natural gas exports can increase regional fuel diversification and advance environmental goals. With production declines now evident in existing fields, development of new reserves that require substantial new investments will be necessary.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to deepen the focus of the discussions with Russia on energy and the investment climate.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to assist U.S. companies in their dialogue on the investment and trade climate with

Russian officials, to encourage reform of the PSA law and other regulations and related tax provisions, as well as general improvements in the overall investment climate. This will help ex pand private investment opportunities in Russia and will increase the inter national role of Russian firms.

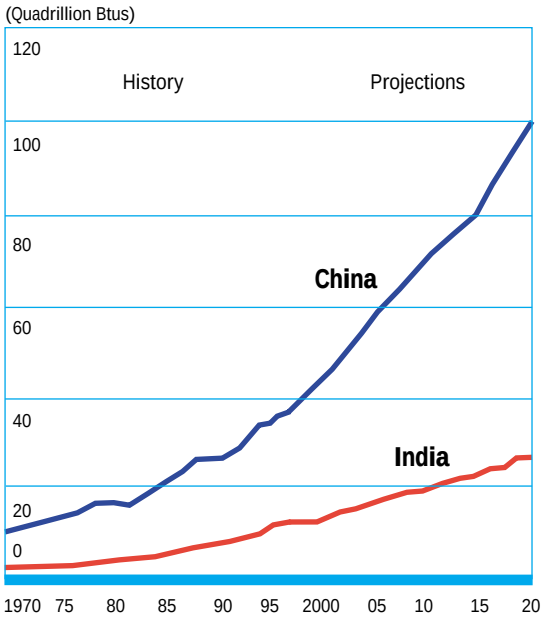
Asia

Asia holds less than 5 percent of world proven oil reserves, but accounts for more than 10 percent of oil production and about 30 percent of world oil consumption. The developing countries of the Pacific Rim are expected to increase their total petro leum imports by almost 43 percent between 1997 and 2020. The developing countries of Asia are expected to remain heavily depen dent on Middle East imports.

China is a critical player in global en ergy security issues, since its net oil im ports are expected to rise from approxi mately 1 million barrels of oil per day at present to possibly 5 to 8 million barrels of oil per day by 2020, with a predominant (over 70 percent) dependence on Middle East imports. China moved in the mid-1990s from being a net oil exporter to a net oil im porter.

About 7 percent of the world's proven natural gas reserves are located in Asia. Asian gas production represents about 11 percent of the world total, and consumption is less than 3 percent of world natural gas demand. Other natural gas producers, such as Malaysia, Myanmar, and Australia, are net gas exporters. Currently Japan, South Korea, and Taiwan are the major gas im porters in Asia. China, in addition to accel erating domestic exploration and develop ment of natural gas resources, is planning to import gas via pipeline from Central Asia. India, likewise, is considering several po tential LNG import projects (Figure 8-11).

Figure 8-11
Energy Consumption in China and India: 1970–2020



China and India account for the bulk of projected growth in oil demand in non-OECD countries.

Source: U.S. Department of Energy, Energy Information Administration.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to con tinue to work in the APEC Energy Working Group to examine oil market data transparency issues and the vari ety of ways petroleum stocks can be used as an option to address oil mar ket disruptions.

★ The NEPD Group recommends that the President direct the Secretaries of State and Energy to work with India's Ministry of Petroleum and Natural Gas to help India maximize its domestic oil and gas production.

Diversification of Fuel Mix

The growing demand for more fuel efficient technologies offers U.S. businesses significant trade and investment opportuni ties overseas, while addressing rising world oil demand. The United States supports a practical, market-based approach that en

courages the adoption of efficient technolo gies, including those relating to natural gas, nuclear energy, and renewable energy. This approach takes into account existing na tional and international programs and has the potential to energize both public action and private involvement. Introduction of these technologies abroad also supports U.S. national interests by reducing competi tion for the oil resources on which the glo bal economy continues to rely. Overall, the U.S. government's goal is to adopt policies that support innovative finance and market mechanisms that will provide U.S. busi nesses and consumers greater incentives to make more cost effective, energy efficient investment and consumption decisions.

Increased use of renewable energy technologies would improve U.S. energy se curity, yield global environmental benefits, improve social and economic stability in the developing world, and provide significant trade and investment opportunities to U.S. businesses. Promotion of clean energy tech nology exports can mitigate international dependence on oil supplies from volatile re gions, help lower energy costs for U.S. con sumers, bring U.S. firms greater access to large foreign markets, and enhance U.S. in tegration with global sources of innovation. In consultation with U.S. industry, the U.S. government is participating in efforts of the IEA, the G-8, the OECD, the United Nations, and multilateral development banks to for mulate effective strategies for accelerated market penetration of renewable energy technologies. Significant market penetra tion will depend on further reducing the costs of deploying these technologies.

The Clean Energy Technology Exports Working Group, a Federal interagency task force comprised of USAID and the Depart ments of Commerce and Energy, is creating a strategic plan that will provide a roadmap for future exports of U.S. clean energy tech nologies. Through its international trade programs, the Department of Commerce will showcase market-ready U.S. technolo gies that generate a cleaner environment and increase energy efficiency.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to pro mote market-based solutions to envi ronmental concerns; support exports of U.S. clean energy technologies and encourage their overseas develop ment; engage bilaterally and multilat erally to promote best practices; ex plore collaborative international basic research and development in energy alternatives and energy efficient tech nologies; and explore innovative pro grams to support the global adoption of these technologies.

Climate Change

The President is committed to ad dressing the issue of global climate change in a manner that protects our environment and economy. Toward this end, the Admin istration is undertaking a Cabinet-level re view of domestic and international policies for addressing this issue.

The United States invited other nations to re-examine global climate change issues, including technologies and market-based systems. Increasing our understanding of the most recent science and further research into the science of climate change will be es sential to developing the optimal strategy.

There is increasing awareness of glo bal competition for fossil fuels and their po tential threats to the global environment. The United States can diminish both risks by becoming more energy efficient at home, by working with other nations, and by en couraging developing countries to use the cleanest and most energy-efficient technolo gies. Through educational programs, the United States can encourage developing countries to use advanced U.S. energy tech nologies, energy management practices, and market-based policies. The United States is uniquely positioned to help emerging na tions build energy and institutional capacity and to finance energy-related activities and services. Doing so could prove to be a cost effective investment, for both the United States and emerging economies.

Recommendation:

★ The NEPD Group recommends that the President direct federal agencies to support continued research into global climate change; continue efforts to identify environmentally and cost-effective ways to use market mechanisms and incentives; continue development of new technologies; and cooperate with allies, including through international processes, to develop technologies, market-based incentives, and other innovative approaches to address the issue of global climate change.

Oil Consumption

Although U.S. energy security can be reinforced by domestic efforts to enhance supply and use energy more efficiently, growth in international oil demand will exert increasing pressure on global oil availability. Worldwide oil consumption is projected to grow by 2.1 percent a year over the next two decades. However, oil demand is projected to grow three times as fast in non-OECD countries as in OECD countries, which will increase worldwide competition for global oil supplies and put increased pressure on our shared environment. Accordingly, non-OECD countries' share of oil demand is expected to rise from 41 percent to 52 percent (Figure 8-12). China and India will be major contributors to this growth in demand and will rely heavily on imports to meet their needs. This growth will increase the stake that many developing countries have in ensuring access to significant energy resources, as well as their incentive to pursue energy efficiency.

Transportation has been responsible for nearly all the growth in OECD oil consumption over the last twenty years, and is projected to be the leading source of future growth in oil consumption through 2020. Transportation-related fuel consumption in the developing world is expected to more than double by 2020, growing at an annual average rate of 4 percent. Therefore, both OECD and developing countries will need to increase their focus on efficiencies in the transportation sector. The momentum to create market mechanisms supporting alternative-fuel vehicles will increase. Best practices that seek to reduce the cost of these technologies and to promote market penetration should be pursued. Without additional efforts to reduce this growth in consumption, the transportation sector's fuel needs will force an increasing dependence on oil in the developed and developing worlds.

Recommendations:

★ The NEPD Group recommends that the President seek to increase international cooperation on finding alternatives to oil, especially for the transportation sector.

★ The NEPD Group recommends that the President direct the Secretary of State to reinvigorate its dialogue with the European Union on energy issues, and resume the consultative process this year in Washington.

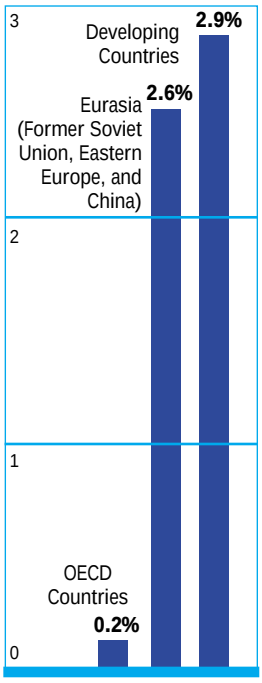
★ The NEPD Group recommends that the President promote a coordinated approach to energy security by calling for an annual meeting of G-8 Energy Ministers or their equivalents.

Emergency Preparedness for Oil Supply Disruption

U.S. and world exposure to oil supply disruptions increases as the size of strategic and commercial stocks relative to demand declines. This vulnerability is a result of rising global demand, tight supplies, and inadequate efforts to establish or expand oil stockpiles. Such a situation magnifies the importance of U.S. coordination with other members of the IEA, comprised of most OECD member governments. Each IEA member that is a net oil importer is required to hold stocks equal to 90 days or more of its net imports. The IEA maintains agreed mechanisms for coordinating the use of these stocks in responding to a physical supply disruption. Collectively, the net oil-importing members of the IEA currently hold

Figure 8-12
Projected Oil Consumption Rates in Three Economic Regions: 1999–2020

(Percent)

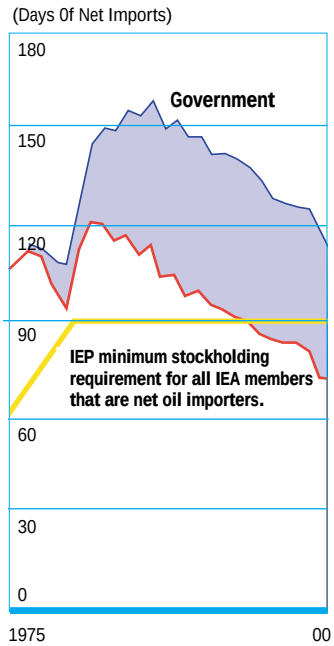


Over the next two decades, oil consumption in developing countries and Eurasia will grow three times faster than in the rest of the world.

Source: U.S. Department of Energy, Energy Information Administration.

Figure 8-13

Stocks of IEA Net Importers: 1975–2000



The International Energy Agency, of which the United States is a member, closely tracks the amount of strategic and commercial petroleum stocks maintained by its member states. The International Energy Program (IEP) Agreement "binds Participating Countries to make specific measures to meet any oil supply emergency and, over the long term, to reduce dependence on oil."

Source: International Energy Agency.

approximately 113 days worth of strategic and commercial stocks. U.S. stocks, which include both government and commercial stocks, are slightly above the IEA average. While this is more than required, it is far be low the peak coverage of 157 days reached in 1986. Moreover, several member states have fallen below the 90-day threshold (Fig ure 8-13).

The United States meets part of its IEA obligation through government-owned stocks held in the U.S. Strategic Petroleum Reserve (SPR). The SPR currently holds 541 million barrels of oil, which is enough to cover the loss of all U.S. imports for 54 days or a partial disruption for much longer. Close to 33 million barrels of oil will be de posited in the SPR by the fourth quarter of 2002, returning oil that had been "ex changed" out of the reserve last year. SPR oil can be withdrawn at a maximum rate of over 4 million barrels of oil per day initially and could reach the market within fifteen days of a Presidential directive. Because of increased net oil imports, the days of oil im port coverage provided by the SPR have de clined considerably over the past decade. In 1990, the SPR contained enough oil to com pensate for the loss of 82 days worth of U.S. imports—substantially more than today's 54-day supply. As domestic production and import patterns evolve, the Administration will work to inform Congress about chang ing coverage levels provided by the SPR. It should be noted that the United States also counts on the SPR as a national defense fuel reserve.

The oil market's day-to-day operation and its ability to respond to supply prob lems depend heavily on the availability of information on supply, demand, and price. The oil market volatility of the past two years has emphasized the need for more comprehensive and timely oil market infor mation.

Recommendations:

★ The NEPD Group recommends that the President reaffirm that the SPR is designed for addressing an imminent or actual disruption in oil supplies, and not for managing prices.

★ The NEPD Group recommend that the President direct the Secretary of Energy to work within the Interna tional Energy Agency (IEA) to ensure that member states fulfill their stock holding.

★ The NEPD Group recommends that the President direct the Secretary of Energy to encourage major oil-con suming countries that are not IEA members to consider strategic stocks as an option for addressing potential supply disruptions. In this regard, we should work closely with Asian econo mies, especially through APEC.

★ The NEPD Group recommends that the President direct the Secretary of Energy offer to lease excess SPR stor age facilities to countries (both IEA and non-IEA members) that might not otherwise build storage facilities or hold sufficient strategic stocks, consis tent with statutory authorities.

★ The NEPD Group recommends that the President, at such time that ex changed SPR barrels are returned to the SPR, should determine whether offshore Gulf of Mexico royalty oil de posits to the SPR should be resumed, thereby increasing the size of our re serve.

★ The NEPD Group recommends that the President direct the Secretary of Energy to work closely with Congress to ensure that our SPR protection is maintained.

★ The NEPD Group recommends that the President direct the Secretary of Energy to work with producer and consumer country allies and the IEA to craft a more comprehensive and timely world oil data reporting system.

Summary of Recommendations

Strengthening Global Alliances: Enhancing National Energy Security and International Relationships

★ The NEPD Group recommends that the President make energy security a priority of our trade and foreign policy.

★ The NEPD Group recommends the President support initiatives by Saudi Arabia, Ku wait, Algeria, Qatar, the UAE, and other suppliers to open up areas of their energy sec tors to foreign investment.

★ The NEPD Group recommends that the President direct the Secretaries of State, En ergy and Commerce work to improve dialogue among energy producing and consuming nations.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue supporting American energy firms competing in markets abroad and use our membership in multilateral organizations, such as the Asia-Pacific Economic Cooperation (APEC) forum, the Organization for Economic Coopera tion and Development (OECD), the World Trade Organization (WTO) Energy Services Negotiations, the Free Trade Area of the Americas (FTAA), and our bilateral relation ships to implement a system of clear, open, and transparent rules and procedures gov erning foreign investment; to level the playing field for U.S. companies overseas; and to reduce barriers to trade and investment.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Energy, and the U.S. Trade Representative, to support a sectoral trade initiative to expand investment and trade in energy-related goods and services that will enhance ex ploration, production, and refining, as well as the development of new technologies.

★ The NEPD Group recommends that the President direct the Secretaries of State, Treasury, and Commerce to initiate a comprehensive review of sanctions. Energy secu rity should be one of the factors considered in such a review.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to engage in a dialogue through the North American Energy Working Group to develop closer energy integration among Canada, Mexico, and the United States and identify areas of cooperation, fully consistent with the countries' re spective sovereignties.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, in consultation with the Federal Energy Regulatory Commission, to review their respective oil, natural gas, and electricity cross-boundary "Presidential Permitting" authorities, and to propose reforms as necessary in order to make their own regulatory regimes more compatible for cross-border trade.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

★ The NEPD Group recommends that the President direct the Secretaries of State and Commerce to conclude negotiations with Venezuela on a Bilateral Investment Treaty, and propose formal energy consultations with Brazil, to improve the energy invest ment climate for the growing level of energy investment flows between the United States and each of these countries.

★ The NEPD Group recommends that the President direct the Secretaries of Energy, Commerce, and State to work through the Summit of the Americas Hemispheric En ergy Initiative to develop effective and stable regulatory frameworks and foster reli able supply sources of all fuels within the region.

★ The NEPD Group recommends that the President direct the Secretaries of State, Energy, and Commerce to reinvigorate the U.S.-Africa Trade and Economic Coopera tion Forum and the U.S.-African Energy Ministerial process; deepen bilateral and mul tilateral engagement to promote a more receptive environment for U.S. oil and gas trade, investment, and operations; and promote geographic diversification of energy supplies, addressing such issues as transparency, sanctity of contracts, and security.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support more transparent, accountable, and responsible use of oil resources in African producer countries to enhance the stability and security of trade and investment environments.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the BTC oil pipeline as it demonstrates its commer cial viability.

★ The NEPD Group recommends that the President direct the Secretaries of Com merce, State, and Energy to continue working with relevant companies and countries to establish the commercial conditions that will allow oil companies operating in Kazakhstan the option of exporting their oil via the BTC pipeline.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the efforts of private investors and regional govern ments to develop the Shah Deniz gas pipeline as a way to help Turkey and Georgia di versify their natural gas supplies and help Azerbaijan export its gas via a pipeline that will continue diversification of secure energy supply routes.

★ The NEPD Group recommends that the President direct appropriate federal agen cies to complete the current cycle of oil spill response readiness workshops and to consider further appropriate steps to ensure the implementation of the workshops' recommendations.

★ The NEPD Group recommends that the President direct the Secretary of State to encourage Greece and Turkey to link their gas pipeline systems to allow European consumers to diversify their gas supplies by purchasing Caspian gas.

★ The NEPD Group recommends that the President direct the Secretaries of Com merce, Energy, and State to deepen their commercial dialogue with Kazakhstan, Azerbaijan, and other Caspian states to provide a strong, transparent, and stable business climate for energy and related infrastructure projects.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to deepen the focus of the discussions with Russia on energy and the investment climate.

★ The NEPD Group recommends that the President direct the Secretaries of Com merce, State, and Energy to assist U.S. companies in their dialogue on the investment and trade climate with Russian officials, to encourage reform of the PSA law and other regulations and related tax provisions, as well as general improvements in the overall investment climate. This will help expand private investment opportunities in Russia and will increase the international role of Russian firms.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue to work in the APEC Energy Working Group to ex amine oil market data transparency issues and the variety of ways petroleum stocks can be used as an option to address oil market disruptions.

★ The NEPD Group recommends that the President direct the Secretaries of State and Energy to work with India's Ministry of Petroleum and Natural Gas to help India maxi mize its domestic oil and gas production.

★ The NEPD Group recommends that the President direct the Secretaries of Com merce, State, and Energy to promote market-based solutions to environmental con cerns; support exports of U.S. clean energy technologies and encourage their overseas development; engage bilaterally and multilaterally to promote best practices; explore collaborative international basic research and development in energy alternatives and energy-efficient technologies; and explore innovative programs to support the global adoption of these technologies.

★ The NEPD Group recommends that the President direct federal agencies to support continued research into global climate change; continue efforts to identify environ mentally and cost-effective ways to use market mechanisms and incentives; continue development of new technologies; and cooperate with allies, including through inter national processes, to develop technologies, market-based incentives, and other inno vative approaches to address the issue of global climate change.

★ The NEPD Group recommends that the President seek to increase international co operation on finding alternatives to oil, especially for the transportation sector.

★ The NEPD Group recommends that the President direct the Secretary of State to re invigorate its dialogue with the European Union on energy issues, and resume the con sultative process this year in Washington.

★ The NEPD Group recommends that the President promote a coordinated approach to energy security by calling for an annual meeting of G-8 Energy Ministers or their equivalents.

★ The NEPD Group recommends that the President reaffirm that the SPR is designed for addressing an imminent or actual disruption in oil supplies, and not for managing prices.

★ The NEPD Group recommend that the President direct the Secretary of Energy to work within the International Energy Agency (IEA) to ensure that member states ful fill their stockholding.

★ The NEPD Group recommends that the President direct the Secretary of Energy to encourage major oil-consuming countries that are not IEA members to consider strate gic stocks as an option for addressing potential supply disruptions. In this regard, we should work closely with Asian economies, especially through APEC.

★ The NEPD Group recommends that the President direct the Secretary of Energy of fer to lease excess SPR storage facilities to countries (both IEA and non-IEA mem bers) that might not otherwise build storage facilities or hold sufficient strategic stocks, consistent with statutory authorities.

★ The NEPD Group recommends that the President, at such time that exchanged SPR barrels are returned to the SPR, should determine whether offshore Gulf of Mexico royalty oil deposits to the SPR should be resumed, thereby increasing the size of our reserve.

★ The NEPD Group recommends that the President direct the Secretary of Energy to work closely with Congress to ensure that our SPR protection is maintained.

★ The NEPD Group recommends that the President direct the Secretary of Energy to work with producer and consumer country allies and the IEA to craft a more compre hensive and timely world oil data reporting system.

CHAPTER ONE
Taking Stock: Energy Challenges Facing the United States

★ The NEPD Group recommends that the President issue an Executive Order to direct all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies, distribution, or use, a detailed statement on: (1) the energy impact of the proposed action, (2) any adverse energy effects that cannot be avoided should the proposal be implemented, and (3) alternatives to the proposed action. The agencies would be directed to include this statement in all submissions to the Office of Management and Budget of proposed regulations covered by Executive Order 12866, as well as in all notices of proposed regulations published in the Federal Register.

★ The NEPD Group recommends that the President direct the executive agencies to work closely with Congress to implement the legislative components of a national energy policy.

★ The NEPD Group recommends to the President that the NEPD Group continue to work and meet on the implementation of the National Energy Policy and explore other ways to advance dependable, affordable, and environmentally responsible production and distribution of energy.

Note: All recommendations in this report are subject to execution in accordance with applicable law. Legislation would be sought where needed. Also, any recommendations that involve foreign countries would be executed in accordance with the customs of international relations, including appropriate diplomatic consultation.

CHAPTER TWO
Striking Home The Impacts of High Energy Prices on Families, Communities, and Businesses

★ The NEPD Group recommends that the President direct the Secretary of Energy to ex plore potential opportunities to develop educational programs related to energy develop ment and use. This should include possible legislation to create public education aware ness programs about energy. Such programs should be long-term in nature, should be funded and managed by the respective energy industries, and should include information on energy's compatibility with a clean environment.

★ The NEPD Group recommends that the President take steps to mitigate impacts of high energy costs on low-income consumers. These steps would include:

- Strengthening the Low Income Home Energy Assistance Program by making $1.7 bil lion available annually. This is an increase of $300 million over the regular FY 2001 ap propriation.
- Directing the Secretaries of Interior and Health and Human Services to propose legis lation to bolster LIHEAP funding by using a portion of oil and gas royalty payments.
- Redirecting royalties above a set trigger price to LIHEAP, whenever crude oil and natural gas prices exceed that trigger price, as determined by the responsible agencies.

★ The NEPD Group recommends that the President increase funding for the Weatheriza tion Assistance Program by $1.2 billion over ten years. This will roughly double the spend ing during that period on weatherization. Consistent with that commitment, the FY 2002 Budget includes a $120 million increase over 2001. The Department of Energy will have the option of using a portion of those funds to test improved implementation approaches for the weatherization program.

★ The NEPD Group recommends that the President support legislation to allow funds dedicated for the Weatherization and State Energy Programs to be transferred to LIHEAP if the Department of Energy deems it appropriate.

★ The NEPD Group recommends the President recognize unique regional energy con cerns by working with the National Governors Association and regional governor associa tions to determine how to better serve the needs of diverse areas of the country.

★ The NEPD Group recommends the President direct FEMA to prepare for potential en ergy emergencies.

- FEMA should work with states' Offices of Emergency Management as they expand existing emergency operations plans to identify potential problems and address conse quences of the power shortages. FEMA should use its current Regional Incident Re porting System to identify any situations that might demand immediate attention.
- Using the structure of the already existing Federal Response Plan, FEMA should con duct Regional Interagency Steering Committee (RISC) meetings for states affected by the energy shortfalls. The RISC is a FEMA-led interagency committee comprised of agencies and departments that support the Federal Response Plan. Either an upcom ing, scheduled RISC meeting or a special-focus RISC meeting can be held to identify the short-term energy outlook, as well as any expected consequences, in each of the states during the peak summer season.

CHAPTER THREE

Protecting America's Environment: Sustaining the Nation's Health and Environment

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to propose multi-pollutant legislation. The NEPD Group recommends that the President direct the EPA Administrator to work with Congress to propose legislation that would establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators. Such a program (with appropriate measures to address local concerns) would provide significant public health benefits even as we increase electricity supplies.

- Establish mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides, and mercury.
- Phase in reductions over a reasonable period of time, similar to the successful acid rain reduction program established by the 1990 amendments to the Clean Air Act.
- Provide regulatory certainty to allow utilities to make modifications to their plants without fear of new litigation.
- Provide market-based incentives, such as emissions trading credits to help achieve the required reductions.

★ The NEPD Group recommends the President direct the Secretary of the Interior to work with Congress to create the "Royalties Conservation Fund."

- This fund will earmark potentially billions of dollars in royalties from new oil and gas production in ANWR to fund land conservation efforts.
- This fund will also be used to eliminate the maintenance and improvements backlog on federal lands.

★ The NEPD Group recommends the President issue an Executive Order to rational ize permitting for energy production in an environmentally sound manner by directing federal agencies to expedite permits and other federal actions necessary for energy related project approvals on a national basis. This order would establish an inter agency task force chaired by the Council on Environmental Quality to ensure that federal agencies responsible for permitting energy-related facilities are coordinating their efforts. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state, tribal, and local permitting activity in particu lar regions where increased activity is expected.

CHAPTER FOUR
Using Energy Wisely: Increasing Energy Conservation and Efficiency

★ The NEPD Group recommends that the President direct the Office of Science and Technology Policy and the President's Council of Advisors on Science and Technology to review and make recommendations on using the nation's energy resources more effi ciently.

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of energy efficiency re search and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

★ The NEPD Group recommends that the President direct the Secretary of Energy to promote greater energy efficiency.

- Expand the Energy Star program beyond office buildings to include schools, re tail buildings, health care facilities, and homes.
- Extend the Energy Star labeling program to additional products, appliances, and services.
- Strengthen Department of Energy public education programs relating to energy efficiency.

★ The NEPD Group recommends that the President direct the Secretary of Energy to improve the energy efficiency of appliances.

- Support the appliance standards program for covered products, setting higher standards where technologically feasible and economically justified.
- Expand the scope of the appliance standards program, setting standards for ad ditional appliances where technologically feasible and economically justified.

★ The NEPD Group recommends that the President direct heads of executive depart ments and agencies to take appropriate actions to conserve energy use at their facilities to the maximum extent consistent with the effective discharge of public responsibili ties. Agencies located in regions where electricity shortages are possible should con serve especially during periods of peak demand. Agencies should report to the Presi dent, through the Secretary of Energy, within 30 days on the conservation actions taken.

★ The NEPD Group recommends that the President direct the Secretary of the Trea sury to work with Congress to encourage increased energy efficiency through combined heat and power (CHP) projects by shortening the depreciation life for CHP projects or providing investment tax credits.

★ The NEPD Group recommends that the President direct the Administrator of the En vironmental Protection Agency (EPA) to work with local and state governments to pro mote the use of well-designed CHP and other clean power generation at brownfields sites, consistent with the local communities' interests. EPA will also work to clarify li ability issues if they are raised at a particular site.

CHAPTER FOUR

★ The NEPD Group recommends that the President direct the EPA Administrator to promote CHP through flexibility in environmental permitting.

★ The NEPD Group recommends that the President direct the Secretary of Transporta tion to:

- Review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards with due consideration of the National Academy of Sciences study to be released in July 2001. Responsibly crafted CAFE standards should increase efficiency without negatively impacting the U.S. automotive indus try. The determination of future fuel economy standards must therefore be ad dressed analytically and based on sound science.
- Consider passenger safety, economic concerns, and disparate impact on the U.S. versus foreign fleet of automobiles.
- Look at other market-based approaches to increasing the national average fuel economy of new motor vehicles.

★ The new NEPD Group recommends that the President direct the Secretary of Trans portation to review and promote congestion mitigation technologies and strategies and work with Congress on legislation to implement these strategies.

★ The NEPD Group recommends that the President direct the Secretary of the Trea sury to work with Congress on legislation to increase energy efficiency with a tax credit for fuel-efficient vehicles. The NEPD Group recommends that a temporary, efficiency based income tax credit be available for purchase of new hybrid fuel cell vehicles be tween 2002 and 2007.

★ The NEPD Group recommends that the President direct all agencies to use techno logical advances to better protect our environment.

- The Administration remains committed to investing in Intelligent Transportation Systems (ITS) and encourages the private sector to invest in ITS applications. This Department of Transportation (DOT) program funds the development of improved transportation infrastructure that will reduce congestion, such as trav eler information/navigation systems, freeway management, and electronic toll collection. ITS applications reduce fuel associated with travel.
- The Administration remains committed to the DOT's fuel-cell-powered transit bus program, authored by the Transportation Equity Act for the 21st Century (TEA-21). This program demonstrates the viability of fuel-cell power plants for transit bus applications.
- The Administration remains committed to the Clean Buses program. TEA-21 es tablishes a new clean fuel formula grant program, which provides an opportu nity to accelerate the introduction of advanced bus propulsion technologies into the mainstream of the nation's transit fleet.

★ The NEPD Group recommends that the President direct the EPA and DOT to develop ways to reduce demand for petroleum transportation fuels by working with the trucking industry to establish a program to reduce emissions and fuel consumption from long-haul trucks at truck stops by implementing alternatives to idling, such as electrification and auxiliary power units at truck stops along interstate highways. EPA and DOT will develop partnership agreements with trucking fleets, truck stops, and manufacturers of idle-reducing technologies (*e.g.*, portable auxiliary packs, electrification) to install and use low emission-idling technologies.

★ The NEPD Group recommends that the President direct the Secretary of Energy to establish a national priority for improving energy efficiency. The priority would be to improve the energy intensity of the U.S. economy as measured by the amount of energy required for each dollar of economic productivity. This increased efficiency should be pursued through the combined efforts of industry, consumers, and federal, state, and local governments.

★ The NEPD Group recommends that the President direct the EPA Administrator to develop and implement a strategy to increase public awareness of the sizable savings that energy efficiency offers to homeowners across the country. Typical homeowners can save about 30 percent (about $400) a year on their home energy bill by using Energy Star labeled products.

Chapter Five Energy for a New Century: Increasing Domestic Energy Supplies

★ The NEPD Group recommends that the President direct the Secretaries of Energy and the Interior to promote enhanced oil and gas recovery from existing wells through new technology.

★ The NEPD Group recommends that the President direct the Secretary of Energy to improve oil and gas exploration technology through continued partnership with public and private entities.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to examine land status and lease stipulation impediments to federal oil and gas leasing, and review and modify those where opportunities exist (consistent with the law, good environmental practice, and balanced use of other resources).

- Expedite the ongoing Energy Policy and Conservation Act study of impediments to federal oil and gas exploration and development.
- Review public lands withdrawals and lease stipulations, with full public consultation, especially with the people in the region, to consider modifications where appropriate.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider economic incentives for environmentally sound offshore oil and gas development where warranted by specific circumstances: explore opportunities for royalty reductions, consistent with ensuring a fair return to the public where warranted for enhanced oil and gas recovery; for reduction of risk associated with production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Interior to re-examine the current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the Outer Continental Shelf (OCS).

★ The NEPD Group recommends that the President direct the Secretary of the Interior continue OCS oil and gas leasing and approval of exploration and development plans on predictable schedules.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider additional environmentally responsible oil and gas development, based on sound science and the best available technology, through further lease sales in the National Petroleum Reserve-Alaska. Such consideration should include areas not currently leased within the Northeast corner of the Reserve.

★ The NEPD Group recommends that the President direct the Secretary of the Interior work with Congress to authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR. Congress should require the use of the best available technology and should require that activities will result in no significant adverse impact to the surrounding environment.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaska Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

★ The NEPD Group recommends that the President direct the Secretary of Energy to propose comprehensive electricity legislation that promotes competition, protects consumers, enhances reliability, promotes renewable energy, improves efficiency repeals the Public Utility Holding Company Act, and reforms the Public Utility Regulatory Policies Act.

★ The NEPD Group recommends that the President encourage FERC to use its existing statutory authority to promote competition and encourage investment in transmission facilities.

★ The NEPD Group recognizes the importance of looking to technology to help us meet the goals of increasing electricity generation while protecting our environment. To that end, the NEPD Group recommends that the President direct the Department of Energy to continue to develop advanced clean coal technology by:

- Investing $2 billion over 10 years to fund research in clean coal technologies.
- Supporting a permanent extension of the existing research and development tax credit.
- Directing federal agencies to explore regulatory approaches that will encourage advancements in environmental technology.

★ The NEPD Group recommends that the President direct federal agencies to provide greater regulatory certainty relating to coal electricity generation through clear policies that are easily applied to business decisions.

★ The NEPD Group recommends that the President support the expansion of nuclear energy in the United States as a major component of our national energy policy. Following are specific components of the recommendation:

- Encourage the Nuclear Regulatory Commission (NRC) to ensure that safety and environmental protection are high priorities as they prepare to evaluate and expedite applications for licensing new advanced-technology nuclear reactors.
- Encourage the NRC to facilitate efforts by utilities to expand nuclear energy generation in the United States by uprating existing nuclear plants safely.
- Encourage the NRC to relicense existing nuclear plants that meet or exceed safety standards.
- Direct the Secretary of Energy and the Administrator of the Environmental Protection Agency to assess the potential of nuclear energy to improve air quality.
- Increase resources as necessary for nuclear safety enforcement in light of the potential increase in generation.
- Use the best science to provide a deep geologic repository for nuclear waste.
- Support legislation clarifying that qualified funds set aside by plant owners for eventual decommissioning will not be taxed as part of the transaction.
- Support legislation to extend the Price–Anderson Act.

★ The NEPD Group recommends that, in the context of developing advanced nuclear fuel cycles and next generation technologies for nuclear energy, the United States should reexamine its policies to allow for research, development and deployment of fuel conditioning methods (such as pyroprocessing) that reduce waste streams and enhance proliferation resistance. In doing so, the United States will continue to discourage the accumulation of separated plutonium, worldwide.

★ The United States should also consider technologies (in collaboration with international partners with highly developed fuel cycles and a record of close cooperation) to develop reprocessing and fuel treatment technologies that are cleaner, more efficient, less waste intensive, and more proliferation-resistant.

CHAPTER FIVE

★ The NEPD Group recognizes there is a need to reduce the time and cost of the hydro power licensing process. The NEPD Group recommends that the President encourage the Federal Energy Regulatory Commission (FERC) and direct federal resource agencies to make the licensing process more clear and efficient, while preserving environmental goals. In addi tion, the NEPD Group recognizes the importance of optimizing the efficiency and reliability of existing hydropower facilities and will encourage the Administration to adopt efforts to ward that end.

- Support administrative and legislative reform of the hydropower licensing process.
- Direct federal resource agencies to reach interagency agreement on conflicting manda tory license conditions before they submit their conditions to FERC for inclusion in a license.
- Encourage FERC to adopt appropriate deadlines for its own actions during the licensing process.

CHAPTER SIX
Nature's Power: Increasing America's Use of Renewable and Alternative Energy

★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to re-evaluate access limitations to federal lands in order to increase renewable energy production, such as biomass, wind, geothermal, and solar.

★ The NEPD Group supports the increase of $39.2 million in the FY 2002 budget amendment for the Department of Energy's Energy Supply account that would provide increased support for research and development of renewable energy re sources.

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of renewable energy and alternative energy research and development programs in light of the recommen dations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to expand the section 29 tax credit to make it available for new landfill methane projects. The credit could be tiered, de pending on whether a landfill is already required by federal law to collect and flare its methane emissions due to local air pollution concerns.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to determine ways to reduce the delays in geothermal lease processing as part of the permitting review process.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to develop a new renewable energy partnership program to help companies more easily buy renewable energy, as well as receive recognition for the environmental benefits of their purchase, and help consumers by promoting consumer choice programs that increase their knowledge about the environmental benefits of purchasing renewable energy.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to extend and expand tax credits for electricity produced using wind and biomass. The President's budget request extends the present 1.7 cents per kilowatt hour tax credit for electricity produced from wind and biomass; expands eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources; and allows a credit for electricity produced from biomass co-fired with coal.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to provide a new 15 percent tax credit for residential solar energy property, up to a maximum credit of $2,000.

★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to work with Congress on legislation to use an estimated $1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR for funding research into alternative and renewable energy resources, including wind, solar, geothermal, and biomass.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to continue the ethanol excise tax exemption.

CHAPTER SIX

★ The NEPD Group recommends that the President direct the Secretary of Energy to develop next-generation technology—including hydrogen and fusion.

- Develop an education campaign that communicates the benefits of alternative forms of energy, including hydrogen and fusion.
- Focus research and development efforts on integrating current programs regarding hydrogen, fuel cells, and distributed energy.
- Support legislation reauthorizing the Hydrogen Energy Act.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to develop legislation to provide for a temporary income tax credit available for the purchase of new hybrid or fuel-cell vehicles between 2002 and 2007.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to issue guidance to encourage the development of well-designed combined heat and power (CHP) units that are both highly efficient and have low emissions. The goal of this guidance would be to shorten the time needed to obtain each permit, provide certainty to industry by ensuring consistent implementation across the country, and encourage the use of these cleaner, more efficient technologies.

CHAPTER SEVEN
America's Energy Infrastructure: A Comprehensive Delivery System

★ The NEPD Group recommends that the President direct the Secretary of Energy to work with the Federal Energy Regulatory Commission (FERC) to improve the reliabil ity of the interstate transmission system and to develop legislation providing for en forcement by a self-regulatory organization subject to FERC oversight.

★ The NEPD Group recommends that the President direct the Secretary of Energy to expand the Department's research and development on transmission reliability and superconductivity.

★ The NEPD Group recommends that the President direct the Secretary of Energy to au thorize the Western Area Power Administration to explore relieving the "Path 15" bottle neck through transmission expansion financed by nonfederal contributions.

★ The NEPD Group recommends that the President direct the appropriate federal agencies to take actions to remove constraints on the interstate transmission grid and allow our nation's electricity supply to meet the growing needs of our economy.

- Direct the Secretary of Energy, by December 31, 2001, to examine the benefits of establishing a national grid, identify transmission bottlenecks, and identify mea sures to remove transmission bottlenecks.
- Direct the Secretary of Energy to work with FERC to relieve transmission con straints by encouraging the use of incentive rate-making proposals.
- Direct the federal utilities to determine whether transmission expansions are nec essary to remove constraints. The Administration should review the Bonneville Power Administration's (BPA's) capital and financing requirements in the context of its membership in a regional RTO, and if additional Treasury financing appears war ranted or necessary in the future, the Administration should seek an increase in BPA's borrowing authority at that time.
- Direct the Secretary of Energy, in consultation with appropriate federal agencies and state and local government officials, to develop legislation to grant authority to obtain rights-of-way for electricity transmission lines, with the goal of creating a re liable national transmission grid. Similar authority already exists for natural gas pipelines in recognition of their role in interstate commerce.

★ The NEPD Group recommends that the President direct the Secretary of the Inte rior to work with Congress and the State of Alaska to put in place the most expedi tious process for renewal of the Trans-Alaskan Pipeline System lease to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

★ The NEPD Group recommends that the President support legislation to improve the safety of natural gas pipelines, protect the environment, strengthen emergency preparedness and inspections and bolster enforcement.

CHAPTER SEVEN

★ The NEPD Group recommends that the President direct agencies to continue their interagency efforts to improve pipeline safety and expedite pipeline permitting in an environmentally sound manner and encourage FERC to consider improvements in the regulatory process governing approval of interstate natural gas pipeline projects.

★ The NEPD Group recommends that the President direct the Administrator of the EPA to study opportunities to maintain or improve the environmental benefits of state and local "boutique" clean fuel programs while exploring ways to increase the flexibility of the fuels distribution infrastructure, improve fungibility, and provide added gasoline market liquidity. In concluding this study, the Administrator shall con sult with the Departments of Energy and Agriculture, and other agencies as needed.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency and the Secretary of Energy to take steps to ensure America has adequate refining capacity to meet the needs of consumers.

- Provide more regulatory certainty to refinery owners and streamline the permitting process where possible to ensure that regulatory overlap is limited.
- Adopt comprehensive regulations (covering more than one pollutant and require ment) and consider the rules' cumulative impacts and benefits.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency, in consultation with the Secretary of Energy and other relevant agencies, to review New Source Review regulations, including adminis trative interpretation and implementation, and report to the President within 90 days on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection.

★ The NEPD Group recommends that the President direct the Attorney General to review existing enforcement actions regarding New Source Review to ensure that the enforcement actions are consistent with the Clean Air Act and its regulations.

★ The NEPD Group supports the President's budget proposal to provide $8 million to maintain the two-million-barrel Northeast Heating Oil Reserve. Operated by the pri vate sector, the Reserve helps ensure adequate supplies of heating oil in the event that colder than normal winters occur in the Northeast United States.

CHAPTER 8
Strengthening Global Alliances: Enhancing National Energy Security and International Relationships

★ The NEPD Group recommends that the President make energy security a priority of our trade and foreign policy.

★ The NEPD Group recommends the President support initiatives by Saudi Arabia, Ku wait, Algeria, Qatar, the UAE, and other suppliers to open up areas of their energy sec tors to foreign investment.

★ The NEPD Group recommends that the President direct the Secretaries of State, En ergy and Commerce work to improve dialogue among energy producing and consuming nations.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue supporting American energy firms competing in markets abroad and use our membership in multilateral organizations, such as the Asia-Pacific Economic Cooperation (APEC) forum, the Organization for Economic Coopera tion and Development (OECD), the World Trade Organization (WTO) Energy Services Negotiations, the Free Trade Area of the Americas (FTAA), and our bilateral relation ships to implement a system of clear, open, and transparent rules and procedures gov erning foreign investment; to level the playing field for U.S. companies overseas; and to reduce barriers to trade and investment.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Energy, and the U.S. Trade Representative, to support a sectoral trade initiative to expand investment and trade in energy-related goods and services that will enhance ex ploration, production, and refining, as well as the development of new technologies.

★ The NEPD Group recommends that the President direct the Secretaries of State, Treasury, and Commerce to initiate a comprehensive review of sanctions. Energy securi ty should be one of the factors considered in such a review.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to engage in a dialogue through the North American Energy Working Group to develop closer energy integration among Canada, Mexico, and the United States and identify areas of cooperation, fully consistent with the countries' re spective sovereignties.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, in consultation with the Federal Energy Regulatory Commission, to review their respective oil, natural gas, and electricity cross-boundary "Presidential Permitting" authorities, and to propose reforms as necessary in order to make their own regulatory regimes more compatible for cross-border trade.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that

CHAPTER EIGHT

may be required.

★ The NEPD Group recommends that the President direct the Secretaries of State and Commerce to conclude negotiations with Venezuela on a Bilateral Investment Treaty, and propose formal energy consultations with Brazil, to improve the energy investment climate for the growing level of energy investment flows between the United States and each of these countries.

★ The NEPD Group recommends that the President direct the Secretaries of Energy, Commerce, and State to work through the Summit of the Americas Hemispheric Ener gy Initiative to develop effective and stable regulatory frameworks and foster reliable supply sources of all fuels within the region.

★ The NEPD Group recommends that the President direct the Secretaries of State, En ergy, and Commerce to reinvigorate the U.S.-Africa Trade and Economic Cooperation Forum and the U.S.-African Energy Ministerial process; deepen bilateral and multilater al engagement to promote a more receptive environment for U.S. oil and gas trade, in vestment, and operations; and promote geographic diversification of energy supplies, addressing such issues as transparency, sanctity of contracts, and security.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support more transparent, accountable, and responsible use of oil resources in African producer countries to enhance the stability and security of trade and investment environments.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the BTC oil pipeline as it demonstrates its commer cial viability.

★ The NEPD Group recommends that the President direct the Secretaries of Com merce, State, and Energy to continue working with relevant companies and countries to establish the commercial conditions that will allow oil companies operating in Kaza khstan the option of exporting their oil via the BTC pipeline.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the efforts of private investors and regional govern ments to develop the Shah Deniz gas pipeline as a way to help Turkey and Georgia di versify their natural gas supplies and help Azerbaijan export its gas via a pipeline that will continue diversification of secure energy supply routes.

★ The NEPD Group recommends that the President direct appropriate federal agen cies to complete the current cycle of oil spill response readiness workshops and to consider further appropriate steps to ensure the implementation of the workshops' rec ommendations.

★ The NEPD Group recommends that the President direct the Secretary of State to en courage Greece and Turkey to link their gas pipeline systems to allow European con sumers to diversify their gas supplies by purchasing Caspian gas.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, Energy, and State to deepen their commercial dialogue with Kazakhstan, Azerbaijan, and other Caspian states to provide a strong, transparent, and stable business climate for energy and related infrastructure projects.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to deepen the focus of the discussions with Russia on energy and the investment climate.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to assist U.S. companies in their dialogue on the investment and trade climate with Russian officials, to encourage reform of the PSA law and other regulations and related tax provisions, as well as general improvements in the overall investment climate. This will help expand private investment opportunities in Russia and will increase the international role of Russian firms.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue to work in the APEC Energy Working Group to examine oil market data transparency issues and the variety of ways petroleum stocks can be used as an option to address oil market disruptions.

★ The NEPD Group recommends that the President direct the Secretaries of State and Energy to work with India's Ministry of Petroleum and Natural Gas to help India maximize its domestic oil and gas production.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to promote market-based solutions to environmental concerns; support exports of U.S. clean energy technologies and encourage their overseas development; engage bilaterally and multilaterally to promote best practices; explore collaborative international basic research and development in energy alternatives and energy-efficient technologies; and explore innovative programs to support the global adoption of these technologies.

★ The NEPD Group recommends that the President direct federal agencies to support continued research into global climate change; continue efforts to identify environmentally and cost-effective ways to use market mechanisms and incentives; continue development of new technologies; and cooperate with allies, including through international processes, to develop technologies, market-based incentives, and other innovative approaches to address the issue of global climate change.

★ The NEPD Group recommends that the President seek to increase international cooperation on finding alternatives to oil, especially for the transportation sector.

★ The NEPD Group recommends that the President direct the Secretary of State to reinvigorate its dialogue with the European Union on energy issues, and resume the consultative process this year in Washington.

★ The NEPD Group recommends that the President promote a coordinated approach to energy security by calling for an annual meeting of G-8 Energy Ministers or their equivalents.

CHAPTER EIGHT

★ The NEPD Group recommends that the President reaffirm that the SPR is designed for addressing an imminent or actual disruption in oil supplies, and not for managing prices.

★ The NEPD Group recommend that the President direct the Secretary of Energy to work within the International Energy Agency (IEA) to ensure that member states ful fill their stockholding.

★ The NEPD Group recommends that the President direct the Secretary of Energy to encourage major oil-consuming countries that are not IEA members to consider stra tegic stocks as an option for addressing potential supply disruptions. In this regard, we should work closely with Asian economies, especially through APEC.

★ The NEPD Group recommends that the President direct the Secretary of Energy of fer to lease excess SPR storage facilities to countries (both IEA and non-IEA mem bers) that might not otherwise build storage facilities or hold sufficient strategic stocks, consistent with statutory authorities.

★ The NEPD Group recommends that the President, at such time that exchanged SPR barrels are returned to the SPR, should determine whether offshore Gulf of Mexi co royalty oil deposits to the SPR should be resumed, thereby increasing the size of our reserve.

★ The NEPD Group recommends that the President direct the Secretary of Energy to work closely with Congress to ensure that our SPR protection is maintained.

★ The NEPD Group recommends that the President direct the Secretary of Energy to work with producer and consumer country allies and the IEA to craft a more compre hensive and timely world oil data reporting system.

Glossary

Barrel (Oil): A unit of volume equal to 42 U.S. gallons.

Barrels per Day (Operable Refinery Capacity): The maximum number of barrels of in put that can be processed during a 24-hour period after making allowances for the following limitations: the capability of downstream facilities to absorb the output of crude oil process ing facilities of a given refinery (no reduction is made when a planned distribution of inter mediate streams through other than downstream facilities is part of a refinery's normal op eration); the types and grades of inputs to be processed; the types and grades of products to be manufactured; the environmental constraints associated with refinery operations; the re duction of capacity for scheduled downtime, such as routine inspection, mechanical prob lems, maintenance, repairs, and turnaround; and the reduction of capacity for unscheduled downtime, such as mechanical problems, repairs, and slowdowns.

Biomass: Organic nonfossil material of biological origin constituting a renewable energy source.

British Thermal Unit (Btu): The quantity of heat needed to raise the temperature of 1 pound of water by 1°F at or near 39.2°F.

Coal: A readily combustible black or brownish-black rock whose composition, including in herent moisture, consists of more than 50 percent by weight and more than 70 percent by volume of carbonaceous material. It is formed from plant remains that have been com pacted, hardened, chemically altered, and metamorphosed by heat and pressure over geo logic time.

Cogeneration: The production of electricity and another form of useful energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes.

Commercial Building: A building with more than 50 percent of its floor space used for commercial activities. Commercial buildings include stores, offices, schools, churches, gym nasiums, libraries, museums, hospitals, clinics, warehouses, and jails. Government buildings are also included, except buildings on military bases or reservations.

Commercial Sector: Business establishments that are not engaged in transportation or in manufacturing or other types of industrial activity (agriculture, mining, or construction). Commercial establishments include hotels, motels, restaurants, wholesale businesses, retail stores, laundries, and other service enterprises; religious and nonprofit organizations; health, social, and educational institutions; and federal, state, and local governments. Streetlights, pumps, bridges, and public services are also included if the establishment oper ating them is considered commercial.

Conversion Factor: A number that translates units of one system into corresponding val ues of another system. Conversion factors can be used to translate physical units of mea sure for various fuels into Btu equivalents.

Crude Oil: A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separat ing facilities. Crude oil may also include:

- Small amounts of hydrocarbons that exist in the gaseous phase in natural under ground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casing head) gas in lease separators and that subsequently are commingled with the crude stream without being separately measured.
- Small amounts of nonhydrocarbons produced with the oil, such as sulfur and other compounds

Crude Oil Stocks: Stocks of crude oil and lease condensate held at refineries, in pipelines, at pipeline terminals, and on leases.

District Heat: Steam or hot water from an outside source used as an energy source in a building. The steam or hot water is produced in a central plant and is piped into the build ing. District heat may be purchased from a utility or provided by a physical plant in a sepa rate building that is part of the same facility (for example, a hospital complex or university).

Electric Power Plant: A station containing prime movers, electric generators, and auxil iary equipment for converting mechanical, chemical, and/or fission energy into electric en ergy.

Electricity Generation: The process of producing electric energy or transforming other forms of energy into electric energy. Also, the amount of electric energy produced or ex pressed in watt-hours (Wh).

End-Use Sectors: The residential, commercial, industrial, and transportation sectors of the economy.

Energy: The capacity for doing work as measured by the capability of doing work (poten tial energy), or the conversion of this capability to motion (kinetic energy). Energy has sev eral forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatt-hours, while heat en ergy is usually measured in British thermal units.

Energy Consumption: The use of energy as a source of heat or power or as an input in the manufacturing process.

Energy Source: A substance, such as oil, natural gas, or coal, that supplies heat or power. Electricity and renewable forms of energy, such as wood, waste, geothermal, wind, and so lar, are considered to be energy sources.

Exports: Shipments of goods from the 50 states and the District of Columbia to foreign countries and to Puerto Rico, the Virgin Islands, and other U.S. possessions and territories.

Federal Energy Regulatory Commission (FERC): The federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification. FERC is an independent regulatory agency within the Department of Energy and is the successor to the Federal Power Com mission.

Fossil Fuel: Any naturally occurring organic fuel formed in the Earth's crust, such as oil, coal, and natural gas.

Fuel Ethanol: An anhydrous, denatured aliphatic alcohol intended for motor gasoline blending.

Gas-Turbine Electric Power Plant: A plant in which the prime mover is a gas turbine. A gas turbine typically consists of an axial-flow air compressor and one or more combustion chambers where liquid or gaseous fuel is burned. The hot gases expand to drive the genera tor and then are used to run the compressor.

Geothermal Energy: Energy from the internal heat of the Earth, which may be residual heat, friction heat, or a result of radioactive decay. The heat is found in rocks and fluids at various depths and can be extracted by drilling or pumping.

Gross Domestic Product (GDP): The total value of goods and services produced by la bor and property located in the United States.

Hydrocarbon: An organic chemical compound of hydrogen and carbon in the gaseous, liq uid, or solid phase. The molecular structure of hydrocarbon compounds varies from the simplest (methane, a constituent of natural gas) to the very heavy and very complex.

Hydropower: The production of electricity from the kinetic energy of falling water.

Hydropower Plant: A plant in which the turbine generators are driven by falling water.

Independent Power Producer: Wholesale electricity producers (other than qualifying fa cilities under the Public Utilities Regulatory Policies Act of 1978) that are unaffiliated with franchised utilities in the area in which the independent power producers are selling power and that lack significant marketing power. Unlike traditional electric utilities, independent power producers do not possess transmission facilities that are essential to their customers and do not sell power in any retail service territory where they have a franchise.

Industrial Sector: Manufacturing industries, which make up the largest part of the sector, along with mining, construction, agriculture, fisheries, and forestry. Establishments in this sector range from steel mills, to small farms, to companies assembling electronic compo nents.

Jet Fuel: A refined petroleum product used in jet aircraft engines. It includes kerosene type jet fuel and naphtha-type jet fuel.

Methane: Hydrocarbon gas, which is the major component of natural gas.

Methanol: A light, volatile alcohol eligible for motor gasoline blending.

Methyl Tertiary Butyl Ether (MTBE): An ether, intended for motor gasoline blending.

Natural Gas: A gaseous mixture of hydrocarbon compounds, primarily methane, delivered via pipeline for consumption. It is used as a fuel for electricity generation, a variety of uses in buildings, and as raw material input and fuel for industrial processes. *Not*e: This product, also referred to as *dry natural gas* or *consumer-grade natural gas*, is the product that re mains after *wet natural gas* has been processed at lease facilities and/or natural gas pro cessing plants. This processing removes nonhydrocarbon gases (e.g., water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen) that would otherwise make the gas unmar ketable and natural gas liquids.

Natural Gas, Dry: The marketable portion of natural gas production, which is obtained by subtracting extraction losses, including natural gas liquids removed at natural gas process ing plants, from total production.

Natural Gas, Wet: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in porous rock formations at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentanes. Typical nonhydrocarbon gases that may be present in reservoir natural gas are water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen. Under reservoir conditions, natural gas and the liquefiable portions occur either in a single gaseous phase in the reservoir or in solution with oil and are not distinguishable at the time as separate substances.

Nitrogen Oxides (NOx): Compounds of nitrogen and oxygen produced by the burning of fossil fuels.

North American Electric Reliability Council (NERC): A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. The NERC consists of ten regional reliability councils and encompasses essentially all the power systems of the contiguous United States and Canada.

Nuclear Electric Power: Electricity generated by an electric power plant whose turbines are driven by steam generated in a reactor by heat from the fissioning of nuclear fuel.

Organization for Economic Cooperation and Development (OECD): Current mem bers are Australia, Austria, Belgium, Canada, Czech Republic, Denmark and its territories (Faroe Islands and Greenland), Finland, France, Germany, Greece, Greenland, Hungary, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, South Korea, Spain, Sweden, Switzerland, Turkey, United Kingdom, and United States and its territories (Guam, Puerto Rico, and Virgin Islands).

Organization of Petroleum Exporting Countries (OPEC): Countries that have orga nized for the purpose of negotiating with oil companies on matters of oil production, prices, and future concession rights. Current members are Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates, and Venezuela.

Photovoltaic Energy: Direct-current electricity generated from sunlight through solid state semiconductor devices that have no moving parts.

Pipeline, Natural Gas: A continuous pipe conduit, complete with such equipment as valves, compressor stations, communications systems, and meters, for transporting natural gas and/or supplemental gaseous fuels from one point to another, usually from a point in or beyond the producing field or processing plant to another pipeline or to points of use. Also refers to a company operating such facilities.

Pipeline, Oil: Oil and product pipelines (including interstate, intrastate, and intracompany pipelines) used to transport oil and petroleum products, respectively, within the 50 states and the District of Columbia.

Proved Reserves, Oil: The estimated quantities of all liquids defined as crude oil that geo logical and engineering data demonstrate with reasonable certainty to be recoverable in fu ture years from known reservoirs under existing economic and operating conditions.

Proved Reserves, Natural Gas: The estimated quantities of natural gas that analysis of geological and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Refinery (Oil): An installation that manufactures finished fuels from oil, unfinished oils, natural gas liquids, other hydrocarbons, and alcohol.

Renewable Energy: Energy obtained from sources that are essentially inexhaustible (un like, for example, fossil fuels, of which there is a finite supply). Renewable sources of en ergy include conventional hydroelectric power, wood, waste, geothermal, wind, photovol taic, and solar thermal energy.

Spot Price: The price for a one-time open market transaction for immediate delivery of the specific quantity of product at a specific location where the commodity is purchased “on the spot” at current market rates.

Strategic Petroleum Reserve (SPR): Petroleum stocks maintained by the federal gov ernment for use during periods of major supply interruption.

Stocks: Supplies of fuel or other energy source(s) stored for future use. Stocks are re ported as of the end of the reporting period.

Sulfur Dioxide (SO_2): A toxic, colorless gas soluble in water, alcohol, and ether. Used as a chemical intermediate in paper pulping and ore refining, and as a solvent.

Transportation Sector: Private and public vehicles that move people and commodities. Included are automobiles, trucks, buses, motorcycles, railroads, and railways (including streetcars), aircraft, ships, barges, and natural gas pipelines.

Wellhead Price: The price of oil or natural gas at the mouth of the well.

Wind Energy: The kinetic energy of wind converted into mechanical energy by wind tur bines (i.e., blades rotating from a hub) that drive generators to produce electricity.

Wood Energy: Wood and wood products used as fuel, including round wood (cord wood), limb wood, wood chips, bark, sawdust, forest residues, charcoal, pulp waste, and spent pulping liquor.


SEAL OF THE PRESIDENT OF THE UNITED STATES

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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 2-100:
Seattle Times Article

The Seattle Times

The Seattle Times

Climate Lab

Centralia coal plant to burn natural gas instead

Dec. 11, 2025 at 10:00 am | *Updated Dec. 11, 2025 at 10:01 am*



Mount Rainer appears behind the TransAlta Centralia Coal Plant during sunset on April 27, 2023. (Daniel Kim / The Seattle Times file)

By Amanda Zhou

Seattle Times climate reporter

CLIMATE LAB

Climate Lab is a Seattle Times initiative that explores the effects of climate change in the Pacific Northwest and beyond. The project is funded in part by The Bullitt Foundation, CO_2 Foundation, Jim and Birte Falconer, Mike and Becky Hughes, Henry M. Jackson Foundation, Martin-Fabert Foundation, Craig McKibben and Sarah Merner, University of Washington and Walker Family Foundation, and its fiscal sponsor is the Seattle Foundation.

Washington state's last coal plant, which was scheduled to close at the end of this year in Centralia, will be converted to burn natural gas.

Power generation company TransAlta announced Wednesday the facility, which will have a capacity of 700 megawatts, will be converted in partnership with the state's largest utility, Puget Sound Energy.

The deal will give PSE exclusive rights to the plant's energy generation. The plant is scheduled to come online in late 2028 and operate through 2044, according to TransAlta. The price of the conversion is estimated at $600 million and the agreement between TransAlta and PSE is subject to review by the Washington Utilities and Transportation Commission, according to the company.

According to PSE spokesperson Christina Donegan, the plant will meet about half of the utility's 2030 summer peak demand needs and about 30% of the utilities expected 2030 winter peak demand needs.

The coal plant was originally scheduled to close by the end of this year in accordance with a 2011 agreement between the state and TransAlta, which is based in Calgary, Alberta. The company has owned and operated the 11,000-acre property since 2000.

The coal plant's second unit has around 670 megawatts of capacity, according to TransAlta, though PSE has relied on the plant for around 370 megawatts.

According to TransAlta, the conversion to natural gas, which is mostly methane, will lower the "emission intensity profile" of the facility. The coal-fired power plant has been the state's largest source of greenhouse gas emissions.

The announcement comes as increasing electricity demand and coal retirements across the Northwest have driven up the risk of rolling blackouts during extreme weather events like cold snaps and heat waves due to insufficient power generation.

All Washington state utilities are also required to stop using coal-fired electricity after this year, which is required by the Clean Energy Transformation Act. The landmark climate law also calls for utilities to become greenhouse gas "neutral" by 2030 and have emission-free electricity by 2045 or risk steep fines.

While Puget Sound Energy has been ramping up renewables, adding resources like the Beaver Creek wind farm in Montana, only around 50% of the utilities electricity came from renewables in 2024 and is below target to meet the state's clean energy goals.

***Amanda Zhou**: 206-464-2508 or azhou@seattletimes.com. Amanda Zhou is a climate and environment reporter at The Seattle Times, where she writes about energy, environmental justice, the intersection of urban planning and climate change — and sometimes, birds.*

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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. 202-26-18

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 2-101:
TransAlta Annual Information Form for Year Ended Dec. 31, 2024

transalta™



Energizing the Future.

Annual Information Form

for the Year Ended December 31, 2024

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Presentation of Information

The information contained in this Annual Information Form (AIF) is given as of or for the year ended Dec. 31, 2024, unless otherwise noted. All dollar amounts are in Canadian dollars, unless otherwise noted. All references to the "Company" and to "TransAlta", "we", "our" and "us" refer to TransAlta Corporation and its subsidiaries on a consolidated basis. Reference to "TransAlta Corporation" refer to TransAlta Corporation only. Certain capitalized terms defined throughout the body of this AIF and abbreviations and acronyms that may not otherwise be defined are defined in Appendix "B" – Glossary of Terms.

Certain portions of TransAlta's management's discussion and analysis dated Feb. 19, 2025 (MD&A) are incorporated by reference into this AIF as stated below and noted elsewhere in this AIF. The MD&A can be found on SEDAR+ at **www.sedarplus.ca** and EDGAR at **www.sec.gov**.

Forward-Looking Statements

This AIF, including the information incorporated by reference herein, includes "forward-looking information," within the meaning of applicable Canadian securities laws, and "forward-looking statements," within the meaning of applicable U.S. securities laws, including the *Private Securities Litigation Reform Act of 1995* (collectively referred to herein as forward-looking statements).

Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "can", "could", "would", "shall", "believe", "expect", "estimate", "anticipate", "intend", "plan", "forecast", "foresee", "potential", "enable", "continue" or other comparable terminology. These statements are not guarantees of our future performance, events or results and are subject to risks, uncertainties and other important factors that could cause our actual performance, events or results to be materially different from those set out in or implied by the forward-looking statements.

In particular, this AIF (including the information incorporated by reference herein) contains forward-looking statements about the following, among other things:

- The strategic objectives of the Company and that the execution of the Company's strategy will realize value for shareholders;
- Our capital allocation and financing strategy;
- Our sustainability goals and targets, including those in our 2024 Sustainability Report;
- Our 2025 Outlook;
- Our financial and operational performance, including our hedge position;
- Optimizing and diversifying our existing assets;
- The increasingly contracted nature of our fleet;
- Expectations about strategies for growth and expansion, including opportunities for Centralia redevelopment, and data centre opportunities;
- Expected costs and schedules for planned projects;
- Expected regulatory processes and outcomes, including in relation to the Alberta restructured energy market;
- The power generation industry and the supply and demand of electricity;
- The cyclicality of our business;
- Expected outcomes with respect to legal proceedings;
- The expected impact of future tax and accounting changes; and
- Expected industry, market and economic conditions.

The forward-looking statements contained in this AIF (or incorporated herein by reference) are based on many assumptions including, but not limited to, the following:

- No significant changes to applicable laws and regulations;
- No unexpected delays in obtaining required regulatory approvals;
- No material adverse impacts to investment and credit markets;
- No significant changes to power price and hedging assumptions;
- No significant changes to gas commodity price assumptions and transport costs;
- No significant changes to interest rates;
- No significant changes to the demand and growth of renewables generation;
- No significant changes to the integrity and reliability of our facilities;
- No significant changes to the Company's debt and credit ratings;
- No unforeseen changes to economic and market conditions; and
- No significant event occurring outside the ordinary course of business.

These assumptions are based on information currently available to TransAlta, including information obtained from third-party sources. Actual results may differ materially from those predicted.

Factors that may adversely impact what is expressed or implied by forward-looking statements contained in this AIF (or incorporated herein by reference) include, but are not limited to:

- Fluctuations in power prices;
- Changes in supply and demand for electricity;
- Our ability to contract our electricity generation for prices that will provide expected returns;
- Our ability to replace contracts as they expire;
- Risks associated with development projects and acquisitions;
- Any difficulty raising needed capital in the future on reasonable terms or at all;
- Our ability to achieve our targets relating to environmental, social and governance (ESG) performance;
- Long-term commitments on gas transportation capacity that may not be fully utilized over time;
- Changes to the legislative, regulatory and political environments;
- Environmental requirements and changes in, or liabilities under, these requirements;
- Operational risks involving our facilities, including unplanned outages and equipment failure;
- Disruptions in the transmission and distribution of electricity;
- Reductions in production;
- Impairments and/or writedowns of assets;
- Adverse impacts on our information technology systems and our internal control systems, including increased cybersecurity threats;
- Commodity risk management and energy trading risks;
- Reduced labour availability and ability to continue to staff our operations and facilities;
- Disruptions to our supply chains;
- Climate-change related risks;
- Reductions to our generating units' relative efficiency or capacity factors;
- General economic risks, including deterioration of equity and debt markets, increasing interest rates or rising inflation;
- General domestic and international economic and political developments, including potential trade tariffs;
- Industry risk and competition;
- Counterparty credit risk;

- Inadequacy or unavailability of insurance coverage;
- Increases in the Company's income taxes and any risk of reassessments;
- Legal, regulatory and contractual disputes and proceedings involving the Company;
- Reliance on key personnel; and
- Labour relations matters.

The foregoing risk factors, among others, are described in further detail under the heading "Governance and Risk Management" in the MD&A, which section is incorporated by reference herein.

Readers are urged to consider these factors carefully when evaluating the forward-looking statements and are cautioned not to place undue reliance on them. The forward-looking statements included in this AIF are made only as of the date hereof and we do not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise, except as required by applicable laws. The purpose of the financial outlooks contained herein (including as may be incorporated by reference) is to give the reader information about management's current expectations and plans and readers are cautioned that such information may not be appropriate for other purposes.

Non-IFRS Financial Measures

We use a number of financial measures to evaluate our performance and the performance of our business segments, including measures and ratios that do not have any standardized meaning under International Financial Reporting Standards (IFRS), and therefore are unlikely to be comparable to similar measures presented by other companies and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS. In addition, TransAlta cautions the reader that information provided in this AIF regarding the Company's outlook on certain matters, is provided to give context to the nature of some of the Company's future plans and may not be appropriate for other purposes. Refer to the "Additional IFRS Measures and Non-IFRS Financial Measures" and "Key Non-IFRS Financial Ratios" sections of the MD&A, for more information, which sections are incorporated by reference.

Corporate Structure

Name and Incorporation

TransAlta is a corporation organized under the *Canada Business Corporations Act* (CBCA). The Company was formed by a Certificate of Amalgamation issued on Oct. 8, 1992. On Dec. 31, 1992, a Certificate of Amendment was issued in connection with a plan of arrangement under the CBCA involving the Company and TransAlta Utilities Corporation (TransAlta Utilities or TAU). The plan of arrangement, which was approved by shareholders on Nov. 26, 1992, resulted in shareholders of TAU exchanging their common shares for common shares of TransAlta Corporation on a one-for-one basis. Upon completion of the arrangement, TAU became a wholly owned subsidiary of TransAlta Corporation.

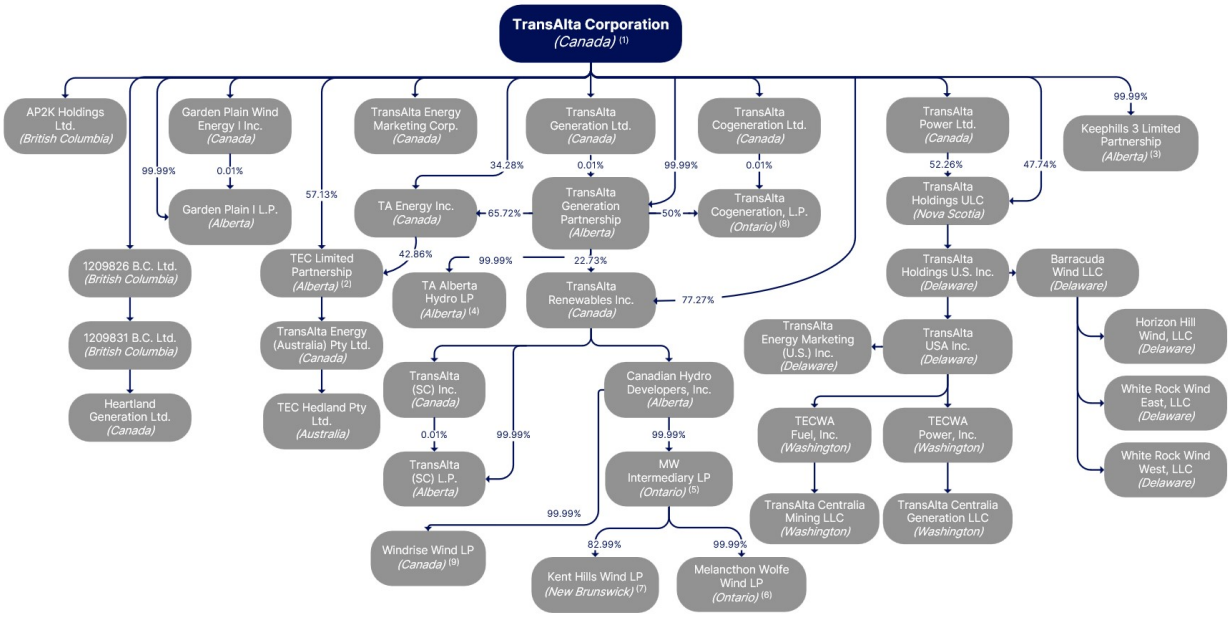
Effective Jan. 1, 2009, we completed a reorganization, whereby the assets and business affairs of TAU and TransAlta Energy Corporation (TransAlta Energy) (with the exception of the wind business) were transferred to TransAlta Generation Partnership, a then new Alberta general partnership, whose partners are the Company and TransAlta Generation Ltd., a wholly owned subsidiary of TransAlta. TransAlta Generation Partnership is managed by TransAlta Corporation pursuant to the terms of a partnership agreement and a management services agreement. Immediately following the transfer of assets by TAU and TransAlta Energy to TransAlta Generation Partnership, TransAlta Corporation amalgamated with TAU, TransAlta Energy and Keephills 3 GP Ltd. pursuant to the provisions of the CBCA. Effective June 1, 2023, TransAlta Corporation amalgamated with its wholly owned subsidiary TransAlta Investment Ltd. On Oct. 5, 2023, TransAlta Corporation acquired all of the outstanding common shares of TransAlta Renewables Inc. (TransAlta Renewables) not already owned, directly or indirectly, by the Company.

We amended our articles at several instances in connection with issuances of preferred shares including on Oct. 1, 2020, when we created the Series I Shares, a new series of redeemable, retractable first preferred shares that were issued to an affiliate of Brookfield Renewable Partners (Brookfield). See the "Capital Structure – Exchangeable Securities" section of this AIF.

Our registered and head office is located at TransAlta Place, Suite 1400, 1100 1 St SE, Calgary, Alberta, Canada, T2G 1B1.

Intercorporate Relationships

As of Dec. 31, 2024, our principal subsidiaries and their respective jurisdictions of formation are set out in the organization chart below. The Company's remaining subsidiaries each account for (i) less than 10 per cent of the Company's consolidated assets as at Dec. 31, 2024 and (ii) less than 10 per cent of the Company's consolidated revenues for the year ended Dec. 31, 2024. The diagram below does not include all of the subsidiaries of TransAlta. The total assets and revenues of excluded subsidiaries in the aggregate did not exceed 20 per cent of the Company's total consolidated assets or total consolidated revenues as at and for the year ended Dec. 31, 2024.



(1) Unless otherwise stated, ownership is 100 per cent.

(2) The remaining 0.01 per cent of TEC Limited Partnership is owned by TransAlta (Ft. McMurray) Ltd, a wholly owned subsidiary of the Company.

(3) The remaining 0.01 per cent of Keephills 3 Limited Partnership is owned by Vision Quest WindElectric Ltd., a wholly owned subsidiary of the Company.

(4) The remaining 0.01 per cent of TA Alberta Hydro LP is owned by TA Alberta Hydro Inc., a wholly owned subsidiary of the Company.

(5) The remaining 0.01 per cent of MW Intermediary LP is owned by MW Intermediary Inc., a wholly owned subsidiary of Canadian Hydro Developers, Inc.

(6) The remaining 0.01 per cent of Melancthon Wolfe Wind LP is owned by Melancthon Wolfe Wind Inc., a wholly owned subsidiary of MW Intermediary LP.

(7) Of the 17.01 per cent of Kent Hills Wind LP, 17.00 per cent is owned by Natural Forces Technologies Inc. and 0.01 percent is owned by Kent Hills Wind Inc.

(8) The remaining 49.99 per cent of TransAlta Cogeneration LP is owned by CPH Cogen Inc.

(9) The remaining 0.01 per cent of Windrise Wind LP is owned by Windrise Wind Energy Inc., a wholly owned subsidiary of Canadian Hydro Developers, Inc.

General Development of the Business

Summarized below are significant developments that have occurred in our business segments during the last three financial years. These events include growth, innovation, acquisitions, recontracting, retirement of assets, dispositions, corporate changes, and other events or conditions that have influenced the general development of the Company's business.

Three-Year History

2024

Acquisition of Heartland Generation from Energy Capital Partners

On Dec. 4, 2024, the Company closed the acquisition of Heartland Generation Ltd. and certain affiliates (collectively, Heartland) for a purchase price of $542 million from an affiliate of Energy Capital Partners (ECP), the parent of Heartland (the Transaction). To meet the requirements of the federal Competition Bureau, the Company entered into a consent agreement with the Commissioner of Competition pursuant to which TransAlta agreed to divest Heartland's Poplar Hill and Rainbow Lake assets (the Planned Divestitures) following closing of the Transaction. In consideration of the Planned Divestitures, TransAlta and ECP agreed to a reduction of $80 million from the original purchase price for the Transaction. ECP will be entitled to receive the proceeds from the sale of Poplar Hill and Rainbow Lake, net of certain adjustments following completion of the Planned Divestitures. TransAlta also received a further $95 million at closing of the Transaction to reflect the economic benefit of the Heartland business arising from Oct. 31, 2023 to the closing date of the Transaction, pursuant to the terms of the share purchase agreement. The net cash payment for the Transaction, before working capital adjustments, totalled $215 million, and was funded through a combination of cash on hand and draws on TransAlta's credit facilities.

Excluding the Planned Divestitures, the Transaction adds 1,747 MW (net interest) of complementary capacity from nine facilities, including contracted cogeneration and peaking generation, legacy gas-fired thermal generation, and transmission capacity, all of which will be critical to support reliability in the Alberta electricity market.

Mothballing of Sundance Unit 6

On Nov. 4, 2024, the Company provided notice to the Alberta Electric System Operator (AESO) that Sundance Unit 6 will be mothballed on April 1, 2025, for a period of up to two years depending on market conditions. TransAlta maintains the flexibility to return the mothballed unit to service when market fundamentals or opportunities to contract are secured. The unit remains available and fully operational for the first quarter of 2025.

Horizon Hill Wind Facility

On May 21, 2024, the 202 MW Horizon Hill wind facility achieved commercial operation. The facility is located in Logan County, Oklahoma and is fully contracted to Meta Platforms Inc. for the offtake of 100 per cent of the generation.

White Rock Wind Facility

On Jan. 1, 2024, the 100 MW White Rock West wind facility achieved commercial operation. On April 22, 2024, the 202 MW White Rock East wind facility also completed commissioning. The facilities are located in Caddo County, Oklahoma and are contracted under two long-term power purchase agreements (PPAs) with Amazon Energy LLC for the offtake of 100 per cent of the generation.

Production Tax Credit (PTC) Sale Agreements

On Feb. 22, 2024, the Company entered into 10-year transfer agreements with an AA- rated customer for the sale of approximately 80 per cent of the expected PTCs to be generated from the White Rock and the Horizon Hill wind facilities.

On June 21, 2024, the Company entered into an additional 10-year transfer agreement with an A+ rated customer for the sale of the remaining 20 per cent of the expected PTCs.

Mount Keith West Network Upgrade Project.

Construction of the Mount Keith West Network upgrade project commenced in the fourth quarter of 2024 under the PPA with BHP Nickel West. The works comprise upgrades to the Mount Keith 132kV network via an extension of existing Gas Insulated Switchgear, new 132kV transformers and new 11kV switchrooms that will replace legacy 11kV switchgear located at TransAlta's diesel power station.

Mount Keith 132kV Transmission Expansion

The Mount Keith 132kV expansion project was completed during the first quarter of 2024. The expansion was developed under the existing PPA with BHP Nickel West (BHP), which extends until Dec. 31, 2038. The expansion will facilitate the connection of additional generating capacity to the transmission network which supports BHP's operations.

Normal Course Issuer Bid

During the year ended Dec. 31, 2024, the Company purchased and cancelled a total of 13,467,400 common shares, pursuant to its Normal Course Issuer Bid program at an average price of $10.59 per common share, for a total cost of $143 million, including taxes.

2023

Northern Goldfields Solar Achieves Commercial Operation

On Nov. 22, 2023, the 48 MW Northern Goldfields solar and battery storage facilities achieved commercial operation. The facilities consist of the 27 MW Mount Keith solar facility, the 11 MW Leinster solar facility, the 10 MW Leinster battery energy storage system and interconnecting transmission infrastructure, all of which are now integrated into TransAlta's existing 145 MW Southern Cross Energy North remote network in Western Australia. The facilities are fully contracted to BHP under a PPA expiring in 2038.

Kent Hills Wind Facilities

Our Kent Hills wind facilities were partially returned to service in the fourth quarter of 2023, with all turbines commissioned and the remediation project completed in the first quarter of 2024. On June 2, 2022, we announced the rehabilitation plan for the Kent Hills 1 and 2 wind facilities. In addition to the announcement, TransAlta amended and extended PPAs with New Brunswick Power Corporation (NB Power) in respect of each of the Kent Hills 1, 2 and 3 wind facilities, providing for an additional 10-year contract term to December 2045 and an effective 10 per cent reduction to the original contract prices from January 2023 through December 2033. In addition, both parties have agreed to work in good faith to evaluate the installation of a battery energy storage system at Kent Hills and to consider a potential repowering of Kent Hills at the end of life in 2045.

Garden Plain Wind Facility Reaches Commercial Operations

In August 2023, the Garden Plain wind facility was commissioned adding 130 MW to our gross installed capacity. The facility is fully contracted with Pembina Pipeline Corporation (Pembina) and PepsiCo Canada (PepsiCo), with a weighted average contract life of approximately 17 years. The facility consists of 26 Siemens-Gamesa turbines.

Acquisition of TransAlta Renewables Inc.

On Oct. 5, 2023, the Company completed the acquisition of TransAlta Renewables for $1.3 billion, consisting of $800 million of cash and approximately 46 million common shares of the Company. TransAlta's acquisition of TransAlta Renewables' common shares resulted in TransAlta Renewables becoming a wholly owned subsidiary of the Company. Prior thereto, TransAlta and its affiliates collectively owned 60.1 per cent of TransAlta Renewables.

Pingston Successfully Recontracted

During 2023, the Company successfully recontracted the Pingston facility for a period of 20 years. Pingston is a 45 MW run-of-river hydroelectric facility located on Pingston Creek, British Columbia.

2022

Public Offering of US Senior Green Bonds and Release of Inaugural Green Bond Framework

On Nov. 17, 2022, the Company issued US$400 million Senior Notes, which have a coupon rate of 7.750 per cent per annum and mature on Nov. 15, 2029.

The Company allocated an amount equal to the net proceeds from this offering to finance or refinance new and/or existing eligible green projects in accordance with its Green Bond Framework (the Framework). The Framework received a second-party opinion from Sustainalytics, which verified that it aligned with the Green Bond Principles from the International Capital Market Association.

Executed Industrial Contract Extensions at Sarnia Cogeneration

During the second and fourth quarters of 2022, the Company executed contracts for the supply of electricity and steam from the Sarnia cogeneration facility with three of its legacy industrial customers, and three new customers, who had previously been resold utilities as part of a legacy customer's contract. Following the contracting efforts in 2021 and 2022, the Sarnia cogeneration facility has been fully recontracted without interruption to the customers' delivery terms. The contracts extend to April 30, 2031, for four customers, and to Dec. 31, 2032 for the other three customers.

Executed Contract Renewals with the IESO at Sarnia Cogeneration and Melancthon 1 Wind Facilities

On Aug. 23, 2022, TransAlta was awarded capacity contracts for the Sarnia cogeneration facility and the Melancthon 1 wind facility from the Ontario Independent Electricity System Operator (IESO) as part of the IESO's Medium-Term Capacity Procurement Request for Proposals. The capacity contracts run from May 1, 2026, to April 30, 2031.

Business of TransAlta

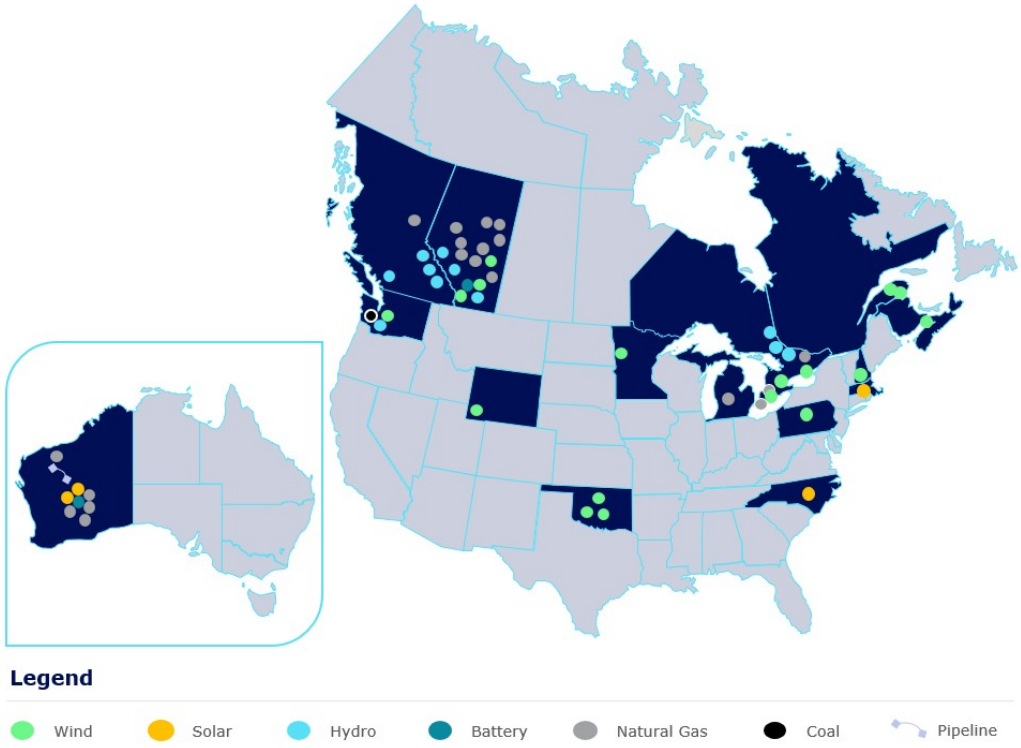
Our Hydro, Wind and Solar, Gas and Energy Transition segments are responsible for operating and maintaining our electrical generation facilities in Canada, the United States and Western Australia. Our Energy Marketing segment is responsible for marketing and scheduling our merchant asset fleet in North America (excluding Alberta) along with the procurement of natural gas, transport and storage for our gas fleet, providing knowledge to support our growth team, and generating a stand-alone gross margin separate from our asset business through a leading North American energy marketing platform and trading.

In Alberta, the Company manages merchant exposure by executing hedging strategies that include a significant base of commercial and industrial customers, supplemented with financial hedges. A significant portion of our thermal generation capacity in Alberta is hedged to provide greater cash flow certainty while also capturing higher returns for our shareholders through the optimization of our merchant generation portfolio.

These segments are all supported by a Corporate segment.

TransAlta's Map of Operations

The following map outlines the Company's operations as of Dec. 31, 2024:



The following sections of this AIF provide detailed information on facilities by geographic location and fuel type.

Hydro Segment

The Hydro segment holds a net capacity interest of 922 MW of generating capacity. The facilities are located in Alberta, British Columbia, and Ontario.

As well as contracting for power, we enter into long and short-term contracts to sell the environmental attributes from our merchant hydro facilities. These activities help to ensure earnings stability from these assets. Generally, for facilities under long-term contracts, the benefit of the environmental attributes generated is provided to the contract holder.

The following table summarizes our hydroelectric facilities as at Dec. 31, 2024:

Facility Name	Province	Nameplate Capacity (MW)[1]	Consolidated Interest	Gross Installed Capacity (MW)[1]	Ownership	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date[2]	Revenue Source[3]	Contract Expiry Date[4]
Alberta - Bow River System									
Barrier[5][6]	AB	13	100 %	13	100 %	13	1947	Merchant	-
Bearspaw[5][6]	AB	17	100 %	17	100 %	17	1954	Merchant	-
Cascade[5][6]	AB	36	100 %	36	100 %	36	1942, 1957	Merchant	-
Ghost[5][6]	AB	54	100 %	54	100 %	54	1929, 1954	Merchant	-
Horseshoe[5][6]	AB	14	100 %	14	100 %	14	1911	Merchant	-
Interlakes[5][6]	AB	5	100 %	5	100 %	5	1955	Merchant	-
Kananaskis[5][6]	AB	19	100 %	19	100 %	19	1913, 1951	Merchant	-
Pocaterra[6]	AB	15	100 %	15	100 %	15	1955	Merchant	-
Rundle[5][6]	AB	50	100 %	50	100 %	50	1951, 1960	Merchant	-
Spray[5][6]	AB	112	100 %	112	100 %	112	1951, 1960	Merchant	-
Three Sisters[5]	AB	3	100 %	3	100 %	3	1951	Merchant	-
Alberta - Oldman River System									
Belly River[6]	AB	3	100 %	3	100 %	3	1991	Merchant	-
St. Mary[6]	AB	2	100 %	2	100 %	2	1992	Merchant	-
Taylor[6]	AB	13	100 %	13	100 %	13	2000	Merchant	-
Waterton[6]	AB	3	100 %	3	100 %	3	1992	Merchant	-
Alberta - North Saskatchewan River System[6]									
Bighorn[5][6]	AB	120	100 %	120	100 %	120	1972	Merchant	-
Brazeau[5][6]	AB	355	100 %	355	100 %	355	1965, 1967	Merchant	-
BC Hydro									
Akolkolex[6]	BC	10	100 %	10	100 %	10	1995	LTC	2046
Bone Creek[6]	BC	19	100 %	19	100 %	19	2011	LTC	2031
Pingston[6]	BC	45	50 %	22.5	100 %	23	2003, 2004	LTC	2043
Upper Mamquam[6]	BC	25	100 %	25	100 %	25	2005	LTC	2045
Ontario Hydro									
Misema	ON	3	100 %	3	100 %	3	2003	LTC	2027
Moose Rapids[6]	ON	1	100 %	1	100 %	1	1997	LTC	2030
Ragged Chute	ON	7	100 %	7	100 %	7	1991	LTC	2029
Total Hydroelectric Capacity		**944**		**922**		**922**			

(1) MW are rounded to the nearest whole number. The gross installed capacity reflects the basis of consolidation of underlying assets owned, whereas net capacity ownership interest deducts capacity attributable to the non-controlling interest in these assets and is calculated after the consolidation of underlying assets.

(2) A second date in this column refers to a second unit that was subsequently operational.

(3) The large majority of the Company's contracted operating facilities benefit from inflation adjustment provisions that apply to all or a portion of our revenues under such contracts.

(4) Where no contract expiry date is indicated, the facility operates as merchant.

(5) These facilities form part of the hydro assets that are subject to an Investment Agreement. See the "Capital Structure – Investment Agreement" section of this AIF for further details.

(6) These facilities are EcoLogo® certified. EcoLogo certification is granted to products with an environmental performance that meets or exceeds all government, industrial safety and performance standards.

Bow River System

Barrier

Barrier is a hydroelectric facility with installed capacity of 13 MW located on the Kananaskis River near Seebe, Alberta. Commercial operations began in 1947. Generation from the facility is currently sold in the Alberta electricity market and creates Emission Performance Credits (EPCs) under the Alberta Technology Innovation and Emissions Reduction (TIER) system.

Bearspaw

Bearspaw is a hydroelectric facility with installed capacity of 17 MW located on the Bow River in Calgary, Alberta. Commercial operations began in 1954. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Cascade

Cascade is a hydroelectric facility with installed capacity of 36 MW located on the Cascade River in Banff National Park, Alberta. This facility was purchased from the Government of Canada in 1941. The following year, we built a new dam and power plant to replace the original, and then, in 1957, added a second generating unit. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Ghost

Ghost is a hydroelectric facility with installed capacity of 54 MW located on the Bow River near Cochrane, Alberta. Commercial operations began in 1929. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Horseshoe

Horseshoe is a run-of-river hydroelectric facility with installed capacity of 14 MW located on the Bow River near Seebe, Alberta. Commercial operations began in 1911. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Interlakes

Interlakes is a hydroelectric facility with installed capacity of 5 MW located at Kananaskis Lakes, Alberta. Commercial operations began in 1955. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Kananaskis

Kananaskis is a run-of-river hydroelectric facility with installed capacity of 19 MW located on the Bow River in Seebe, Alberta. Commercial operations began in 1913. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Pocaterra

Pocaterra is a hydroelectric facility with installed capacity of 15 MW located at Kananaskis Lakes, Alberta. Commercial operations began in 1955. Generation from the facility is sold in the Alberta electricity market and creates EPCs under the TIER system.

Rundle

Rundle is a hydroelectric facility with installed capacity of 50 MW located in Canmore, Alberta, on the Spray system. Commercial operations began in 1951. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Spray

Spray is a hydroelectric facility with installed capacity of 112 MW located in Canmore, Alberta, on the Spray system. Commercial operations began in 1951. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Three Sisters

Three Sisters is a hydroelectric facility with installed capacity of 3 MW located at the base of the Three Sisters Dam near Canmore, Alberta, on the Spray system. Commercial operations began in 1951. Generation from the facility is currently sold in the Alberta electricity market.

Oldman River System

Belly River

Belly River is a run-of-river hydroelectric facility with installed capacity of 3 MW located on the Waterton-St. Mary Headworks Irrigation Canal System, east of the Waterton Reservoir, approximately 75 kilometres southwest of Lethbridge in southern Alberta. Due to its location along the irrigation canal, Belly River operates from April to October when water is diverted through the canal as part of the St. Mary Irrigation District Water Management Plan. Commercial operations began in March 1991. Generation from the facility is currently sold in the Alberta electricity market.

St. Mary

St. Mary is a run-of-river hydroelectric facility with installed capacity of 2 MW located at the base of the dam impounding the St. Mary Reservoir, near Magrath, in southern Alberta. Commercial operations began in 1992. Generation from the facility is currently sold in the Alberta electricity market.

Taylor

Taylor is a run-of-river hydroelectric facility with installed capacity of 13 MW and is located adjacent to the Taylor Coulee Chute on the Waterton-St. Mary Headworks Irrigation Canal System, which is owned by the Government of Alberta. Commercial operations began in 2000. Generation from the facility is currently sold in the Alberta electricity market.

Waterton

Waterton is a run-of-river hydroelectric facility with installed capacity of 3 MW located at the base of the Waterton Dam on the Waterton Reservoir, near Hill Spring, southwest of Lethbridge, Alberta. Commercial operations began in 1992. Generation from the facility is currently sold in the Alberta electricity market.

North Saskatchewan River System

Bighorn

Bighorn is a hydroelectric facility with installed capacity of 120 MW located near Nordegg, Alberta. Commercial operations began in 1972. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Brazeau

Brazeau is a hydroelectric facility with installed capacity of 355 MW located near Drayton Valley, Alberta. Commercial operations began in 1967. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

BC Hydro Facilities

Akolkolex

Akolkolex is a run-of-river hydroelectric facility with installed capacity of 10 MW and is located on the Akolkolex River, south of Revelstoke, British Columbia. Commercial operations began in 1995. The output from the facility is sold to British Columbia Hydro and Power Authority (BC Hydro) under a PPA that terminates in 2046.

Bone Creek

Bone Creek is a run-of-river hydroelectric facility with installed capacity of 19 MW and is located on Bone Creek, 90 kilometres south of Valemount, British Columbia. Commercial operations began in 2011. The output from the facility is sold to BC Hydro under a PPA that terminates in 2031.

Pingston

Pingston is a run-of-river hydroelectric facility with installed capacity of 45 MW and is located on Pingston Creek, southwest of Revelstoke, British Columbia, and downriver of the Akolkolex facility. Pingston is equally owned with Evolugen Trading and Marketing LP, a subsidiary of Brookfield. Commercial operations began in 2003. The output from the facility is sold to BC Hydro under a recontracted 20-year PPA that expires on May 8, 2043.

Upper Mamquam

Upper Mamquam is a run-of-river hydroelectric facility with installed capacity of 25 MW located on the Mamquam River, east of Squamish, British Columbia, and north of Vancouver. Commercial operations began in 2005. The output from the facility is sold to BC Hydro under a PPA that terminates in 2045.

Ontario Hydro Facilities

Misema

Misema is a run-of-river hydroelectric facility with installed capacity of 3 MW located on the Misema River, close to Englehart, in northern Ontario. Commercial operations began in 2003. Generation from this facility is sold to the IESO under a contract that terminates on May 3, 2027.

Moose Rapids

Moose Rapids is a run-of-river hydroelectric facility with installed capacity of 1 MW located on the Wanapitei River, near Sudbury, in northern Ontario. Commercial operations began in 1997. Generation from this facility is sold to the IESO under a contract that terminates on Dec. 31, 2030.

Ragged Chute

Ragged Chute is a run-of-river hydroelectric facility with installed capacity of 7 MW located on the Montréal River, south of Temiskaming Shores, in northern Ontario. The Company leases this facility from Ontario Power Generation Inc. (OPG). The facility has been operating since 1991. Generation from this facility is sold to the IESO under a contract that terminates on June 30, 2029. Upon termination, the asset will transfer to OPG together with a payment of $6.6 million to the Company.

Wind and Solar Segment

As at Dec. 31, 2024, the Wind and Solar segment held interests in approximately 2,559 MW of net wind and solar generating capacity. This capacity consists of 12 wind facilities in Western Canada, four in Ontario, two in Québec, three in New Brunswick and eight in the United States, more specifically in Washington, Wyoming, Minnesota, Oklahoma, Pennsylvania and New Hampshire. The Company also holds a 10 MW utility-scale battery energy storage system in Alberta, 143 MW of solar facilities in Massachusetts and North Carolina, and a 38 MW solar facility and a 10 MW battery energy storage system in Western Australia.

In addition to contracting for the sale of the power generation, we also enter into long- and short-term contracts to sell the environmental and tax attributes from the merchant wind and solar facilities. These activities help to ensure earnings consistency from these assets. Generally, for facilities under a long-term PPA, the purchaser also benefits from any environmental attributes associated with the facility.

The following table summarizes our Wind and Solar generation facilities as at Dec. 31, 2024:

Facility Name	Province / State	Nameplate Capacity (MW)[1]	Consolidated Interest	Gross Installed Capacity (MW)[1]	Ownership	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date[2]	Revenue Source[3]	Contract Expiry Date[4]
Alberta Wind									
Ardenville[5]	AB	69	100 %	69	100 %	69	2010	Merchant	-
Blue Trail and Macleod Flats[5]	AB	69	100 %	69	100 %	69	2009 and 2004	Merchant	-
Castle River[5][6]	AB	44	100 %	44	100 %	44	1997-2001	Merchant	-
Cowley North[5]	AB	20	100 %	20	100 %	20	2001	Merchant	-
Garden Plain	AB	130	100 %	130	100 %	130	2023	LTC	2035-2041
McBride Lake[5]	AB	75	50 %	38	100 %	38	2004	Merchant	
Oldman[5]	AB	4	100 %	4	100 %	4	2007	Merchant	-
Sinnott[5]	AB	5	100 %	5	100 %	5	2001	Merchant	-
Soderglen[5]	AB	71	50 %	36	100 %	36	2006	Merchant	-
Summerview 1[5]	AB	68	100 %	68	100 %	68	2004	Merchant	-
Summerview 2[5]	AB	66	100 %	66	100 %	66	2010	Merchant	-
Windrise	AB	206	100 %	206	100 %	206	2021	LTC	2041
Alberta Battery Energy Storage									
WindCharger	AB	10	100 %	10	100 %	10	2020	Merchant	-
Eastern Canada Wind									
Kent Breeze	ON	20	100 %	20	100 %	20	2011	LTC	2031
Kent Hills 1	NB	96	100 %	96	83 %	80	2008	LTC	2045
Kent Hills 2	NB	54	100 %	54	83 %	45	2010	LTC	2045
Kent Hills 3	NB	17	100 %	17	83 %	14	2018	LTC	2045
Le Nordais[5][7]	QC	98	100 %	98	100 %	98	1999	LTC	2033
Melancthon 1	ON	68	100 %	68	100 %	68	2006	LTC	2031
Melancthon 2	ON	132	100 %	132	100 %	132	2008	LTC	2028
New Richmond[5]	QC	68	100 %	68	100 %	68	2013	LTC	2033
Wolfe Island	ON	198	100 %	198	100 %	198	2009	LTC	2029
US Wind									
Antrim	NH	29	100 %	29	100 %	29	2019	LTC	2039
Big Level	PA	90	100 %	90	100 %	90	2019	LTC	2034
Horizon Hill	OK	202	100 %	202	100 %	202	2024	LTC	-
Lakeswind	MN	50	100 %	50	100 %	50	2014	LTC	2034
Skookumchuck Wind	WA	137	49 %	67	100 %	67	2020	LTC	2040
White Rock East	OK	202	100 %	202	100 %	202	2024	LTC	-
White Rock West	OK	100	100 %	100	100 %	100	2024	LTC	-
Wyoming Wind	WY	140	100 %	140	100 %	140	2003	LTC	2028
US Solar									
Mass Solar[7]	MA	21	100 %	21	100 %	21	2012-2015	LTC	2032-2045
North Carolina Solar[7]	NC	122	100 %	122	100 %	122	2019-2021	LTC	2033
Australian Solar									
Northern Goldfields[7]	WA	38	100 %	38	100 %	38	2023	LTC	2038
Australia Battery Energy Storage									
Northern Goldfields Battery	WA	10	100 %	10	100 %	10	2023	LTC	2038
Total Wind and Solar Capacity		**2,729**		**2,587**		**2,559**			

(1) MW are rounded to the nearest whole number. The gross installed capacity reflects the basis of consolidation of the underlying assets owned, whereas net capacity ownership interest deducts capacity attributable to non-controlling interest in these assets and is calculated after consolidation of the underlying assets.

(2) A second date in this column refers to a second facility that was subsequently operational.

(3) The large majority of the Company's contracted operating facilities benefit from inflation adjustment provisions that apply to all or a portion of our revenues under such contracts.

(4) Where no contract expiry date is indicated, the facility operates as merchant or certain contract terms are confidential and have note been disclosed.

(5) These facilities are EcoLogo® certified. EcoLogo certification is granted to products with an environmental performance that meets or exceeds all government, industrial safety and performance standards.

(6) Includes six additional turbines at other locations.

(7) Includes multiple facilities.

Alberta Wind Facilities

Ardenville

Ardenville is a 69 MW wind facility located approximately 14 kilometres south of Fort Macleod. The facility began commercial operations in November 2010. It satisfies the eligibility criteria for an opted-in facility under Section 4 of the TIER regulation and is voluntarily choosing to participate in the regulation for the purposes of being able to generate emission performance credits (opt-in facility). An opt-in facility is not considered a large emitter of greenhouse gases (GHG) and as such we elected to participate in TIER. Generation from the facility is currently sold in the Alberta electricity market.

Blue Trail and Macleod Flats

Blue Trail is a 66 MW wind facility located in southern Alberta. The facility began commercial operations in November 2009. The Blue Trail wind facility created carbon offset credits under TIER until Sept. 16, 2022, at which time the facility became an opt-in facility under TIER.

Macleod Flats is a 3 MW wind facility located near Fort Macleod. It was commissioned in 2004 and was acquired by TransAlta in 2009. This facility generates Renewable Energy Certificate (REC) credits. Generation from the facilities is currently sold in the Alberta electricity market.

Castle River

Castle River is a 39.5 MW wind facility located southwest of Pincher Creek. This facility also includes an additional six turbines, totalling 4 MW that are located individually in the Cardston County and Hill Spring areas of southwestern Alberta. The facility began commercial operations in stages from November 1997 through to July 2001. This facility generates EPCs under the TIER system. Generation from the facility is currently sold in the Alberta electricity market.

Cowley North

Cowley North is a 19.5 MW wind facility located near the towns of Cowley and Pincher Creek, in southern Alberta. The facility began commercial operations in the fall of 2001. The Cowley North facility creates EPCs under the TIER system. Generation from the facility is currently sold in the Alberta electricity market.

Garden Plain

Garden Plain is a 130 MW wind facility located approximately 30 kilometres north of Hanna. This facility began commercial operations in August 2023. The facility is fully contracted with 100 MW being sold under a PPA with Pembina that terminates in 2041 and the remaining 30 MW of generation being contracted to PepsiCo under a PPA and terminates in 2035.

McBride Lake

McBride Lake is a 75.2 MW wind facility located south of Fort Macleod. The McBride Lake facility is co-owned with ENMAX Generation Portfolio Inc. The facility began commercial operations on April 30, 2004. A 20-year PPA with ENMAX Energy Corporation terminated on April 30, 2024 and generation from the facility is currently sold in the Alberta electricity market.

Oldman

Oldman is a 3.6 MW wind facility located east of the Oldman River Dam, near Pincher Creek in southern Alberta. The facility has been in operation since March 2007. In 2021, TransAlta acquired 100 per cent of the facility from a subsidiary of Boralex. This facility sells energy into the Alberta electricity market.

Sinnott

Sinnott is a 5 MW wind facility located directly east of the Cowley North wind facility and north of Pincher Creek. The facility began commercial operations in the fall of 2001. The facility sells energy into the Alberta electricity market and generates EPCs under the TIER system.

Soderglen

Soderglen is a 71 MW wind facility located southwest of Fort Macleod. The facility is co-owned with CNOOC Petroleum North America ULC. The facility began commercial operations in September 2006. The Soderglen wind facility creates EPCs under the TIER system, of which TransAlta receives 25 per cent. The Company is entitled to 50 per cent of the generation that is sold into the Alberta electricity market.

Summerview 1

Summerview 1 is a 68 MW wind facility located approximately 15 kilometres northeast of Pincher Creek. The facility began commercial operations in September 2004. The facility sells energy into the Alberta electricity market and generates EPCs under the TIER system.

Summerview 2

Summerview 2 is a 66 MW wind facility located approximately 15 kilometres northeast of Pincher Creek. The facility began commercial operations in February 2010. The facility sells energy into the Alberta electricity market and generated carbon offset credits under TIER until November 2022, after which it became an opt-in facility under TIER.

Windrise

Windrise is a 206 MW wind facility located in the county of Willow Creek. The facility began commercial operations in November 2021. Generation from the facility is sold to the AESO under a 20-year PPA that expires in 2041.

Alberta Battery Energy Storage

WindCharger

WindCharger is Alberta's first utility-scale battery storage facility. The facility consists of a lithium-ion battery using Tesla Megapack technology that has a nameplate capacity of 10 MW and a total storage capacity of 20 MWh. WindCharger is located in southern Alberta in the Municipal District of Pincher Creek, next to the Summerview wind facility substation. The storage project achieved commercial operations on Oct. 15, 2020. WindCharger stores energy produced by the nearby Summerview 2 wind facility and discharges this energy for ancillary services. The facility is an opt-in facility under TIER.

Eastern Canada Wind Facilities

Kent Breeze

Kent Breeze is a 20 MW wind facility located in Thamesville, Ontario. The facility began commercial operations in 2011. Generation from this facility is sold to the IESO under a 20-year PPA that expires in 2031.

Kent Hills 1

Kent Hills 1 is a 96 MW wind facility located near Moncton, New Brunswick. The facility began commercial operations in December 2008. The Company owns 83 per cent of the facility and Natural Forces Technologies Inc., a wind developer based in Atlantic Canada that co-developed the project with TransAlta, owns 17 per cent. Generation from this facility is sold under a PPA with NB Power that expires in 2045.

Kent Hills 2

Kent Hills 2 is a 54 MW wind facility located near Moncton, New Brunswick. The facility began commercial operations in November 2010. The Company owns 83 per cent of the facility and Natural Forces Technologies Inc., a wind developer based in Atlantic Canada that co-developed the project with TransAlta, owns 17 per cent. On June 2, 2022, the Company announced the extension of the previous 2035 PPA term for an additional 10-year period through to December 2045.

Kent Hills 3

Kent Hills 3 is a 17.25 MW wind facility located near Moncton, New Brunswick. The facility began commercial operations in November 2018. The Company owns 83 per cent of the facility and Natural Forces Technologies Inc., a wind developer based in Atlantic Canada that co-developed the project with TransAlta, owns 17 per cent. On June 2, 2022, we announced the extension of the previous 2035 PPA term for an additional 10-year period through to December 2045.

Le Nordais

Le Nordais is a 97.5 MW wind facility located on the Gaspé Peninsula of Québec. The facility has two sites, Cap-Chat with 74 turbines and Matane with 56 turbines. The facility began commercial operations in 1999. Generation from this facility is sold to Hydro-Québec pursuant to an energy supply agreement that terminates in 2033, and the facility generates RECs.

Melancthon 1

Melancthon 1 is a 67.5 MW wind facility located in Melancthon Township near Shelburne, Ontario. The facility began commercial operations in March 2006. Generation from this facility is sold to the IESO pursuant to a PPA that expires in 2026; a new Medium-Term 1 (MT1) capacity contract with the IESO will begin on May 1, 2026, and terminate on April 30, 2031. The Company submitted a binding offer in January 2025 to participate in the 5-year Medium-Term 2 Energy Contract (MT2(e)), which will be awarded by April 1, 2025. If successful, this energy contract will replace the MT1 and be effective May 1, 2026 to April 30, 2031.

Melancthon 2

Melancthon 2 is a 132 MW wind facility located adjacent to Melancthon 1, in the Melancthon and Amaranth townships, Ontario. The facility began commercial operations in November 2008. Generation from this facility is sold to the IESO pursuant to a PPA that terminates in 2028. The Company submitted a binding offer in January 2025 to participate in the 5-year MT2(e), which will be awarded by April 1, 2025. If successful, the current PPA will extend to April 30, 2029 and the MT2(e) will be effective May 1, 2029 to April 30, 2034.

New Richmond

New Richmond is a 68 MW wind facility located in New Richmond, Québec. The facility began commercial operations in March 2013. Generation from this facility is sold under a 20-year electricity supply agreement with Hydro-Québec Distribution that terminates in 2033.

Wolfe Island

Wolfe Island is a 197.8 MW wind facility located on Wolfe Island, near Kingston, Ontario. The facility began commercial operations in June 2009. Generation from this facility is sold to the IESO pursuant to a PPA that terminates in 2029. The Company submitted a binding offer in January 2025 to participate in the 5-year MT2(e), which will be awarded by April 1, 2025. If successful, the current PPA will terminate early and the MT2(e) will be effective May 1, 2029 to April 30, 2034.

US Wind and Solar Facilities

Antrim

Antrim is a 28.8 MW wind facility located in Antrim, New Hampshire. The wind facility was commissioned in December 2019. The wind facility is fully operational and contracted under two long-term PPAs until 2039 with Partners Healthcare and New Hampshire Electric. Ninety-nine per cent of production tax credits are allocated to tax equity partners and the remainder is allocated to TransAlta.

Big Level

Big Level is a 90 MW wind facility located in Potter County, Pennsylvania. The wind facility was commissioned in December 2019. Generation from the facility is sold under a PPA with Microsoft that terminates in 2034. Ninety-nine per cent of production tax credits are allocated to tax equity partners and the remainder is allocated to TransAlta.

Horizon Hill

Horizon Hill is a 202 MW wind facility located in Logan County, Oklahoma. 100 per cent of the generation offtake from the project is sold to Meta, under a long-term PPA. Under the PPA, Meta receives both renewable electricity and environmental attributes. The Horizon Hill facilities achieved commercial operation on May 21, 2024. The company has entered into two 10-year transfer agreements with A+ and AA- rated customers for the sale of 100 per cent of the expected production tax credits to be generated from the Horizon Hill, White Rock East, and White Rock West facilities. See the "General Development of the Business – Three-Year History" section of this AIF for further details.

Lakeswind

Lakeswind is a 50 MW wind facility located near Rollag, Minnesota, and is fully operational and contracted under a long-term PPA until 2034 with several high-quality counterparties. Ninety-nine per cent of production tax credits are allocated to tax equity partners and the remainder is allocated to TransAlta.

Mass Solar

Mass Solar is a 21 MW solar portfolio consisting of multiple sites located in Massachusetts, and is contracted under long-term PPAs expiring between 2032 and 2045 with several high-quality counterparties.

North Carolina Solar

North Carolina Solar is a 122 MW solar portfolio consisting of 20 sites located in North Carolina. The facilities were commissioned between November 2019 and May 2021. The facilities are secured by long-term PPAs with two subsidiaries of Duke Energy and are automatically extended unless terminated by either party.

Skookumchuck

Skookumchuck is a 137 MW wind facility that located in Lewis and Thurston counties, Washington. The facility began commercial operations in November 2020 and is secured by a long-term PPA with Puget Sound Energy Inc. that expires in 2040. Ninety-nine per cent of production tax credits are allocated to tax equity partners and the remainder are allocated to the Company and our partner Southern Power Company.

White Rock East and White Rock West

White Rock East and White Rock West are 201.5 MW and 99.5 MW wind facilities located in Caddo County, Oklahoma. On Dec. 22, 2021, TransAlta executed two long-term Power PPAs with Amazon for the offtake of 100 per cent of the generation from both facilities. White Rock West achieved commercial operation on Jan. 1, 2024 and White Rock East achieved commercial operation on April 22, 2024. The company has entered into two 10-year transfer agreements with A+ and AA- rated customers for the sale of 100 per cent of the expected production tax credits to be generated from the Horizon Hill, White Rock East, and White Rock West facilities. See the "General Development of the Business – Three-Year History" section of this AIF for further details.

Wyoming

Wyoming is a 140 MW wind facility located near Evanston, Wyoming. The facility began commercial operations in December 2003, and is contracted under a long-term PPA until 2028 with an investment-grade counterparty.

Australia Battery and Solar Facilities

Northern Goldfields Solar

Northern Goldfields Solar facilities consist of the 27 MW Mount Keith solar facility, 11 MW Leinster solar facility, 10 MW/5 MWh Leinster battery energy storage system facility and interconnecting transmission infrastructure, all of which are integrated into the existing Southern Cross Energy North remote electrical network in Western Australia. The combined solar and energy storage facilities began commercial operations in November 2023 and is contracted with BHP to 2038. See the "General Development of the Business" section of this AIF for further details.

Gas Segment

The Gas segment holds a net capacity ownership interest of 4,525 MW. The facilities are located in Alberta, Ontario, Michigan and Western Australia.

The following table summarizes our natural-gas-fired generation facilities as at Dec. 31, 2024:

Facility Name	Province/ State	Nameplate Capacity (MW)[1]	Consolidated Interest	Gross Installed Capacity (MW)[1]	Ownership	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date	Revenue Source[2]	Contract Expiry Date[3]
British Columbia									
McMahon	BC	120	50 %	60	100 %	60	1993	LTC	2029
Alberta									
Battle River 4	AB	155	100 %	155	100 %	155	1975	Merchant	-
Battle River 5	AB	395	100 %	395	100 %	395	1981	Merchant	-
Fort Saskatchewan	AB	118	60 %	71	50 %	35	1999	LTC/Merchant	2029
Joffre	AB	474	40 %	190	100 %	190	2000	LTC/Merchant	2041
Keephills Unit No. 2	AB	395	100 %	395	100 %	395	1984	Merchant	-
Keephills Unit No. 3	AB	466	100 %	466	100 %	466	2011	Merchant	-
Muskeg River	AB	202	100 %	202	100 %	202	2003	LTC	2042
Poplar Creek[4]	AB	230	100 %	230	100 %	230	2001	LTC	2030
Primrose	AB	100	50 %	50	100 %	50	1998	LTC	2028
Scotford	AB	195	100 %	195	100 %	195	2003	LTC/Merchant	2043
Sheerness Unit No.1	AB	400	100 %	400	75 %	300	1986	Merchant	-
Sheerness Unit No.2	AB	400	100 %	400	75 %	300	1990	Merchant	-
Sundance Unit No. 6	AB	401	100 %	401	100 %	401	1980	Merchant	-
Valleyview 1	AB	50	100 %	50	100 %	50	2001	Merchant	-
Valleyview 2	AB	50	100 %	50	100 %	50	2008	Merchant	-
Total Alberta Gas Capacity		**4,031**		**3,650**		**3,414**			
Ontario and United States									
Ada	MI	29	100 %	29	100 %	29	1991	LTC	2026
Ottawa	ON	74	100 %	74	50 %	37	1992	LTC/Merchant	2033
Sarnia	ON	499	100 %	499	100 %	499	2003	LTC	2031
Windsor	ON	72	100 %	72	50 %	36	1996	LTC/Merchant	2031
Total Ontario and United States Gas Capacity		**674**		**674**		**601**			
Australia									
Fortescue River Gas Pipeline	WA	N/A	100 %	N/A	43 %	N/A	2015	LTC	2035
Parkeston	WA	110	50 %	55	100 %	55	1996	LTC/Merchant	2027
South Hedland	WA	150	100 %	150	100 %	150	2017	LTC	2042
Southern Cross [5]	WA	245	100 %	245	100 %	245	1996	LTC	2038
Total Australian Gas Capacity		**505**		**450**		**450**			
Total Gas Capacity		**5,330**		**4,834**		**4,525**			

(1) MW are rounded to the nearest whole number. The gross installed capacity reflects the basis of consolidation of the underlying assets owned, whereas net capacity ownership interest deducts capacity attributable to non-controlling interest in these assets and is calculated after the consolidation of the underlying assets.

(2) The large majority of the Company's contracted operating facilities benefit from inflation-adjustment provisions that apply to all or a portion of our revenues under such contracts.

(3) Where no contract expiry date is indicated, the facility operates as merchant.

(4) The Poplar Creek facility is operated by Suncor Energy Inc. (Suncor)

(5) Includes four facilities. Excludes the Northern Goldfields facilities, which are in the Wind and Solar segment.

British Columbia Gas Facilities

McMahon

The McMahon natural-gas-fired cogeneration facility is located in Taylor. The 120 MW McMahon facility has been in operation since 1993, and is fully contracted with Brookfield and NorthRiver Midstream for steam and BC Hydro for electricity through to 2029.

Alberta Gas Facilities

Battle River 4 and 5

The Battle River 4 and 5 facilities are located near Forestburg. Battle River 4 and 5 are 155 MW and 395 MW, respectively, having completed their conversion to natural gas in 2021 and 2019, respectively. The end of regulatory life for Battle River 4 and 5 is set for 2033 and 2037, respectively. Generation from the facilities is currently sold in the Alberta electricity market.

Fort Saskatchewan

We have a net ownership interest of 30 per cent in the Fort Saskatchewan facility. See the "Business of TransAlta – Non-Controlling Interests" section of this AIF for further details. The 118 MW natural-gas-fired combined-cycle cogeneration facility is owned by TA Cogen and Prairie Boys Capital Corporation. The contract at the facility has an initial 10-year term, which began on Jan. 1, 2020, with the option for two five-year extensions. Generation from the facility is currently sold in the Alberta electricity market.

Joffre

The Joffre natural-gas-fired cogeneration facility is located in Red Deer. TransAlta owns a 40 per cent interest in the facility, with Capital Power and Nova Chemicals owning 40 per cent and 20 per cent, respectively. The 474 MW Joffre facility has been in operation since 2000 and is 26 per cent (122 MW) contracted to Nova Chemicals through to 2041. The remaining uncontracted electricity capacity is sold in the Alberta energy market.

Keephills 2

The Keephills 2 facility is located approximately 70 kilometres west of Edmonton. Keephills 2 is a 395 MW gas-fired unit that completed its conversion to natural gas in 2021. The end of regulatory life for this unit is set for 2037. Generation from the facility is currently sold in the Alberta electricity market.

Keephills 3

The Keephills 3 facility is located approximately 70 kilometres west of Edmonton. Keephills 3 is a 466 MW gas-fired unit that completed its conversion to natural gas in 2021. The end of regulatory life for this unit is set for 2039. Generation from the facility is currently sold in the Alberta electricity market.

Muskeg River

The Muskeg River natural-gas-fired cogeneration facility is located in Fort McMurray. The 202 MW Muskeg River facility has been in operation since 2003 and is fully contracted to the Athabasca Oil Sands Project, which consists of Canadian Natural Resources Limited (CNRL), Chevron and Shell, through to 2042.

Poplar Creek

The Poplar Creek natural-gas-fired cogeneration facility is located in Fort McMurray. The Poplar Creek cogeneration facility had been built and contracted to provide steam and electricity to Suncor's oil sands operations. In 2015, Suncor acquired the Company's two steam turbines with an installed capacity of 126 MW and certain transmission interconnection assets. In addition, Suncor assumed full operational control of the cogeneration facility and has the right to use the full 230 MW capacity of the Company's gas generators until Dec. 31, 2030. The ownership of the Poplar Creek facility will transfer to Suncor on Dec. 31, 2030.

Primrose

The Primrose natural-gas-fired cogeneration facility is located near Bonnyville. TransAlta owns a 50 per cent interest with CNRL owning the remaining 50 per cent of the facility. The 100 MW Primrose facility has been in operation since 1998 and is fully contracted to CNRL through to 2028, at which time, will be transferred to CNRL at the expiry of the PPA with no remaining liabilities for TransAlta.

Scotford

The Scotford natural-gas-fired cogeneration facility is located in northeast of Fort Saskatchewan. The 195 MW Scotford facility has been in operation since 2003, and is fully contracted to CNRL, Chevron and Shell through to 2043.

Sheerness 1 and 2

The Sheerness 1 and 2 facilities are located approximately 200 kilometres northeast of Calgary. The 400 MW Sheerness 1 and 400 MW Sheerness 2 facilities are gas-fired units that completed their conversion to natural gas in 2021 and 2020, respectively. The end of regulatory life for these units is set for 2037. Generation from the facilities is currently sold in the Alberta electricity market.

Sundance 6

The Sundance 6 facility is located approximately 70 kilometres west of Edmonton. Sundance 6 is a 401 MW gas-fired unit that completed its conversion to natural gas in 2021. The end of regulatory life for this unit is set for 2037. Generation from the facility is currently sold in the Alberta electricity market. In November of 2024, the Company announced that the unit will be mothballed at the end of the first quarter of 2025.

Valleyview 1 and 2

The Valleyview 1 and 2 natural-gas-fired simple-cycle gas turbine generator facilities are located in Valleyview. The 50 MW Valleyview 1 and 50 MW Valleyview 2 facilities have been in operation since 2001 and 2008, respectively. Generation from the facilities is currently sold in the Alberta electricity market.

Off-Coal Agreement

On Nov. 24, 2016, we entered into the Off-Coal Agreement with the Government of Alberta pertaining to our cessation of emissions from the Keephills 3 and Sheerness coal-fired facilities. Under the Off-Coal Agreement, we are entitled to receive annual cash payments of approximately $41 million, net to TransAlta, from the Government of Alberta that commenced in 2017, and will terminate in 2030, subject to satisfaction of certain terms and conditions that include our cessation of all coal-fired emissions on or before Dec. 31, 2030. Other conditions include maintaining prescribed spending on investment and investment-related activities in Alberta, maintaining a significant business presence in Alberta (including through the maintenance of prescribed employment levels), maintaining spending on programs and initiatives to support the communities surrounding the facilities and the employees of the Company negatively impacted by the phase-out of coal generation, and the fulfilment of all obligations to affected employees, in each case as prescribed by the Off-Coal Agreement.

Eastern Canada and US Gas Facilities

Ada

Ada is a 29 MW contracted cogeneration facility located in Ada, Michigan. The facility has been in operation since 1991 and produces approximately 18,000 tonnes of steam hourly. The electricity and steam output of the facility are fully contracted until 2026 with Consumers Energy and Amway.

Ottawa

The Ottawa facility is owned by TA Cogen. See the "Business of TransAlta – Non-Controlling Interests" section of this AIF for further details. It is a 74 MW combined-cycle cogeneration facility located in Ottawa, Ontario. On Aug. 30, 2013, the Company announced the recontracting of the facility with the IESO for a 20-year term, effective January 2014. The Ottawa facility also provides thermal energy to the member hospitals and treatment centres of the Ottawa Health Sciences Centre and the National Defence Medical Centre. The thermal energy contract with the Ottawa Health Sciences Centre has a term to Dec. 31, 2033, with an automatic renewal of a five-year term unless terminated by either party.

Sarnia

The Sarnia cogeneration facility is a 499 MW combined-cycle cogeneration facility located in Sarnia, Ontario, that provides power and/or steam to nearby industrial facilities. The facility also provides electricity to the IESO under a contract that terminates on April 30, 2031, with the industrial customer contract terminations occurring from April 30, 2031, through Dec. 31, 2032.

Windsor

The Windsor facility is owned by TA Cogen. See the "Business of TransAlta – Non-Controlling Interests" section of this AIF for further details. It is a 72 MW combined-cycle cogeneration facility located in Windsor, Ontario. Effective Dec. 1, 2016, the Windsor facility began operating under an agreement with the IESO with a 15-year term for up to 72 MW of capacity. The Windsor facility also provides thermal energy to Stellantis Canada (formerly, FCA Canada, Inc. and Chrysler Canada) in Windsor under a contract that expires in 2028, with a series of six successive renewal terms of one year each.

Australian Gas Facilities

Fortescue River Gas Pipeline

In 2014, we established the Fortescue River Gas Pipeline joint venture with AGI Fortescue River Pty Limited. The joint venture (of which TransAlta is a 43 per cent partner) was successfully awarded the contract to design, build, own and operate the 270-kilometre Fortescue River Gas Pipeline, located in the Pilbara region of Western Australia, to deliver natural gas to Fortescue Metal Group's (FMG) Solomon facility. The pipeline was completed in the first quarter of 2015 and operates under a take-or-pay natural gas transport agreement with a subsidiary of FMG for an initial term of 20 years. The 16-inch diameter pipeline has an initial free-flow capacity of 64 terajoules per day. Under the gas tariff agreement, FMG has the option to purchase the Fortescue River Gas Pipeline commencing March 2020. FMG maintains its option and the joint venture continues to deliver natural gas to the Solomon facility.

Parkeston

The Parkeston facility is a 110 MW dual-fuel natural gas- and diesel-fired power station located near Kalgoorlie, Western Australia, which is owned in partnership through a 50/50 joint venture with Northern Star (NPK) Pty Ltd., a subsidiary of Northern Star Resources Limited. The Parkeston facility primarily supplies energy to Kalgoorlie Consolidated Gold Mines pursuant to a supply contract that extends to October 2027. Any merchant capacity and energy are sold in Western Australia's wholesale electricity market.

South Hedland

The South Hedland Power Station is a 150 MW combined-cycle power station located near South Hedland, Western Australia, which achieved commercial operation in 2017. The facility is contracted with two customers. Horizon Power, the state-owned electricity supplier in the region has contracted 110MW until 2042. The second customer is the port operations of FMG for 35 MW of capacity until 2037.

Southern Cross Energy

Southern Cross Energy Partnership (SCE) has power stations at Mount Keith, Leinster, Kalgoorlie and Kambalda. In total, a combined gas- and diesel-fired capacity of 245 MW is available from these facilities. In 2023, SCE added battery and renewable energy capacity to the SCE fleet with separate solar facilities at Leinster (11 MW) and Mount Keith (27 MW), as well as a battery energy storage system at Leinster (10 MW/5 MWh). SCE also completed the expansion of the Mount Keith 132kV transmission system to support BHP's Northern Goldfields-based operations in the first quarter of 2024.

The PPA with BHP for the facilities expires on Dec. 31, 2038. The PPA provides, among other things, SCE with the exclusive right to supply electricity, transmission, and distribution infrastructure for BHP's mining operations located within a specified area in the Goldfields region of Western Australia for the duration of the PPA.

The PPA supports BHP's future power requirements and emission reduction targets by providing BHP participation rights in integrating renewable electricity generation, including solar, wind and energy storage technologies, into BHP's mining operations located in the Goldfields region, subject to the satisfaction of certain conditions. New-build projects have already been completed under this contract, including the Northern Goldfields solar and battery project in Mount Keith and Leinster that reached commercial operation in November 2023. Additional projects are in the development and construction stages. See the "General Development of the Business" section of this AIF for further details.

On July 11, 2024, BHP announced a period of temporary suspension of operations for its Western Australian nickel operations in response to the low nickel price outlook. The PPA remains in place and SCE is working closely with BHP to manage the impact of reduced load. BHP intends to review the decision to temporarily suspend its Western Australian nickel operations by February 2027.

Energy Transition Segment

The Energy Transition segment holds a net ownership interest in 671 MW of generating capacity. The two facilities are located in the United States.

The following table summarizes our Energy Transition facilities as at Dec. 31, 2024:

Facility Name	Province/ State	Nameplate Capacity (MW)[1]	Consolidated Interest	Gross Installed Capacity (MW)[1]	Ownership	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date	Revenue Source	Contract Expiry Date
US									
Centralia	WA	670	100 %	670	100 %	670	1971	LTC/Merchant	2025
Skookumchuck[2]	WA	1	100 %	1	100 %	1	1970	LTC	2025
Total Energy Transition Capacity		**671**		**671**		**671**			

(1) MW are rounded to the nearest whole number. The gross installed capacity reflects the basis of consolidation of underlying assets owned, whereas net capacity ownership interest deducts capacity attributable to non-controlling interest in these assets and is calculated after consolidation of underlying assets.

(2) This facility is used to provide a reliable water supply to the Centralia facility.

Centralia

The Centralia coal-fired facility is located in Centralia, Washington, and consists of one 670 MW unit. On July 25, 2012, we announced that we entered into an 11-year PPA to provide electricity from the Centralia thermal facility to Puget Sound Energy. The contract terminates on Dec. 31, 2025 when the facility is scheduled to stop burning coal. Under the agreement, Puget Sound Energy purchases 380 MW of baseload power to December 2024 and 300 MW in 2025. The coal used to fuel the Centralia facility is sourced from the Powder River Basin in Montana and Wyoming. The Centralia facility has coal contracts in place that expire at the end of 2025.

We sell electricity from the Centralia thermal facility into the Western Electricity Coordinating Council and, in particular, to the U.S. Pacific Northwest electricity market. Our strategy is to balance contracted and non-contracted sales of electricity to manage production and price risk.

Since 2015, we have invested US$55 million to support energy efficiency, economic and community development, and education and retraining initiatives in Washington State. The initiatives are part of Centralia's transition from coal-fired operations in Washington, beginning on Dec. 31, 2020. Such community investment is part of the *TransAlta Energy Transition Bill (chapter 180, Laws of 2011)* (the Bill). The Bill was an agreement between policymakers, environmentalists, labour leaders and TransAlta to transition away from coal in Washington State.

Skookumchuck Hydro

We own a 1 MW hydroelectric generating facility that is located on the Skookumchuck River near Centralia, Washington, and related assets that are used to provide water supply to our generation facilities in Centralia. On Dec. 7, 2020, we entered into a PPA with Puget Sound Energy for the Skookumchuck hydro facility. The contract terminates in 2025 when the facility is scheduled to retire.

Reclamation Activities

Centralia Mine

We own a coal mine adjacent to the Centralia facility, although mining operations were discontinued at the Centralia coal mine on Nov. 27, 2006. The mine is currently in the reclamation phase and we continue to perform reclamation and associated work.

Under the U.S. *Federal Mine Safety and Health Act*, we must report all citations at our Centralia mine. There was one injury incident reported at the mine during 2024. The total dollar value of all Mine Safety and Health Administration (MSHA) assessments is not material.

Mine or Operating Name/MSHA Identification Number	Total Number of Section 104 Violations for which Citations Received	Total Number of Orders Issued Under Section 104(b)	Total Number of Citations and Orders for Unwarrantable Failure to Comply with Mandatory Health or Safety Standards Under Section 104(d)	Total Number of Flagrant Violations Under Section 110(b)(2)	Total Number of Imminent Danger Orders Issued Under Section 107(a)	Total Dollar Value of MSHA Assessments Proposed	Total Number of Mining Related Fatalities	Received Notice of Pattern Violations Under Section 104(e) (yes/no)	Received Notice of Potential to Have Pattern Under Section 104(e) (yes/no)	Number of Legal Actions Initiated or Pending During Period
4500416	10[1]	0	0	0	0	1,430 [2]	0	No	No	0

(1) Section 104 Violations: TransAlta Centralia Mining (9 violations) and Dickson Company (contractor) (1 violation).

(2) Citations in Contest: Coalview Centralia LLC ($1,287) and Dickson Company ($143).

Highvale Mine

We own the Highvale mine that supplied coal to the previously coal-fired Sundance and Keephills facilities. The Company discontinued all mining operations at the Highvale mine at the end of 2021 and the mine is currently in the reclamation phase as of Jan. 1, 2022.

Coal Retirements

In aggregate, TransAlta has retired 4,464 MW of coal-fired generation capacity since 2018 while converting 1,659 MW to cleaner-burning natural gas. The following seven units have been retired: Centralia Thermal No. 1, Keephills 1, and Sundance 1, 2, 3, 4 and 5. The retirements remain consistent with our strategy to transition to clean electricity. Pursuant to the Bill, Centralia Unit 2 will cease operation on coal effective Dec. 31, 2025.

Energy Marketing Segment

Our Energy Marketing segment provides a number of strategic functions, including the following:

- Gathering and analyzing market trends to enable more effective strategic planning and decision-making;
- Actively engaging in the trading of power, natural gas and environmental products across a variety of North American markets, excluding Alberta;
- Negotiating and managing fuel supply arrangements with third parties for our generation assets, including scheduling, billing and settlement of physical deliveries of natural gas and other fuels; and
- Negotiating and entering into contractual agreements with customers for the sale of output from our generation assets outside of Alberta, including electricity, steam or other energy-related commodities.

The Energy Marketing segment derives all of its revenue by trading electricity and other energy commodities (i.e., fuels and environmental products), by providing fee-based asset management services to third parties and earning margins on third-party gas and power transactions. The origination and trading activities are primarily focused on proprietary trading, with additional focus on the existing assets and customers of the Company.

The key risk control activities of the Energy Marketing segment include the measurement and management of market, credit, operational, reputational, compliance and legal risks. The segment uses value at risk, gross margin at risk and tail risk measures to monitor and manage the risks within our asset and trading portfolios. Value at risk and gross margin at risk measure the potential losses that could occur over a given time period due to changes in market risk factors. Back tests are used to provide further sensitivities to the market risks within the portfolio. Compliance, goodwill and legal risks are managed within our legal and compliance policies, and monitoring tools are used to flag compliance risks. The Energy Marketing segment actively manages the risks within approved limits of our governance policies.

Corporate Segment

Our Corporate segment includes the Company's finance, sustainability, legal, human resources, administrative, business development and investor relations functions.

Non-Controlling Interests

Our operations in which we have non-controlling interests are as follows:

TA Cogen

We hold a 50.01 per cent limited partnership interest in TA Cogen, which is an Ontario limited partnership. The remaining 49.99 per cent is held by CPH Cogen Inc., a subsidiary of CK Infrastructure Holdings Limited.

TA Cogen holds a 50 per cent interest in the 800 MW Sheerness dual-fuel generating facility in Alberta and a 60 per cent interest in the 118 MW Fort Saskatchewan natural-gas-fired cogeneration facility in Alberta. TA Cogen also holds an interest in two natural-gas-fired cogeneration facilities located in Ontario: the 74 MW Ottawa plant and the 72 MW Windsor plant. See the "Gas Segment" section of this AIF for further details.

Kent Hills Wind LP

We hold an 83 per cent partnership interest in Kent Hills Wind LP, which owns and operates the 167 MW Kent Hills (1, 2 and 3) wind facilities located in New Brunswick. The remaining 17 per cent is held by Natural Forces Technologies Inc., a wind developer based in Atlantic Canada that helped develop the Kent Hills wind projects with TransAlta.

Competitive Environment

Power generation is an industry in the midst of an exciting transformation and the demand for electricity has the potential to grow significantly over the long-term due to general trends toward electrification. We also anticipate the generation mix to undergo a major shift in our key markets. In addition to the need to keep pace with ongoing demand growth for electricity, there are several key factors driving the need for significant investment in new generating capacity, which include, without limitation:

- Coal-based generation is being retired. These retirements are being driven by asset age, as well as government policy that places an escalating price on GHG emissions and, in some cases, mandates the retirement of these assets;
- Government policies that impose costs or provide incentives for lower emission technologies are creating opportunities for renewable generation technologies. These opportunities are coinciding with a significant decline in the installed costs of wind and solar generation and battery storage. As a result, these technologies now account for the majority of the new generating capacity added to many of the world's electricity grids;
- In tandem, the need and value of reliability within electricity systems across TransAlta's portfolio is becoming an important focus for system operators and customers. Opportunities for legacy gas-fired generation are being identified as systems seek to balance renewable demands with the need for reliable generation; and
- Growing electricity demand, from electrification and data centre development, is driving load growth. Electrification is seen as one of the most effective levers to reduce GHG emissions in many sectors, such as transportation. In tandem, growing demand related to artificial intelligence and data centre development is resulting in expanded load forecasts.

Alberta

Approximately 58 per cent of our gross installed capacity is located in Alberta. As of Dec. 31, 2024, our portfolio of merchant assets in Alberta is a combination of hydro facilities, wind facilities, a battery storage facility, natural-gas-fired cogeneration and converted natural-gas-fired thermal facilities. This balance of fuel types provides us with portfolio generation diversification, along with capacity that can be monetized as ancillary services or dispatched into the energy market during times of supply tightness. To reduce the exposure from variable spot power prices on our merchant generation, we enter into financial hedges and/or physical retail supply contracts through our Commercial and Industrial Business. The combined liquidity provided by these channels enables us to actively secure revenue, and respond to changing market conditions and adjust the proportion of our hedges we have in relation to the expected generation from our asset portfolio.

Alberta's annual electricity demand increased from 2023 to 2024 by approximately three per cent. The average pool price in Alberta declined from $134/MWh in 2023 to $63/MWh in 2024. While demand growth was

positive, lower natural gas prices and supply additions - renewables, natural gas and cogeneration - meant the market was more supplied as compared to 2023.

We currently expect additional compliance costs as a result of the Canadian federal government's *Greenhouse Gas Pollution Pricing Act* (GGPPA), which sets a national price on GHG emissions with each province expected to implement a GHG policy equivalent to a carbon price of $170 per tonne by 2030. We believe our portfolio of assets provides us with brownfield development opportunities in wind, solar, hydro and natural gas that give us an advantage over competitors when constructing generation facilities that use these fuel types.

US Pacific Northwest

Our generating capacity in the U.S. Pacific Northwest includes the remaining Centralia coal unit and our 49 per cent interest in the Skookumchuck wind facility. The Centralia coal unit is scheduled to be legislatively retired on Dec. 31, 2025.

System capacity in the region is primarily composed of hydro and gas generation, with some wind additions over the last few years in response to government programs favouring renewable generation. Demand growth in the region has been limited and further constrained by an emphasis on energy efficiency. We expect to see significant change in this market over the next decade as coal generation is retired and renewable portfolio standard requirements continue to strengthen.

Our competitiveness is enhanced by our contract with Puget Sound Energy for up to 300 MW over the remaining life of the Centralia facility. The contract and our hedges allow us to satisfy power requirements from the market during low-priced periods. The Centralia site also holds potential value for future redevelopment opportunities given its access to existing infrastructure and transmission interconnection.

Australia

Our business is solely in Western Australia, and is focused on the large, remote mining industry in the state. The primary exports from Western Australia are iron ore, natural gas and gold. Commodity exports from Western Australia contribute significantly to the economy, driven by large-scale creditworthy producers. Remote mining operations are exploring options to add renewable generation with firming options via thermal generation and battery energy storage systems to their existing and new sites in an effort to reduce the amount of gas and diesel required in these operations. We expect this trend to continue and to create further opportunities for our business in Western Australia.

Contracted Gas and Renewables

We develop and acquire gas and renewable generation facilities in highly competitive markets. Our track record as an experienced operator and developer supports our competitive position. Where possible, we aim to reduce our cost of capital and improve our competitive profile through efficient financing structures. In the United States, our substantial tax attributes further increase our competitiveness.

In renewables, we are primarily evaluating greenfield opportunities in Western Canada and the United States along with acquisitions in markets where we have existing operations. We maintain highly qualified and experienced development teams to identify and develop these opportunities. In cogeneration, we are working with experienced development and construction teams to evaluate behind-the-fence solutions.

Some of our older gas facilities are now reaching the end of their original contract life. These facilities generally have a substantial cost advantage over new builds and we have been able to add value by recontracting these facilities without incurring the significant capital expenditures required for a new facility.

Seasonality and Cyclicality

Our business is cyclical due to: (a) the nature of electrical generation and the limited storage capacity; and (b) the nature of wind, solar and run-of-river hydroelectric resources, which fluctuate based on both seasonal patterns and annual weather variation.

Typically, run-of-river hydroelectric facilities and solar facilities generate most of their electricity and revenues during the spring and summer months when the melting snow starts feeding the watersheds and the rivers, and the sun is at its peak. Inversely, wind speeds are historically greater during the cold winter months when the air density is at its peak. Our strategy of technological and geographical diversification reduces our exposure to the variations of any one natural resource in any regions. Financial results in any one quarter may not, however, be representative of all quarters. See the "Risk Factors" section of this AIF for further details.

Regulatory Framework

Below is a description of the regulatory framework in the markets that are material to the Company.

Canadian Federal Government

In November 2016, the Canadian federal government announced that coal-fired generation would be phased out by 2030, following a similar commitment by the Alberta provincial government in November 2015. On Dec. 12, 2018, Environment and Climate Change Canada (ECCC) published two final regulations in the Canada Gazette, Part II to phase out coal-fired generation by 2030, as well as regulations for gas-fired electricity generation including provisions for the conversion of boiler units from coal-fired generation to natural-gas-fired generation. In addition, the *Clean Electricity Regulations* (CER), issued by the Canadian federal government on Dec. 17, 2024, impose further emission limits on electricity generation facilities in Canada. See the "Environmental Risk Management – Climate-Related Financial Disclosure" and "Environmental Risk Management – Canadian Federal Government" sections of this AIF for further details.

Alberta

Alberta operates under a competitive wholesale energy-only market structure where generators offer their power supply into a power pool and those offers clear against power demand. Market clearing prices are determined by the dynamics of supply and demand in the wholesale electricity market. Since the first quarter of 2024, the Government of Alberta and the AESO have advanced a Restructured Energy Market (REM) that will replace the existing market design and is expected to be implemented in 2027.

On July 3, 2024, Alberta's Minister of Affordability and Utilities issued a letter to the AESO identifying a proposed high-level design for the REM that includes: (i) a mandatory day-ahead market; (ii) a review of the wholesale electricity market price floor and price cap; (iii) a uniform system-wide market price; (iv) co-optimization of the energy and ancillary services markets; and (v) optimization of dispatch around transmission constraints. The REM contemplates additional changes that will impact the Alberta energy market including a move away from the congestion-free planning paradigm to an "optimally planned transmission standard" as well as a strategic reserve mechanism to contract with out-of-market generation for reliability purposes. The AESO commenced detailed design sessions in consultation with industry stakeholders in October 2024 and issued a High-Level Design Proposal for the REM for stakeholder comment in December 2024. Development of the detailed REM is scheduled to take place in the first quarter and early in the second quarter of 2025. The provincial government plans to propose legislative changes to enable the REM in spring 2025, which will be followed by AESO market rule development activities between December 2025 and December 2026 before REM is implemented in 2027.

The Government of Alberta also continues to make changes to the policy framework for the development of renewable energy facilities. This work follows the government's pause on the issuance of power plant approvals for new renewable energy facilities that occurred between Aug. 3, 2023 and Feb. 29, 2024, and the recommendations stemming from the Alberta Utilities Commission inquiry that occurred during that time. On Dec. 6, 2024, the government issued a new *Electric Energy Land Use and Visual Assessment Regulation* that establishes visual impact assessment requirements for renewable energy facilities proposed within buffer zones and visual impact assessment zones and agricultural impact assessment requirements for renewable energy facilities proposed on high-quality agricultural lands (Class 1 and 2 lands, and Class 3 lands in certain

areas). The Government of Alberta is also amending the *Activities Designation Regulation* and *Conservation and Reclamation Regulation* to require renewable energy operators to post security with the Government of Alberta that is sufficient to cover estimated decommissioning and reclamation costs, or provide evidence that such security has been provided to the application landowner(s) pursuant to a surface lease.

Ontario

Ontario's electricity market is a hybrid market that includes a wholesale electricity market, as well as regulated prices for certain electricity consumers and long-term contracts for the purchase of power by the IESO from power producers. The Ontario Ministry of Energy and Electrification supports the IESO in defining the electricity mix to be procured by the IESO. The IESO has the mandate to undertake long-term planning of the electric power system, procure the electricity generation in that plan and manage contracts for privately owned generation. The IESO is responsible for managing the Ontario wholesale market and ensuring the reliability of the electricity system in Ontario. The electricity sector is regulated by the Ontario Energy Board.

The IESO is currently in the stages of market manual development and settlement rule testing, finalization and approval, with the intent to implement the Market Renewal Program in the second quarter of 2025. The program includes the introduction of a day-ahead market, locational pricing, enhanced unit commitment and market power mitigation. The impact on existing facilities is mitigated due to existing contracts and related proposed amendments that account for the impacts of the Market Renewal Program (e.g., capacity contracts for gas facilities and wind power purchase arrangements for wind facilities). The IESO is coordinating its changes to its energy market with new resource adequacy procurements, including new contract types for medium- and long-term requests for proposals, re-contracting with existing facilities (small hydro re-contracting) and improving market operations and reliability. Our Ontario facilities are generally contracted, and therefore we expect market rule changes to have minimal near-term impact on the Company.

U.S. Wholesale Power Market

The *Federal Power Act* gives the Federal Energy Regulatory Commission (FERC) rate-making jurisdiction over public utilities engaged in wholesale sales of electricity and the transmission of electricity in interstate commerce. FERC oversees the market structure for all integrated market rules and wholesale sales from generators. The *Federal Power Act* also provides FERC with the authority to certify and oversee an electric reliability organization that promulgates and enforces mandatory reliability standards applicable to all users, owners and operators of the bulk power system. FERC has certified the North American Electric Reliability Corporation (NERC) as the electric reliability organization. NERC has promulgated mandatory reliability standards and, in conjunction with the regional reliability organizations that operate under FERC's and NERC's authority and oversight, enforces those mandatory reliability standards.

Regulatory changes are not expected to have a material impact in the near term on generation from our facilities in Minnesota, Massachusetts, New Hampshire, North Carolina, Oklahoma, Pennsylvania and Wyoming as generation from these facilities is fully contracted to creditworthy counterparties.

Washington

Centralia and Skookumchuck are operated in the state of Washington. The Washington Transportation and Utilities Commission (WTUC) has the power to regulate and supervise every "public utility," which includes investor-owned electric utilities. For regulated electric utilities, the WTUC approves regulated rates, reviews integrated resource plans, approves mergers and acquisitions, and grants certificates of public convenience and necessity for large facilities (i.e., power plants and transmission lines). The Centralia facility, the Skookumchuck hydro facility and the Skookumchuck wind facility are not regulated by the WTUC as they only sell wholesale electricity and do not sell retail electricity in the state. Only FERC and NERC requirements apply to these facilities. As a result, the Company does not expect any material impacts on revenue streams from any decisions of the WTUC.

Australia

Australia has two separate major electricity markets: the National Electricity Market (NEM) encompassing all the major population centres on the eastern seaboard and the Wholesale Electricity Market (WEM) covering the southwest of Western Australia including its capital city, Perth. A number of smaller, standalone electricity grids serve regional population centres including the North West Interconnected System (NWIS) in the Pilbara region of Western Australia and the Darwin-Katherine System in the Northern Territory.

The Australian Energy Market Operator is the market operator for both the WEM and the NEM. The two markets are completely independent of each other with different market rules and no physical interconnection between them. The WEM includes both a market for generation capacity and a gross pool to trade energy with a single reference node for wholesale prices. The NEM is a pure energy-only market with five regional reference nodes for wholesale prices corresponding to each of the participating states of Queensland, New South Wales, Victoria, Tasmania and South Australia.

In October 2023, significant reforms to the WEM were implemented, including security constrained dispatch in the energy market and the introduction of additional ancillary services to support the transition to renewable energy sources.

Reforms to the NWIS have been gradually implemented, including providing third-party access to the transmission networks, coordination of outage planning and ensuring generation adequacy.

Environmental Risk Management

We are subject to federal, provincial, state and local environmental laws, regulations and guidelines concerning the generation and transmission of energy. We are committed to complying with legal requirements and to minimizing the environmental impact of our operations. We work with governments, stakeholders and the public to develop appropriate frameworks to protect the environment, as well as to promote sustainable development.

Climate-Related Financial Disclosure

We have prepared an assessment of climate-related risks and opportunities to partially align with the IFRS S2 Climate-related Disclosures Standard and Task Force on Climate-related Financial Disclosures describing our climate change strategy, governance, risk management approach, metrics and targets. In 2024, we reviewed and updated our climate transition plan and prepared climate-related financial metrics. See the "Sustainability" section of the 2024 Integrated Report for further details.

Canada

Federal Carbon Pricing and Regulations on GHG Emissions

On June 21, 2018, the Canadian federal GGPPA came into force. Under the GGPPA, the Canadian federal government implemented a national price on GHG emissions. In April 2021, the Government of Canada announced a revised GHG emissions target of 40 to 45 per cent below 2005 levels by 2030. Amendments to the GGPPA were completed in October 2022 to align facility emission charges with the government's updated carbon price trajectory of $65 per tonne of carbon dioxide equivalent (CO_2e) in 2023 with increases of $15 per year to $170 per tonne by 2030.

In March 2022, the Government of Canada's Department of ECCC released a discussion document regarding the CER to achieve a net-zero electricity sector in Canada by 2035. The draft CER was published in Canada Gazette I in August 2023 and the finalized regulations were issued under the *Canadian Environmental Protection Act, 1999* on Dec. 17, 2024. The CER imposes an annual emissions limit (AEL) on electricity generation units that use fossil fuels based on each unit's generation capacity, its annual hours of operation and an applicable emissions intensity. The applicable emissions intensity is 65 tonnes of CO_2e/GWh between 2035 and 2049, during which time regulated units may emit up to 35 t/GWh above the AEL by remitting an equivalent amount of eligible offset credits. The applicable emissions intensity is reduced to 0 t/GWh as of 2050, but up to 42 t/GWh of emissions are permitted, subject to remitting an equivalent amount of eligible offset credits. Eligible offset credits include those issued or recognized under the GGPPA regime, including several TIER offset protocols. Subject to limited exceptions, the AEL will apply to most generating units as of Jan. 1, 2035. At this time, TransAlta does not expect the CER to have a material impact on its business.

In addition to carbon pricing and the CER, the Canadian federal government continues to further develop federal incentives for renewable generation and new and emerging technology and infrastructure. We continue

to actively engage with the Canadian federal government to understand the implications of these initiatives to our business in order to manage risks and identify opportunities.

Oil and Gas Sector Greenhouse Gas Emissions Cap

In December 2023, the Canadian federal government introduced a draft framework to cap emissions from the oil and gas sector. Consultation on the draft framework has been ongoing since that time. The draft Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations were introduced on Nov. 4, 2024. The proposed regulations would set a cap on GHG emissions within the sector, equivalent to 35 per cent below 2019 levels and create a cap and trade system to incentivize emission reductions and facilitate compliance across the sector. While the proposed cap-and-trade system is expected to allow for cross-recognition of offset credits from other emission reduction regimes, the interplay between the proposed cap-and-trade system and regulations like TIER remains unclear. The public comment period for the draft regulations closed on Jan. 8, 2025, and the government is expected to publish final regulations later in 2025. Given that the use of provincial offsets as a compliance mechanism has implications for TransAlta, we will continue to follow developments and engage where appropriate in the development of the final regulations.

Alberta

Large Emitter Greenhouse Gas Regulations

Facilities with emissions above the set benchmark must comply with TIER by: (a) paying into the TIER Fund (a provincial government-controlled fund that invests in emissions reductions in the province) at the current carbon price; (b) making emission reductions at their facility; (c) remitting EPCs from other facilities; or (d) remitting emission offset credits.

On Dec. 15, 2022, amendments to TIER and the *Administrative Penalty Regulation* were announced to ensure alignment with the Canadian federal government's requirements under the GGPPA, which included the following changes:

- The TIER Fund price for the 2023 to 2030 period was set via a Ministerial Order. The price was set at $65 per tonne of CO_2e in 2023, increasing by $15 per tonne CO_2e annually to $170 per tonne CO_2e by 2030;
- Starting in 2023, a two per cent annual tightening rate will apply to the electricity high performance benchmark from 0.3626 CO_2e tonnes per MWh in 2023 to 0.3108 CO_2e tonnes per MWh in 2030;
- The maximum allowable emissions offsets, emissions performance standards or sequestration credits that can be used by a given facility in a year was set to 60 per cent in 2023, 70 per cent in 2024, 80 per cent in 2025, and 90 per cent in 2026 and beyond; and
- EPCs issued in 2023 or a subsequent year may only be used within the five-year period after the EPC was issued, while offsets may only be used within a six-year period, including the reduction year.

These changes will result in lower emissions offset crediting for new renewables projects but, all things being equal, should also result in higher demand for emissions offset credits from TransAlta's renewables facilities. TransAlta's gas-fired facilities will face more stringent performance standards. TIER will remain in effect through 2030 and will be reviewed on or before Dec. 31, 2026.

Ontario

Large Emitter Greenhouse Gas Regulations

As of Jan. 1, 2022, the Emissions Performance Standards (EPS) system applies in Ontario and the federal Output-Based Performance Standards no longer directly applies to covered emitters.

In December 2022, Ontario announced changes to the EPS to ensure alignment with the Canadian federal government's requirements under the GGPPA. Two electricity-related changes will impact TransAlta's gas-fired facilities in Ontario:

- Changing the electricity performance standard from 0.37 tonnes CO_2e per MWh in 2022 to 0.31 tonnes CO_2e per MWh starting in 2023, remaining flat to 2030; and

- Allowing cogeneration units to utilize separate performance standards for electricity and heat to enable a level playing field for all electricity under the EPS.

The change in cogeneration performance standard treatment will benefit TransAlta's facilities by removing a previous, single cogeneration standard that was more stringent than using separate standards for heat and electricity. The value from this change flows to contracted customers but helps make cogeneration more competitive as an energy solution.

Ontario is continuing its work on the natural gas transition and has developed a voluntary clean energy credit market for specified asset types directly connected to the IESO grid or a distribution system. TransAlta will continue to engage the government on relevant policy initiatives to mitigate risk and identify areas of potential opportunity.

United States

Following the inauguration of President Trump on Jan. 20, 2025, the President signed an Executive Order, directing the withdrawal of the United States from the Paris Agreement. It is expected that the United States may reduce current climate commitments; however, state level governments may choose to retain targets if this occurs. Existing commitments for carbon emissions reductions, include: achieving a 50 to 52 per cent national emissions reduction below 2005 levels by 2030, a net-zero electricity grid by 2035 and a net-zero national economy by 2050. Although the United States does not have a national carbon pricing regime, it currently offers federal incentives for renewable generation and new technology and infrastructure, including spending under the *Inflation Reduction Act*.

State and regional climate and market policies have a significant impact on the pace of energy transition in the United States, with many state governments operating under renewable portfolio standards and carbon pricing regimes. Similar to Canada, independent estimates suggest that the United States will require substantial growth in zero-emissions generation to meet its national climate targets.

Washington State

Large Emitter Cap and Trade Program

In 2010, the Washington Governor's Office and Department of Ecology negotiated agreements with TransAlta to retire Centralia's two coal-fired electricity generating units, one in 2020 and the other in 2025. This agreement is formally part of the state's climate change program. We currently believe that there will be no additional GHG regulatory burden on Centralia given these commitments. The related TransAlta Energy Transition Bill was enacted in 2011 and provides a framework to transition from coal to other forms of generation in the State of Washington.

On May 17, 2021, Governor Inslee signed Washington State's *Climate Commitment Act*. which came into effect on Jan. 1, 2023. This law covers entities that emit over 25,000 tonnes of CO_2e per year. It creates a "cap-and-invest" program, which sets a state-wide cap on GHG emissions and then auctions or allocates emissions allowances. TransAlta's Centralia coal facility will be exempt from the cap-and-invest program until it closes in 2025, as per the agreement with the state of Washington. The Washington Department of Ecology held quarterly auctions for compliance in 2024. The auctions offered 2023 and 2024 vintage allowances, and an advance auction of 2027 vintage allowances. TransAlta continues to track the cap-and-invest program as it develops and moves into its second year of implementation. The Company will engage when necessary with relevant government departments should there be any future implementation changes that impact our operations or energy trading in Washington.

Australia

In October 2021, the Australian government announced a target to reach net-zero emissions by 2050. Following the May 2022 federal election, the elected Labor government enacted a more ambitious near-term target through the *Climate Change Act 2022*, which commits Australia to a 43 per cent emissions reduction below 2005 levels by 2030. The government also confirmed its intent to boost renewable electricity production to 82 per cent of the electricity supply by 2030. Large GHG emitters are required to reduce their scope 1

emissions under the Australian Government's National Safeguard Mechanism (SGM). While the government has made recent changes to the SGM, these changes are not expected to have a material impact on TransAlta's assets.

The Australian government's plan to achieve the necessary reductions is focused on a combination of technology development and cost reduction, enabling deployment at scale through incentives and infrastructure development as well as updating some of its regulatory mechanisms. In particular, an AU$20 billion fund has been set aside to support infrastructure investment, such as transmission network reinforcement, and enable the shift to renewables. Decarbonization efforts have been centred on funding for clean technologies, upgrading the electricity grid to support more renewables, regulating and reporting of GHGs, and incentivizing zero-emission vehicle adoption.

Australian state-level policies continue to focus on moving toward greater reliance on renewables, hydrogen and energy storage and away from coal.

TransAlta does not see any significant risk to our existing Australian assets. Policy and funding supporting continued industrial decarbonization could provide additional growth opportunities in the Australian market.

TransAlta Activities

Reducing the environmental impact of our activities benefits not only our operations and financial results, but also the communities in which we operate. We expect that increased scrutiny will continue to be placed on GHG emissions and compliance. We take a proactive approach to minimizing environmental and safety risks to our results. The board of directors of the Company (the Board or the Board of Directors) provides oversight to our environmental management programs and emissions reduction initiatives in order to ensure continued compliance with environmental regulations.

For a description of our environmental management system and other aspects of our environmental strategy see the "Managing Environmental Resources" section of the MD&A, which is incorporated by reference herein.

Emission Offset Portfolio

TransAlta also maintains a GHG emissions offset portfolio with a variety of instruments that can be used for compliance purposes or otherwise banked or sold. We continue to examine additional emission offset opportunities that also allow us to meet our emissions compliance obligations at a competitive cost. We invest in offsets that we expect will meet certification criteria in the market in which they are to be used.

Risk Factors

For a discussion of risk factors affecting TransAlta, see the "Governance and Risk Management" section of the MD&A, which is incorporated by reference herein.

Employees

The Company is required to develop and retain a skilled workforce for its operations. Many of TransAlta's employees possess specialized skills and training and we must compete in the labour market for these workers. As at Dec. 31, 2024, we had 1205 active employees, which includes full-time, part-time and temporary employees. Approximately 29 per cent of our employees are represented by labour unions. We are currently a party to 12 different collective bargaining agreements. As at Dec. 31, 2024, women accounted for 28 per cent of all employees and 32 per cent of our executive team.

For a description of social policies implemented by TransAlta please see "Engaging with Our Stakeholders to Create Positive Relationships" and "Building a Diverse and Inclusive Workforce" sections of the MD&A which are incorporated by reference herein.

Capital Structure

Share Capital

Our authorized share capital consists of an unlimited number of common shares and an unlimited number of first preferred shares, issuable in series. For the number of common shares and first preferred shares issued and outstanding as at Dec. 31, 2024, see the "Financial Capital – Share Capital" section of the MD&A, which is incorporated by reference herein.

Common Shares

Each common share of the Company entitles the holder thereof to one vote for each common share held at all meetings of shareholders of the Company, except meetings at which only holders of another specified class or series of shares are entitled to vote, to receive dividends if, as and when declared by the Board of Directors, subject to prior satisfaction of preferential dividends applicable to any first preferred shares, and to participate rateably in any distribution of our assets upon a liquidation, dissolution or winding up and subject to prior rights and privileges attaching to first preferred shares. The common shares are not convertible and are not entitled to any pre-emptive rights. The common shares are not entitled to cumulative voting.

First Preferred Shares

We are authorized to issue an unlimited number of first preferred shares, issuable in series and, with respect to each series, the Board of Directors is authorized to fix the number of shares comprising the series and determine the designation, rights, privileges, restrictions and conditions attaching to such shares, subject to certain limitations.

The first preferred shares of all series rank senior to all other shares of the Company with respect to priority in payment of dividends and with respect to distribution of assets in the event of liquidation, dissolution or winding up of the Company, or a reduction of stated capital. Holders of first preferred shares are entitled to receive cumulative quarterly dividends on the subscription price thereof as and when declared by the Board of Directors at the rate established by the Board of Directors at the time of issue of shares of a series. No dividends may be declared or paid on any other shares of the Company unless all cumulative dividends accrued upon all outstanding first preferred shares have been paid or declared and set apart. In the event of the liquidation, dissolution or winding up of the Company, or a reduction of stated capital, no sum shall be paid or assets distributed to holders of other shares of the Company until the holders of first preferred shares shall have been paid the subscription price of the shares, plus a sum equal to the premium payable on a redemption, plus a sum equal to the arrears of dividends accumulated on the first preferred shares to the date of such liquidation, dissolution, winding up or reduction of stated capital, as applicable. After the payment of such amount, the holders of first preferred shares shall not be entitled to share further in the distribution of our assets.

The Board of Directors may include, in the share conditions attaching to a particular series of first preferred shares, certain voting rights effective upon our failing to make payment of six quarterly dividend payments, whether or not consecutive. These voting rights continue for so long as any dividends remain in arrears. These voting rights are the right to one vote for each $25.00 of subscription price on all matters in respect of which shareholders vote, and additionally, the right of all series of first preferred shares, voting as a combined class, to elect two directors of TransAlta if the Board of Directors then consists of less than 16 directors, or three directors if the Board of Directors consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Company.

Subject to the share conditions attaching to any particular series providing to the contrary, we may redeem the first preferred shares of a series, in whole or from time to time in part, at the redemption price applicable to each series and we have the right to acquire any of the first preferred shares of one or more series by purchase for cancellation in the open market or by invitation for tenders at a price not to exceed the redemption price applicable to the series.

Series A, B, C, D, E, F and G First Preferred Shares

The holders of Series A, C, E and G first preferred shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, as and when declared by the Board, to be reset periodically on prescribed dates to an annualized rate equal to the sum of the then five-year Government of Canada bond yield, calculated at the start of the applicable five-year period, and a spread as set forth in the table below and have the right to convert their shares into cumulative redeemable Series B, D, F and H first preferred shares, respectively, subject to certain conditions, on such conversion dates as set forth in the table below. The Series A, C, E and G first preferred shares are redeemable by TransAlta in whole or in part on such redemption dates as set forth in the table below, by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon.

The holders of Series B, D, F and H first preferred shares will be entitled to receive quarterly floating rate cumulative preferential cash dividends, as and when declared by the Board, at an annualized rate equal to the sum of the then 90-day Government of Canada treasury bill rate, recalculated quarterly, and a spread as set forth in the table below and have the right to convert their shares into Series A, C, E and G first preferred shares, respectively, subject to certain conditions, on such conversion dates as set forth in the table below. The Series B, D, F and H first preferred shares are redeemable by TransAlta in whole or in part after their respective initial redemption date as set forth in the table below, by the payment of an amount in cash for each share to be redeemed equal to (i) $25.00 in the case of redemptions on such redemption dates as set out in the table below, or (ii) $25.50 in the case of redemptions on any other date, in each case plus all accrued and unpaid dividends thereon.

Series of First Preferred Shares	Initial Redemption/ Conversion Date	Redemption/ Conversion Dates	Spread (%)
Series A	March 31, 2016	March 31, 2021 and every fifth year thereafter	2.03
Series B	-	March 31, 2021 and every fifth year thereafter	2.03
Series C	June 30, 2017	June 30, 2022 and every fifth year thereafter	3.10
Series D	-	June 30, 2022 and every fifth year thereafter	3.10
Series E	Sept. 30, 2017	Sept. 30, 2022 and every fifth year thereafter	3.65
Series F	-	Sept. 30, 2022 and every fifth year thereafter	3.65
Series G	Sept. 30, 2019	Sept. 30, 2024 and every fifth year thereafter	3.80
Series H	-	Sept. 30, 2024 and every fifth year thereafter	3.80

The holders of the Series A, B, C, D, E, F and G first preferred shares are not entitled to any voting rights or to receive notice of or to attend shareholders' meetings unless dividends on such series of first preferred shares are in arrears to the extent of six quarterly dividends, whether or not consecutive. Until all arrears of dividends have been paid, holders of the first preferred shares of such series will be entitled: (i) to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class or series of shares); (ii) to one vote in respect of each first preferred share of such series held on all matters in respect of which shareholders vote; and (iii) to vote, together with all other holders of first preferred shares of any series, as a combined class, to elect two directors of the Company if the Board of Directors then consists of fewer than 16 directors, or three directors if the Board of Directors consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Company.

Series I First Preferred Shares

The first preferred shares, Series I (Series I Shares), are issued to an affiliate of Brookfield and have a perpetual term and rank *pari passu* to all existing series of first preferred shares of the Company with respect to dividends and liquidation preferences. The Series I Shares are entitled to a seven per cent cumulative dividend payable quarterly in cash.

Under the Investment Agreement with Brookfield, redemption of the Series I Shares will be satisfied through the Hydro Equity Interest (as defined below), or in some cases cash, based on their redemption price. The redemption price payable is equal to the subscription price paid by Brookfield together with all accrued but unpaid dividends thereon (the Redemption Price). Upon the occurrence of an Optional Redemption, as defined

and described below, or a Cash Acceleration Event, as defined and described below, the Company will pay the Redemption Price in cash (the Cash Redemption Amount).

Except in the case of an Optional Redemption by the Company or a Cash Acceleration Event, as described below, the Series I Shares will be exchangeable into interests (Hydro Equity Interest) in the equity (the Hydro Equity) of TA Alberta Hydro LP (Hydro Assets Owner), a special purpose vehicle formed by the Company. At any time after Dec. 31, 2024, but prior to Dec. 31, 2028, Brookfield will be entitled to exchange all, but not less than all, of the Series I Shares requiring the Company to redeem or exchange all of the Series I Shares held by Brookfield (minus the number of Series I Shares that have been redeemed pursuant to an Optional Redemption) (the Exchange Right).

Prior to any Optional Redemption by the Company, the exercise of the Exchange Right or the occurrence of an Equity Acceleration Event, as defined and described below, will entitle Brookfield to receive that percentage of a Hydro Equity Interest that is equal to the aggregate Redemption Price for all Series I Shares issued to Brookfield divided by the tax-affected equity value of the Hydro Assets Owner, as further described in the Investment Agreement (Equity Redemption Amount). The maximum Hydro Equity Interest issuable to Brookfield upon the exercise of the Exchange Right is 49 per cent of the total Hydro Equity. The balance of the Redemption Price will be paid by the Company in cash.

If, at the time the Exchange Right is exercised, the Equity Redemption Amount is insufficient to permit Brookfield to acquire 49 per cent of the Hydro Equity, Brookfield has a one-time top-up option, exercisable until Dec. 31, 2028, to acquire an additional amount of Hydro Equity. As long as Brookfield holds at least 8.5 per cent of the Company's issued and outstanding common shares, Brookfield may purchase: (a) if the 20-day volume weighted average price (VWAP) of the common shares is not less than $14, up to an additional 10 per cent of Hydro Equity, to a maximum interest of 49 per cent of the Hydro Equity; or (b) if the 20-day VWAP of the common shares is not less than $17, the additional percentage required that would bring Brookfield's ownership level up to but not exceeding 49 per cent of the Hydro Equity. If the Exchange Right is exercised and the Equity Redemption Amount is insufficient to permit Brookfield to acquire at least 25 per cent of the Hydro Equity, Brookfield will have an option to acquire that additional percentage of Hydro Equity that would result in Brookfield having 25 per cent of the Hydro Equity upon payment in cash. If Brookfield exercises its top-up option, the cash amount payable by Brookfield is calculated as the same price as in the case of an exchange for the Hydro Equity Interest; however, in such a case, the price is based on the equity value of the Hydro Assets Owner without any reduction for the tax deficiency value associated with certain tax pools. Exercise of this top-up option triggers a lock-up obligation of Brookfield for a further period of 18 months following its exercise.

At any time after Dec. 31, 2028, the Company may redeem the Series I Shares and the related debentures, in whole or in part, at the Redemption Price (the Optional Redemption) provided that the minimum proceeds to Brookfield for each such redemption (other than the final redemption) may not be less than $100,000,000 and further provided that all Series I Shares and related debentures must be redeemed by the Company within 36 months of the date of the first Optional Redemption.

The Investment Agreement also provides for certain acceleration events. In the event of bankruptcy or a breach of certain material covenants by the Company (each, an Equity Acceleration Event), Brookfield will be entitled to give notice and will be entitled to the Equity Redemption Amount. If the Company does not obtain the requisite regulatory approvals for the exchange of Hydro Equity contemplated by the Exchange Right or the Equity Redemption Amount or a final order is made that enjoins the completion of the Exchange Right (Cash Acceleration Event), then Brookfield will be entitled to the Cash Redemption Amount.

Related-Party Articles Provisions

The articles of the Company contain provisions restricting the ability of the Company to enter into a "Specified Transaction" with a "Major Shareholder." A Specified Transaction requires the approval of a majority of the votes cast by holders of voting shares of the Company, as well as the approval of a majority of the votes cast by holders of such voting shares, excluding any Major Shareholder. A Major Shareholder generally means the beneficial owner of more than 20 per cent of the outstanding voting shares of the Company. The articles contain a broad definition of beneficial ownership, and in particular, a person is considered to beneficially own shares owned by their associates and affiliates, as those terms are defined in the articles. Transactions that are considered to be Specified Transactions include the following: a merger or amalgamation of the Company with a Major Shareholder; the furnishing of financial assistance by the Company to a Major Shareholder; certain sales of assets or provision of services by the Company to a Major Shareholder or vice versa; certain issuances of securities by the Company that increase the proportionate voting interest of a Major Shareholder; a reorganization or recapitalization of the Company that increases the proportionate voting interest of a Major Shareholder; and the creation of a class or series of non-voting shares of the Company that has a residual right to participate in earnings of the Company and assets of the Company upon dissolution or winding up.

Shareholder Rights Plan

The Company implemented a shareholder rights plan (Rights Plan) pursuant to a Shareholder Rights Plan Agreement (Rights Plan Agreement) dated as of Oct. 13, 1992, as amended and restated as of April 28, 2022, between the Company and Computershare Trust Company of Canada. The Rights Plan was last confirmed at our annual and special meeting of shareholders on April 28, 2022, and will expire at the close of business on the date of our 2025 Annual and Special Meeting of Shareholders, unless ratified and extended by a further vote of the shareholders. For further particulars, see the Rights Plan Agreement, as amended and restated. A copy of the Rights Plan Agreement is also available electronically on SEDAR+ under our profile, which can be accessed at **www.sedarplus.ca**, and on the SEC's EDGAR system at **www.sec.gov**. A copy of the Rights Plan Agreement may be obtained by contacting the Corporate Secretary, TransAlta Corporation, TransAlta Place, Suite 1400, 1100 1 St SE, Calgary, Alberta T2G 1B1; telephone: (403) 267-7110; or by email: **corporate_secretary@transalta.com**.

For additional information regarding our Capital Structure, please refer see the "Financial Capital" section of the MD&A, which is incorporated by reference herein.

Exchangeable Securities

On March 22, 2019, we entered into the Investment Agreement, whereby Brookfield invested $750 million in the Company through the purchase of Exchangeable Securities, which are exchangeable into an equity ownership interest of TA Alberta Hydro LP. See the "Capital Structure – First Preferred Shares – Series I First Preferred Shares" section of this AIF for further details.

Investment Agreement

The following description of certain provisions of the Investment Agreement is a summary only; it is not comprehensive and is qualified in its entirety by reference to the full text of the Investment Agreement, a copy of which can be found on SEDAR+ under our profile at **www.sedarplus.ca** and on EDGAR under our profile at **www.sec.gov**.

Under the terms of the Investment Agreement, Brookfield committed to purchase TransAlta common shares on the open market to increase its share ownership in TransAlta to not less than nine per cent by May 1, 2021. As of Dec. 31, 2024, Brookfield, through its affiliates, held, owned or had control over an aggregate of 35,523,345 common shares, representing 11.9 per cent of the issued and outstanding common shares, calculated on an undiluted basis. On January 7, 2025, Brookfield, through its affiliates, sold 8,600,000 common shares reducing its ownership to 26,923,345 common shares, representing approximately nine per cent of the issued and outstanding common shares on an undiluted basis.

The Investment Agreement contemplates that the Exchangeable Securities will be a long-term investment and therefore may not be transferred except by Brookfield to one of its affiliates. Brookfield has agreed to be the

sole representative of all of its permitted transferees for the purpose of the Investment Agreement. So long as Brookfield holds the Exchangeable Securities, it is entitled to nominate two directors for election to the Board.

The Investment Agreement included certain standstill commitments by Brookfield that are extended for so long as Brookfield has nominees on the Board of Directors, including restrictions on Brookfield's ability to solicit proxies from the Company's shareholders or making a shareholder proposal.

In accordance with the terms of the Investment Agreement, TransAlta formed a hydro assets operating committee consisting of two representatives from Brookfield and two representatives from TransAlta to provide advice and recommendations in connection with the operation and value maximization of the Alberta hydro assets. In connection with this, the Company committed to pay Brookfield an annual management fee of $1.5 million for six years commencing on May 1, 2019.

Registration Rights Agreement

The following description of certain provisions of the Registration Rights Agreement entered into between Eagle Hydro II (an affiliate of Brookfield) and the Company on May 1, 2019 (Registration Rights Agreement) is a summary only; it is not comprehensive and is qualified in its entirety by reference to the full text of the Registration Rights Agreement, a copy of which can be found on SEDAR+ under our profile at **www.sedarplus.ca**.

The Registration Rights Agreement provides that Eagle Hydro II and any affiliate of Brookfield that becomes party to the Registration Rights Agreement (each a Holder) may, at any time and from time to time, make a written request (Demand Registration) to the Company to file a Prospectus Supplement with the securities commissions or similar authorities in each of the provinces of Canada in respect of the distribution of all or part of the common shares then held by the Holder (Registrable Securities), subject to certain restrictions set forth in the Registration Rights Agreement. Upon receipt by the Company of a Demand Registration, the Company will promptly file a Prospectus Supplement in order to permit the offer and sale or other disposition or distribution in Canada of all or any portion of the Registrable Securities held, directly or indirectly, by the Holder (a Demand Offering). The Company will not be obligated to effect: (a) more than three Demand Offerings in total during the term of the Registration Rights Agreement; or (b) a Demand Offering if the Registrable Securities have an aggregate market price of less than $50 million.

If at any time the Company proposes to file a prospectus supplement with respect to the distribution of any TransAlta common shares to the public, then the Company will give notice of the proposed distribution to each Holder not less than five business days in advance of the anticipated filing date of the prospectus supplement (or, in the case of a “bought deal” or another public offering that is not expected to include a road show, such notice as is practicable under the circumstances), which notice will offer each Holder the opportunity to qualify for distribution such number of Registrable Securities as such Holder may request. The Company will use commercially reasonable efforts to include in such Prospectus Supplement such Registrable Securities (a Piggy Back Offering), unless the Company’s managing underwriter or underwriters determine, in good faith, that including such Registrable Securities in the distribution would, in their opinion, adversely affect the Company’s distribution or sales price of the securities being offered by the Company.

The Demand Offerings and Piggy Back Offerings are subject to various conditions and limitations. The Company is entitled to defer any Demand Offering in certain circumstances, including during a regular annual and quarterly blackout period in respect of the release of its financial results.

The Registration Rights Agreement includes provisions providing for each of the Company and the Holders to indemnify each other for losses or claims caused by the applicable party’s inclusion of a misrepresentation in disclosure included in any prospectus and for breaches of applicable securities laws.

In the case of a prospectus supplement filed in connection with a Demand Offering or Piggy Back Offering, the Company will pay all applicable fees and expenses incidental to the Company’s performance of, or compliance with, the terms of such offering, provided that in the event any Registrable Securities are freely tradeable at the time the Company receives the offering request, the Company and the Holders will be jointly and severally responsible for the proportionate share of registration fees and expenses of any Holders based on the total offering price of the freely tradeable securities sold by the Holders to the total offering price of all the Securities sold by the Company in such offering. The Company and the Holders will be jointly and severally

responsible for paying all selling expenses (including fees or commissions payable to an underwriter, investment banker, manager or agent and any transfer taxes attributable to the sale of Registrable Securities) with respect to Registrable Securities sold by the Holders and the Company will pay all selling expenses with respect to any Securities sold for the account of the Company. The Company and the Holders will be solely responsible on a joint and several basis for all out-of-pocket expenses incurred by any Holders in connection with a Demand Offering or Piggy Back Offering.

If a Holder ceases to be affiliated with the Company, the Holder will cease to have any rights or obligations under the Registration Rights Agreement. The Registration Rights Agreement will terminate when Brookfield, together with its affiliates, beneficially owns in the aggregate less than three per cent of the issued and outstanding common shares.

Additional details about the Brookfield Investment can be found in our material change report dated March 26, 2019, available electronically on SEDAR+ at **www.sedarplus.ca** and on EDGAR at **www.sec.gov**. Copies of the Investment Agreement, together with copies of the exchangeable debenture and the Registration Rights Agreement are also available on SEDAR+ and on EDGAR. Shareholders are encouraged to read these documents in their entirety.

Credit Ratings

Credit ratings provide information relating to our financing costs, liquidity and operations and affect our ability to obtain short-term and long-term financing and/or the cost of such financing. Our credit ratings as at Dec. 31, 2024, are as follows:

	Morningstar DBRS	Moody's	S&P Global Ratings
Issuer Rating	BBB (low)	Not applicable	BB+
Corporate Family Rating	Not applicable	Ba1	Not applicable
Preferred Shares	Pfd-3 (low)[(1)]	Not applicable	P-4(High)
Unsecured Debt/MTNs	BBB (low)	Ba1/LGD4	BB+
Rating Outlook	Stable	Stable	Stable

(1) The outstanding Preferred Shares all have the same rating.

Morningstar DBRS

Morningstar DBRS' corporate rating analysis begins with evaluation of the fundamental creditworthiness of the issuer and also takes the issuer's business and financial risks into account, which is reflected in an "issuer rating." Issuer ratings address the overall credit strength of the issuer. Unlike ratings on individual securities or classes of securities, issuer ratings are based on the entity itself and do not include consideration for security or ranking. Ratings that apply to actual securities (secured or unsecured) may be higher, lower or equal to the issuer rating for a given entity. As at Dec. 31, 2024, our issuer rating was BBB (low) with a stable outlook. An issuer rating of BBB means the issuer has adequate credit quality, its capacity for the payment of financial obligations is considered acceptable, and it may be vulnerable to future events. Each rating category is denoted by the subcategories "high" and "low." The absence of either a "high" or "low" designation indicates the rating is in the middle of the category. A BBB rating is the fourth highest out of 10 categories.

The Morningstar DBRS preferred share rating scale is used in the Canadian securities market and is meant to give an indication of the risk that a borrower will not fulfil its full obligations in a timely manner, with respect to both dividend and principal commitments. Every Morningstar DBRS rating is based on quantitative and qualitative considerations relevant to the borrowing entity. Each rating category is denoted by the subcategories "high" and "low." The absence of either a "high" or "low" designation indicates the rating is in the middle of the category. Preferred shares rated Pfd-3 are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present that detract from

debt protection. Each of the Series A, B, C, D, E and G first preferred shares have been rated Pfd-3 (low) (stable). The Pfd-3 rating is the third highest out of six categories.

The Morningstar DBRS long-term rating scale provides an opinion on the risk of default, which is the risk that an issuer will fail to satisfy its financial obligations in accordance with the terms under which an obligation has been issued. Ratings are based on quantitative and qualitative considerations relevant to the issuer, and the relative ranking of claims. All rating categories other than AAA and D also contain subcategories "high" and "low". The absence of either a "high" or "low" designation indicates the rating is in the middle of the category. Debt securities rated BBB are of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, but may be vulnerable to future events. A BBB rating is the fourth highest out of 10 categories.

Moody's

Moody's Corporate Family Ratings (CFRs) are long-term ratings that reflect the relative likelihood of a default on a corporate family's debt and debt-like obligations and the expected financial loss suffered in the event of default. A CFR is assigned to a corporate family as if it had a single class of debt and a single consolidated legal entity structure. A CFR does not refer to an obligation or class of debt and thus does not reflect priority of claim. As at Dec. 31, 2024, our Corporate Family Rating was Ba1 with a stable outlook. Obligations rated Ba are judged to be speculative and are subject to substantial credit risk. Moody's appends the numerical modifiers 1, 2 and 3 to each generic rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking, and the modifier 3 indicates a ranking in the lower end of that generic rating category. The Ba rating category is the fifth-highest rating out of nine rating categories.

Moody's long-term ratings are assigned to issuers or obligations with an original maturity of 11 months or more and reflect both the likelihood of a default or impairment on contractual financial obligations and the expected financial loss suffered in the event of default or impairment. As at Dec. 31, 2024, our senior unsecured long-term debt is rated Ba1/LGD4. The Ba rating category is the fifth-highest rating out of nine rating categories. Obligations rated Ba are judged to be speculative and are subject to substantial credit risk.

Moody's Loss Given Default (LGD) assessments are point-in-time opinions about expected loss given default expressed as a percentage of principal and accrued interest at the resolution of the default. One of the six LGD assessments is assigned to individual loan, bond and preferred stock issues. The firm-wide or enterprise expected LGD rate generally approximates a weighted average of the expected LGD rates on the firm's liabilities (excluding preferred stock), where the weights equal each obligation's expected share of the total liabilities at default. As at Dec. 31, 2024, our LGD assessment from Moody's was LGD4, which represents a loss range of greater than or equal to 50 per cent and less than 70 per cent. LGD4 is the fourth-highest assessment category out of six categories.

S&P Global Ratings

The S&P Global Ratings issue credit rating is a forward-looking opinion about the creditworthiness of an obligor with respect to a specific financial obligation, a specific class of financial obligations or a specific financial program (including ratings on medium-term note programs and commercial paper programs). It takes into consideration the creditworthiness of guarantors, insurers or other forms of credit enhancement on the obligation and takes into account the currency in which the obligation is denominated. The opinion reflects S&P Global Ratings' view of the obligor's capacity and willingness to meet its financial commitments as they come due, and may assess terms, such as collateral security and subordination, which could affect ultimate payment in the event of default. As at Dec. 31, 2024, our issuer credit rating was BB+ with a stable outlook. This is the fifth highest of 11 ratings categories. An obligor rated BB is less vulnerable in the near-term than other lower-rated obligors. However, it faces major ongoing uncertainties and exposure to adverse business, financial, or economic conditions that could lead to the obligor's inadequate capacity to meet its financial commitments. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

The S&P Global Ratings Canadian preferred share rating scale serves issuers, investors and intermediaries in the Canadian financial markets by expressing preferred share ratings (determined in accordance with global rating criteria) in terms of rating symbols that have been actively used in the Canadian market over a number of years. The S&P Global Ratings preferred share rating on the Canadian scale is a forward-looking opinion about the creditworthiness of an obligor with respect to a specific preferred share obligation issued in the Canadian market, relative to preferred shares issued by other issuers in the Canadian market. There is a direct correspondence between the specific ratings assigned on the Canadian preferred share scale and the various rating levels on the global debt rating scale of S&P Global Ratings. Each of our outstanding Preferred Shares Series has been rated P-4 (High). The P-4 (High) rating is the fourth highest of eight categories. A P-4 (High) rating corresponds to a B+ rating on the global preferred share rating scale. Obligors rated BB, B, CCC, CC and C are regarded as having significant speculative characteristics, of which BB indicates the least degree of speculation and C the highest. While some obligors will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposures to adverse conditions. An obligor rated B is more vulnerable to nonpayment than obligations rated BB, but the obligor currently has the capacity to meet its financial commitments on the obligation. Adverse business, financial or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitments.

We are focused on maintaining a strong financial position and cash flow coverage ratios to support our business. Our available credit facilities, funds from operations and debt financing options provide us with financial flexibility.

Note Regarding Credit Ratings

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. The credit ratings accorded to our outstanding securities by Morningstar DBRS, Moody's and S&P Global Ratings, as applicable, are not recommendations to purchase, hold or sell such securities. There is no assurance that the ratings will remain in effect for any given period or that a rating will not be revised or withdrawn entirely by Morningstar DBRS, Moody's or S&P Global Ratings in the future if, in its judgement, circumstances so warrant.

We have paid fees for rating services to Morningstar DBRS, Moody's and S&P Global Ratings during the last two years. We have also paid fees to S&P Global Ratings, Morningstar DBRS and Kroll Bond Rating Agency for certain other services provided to the Company during the last two years.

Dividends

Dividends on our common shares are paid at the discretion of the Board of Directors. In determining the payment and level of future dividends, the Board of Directors considers our financial performance, results of operations, cash flow and needs, with respect to financing our ongoing operations and growth, balanced against returning capital to shareholders.

Dividends on our first preferred shares are payable quarterly, as and when declared by the Board.

TransAlta has declared and paid the following dividends per share on its outstanding common shares and Series A, B, C, D, E, and G first preferred shares for the past three years:

Year	Quarter	Common	Series A First Preferred	Series B First Preferred	Series C First Preferred	Series D First Preferred	Series E First Preferred	Series G First Preferred
2022	First Quarter	$0.0500	$0.17981	$0.13309	$0.25169	-	$0.32463	$0.31175
	Second Quarter	$0.0500	$0.17981	$0.16505	$0.25169	-	$0.32463	$0.31175
	Third Quarter	$0.0500	$0.17981	$0.22099	$0.36588	$0.28841	$0.32463	$0.31175
	Fourth Quarter	$0.0550	$0.17981	$0.33700	$0.36588	$0.40442	$0.43088	$0.31175
2023	First Quarter	$0.0550	$0.17981	$0.37991	$0.36588	$0.45578	$0.43088	$0.31175
	Second Quarter	$0.0550	$0.17981	$0.41100	$0.36588	$0.47769	$0.43088	$0.31175
	Third Quarter	$0.0550	$0.17981	$0.41545	$0.36588	$0.48287	$0.43088	$0.31175

	Fourth Quarter	$0.0550	$0.17981	$0.45288	$0.36588	$0.52030	$0.43088	$0.31175
2024	**First Quarter**	$0.0600	$0.17981	$0.43958	$0.36588	$0.50609	$0.43088	$0.31175
	Second Quarter	$0.0600	$0.17981	$0.43579	$0.36588	$0.50230	$0.43088	$0.31175
	Third Quarter	$0.0600	$0.17981	$0.43373	$0.36588	$0.50097	$0.43088	$0.31175
	Fourth Quarter	$0.0600	$0.17981	$0.39182	$0.36588	$0.45906	$0.43088	$0.42331
2025	**First Quarter**[1]	$0.0600	$0.17981	$0.33972	$0.36588	$0.40568	$0.43088	$0.42331

(1) Dividends have been declared but not yet paid.

TransAlta also declared an aggregate cash dividend in respect to the issued and outstanding Series I Shares for the period starting from and including Dec. 31, 2023, up to but excluding Dec. 31, 2024. The Series I Shares are entitled to a seven per cent cumulative dividend payable quarterly in cash.

Market for Securities

Common Shares

Our common shares are listed on the Toronto Stock Exchange (TSX) under the symbol "TA" and on the New York Stock Exchange (NYSE) under the symbol "TAC".

Our Series A, B, C, D, E, and G first preferred shares are listed on the TSX under the symbols "TA.PR.D", "TA.PR.E", "TA.PR.F", "TA.PR.G", "TA.PR.H" and "TA.PR.J", respectively.

The following table sets forth the reported high and low trading prices and trading volumes of our common shares as reported by the TSX for the periods indicated:

	Price ($)		
Month	**High**	**Low**	**Volume**
2024			
January	11.17	9.72	15,716,148
February	10.12	9.16	14,010,132
March	9.41	8.44	26,988,640
April	9.34	8.22	23,115,015
May	10.06	9.06	22,130,780
June	10.09	9.41	21,249,930
July	10.47	9.30	20,330,194
August	12.15	10.43	22,689,550
September	14.28	11.65	29,752,508
October	14.75	13.86	22,527,880
November	15.99	12.86	28,263,180
December	20.98	15.54	41,514,720
2025			
January	21.22	14.84	53,921,040

The following table sets forth the reported high and low trading prices and trading volumes of our Series A, B, C, D, E and G first preferred shares as reported by the TSX for the periods indicated:

Year	Quarter	Series A First Preferred	Series B First Preferred	Series C First Preferred	Series D First Preferred	Series E First Preferred	Series G First Preferred
2024							
January	High	13.97	16.23	18.68	20.10	21.99	21.48
	Low	12.18	14.62	17.85	18.40	21.17	19.68
	Volume Traded	111,046	84,044	104,865	6,770	97,836	95,042
February	High	14.30	16.71	18.70	21.00	21.78	21.49
	Low	13.33	15.84	17.91	19.25	21.20	20.61
	Volume Traded	96,122	56,407	126,735	9,308	68,959	51,669
March	High	13.70	15.90	18.99	20.35	21.90	21.61
	Low	13.40	15.50	17.95	19.41	21.00	20.61
	Volume Traded	32,541	23,986	46,169	8,997	72,010	71,542
April	High	13.93	16.00	19.07	22.00	21.95	23.56
	Low	13.46	15.65	18.30	18.66	21.30	21.63
	Volume Traded	369,647	49,916	113,916	11,440	154,380	162,722
May	High	15.50	17.04	19.39	22.50	22.66	24.10
	Low	13.90	15.85	18.40	19.50	21.62	23.15
	Volume Traded	353,680	$77,680.00	411,190	4,428	104,512	167,660
June	High	15.01	16.69	19.25	20.88	22.44	23.67
	Low	13.84	15.82	17.75	19.4	20.55	22.32
	Volume Traded	71,297	37,652	191,729	7,850	94,486	148,295
July	High	15.00	16.50	19.28	20.75	22.64	24.05
	Low	14.31	16.00	18.40	18.00	21.30	22.80
	Volume Traded	100,731	25,222	123,209	12,395	240,777	106,144
August	High	14.90	16.59	20.15	21.50	23.60	24.10
	Low	14.26	15.96	19.00	19.48	22.41	23.02
	Volume Traded	84,054	39,030	82,518	5,050	119,993	168,653
September	High	15.39	17.40	19.99	21.50	23.57	23.70
	Low	14.65	16.01	19.42	19.25	22.75	22.98
	Volume Traded	84,054	96,635	100,089	14,014	86,178	411,005
October	High	15.43	17.50	20.02	21.50	23.72	23.75
	Low	14.75	16.52	19.52	19.51	22.75	23.10
	Volume Traded	189,328	45,150	99,026	9,935	76,280	121,387
November	High	15.29	16.85	20.51	21.99	23.41	23.59
	Low	14.71	16.04	19.55	20.00	22.72	22.95
	Volume Traded	102,870	30,966	110,820	7,720	69,656	68,872
December	High	15.53	16.90	20.72	22.19	23.55	23.82
	Low	14.93	16.01	19.92	19.45	22.72	23.20
	Volume Traded	106,310	54,438	98,402	11,340	85,245	73,067
2025							
January	High	16.06	16.85	21.40	21.65	24.09	24.38
	Low	15.44	16.20	20.58	19.60	23.23	23.55
	Volume Traded	572,628	56,417	130,080	12,815	337,601	98,503

Directors and Officers

The name, province or state and country of residence of each of our directors as at Dec. 31, 2024, their respective position and office and their respective principal occupation during the five preceding years, are set out below. The year in which each director was appointed to serve on the Board of Directors is also set out below. Each director is appointed to serve until the next annual meeting of TransAlta or until his or her successor is elected or appointed.

Name, Province (State) and Country of Residence	Year First Became Director	Principal Occupation
John P. Dielwart Alberta, Canada	2014	Mr. Dielwart is the Chair of the Board of Directors. He was formerly Chief Executive Officer of ARC Resources Ltd., overseeing the growth of the company from a startup in 1996 to a company with a total capitalization of approximately $10 billion at the time of his retirement in 2013. After his retirement from ARC Resources, Mr. Dielwart re-joined ARC Financial Corp. as Vice-Chair and Partner. In 2020, Mr. Dielwart resigned from the Board of ARC Financial but remained as Partner and a member of ARC Financial's Investment Committee. He is currently representing ARC Financial on the board of Aspenleaf Energy Limited. He is a past-Chair of the Board of Governors of the Canadian Association of Petroleum Producers and a member of the Association of Professional Engineers and Geoscientists of Alberta.
Alan J. Fohrer California, United States	2013	Mr. Fohrer is the former Chair and Chief Executive Officer of Southern California Edison Company, a subsidiary of Edison International (Edison) that is one of the largest electric utilities in the United States. Mr. Fohrer served as President and Chief Executive Officer of Edison Mission Energy (EME) from 2000 to 2001, a former subsidiary of Edison that owned and operated independent power facilities. During his tenure at EME, Mr. Fohrer restructured a number of international projects, which enhanced the value of the assets sold in subsequent years. Mr. Fohrer also served as Vice-President, Senior Vice-President, Executive Vice-President and Chief Financial Officer of both Edison and Southern California Edison from 1991 to 2000. After 37 years with Edison, Mr. Fohrer retired in December 2010. Mr. Fohrer is currently an independent member of the board of TXNM Energy, Inc. (previously PNM Resources, Inc.), a publicly traded energy holding company. He is also a member of the Viterbi School of Engineering Board of Councilors for the University of Southern California and on the Board of the California Science Center Foundation. Mr. Fohrer has served on boards of directors of the Institute of Nuclear Power Operations, the California Chamber of Commerce, Duratek, Inc., Osmose Utilities Services, Inc., MWH, Inc., Blue Shield of California and Synagro.

Name, Province (State) and Country of Residence	Year First Became Director	Principal Occupation
Laura W. Folse Texas, United States	2021	Ms. Folse was the Chief Executive Officer of BP Wind Energy North America Inc. As Chief Executive Officer for BP Wind Energy she led a business with over 500 employees and contractors that consisted of 14 wind energy generation plants across eight states with an operating capacity of over 2.5 gigawatts. Prior to her role as Chief Executive Officer of BP Wind Energy, she served at BP p.l.c. as Executive Vice President, Science, Technology, Environment and Regulatory Affairs, in which she led the operational, scientific and technological programs within the multi-billion dollar cleanup and restoration effort in response to the 2010 BP Macondo well explosion off the coast of Louisiana. At its peak, the cleanup project team that she led consisted of over 45,000 people working across the U.S. Gulf and Mexico. She successfully negotiated with federal, state and local government officials to implement and conclude the offshore and onshore cleanup efforts. Prior thereto, she held numerous leadership roles with increasing responsibility and complexity within BP p.l.c. Ms. Folse is an independent member of the Board of Directors of Pacolet Milliken, a private investment company operating in real estate and power and infrastructure. Ms. Folse was a board member for the American Wind Energy Association from 2016 to 2019.
Harry A. Goldgut Ontario, Canada	2019	Mr. Goldgut is Vice Chair of Brookfield's Infrastructure and Renewable Power and Transition groups and provides strategic advice related to Brookfield's open-ended Infrastructure Fund. He is also one of two Brookfield nominees to the Board. Mr. Goldgut was the Chief Executive Officer or Co-CEO and Chair of Brookfield Renewable Power Inc. from 2000 to 2008, and thereafter, until 2015, he was Chair of Brookfield's Power and Utilities Group. From 2015 to 2018, he served as Executive Chair of Brookfield's Infrastructure and Renewable Power groups. He joined Brookfield in 1997 and led the expansion of Brookfield's renewable power and utilities operations. He had primary responsibility for strategic initiatives, acquisitions and senior regulatory relationships. He was responsible for the acquisition of the majority of Brookfield's renewable power assets. He also played a role in the restructuring of the electricity industry in Ontario as a member of several governmental committees, including the Electricity Market Design Committee, the Minister of Energy's Advisory Committee, the Clean Energy Task Force, the Ontario Energy Board Chair's Advisory Roundtable and the Ontario Independent Electricity Operator CEO Roundtable on Market Renewal. Mr. Goldgut also serves on the board of directors of Isagen S.A. ESP, the third-largest power generation company in Colombia, and the Princess Margaret Cancer Foundation in Toronto.

Name, Province (State) and Country of Residence	Year First Became Director	Principal Occupation
John H. Kousinioris Alberta, Canada	2021	Mr. Kousinioris is President and Chief Executive Officer of TransAlta. Prior to his appointment as President and CEO in 2021, Mr. Kousinioris served as Chief Operating Officer of the Company. As Chief Operating Officer, he was responsible for overseeing operations, shared services, commercial, trading, customer solutions, hedging and optimization at the Company. Prior thereto, Mr. Kousinioris was TransAlta's Chief Growth Officer and Chief Legal and Compliance Officer. Mr. Kousinioris' prior leadership roles have provided him with responsibility for almost every aspect of the Company's business. He was also the President of TransAlta Renewables Inc. until Feb. 5, 2021. Prior to joining TransAlta, Mr. Kousinioris was a partner and co-head of the corporate commercial department at Bennett Jones LLP with 30 years of experience in securities law, mergers and acquisitions, and corporate governance matters. He is also Chair of the Board of Governors of Bow Valley College and a member of the Board of Directors of the Calgary Stampede Foundation.
Candace J. MacGibbon Ontario, Canada	2023	Ms. MacGibbon is the former Chief Executive Officer and Director of INV Metals Inc., a TSX-listed mining company, from 2015 to 2021, where she was responsible for determining and implementing corporate strategy. Prior thereto, Ms. MacGibbon was the former President and Chief Financial Officer of INV Metals Inc. from 2008 to 2015, responsible for financial and regulatory reporting and for the company's treasury, financial strength and investment policy. Ms. MacGibbon previously held roles within global mining institutional equity sales with RBC Capital Markets and in base metals research as an equity research associate with BMO Capital Markets. Ms. MacGibbon was a former manager at Deloitte LLP and cost analyst with Inco Limited. She is also a board member of Osisko Gold Royalties and a member of Osisko Gold Royalties Audit and Human Resources Committees. Ms. MacGibbon is the president-elect of the Canadian Institute of Mining, Petroleum and Metallurgy. She is a Chartered Professional Accountant with over 25 years' experience in the mining sector and capital markets.

Name, Province (State) and Country of Residence	Year First Became Director	Principal Occupation
Thomas M. O'Flynn New Jersey, United States	2021	Mr. O'Flynn was the Chief Executive Officer and Chief Investment Officer, AES Infrastructure Advisors. Prior thereto, until 2019, he was Executive Vice President and Chief Financial Officer, Head of U.S. Renewables at AES Corporation and responsible for all aspects of global finance and merger and acquisition (M&A) teams across six global regions. During his tenure, Mr. O'Flynn helped lead AES through a significant transformation, including strategic exits of non-core markets, which resulted in improved financial stability and allowed for the redeployment of cash to primary growth markets. AES's total shareholder return increased 54 per cent during his tenure and its credit rating improved significantly. Mr. O'Flynn was also a key driver in initiating a major transition to renewables and green energy to significantly improve AES's growth profile and reduce its carbon footprint. Mr. O'Flynn is the Lead Operating Director of Dimension Renewable Energy, a community solar company. He is an Operating Director of Exus Management Partners, a renewables management and development company. Mr. O'Flynn is a director of Nexus Water Group, a water utility company. Mr. O'Flynn is a Senior Advisor with Energy Impact Partners, a private energy technology fund investing in high-growth companies in the energy, utility and transportation industries. Mr. O'Flynn was Chief Financial Officer of Powin Energy from December 2021 until December 2022, a battery energy storage company in which Energy Impact Partners is a significant investor. Mr. O'Flynn was with The Blackstone Group Inc. where he was Senior Advisor, Power and Utility Sector, and Chief Operating Officer and Chief Financial Officer of Transmission Developers Inc., a Blackstone-controlled entity that develops innovative power transmission projects in an environmentally responsible manner. Prior thereto he was Executive Vice President and Chief Financial Officer at Public Service Enterprise Group Incorporated and was Head of North American Power at Morgan Stanley.
Bryan D. Pinney Alberta, Canada	2018	Mr. Pinney has over 30 years of experience serving many of Canada's largest corporations, primarily in energy and resources and construction. Mr. Pinney served as Calgary Managing Partner of Deloitte LLP from 2002 through 2007 and as National Managing Partner of Audit & Assurance from 2007 to 2011 and Vice-Chair until June 2015. Mr. Pinney was a past member of Deloitte LLP's Board of Directors. He was a partner at Andersen LLP and served as Calgary Managing Partner from 1991 through May 2002. Mr. Pinney is currently the lead director for North American Construction Group Ltd. (NYSE, TSX) and a director of SNDL Inc. (NASDAQ). Mr. Pinney is the former chair of the Board of Governors of Mount Royal University and has served on a number of non-profit boards. He is a Fellow of the Institute of Chartered Accountants and a Chartered Business Valuator, and he holds the ICD.D designation granted by the Institute of Corporate Directors.

Name, Province (State) and Country of Residence	Year First Became Director	Principal Occupation
James Reid Alberta, Canada	2021	Mr. Reid is a former Managing Partner of Brookfield Asset Management Inc. who led Brookfield's Private Equity Group in Calgary, Alberta. In that role he was responsible for originating, evaluating and structuring investments and financings in the energy sector and overseeing operations in Brookfield's private equity energy segment. Prior to moving into the private equity group, Mr. Reid was the Chief Investment Officer, Energy for Brookfield's Infrastructure Group. He established Brookfield's Calgary office in 2003 after spending several years as Chief Financial Officer for two oil and gas exploration and production companies in Western Canada. Mr. Reid is also one of two Brookfield nominees to the Board pursuant to the Investment Agreement. Mr. Reid obtained his Chartered Accountant designation at PricewaterhouseCoopers in Toronto.
Manjit K. Sharma Ontario, Canada	2023	Ms. Sharma has over 30 years of experience that spans a variety of industries (power generation, oil and gas, financial services, manufacturing, engineering services and others). From 2020 to 2021, she was the Chief Financial Officer of WSP Canada Inc. In this role, she was responsible for leading the finance, real estate, procurement, tax and shared services functions on an interim contract. She was the Chief Financial Officer of GE Canada from 2016 to 2019. From 1999 to 2016, she held various senior positions with GE Canada, with responsibilities that spanned business strategy development and execution, business product and services development, mergers and acquisitions, tax oversight, risk, governance, key components of human resources strategy (including compensation, union negotiations, pension and benefits), and diversity and inclusion. Ms. Sharma currently serves as a board member of each of Vermilion Energy Inc., Finning International Inc. and Export Development Canada. Ms. Sharma is a Fellow Chartered Accountant and holds the ICD.D Directors designation and the GCB.D Global Competent Boards designation.

Name, Province (State) and Country of Residence	Year First Became Director	Principal Occupation
Sandra R. Sharman Ontario, Canada	2020	Ms. Sharman is the Senior Vice President and Group Head, People, Culture and Brand of Canadian Imperial Bank of Commerce (CIBC) (chartered bank). In this role, she leads the Human Resources, Communications, Marketing and Enterprise Real Estate teams at CIBC, supporting execution of business strategy, transforming to a purpose-driven bank and enabling a world-class culture. Ms. Sharman and her team are responsible for developing and delivering the Global Human Capital Strategy designed to challenge conventional thinking, drive business solutions and shape the culture of the bank. Ms. Sharman is a proven business leader with over 30 years of human resources and financial services experience in both Canada and the United States, and she has played a leading role in shaping an inclusive and collaborative culture at CIBC, focused on empowering and enabling employees to reach their full potential. Ms. Sharman assumed the leadership of Human Resources at CIBC in 2014 and added accountability for communications and public affairs in 2017. Since then, her portfolio has expanded to encompass purpose, brand, marketing and, most recently, corporate real estate.
Sarah A. Slusser Washington, United States	2021	Ms. Slusser is the Chief Executive Officer of Cypress Creek Renewables, LLC (Cypress Creek), a solar and storage independent power producer that develops, owns and operates projects in the United States. She joined Cypress Creek as Chief Executive Officer in 2019 to reposition the company for sustainable growth. Prior to this, she founded Point Reyes Energy Partners LLC, a solar and energy storage advisory and development company, where she provided strategic advice to a number of large companies in the renewable sector. She remains a founding partner of Point Reyes Energy Partners. Prior to this, she co-founded GeoGlobal Energy LLC, a geothermal company in the United States, Chile and Germany, which was sold to its cornerstone investor in 2015. Before co-founding GeoGlobal Energy, Ms. Slusser worked at AES for 21 years, where she advanced into increasingly significant leadership roles, ultimately being appointed Senior Vice President and Managing Director reporting directly to the Chief Executive Officer and leading the corporate M&A group. She was President of one of eight divisions of AES that was responsible for all development, construction and operations in the Caribbean, Mexico and Central America. Ms. Slusser is a member of the Board of Directors of the Redwood Foundation, a family foundation promoting education and the environment and Our Food Chain, a non-profit promoting healthy eating.

Officers

The name, province or state and country of residence of each of our executive officers as at Feb. 19, 2025, their respective position and office and their respective principal occupation are set out below.

Name	Principal Occupation	Residence
John H. Kousinioris	President and Chief Executive Officer	Alberta, Canada
Joel E. Hunter	Executive Vice President, Finance and Chief Financial Officer	Alberta, Canada
Jane N. Fedoretz	Executive Vice President, People, Culture and Chief Administrative Officer	Alberta, Canada
Kerry L. O'Reilly Wilks	Executive Vice President, Growth and Energy Marketing	Alberta, Canada
Christopher D. Fralick	Executive Vice President, Generation	Alberta, Canada
Mark A. Flickinger	Executive Vice President, Project Delivery and Construction	Idaho, United States
Blain M. van Melle	Executive Vice President, Commercial and Customer Relations	Alberta, Canada
Nancy L. Brennan	Executive Vice President, Legal and External Affairs	Alberta, Canada
David C. Little	Senior Vice President, Growth	California, United States

All the executive officers of TransAlta have held their present principal occupation or position for the past five years, except for the following:

- Prior to April 2021, Mr. Kousinioris was Chief Operating Officer of TransAlta.
- Prior to July 2024, Mr. Hunter was Executive Vice-President and Chief Financial Officer at TC Energy Corporation. Prior to August 2021, Mr. Hunter was Senior Vice-President, Capital Markets at TC Energy Corporation.
- Prior to November 2023, Ms. Fedoretz was Executive Vice President, People, Talent and Transformation of TransAlta. Prior to February 2021, Ms. Fedoretz was Chief Talent and Transformation Officer of TransAlta.
- Prior to November 2023, Ms. O'Reilly Wilks was Executive Vice President, Legal, Commercial and External Affairs of TransAlta. Prior to February 2021, Ms. O'Reilly Wilks was Chief Officer, Legal, Regulatory and External Affairs of TransAlta.
- Prior to September 2022, Mr. Fralick was President and Chief Executive Officer of Atura Power, a Canadian power generation company. Prior to 2020, Mr. Fralick was Chief Operating Officer of Ontario Power Generation.
- Prior to July 2024, Mr. Flickinger was Vice President of Engineering and Construction of Pattern Energy Group LP.
- Prior to November 2023, Mr. van Melle was Executive Vice President, Alberta Business of TransAlta. Prior to February 2021, Mr. van Melle was Senior Vice President, Trading and Commercial of TransAlta.
- Prior to December 2024, Ms. Brennan was Executive Vice President, Legal, External Affairs and Corporate Secretary. Prior to July 2024, Ms. Brennan was Executive Vice President, Legal of TransAlta. Prior to February 2024, Ms. Brennan was Senior Vice President, Sustainability, External Relations and General Counsel of Keyera Corp.
- Prior to November 2023, Mr. Little was Vice President and Managing Director - USA of Innergex Renewable Energy Inc. Prior to July 2021, Mr. Little was Senior Director and Head of USA of Innergex Renewable Energy Inc.

As of Feb. 19, 2025, the directors and executive officers of TransAlta, as a group, beneficially owned, directly or indirectly, or exercised control or direction over less than one per cent of our outstanding common shares.

Interests of Management and Others in Material Transactions

No director or executive officer of TransAlta, no person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over more than 10 per cent of our common shares, and no associate or affiliate of any of them, has or has had any material interest, direct or indirect, in any transaction involving TransAlta within the three most recently completed financial years or to date in 2025 or in any proposed transactions that have materially affected or will materially affect TransAlta.

In connection with the Brookfield Investment, Mr. James Reid and Mr. Harry Goldgut were initially nominated by Brookfield and elected to the Board of Directors on May 4, 2021, and April 26, 2019, respectively. See the "Directors and Officers" section of this AIF for further details. Brookfield is also entitled to receive certain funding fees, management fees and interest and dividends on its $750 million investment.

Indebtedness of Directors, Executive Officers and Senior Officers

Since Jan. 1, 2024, there has been no indebtedness outstanding to TransAlta from any of our directors, executive officers, senior officers or associates of any such directors, executive officers or senior officers.

Corporate Cease Trade Orders, Bankruptcies or Sanctions

Corporate Cease Trade Orders and Bankruptcies

Except as noted below, no director, executive officer or controlling security holder of the Company is, as at the date of this AIF, or has been, within the past 10 years before the date hereof, a director or executive officer of any other issuer that, while that person was acting in that capacity:

- Was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or
- Was subject to an event that resulted, after the person ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or
- Within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Mr. Reid is a director of Second Wave Petroleum Inc. (SWP), a private oil and gas exploration and production company. On June 30, 2017, SWP made an assignment into bankruptcy pursuant to the *Bankruptcy and Insolvency Act* (Canada) (BIA). On Sept. 7, 2017, SWP made a proposal under the BIA and on Oct. 5, 2017, the proposal was approved by the Court of Queen's Bench of Alberta and the bankruptcy was annulled.

Mr. Dielwart was chair of the board of directors of Denbury Resources Inc. (Denbury), which filed for bankruptcy protection in the United States on July 29, 2020, under a prepackaged reorganization plan with its bondholders. Denbury emerged from Chapter 11 on Sept. 18, 2020, at which time the board of directors was reconstituted and Mr. Dielwart ceased being a director.

Personal Bankruptcies

No director, executive officer or controlling security holder of the Company has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or

became subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold such person's assets.

Penalties or Sanctions

No director, executive officer or controlling security holder of the Company has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, other than penalties for late filing of insider reports; or been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Material Contracts

Other than contracts entered into in the ordinary course of business, the Company believes that the following are material contracts, the particulars of which are disclosed elsewhere in this AIF, to which the Company or its subsidiaries are a party:

- Investment Agreement – See the "Capital Structure – Exchangeable Securities – Investment Agreement" section of this AIF for further details.
- Registration Rights Agreement – See the "Capital Structure – Exchangeable Securities – Registration Rights Agreement" section of this AIF for further details.
- Off-Coal Agreement – See the "Business of TransAlta – Gas Segment – Off-Coal Agreement" section of this AIF for further details.

Conflicts of Interest

Circumstances may arise where members of the Board of Directors serve as directors or officers of corporations that are in competition with the interests of TransAlta. No assurances can be given that opportunities identified by such members of the Board of Directors will be provided to us. However, our policies provide that each director and executive officer must comply with the disclosure requirements of the CBCA regarding any material interest. If a declaration of material interest is made, the declaring director shall not vote on the matter if put to a vote of the Board of Directors. In addition, the declaring director may be requested to recuse himself or herself from the meeting when such matter is being discussed.

Legal Proceedings and Regulatory Actions

TransAlta is occasionally named as a party in claims and legal proceedings that arise during the normal course of its business. We review each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in our favour or that such claim may not have a material adverse effect on TransAlta.

Brazeau Facility — Well Licence Applications to Consider Hydraulic Fracturing

The Alberta Energy Regulator (AER) issued a subsurface order on May 27, 2019, which does not permit any hydraulic fracturing within three kilometres of the Brazeau facility, but permits hydraulic fracturing in all formations (except the Duvernay) within three to five kilometres of the Brazeau facility. Subsequently, two oil and gas operators submitted applications to the AER for 10 well licences (which include hydraulic fracturing activities) within three to five kilometres of the Brazeau facility.

The Company's position, based on independent expert analysis commissioned by the Government of Alberta, is that hydraulic fracturing activities within five kilometres of the Brazeau facility pose an unacceptable risk and that the applications should be denied. The regulatory hearing to consider these applications - Proceeding 379 - has been adjourned to November 2025.

Brazeau Facility — Claim against the Government of Alberta

On Sept. 9, 2022, the Company filed a Statement of Claim against the Government of Alberta in the Alberta Court of King's Bench seeking a declaration that: (a) granting mineral leases within five kilometres of the Brazeau facility is a breach of a 1960 agreement between the Company and the Alberta Government; and (b) the Government of Alberta is required to indemnify the Company for any costs or damages that result from the risks of hydraulic fracturing near the Brazeau facility. On Sept. 29, 2022, the Government of Alberta filed its Statement of Defence, which asserts, among other things, that the Company: (a) is trying to usurp the jurisdiction of the AER; and (b) is out of time under the *Limitations Act (Alberta)*. The trial is scheduled to be heard in September or October 2025 in the event the parties are unable to resolve the dispute prior to such date.

Brazeau — Spinning Reserve Self-Report

On Nov. 30, 2022, TransAlta self-reported to the Market Surveillance Administrator (MSA) a potential violation of the Independent System Operator rules relating to offers of active spinning reserves at Brazeau when it was not properly configured to do so between Aug. 13, 2021, and Nov. 1, 2022. In 2022 a provision of $20 million was initially recognized in revenue reflecting a potential disgorgement of revenue and $2 million for potential penalties and fines. On Nov. 29, 2024, the MSA issued penalties to TransAlta for this self-report and TransAlta made a payment of $33 million in January 2025.

Transfer Agent and Registrar

The transfer agent and registrar for our common shares and Series A, B, C, D, E and G first preferred shares is Odyssey Trust Company. Common shares are transferable in Vancouver, Calgary and Toronto. Series A, B, C, D, E and G first preferred shares are transferable in Calgary and Toronto. The transfer agent and registrar for our common shares in the United States is Odyssey Transfer and Trust Company at its principal office in Woodbury, Minnesota.

Interests of Experts

The Company's auditors are Ernst & Young LLP, Chartered Professional Accountants, located at 2200, 215 – 2nd Street, S.W., Calgary, Alberta, T2P 1M4.

Our auditors, Ernst & Young LLP is the Company's independent public accountant in the context of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta and the rules and regulations adopted by the United States Securities and Exchange Commission and the Public Company Accounting Oversight Board (United States).

Additional Information

Additional information in relation to TransAlta may be found on our website at **www.transalta.com** and under TransAlta's profile on SEDAR+ at **www.sedarplus.ca** and EDGAR at **www.sec.gov**.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities authorized for issuance under equity compensation plans (all where applicable) is contained in our Management Proxy Circular for the most recent annual meeting of shareholders that involved the election of directors and can be obtained upon request from our Investor Relations department, or as filed on SEDAR+ at **www.sedarplus.ca** and EDGAR at **www.sec.gov**.

Additional financial information is provided in our audited consolidated financial statements as at and for the year ended Dec. 31, 2024, and in the related MD&A.

Audit, Finance and Risk Committee

General

The members of TransAlta's Audit, Finance and Risk Committee (AFRC) satisfy the requirements for independence under the provisions of the Canadian Securities Administrators, National Instrument 52-110 – Audit Committees, Section 303A of the NYSE Rules and Rule 10A-3 under the U.S. *Securities and Exchange Act of 1934*. The AFRC's Charter requires that it be made up of a minimum of three independent directors. The AFRC currently consists of five independent members: Thomas M. O'Flynn (Chair), Alan J. Fohrer, Candace J. MacGibbon, Bryan D. Pinney and Manjit K. Sharma.

All members of the committee are financially literate pursuant to both Canadian and U.S. securities requirements and each member of the AFRC has also been determined by the Board of Directors to be an "audit committee financial expert," within the meaning of Section 407 of the U.S. *Sarbanes-Oxley Act of 2002*.

Audit, Finance and Risk Committee Charter

The Charter of the AFRC is attached as Appendix "A".

Relevant Education and Experience of Audit, Finance and Risk Committee Members

The following is a brief summary of the education or experience of each member of the AFRC that is relevant to the performance of his or her responsibilities as a member of the AFRC, including any education or experience that has provided the member with an understanding of the accounting principles that we use to prepare our annual and interim financial statements.

Name of AFRC Member	Relevant Education and Experience
Thomas M. O'Flynn (Chair)	Mr. O'Flynn was the Chief Financial Officer of Powin Energy, an entity in which Energy Impact Partners LP (a private energy technology fund) is a major investor. Prior thereto, Mr. O'Flynn was Chief Executive Officer and Chief Investment Officer at the AES Infrastructure Advisors, Executive Vice President and Chief Financial Officer at Public Service Enterprise Group Incorporated and Head of North American Power at Morgan Stanley. Mr. O'Flynn has a Bachelor of Arts in economics from Northwestern University and a Master of Business Administration, Finance from the University of Chicago.
Alan J. Fohrer	Prior to his retirement in December 2010, Mr. Fohrer was Chair and Chief Executive Officer of Southern California Edison Company, a subsidiary of Edison and one of the largest electric utilities in the United States. Prior to that, Mr. Fohrer served as Vice-President, Senior Vice-President, Executive Vice-President and Chief Financial Officer of both Edison and Southern California Edison Company. Mr. Fohrer also serves on the audit committee of TXNM Energy, Inc., a public company. Mr. Fohrer holds a Master of Business Administration from California State University in Los Angeles.
Candace J. MacGibbon	Ms. MacGibbon was the former Chief Executive Officer and Chief Financial Officer of INV Metals Inc. Prior to this, she was a former manager at Deloitte LLP and held roles within RBC Capital Markets and BMO Capital Markets. Ms. MacGibbon currently serves as a board member of Osisko Gold Royalties, and she is a member of the Audit of Human Resources Committees of Osisko Gold Royalties. Ms. MacGibbon holds a Bachelor of Arts degree in economics from the University of Western Ontario and is a Chartered Professional Accountant with over 25 years of experience in the mining sector and capital markets.
Bryan D. Pinney	Mr. Pinney has 40 years of experience in financial auditing, valuation and advising companies in energy and natural resources. He is an independent director of North American Construction Group Ltd. and chair of its Audit and Finance Committee. He is also an independent director of SNDL, Inc. and chair of its Audit and Finance Committee. He served as a member of Deloitte's Board of Directors and chair of the Finance and Audit Committee. He was the recent Chair and a member of the Board of Governors of Mount Royal University and has previously served on a number of non-profit boards. He has been a Chartered Accountant since December 1978, a Fellow of the Chartered Professional Accountants of Alberta since January 2009 and a Chartered Business Valuator of Canada since December 1990. Mr. Pinney obtained a Bachelor of Arts in business administration from the University of Western Ontario in 1975 and also completed the Directors Education Program offered by the Institute of Corporate Directors in Canada in 2012.
Manjit K. Sharma	Ms. Sharma was the Chief Financial Officer of WSP Canada Inc. Prior to WSP Canada Inc., she was on the National Executive Team of General Electric Canada (GE Canada), serving as Chief Financial Officer from 2016 to 2019. Ms. Sharma currently serves as a board member of each of Vermilion Energy Inc., Finning International Inc. and Export Development Canada. Ms. Sharma holds a Bachelor of Commerce degree (with honours) from the University of Toronto, is a Fellow Chartered Accountant and holds the ICD.D Directors designation and the GCB.D Global Competent Boards designation.

Other Board Committees

In addition to the AFRC, TransAlta has three other standing committees: the Governance, Safety and Sustainability Committee, the Human Resources Committee and the Investment Performance Committee. The members of these committees as at Dec. 31, 2024, are:

Governance, Safety and Sustainability Committee

Chair: Bryan D. Pinney

Alan J. Fohrer

Laura W. Folse

Sandra R. Sharman

Human Resources Committee

Chair: Sandra R. Sharman

Candace J. MacGibbon

Manjit K. Sharma

Sarah A. Slusser

Investment Performance Committee

Chair: Laura W. Folse

Thomas M. O'Flynn

Harry A. Goldgut

James Reid

Sarah A. Slusser

Mr. John P. Dielwart also attends each of the Committee meetings in his capacity as Chair of the Board of Directors.

Charters of the Governance, Safety and Sustainability Committee, the Human Resources Committee and the Investment Performance Committee may be found on our website under Governance, Board Committees at **www.transalta.com**. Further information about the Board of Directors and our corporate governance may also be found on our website or in our Management Proxy Circular, which is filed on SEDAR+ at **www.sedarplus.ca** and EDGAR at **www.sec.gov**.

Fees Paid to Ernst & Young LLP

For the years ended Dec. 31, 2024, and Dec. 31, 2023, Ernst & Young LLP and its affiliates billed $4,407,734 and $4,788,655, respectively, as detailed below.

Ernst & Young LLP

Year Ended Dec. 31	2024	2023
Audit fees	$ 3,653,823	$ 4,075,612
Audit-related fees	347,345	668,168
Tax fees	356,391	5,850
All other fees	50,175	39,025
Total	**$ 4,407,734**	**$ 4,788,655**

The nature of each category of fees is described below:

Audit Fees

Audit fees are for professional services rendered for the audit and review of our financial statements or services provided in connection with statutory and regulatory filings and providing comfort letters associated with securities documents and statutory audits.

Audit-Related Fees

Assurance and related services that are reasonably related to the performance of the audit or review of our financial statements that are not included in the audit fees. Audit-related fees include pension audits and other compliance audits.

Tax Fees

Tax fees are tax-related services for the review of tax returns, assistance with questions on tax audits and tax planning.

All Other Fees

Products and services provided by the Company's auditor other than those services reported under audit fees, audit-related fees and tax fees. This includes fees related to training services and advice and assistance with ESG services provided by the auditor.

Pre-Approval Policies and Procedures

The AFRC has considered whether the provision of services other than audit services is compatible with maintaining the auditors' independence. In May 2002, the AFRC adopted a policy that prohibits TransAlta from engaging the auditors for "prohibited" categories of non-audit services and requires pre-approval of the AFRC for other permissible categories of non-audit services, such categories being determined under the *Sarbanes Oxley Act of 2002*. This policy also provides that the Chair of the AFRC may approve permissible non-audit services during the quarter and report such approval to the AFRC at its next regularly scheduled meeting.

Appendix "A"

TransAlta Corporation (the “Corporation”)

Audit, Finance and Risk Committee Charter

A. Establishment of Committee and Procedures

1. Composition of Committee

The Audit, Finance and Risk Committee (the "Committee") of the board of directors (the "Board") of TransAlta Corporation (the "Corporation") shall consist of not less than three directors. All members of the Committee shall be determined by the Board to be independent as required under the provisions of Canadian Securities Regulators' Multilateral Instrument 52-110 Audit Committees, Section 303A of the New York Stock Exchange rules and Rule 10A-3 of the U.S. *Securities and Exchange Act of 1934*, as such rules apply to audit committee members. All members of the Committee must be financially literate pursuant to both Canadian and US securities requirements and at least one member must be determined by the Board to be an "audit committee financial expert" within the meaning of Section 407 of the United States *Sarbanes-Oxley Act of 2002* ("Sarbanes-Oxley Act"). Determinations as to whether a particular director satisfies the requirements for membership on the Committee shall be made by the Board at the recommendation of the Governance, Safety and Sustainability Committee (the "GSSC") of the Board.

2. Appointment of Committee Members

Members of the Committee shall be appointed from time to time by the Board, on the recommendation of the GSSC, and shall hold office until the next annual meeting of shareholders, or until their successors are earlier appointed, or until they cease to be directors of the Corporation.

3. Vacancies

Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board and on the recommendation of the GSSC. The Board shall fill any vacancy if the membership of the Committee is less than three directors.

4. Committee Chair

The Board shall appoint a Chair for the Committee on the recommendation of the GSSC.

5. Absence of Committee Chair

If the Chair of the Committee is not present at any meeting of the Committee, one of the members of the Committee who is present at the meeting shall be chosen by the Committee to preside at the meeting.

6. Secretary of Committee

The Committee shall appoint a Secretary who need not be a director of the Corporation.

7. Meetings

The Chair of the Committee may call a regular meeting of the Committee. The Committee shall meet at least quarterly and at such other times each year as it deems appropriate to fulfill its responsibilities. In addition, the Chair of the Committee or any two members may call a special meeting of the Committee at any time.

The Committee shall also meet in separate executive sessions.

8. Quorum

A majority of the members of the Committee, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak to each other, shall constitute a quorum.

9. Notice of Meetings

Notice of the time and place of every meeting shall be given in writing (including by way of written facsimile communication or email) to each member of the Committee at least 48 hours prior to the time fixed for such meeting, provided, however, that a member may in any manner waive notice of a meeting; and attendance of a member at a meeting constitutes a waiver of notice of the meeting, except where a member attends for the express purpose of objecting to the transaction of any business on the ground that the meeting is not lawfully called. Notice of every meeting shall also be provided to the external and internal auditors.

10. Attendance at Meetings

At the invitation of the Chair of the Committee, other Board members, the President and Chief Executive Officer ("CEO") of the Corporation, other officers or employees of the Corporation, the external auditors, and other experts or consultants may attend a meeting of the Committee.

11. Procedure, Records and Reporting

Subject to any statute or the articles and by-laws of the Corporation, the Committee shall fix its own procedures at meetings, keep records of its proceedings and report to the Board generally not later than the next scheduled meeting of the Board.

12. Review of Charter and Evaluation of Committee

The Committee shall evaluate its performance and review and assess the adequacy of its Charter at least annually or otherwise, as it deems appropriate. All changes proposed by the Committee are reviewed and approved by the GSSC and the Board.

13. Outside Experts and Advisors

In consultation with the Board, the Committee Chair, on behalf of the Committee or any of its members, is authorized, at the expense of the Corporation, when deemed necessary or desirable, to retain independent counsel, outside experts and other advisors to advise the Committee independently on any matter. The retention of such counsel, expert or advisor in no way requires the Committee to act in accordance with the recommendations of such counsel, expert or advisor.

B. Duties and Responsibilities of the Chair

The fundamental responsibility of the Chair of the Committee is to effectively manage the duties of the Committee.

The Chair is responsible for:

1. Chairing meetings of the Committee and ensuring that the Committee is properly organized so that it functions effectively and meets its obligations and responsibilities.
2. Establishing the frequency of Committee meetings, duly convening the same and confirming that quorum is present when required.
3. Working with the CEO, the Executive Vice President, Finance and Chief Financial Officer (the "CFO") of the Corporation, or the Corporate Secretary of the Corporation, as applicable, on the development of agendas and related materials for the meetings.
4. Providing leadership to the Committee and assisting the Committee in ensuring the proper and timely discharge of its responsibilities.
5. Reporting to the Board on the recommendations and decisions of the Committee.

The Chair of the Committee shall review all expense accounts and perquisites of the Chair of the Board and the CEO not less than quarterly to ensure compliance with the Corporation's policies, and shall report to the Committee on an annual basis.

C. Mandate of the Committee

The Committee provides assistance to the Board in fulfilling its oversight responsibilities with respect to: i) the integrity of the Corporation's financial statements and financial reporting process; ii) the systems of internal financial controls and disclosure controls established by management of the Corporation ("Management"); iii) the risk identification and assessment process conducted by Management including the programs established by Management to respond to such risks; iv) the internal audit function; v) compliance with financial, legal and regulatory requirements; and vi) the external auditors' qualifications, independence and performance. In so doing, it is the Committee's responsibility to maintain an open avenue of communication between it and the external auditors, the internal auditors and Management.

The function of the Committee is oversight. Management is responsible for the preparation, presentation and integrity of the interim and annual financial statements and related disclosure documents. Management is also responsible for maintaining appropriate accounting and financial reporting policies and systems of internal controls and disclosure controls and procedures to comply with accounting standards, applicable laws and regulations that provide reasonable assurance that the assets of the Corporation are safeguarded and transactions are authorized, executed, recorded and properly reported.

While the Committee has the responsibilities and powers set forth herein, it is not the duty of the Committee to plan or conduct audits or to determine that the Corporation's financial statements are complete and accurate and in accordance with generally accepted accounting principles. This is the responsibility of Management and the external auditors.

The Committee must also designate at least one member as an "audit committee financial expert." The designation of a member or members as an "audit committee financial expert" is based on that individual's education and experience, which the individual will bring to bear in carrying out his or her duties on the Committee. Designation as an "*audit committee financial expert*" does not impose on such person any duties, obligations and liability that are greater than the duties, obligations and liability imposed on another member of the Committee and Board in the absence of such designation.

Management is also responsible for the identification and management of the Corporation's risks and the development and implementation of policies and procedures to mitigate such risks. The Committee's role is to provide oversight in order to ensure that the Corporation's assets are protected and safeguarded within reasonable business limits. The Committee reports to the Board on its risk oversight responsibilities.

D. Duties and Responsibilities of the Committee

1. Financial Reporting, External Auditors and Financial Planning

A) Duties and Responsibilities Related to Financial Reporting and the Audit Process

(a) Review with Management and the external auditors the Corporation's financial reporting process the work to be conducted in conjunction with the annual audit and the preparation of the financial statements, including, without limitation, the annual audit plan of the external auditors, the judgment of the external auditors as to the quality, not just the acceptability, of and the appropriateness of the Corporation's accounting principles as applied in its financial reporting and the degree of aggressiveness or conservatism of the Corporation's accounting principles and underlying estimates;

(b) Review with Management and the external auditors the Corporation's audited annual financial statements, including the notes thereto, "Management's Discussion and Analysis," the related earnings release, and recommend their approval to the Board for release to the public;

(c) Review with Management and the external auditors the Corporation's interim financial statements, including the notes thereto, "Management's Discussion and Analysis," the related earnings release, and approve their release to the public as required;

(d) In reviewing the financial statements and related financial disclosure, the Committee shall review and discuss with Management and the external auditors:

(i) any changes in accounting principles, practices or policies considering their applicability to the business and financial impact;

(ii) Management's processes for formulating sensitive accounting estimates and the reasonableness of the estimates;

(iii) the use of "pro forma" or "non-comparable" information and the applicable reconciliation;

(iv) alternative treatments of financial information within generally accepted accounting principles that have been discussed between Management and the auditors, ramifications of the use of such alternative disclosures and treatments and the treatment preferred by the external auditors; and

(v) disclosures made to the Committee by the CEO and CFO during their certification process for the relevant periodic/annual report filed with securities regulators to ensure that information required to be disclosed is recorded, processed, summarized and reported within the time periods specified for the reporting period. Obtain assurances from the CEO and CFO as to the adequacy and effectiveness of the Corporation's disclosure controls and procedures and systems of internal control over financial reporting and that any fraud involving Management or other employees who have a significant role in the Corporation's internal controls is reported to the Committee.

(e) In reviewing the financial statements and related financial disclosure, the Committee shall also, with the external auditors:

(i) discuss the cooperation they received from Management during the course of their review and their access to all records, data and information requested; and

(ii) satisfy itself that there are no unresolved issues between Management and the external auditors that could reasonably be expected to materially affect the financial statements.

(f) Review quarterly with senior Management, the Executive Vice President, Legal (or, as necessary, outside legal advisors) of the Corporation, and the Corporation's internal and external auditors, the effectiveness of the Corporation's internal controls to ensure the Corporation is in compliance with legal and regulatory requirements and the Corporation's policies;

(g) Review with Management and the external auditors the processes relating to the assessment of potential fraud, programs and controls to mitigate the risk of fraud, and the processes put in place for monitoring the risks within the targeted areas; and

(h) Discuss with Management and the external auditors any correspondence from or with regulators or governmental agencies, any employee complaints or any published reports that raise material issues regarding the Corporation's financial statements or accounting policies.

B) Duties and Responsibilities Related to the External Auditors

(a) The Committee shall have direct responsibility for the compensation and oversight of the external auditors including nominating the external auditors to the Board for appointment by the shareholders at the Corporation's general annual meeting. In performing its function, the Committee shall:

(i) review and approve annually the external auditors audit plan;

(ii) review and approve the basis and amount of the external auditors' fees and ensure the Corporation has provided appropriate funding for payment of compensation to the external auditors;

(iii) subject to the delegation granted to the Chair of the Committee, pre-approve all audit related services including all non-prohibited non-audit services provided by the external auditors; the Chair of the Committee is authorized to approve all audit related services including non-prohibited non-audit services provided by the external auditors, and shall report all such approvals to the Committee at its next scheduled meeting;

(iv) review and discuss annually with the external auditors all relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence, including, without limitation: (a) requesting, receiving and reviewing, at least annually, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on their independence with the Corporation; (b) discussing with the external auditors any relationships or services that the external auditors believe may affect their objectivity and professional skepticism; (c) reviewing with the external auditors the experience and qualifications of the senior personnel who are providing audit services to the Corporation; (d) reviewing the quality control procedures of the external auditors, including obtaining confirmation that the external auditors are in compliance with Canadian and U.S. regulatory registration requirements; and (e) evaluating the communication and interaction with the external auditor including quality of service considerations;

(v) in the year preceding the change of the lead (or coordinating) audit partner (having primary responsibility for the audit), and in any event not less than every five years, perform a comprehensive review of the external auditor which takes into consideration (a) the impact of the tenure of the audit firm on audit quality, trends in the audit firm's performance and expertise in the industry, incidences of independence threats and the effectiveness of safeguards to mitigate those threats, (b) the responsiveness of the audit firm to changes in the entity's business and suggestions for improvement from regulators, the Committee and/or Management, (c) the consistency and rigour of the professional skepticism applied by the external auditor, and the quality of the engagement team and its communications, review of Canadian Public Accountability Board (CPAB) inspection findings since the previous comprehensive review and how the audit firm responded to these findings, and following this comprehensive review, determine whether the audit firm should be nominated to the Board as the external auditors for appointment by the shareholders at the Corporation's next general annual meeting;

(vi) inform the external auditors and Management that the external auditors shall have direct access to the Committee at all times, as well as the Committee to the external auditors;

(vii) instruct the external auditors that they are ultimately accountable to the Committee as representatives of the shareholders of the Corporation; and

(viii) at least annually, obtain and review the external auditors' report with respect to the auditing firm's internal quality-control procedures, any material issues raised by the most recent internal quality-control review or peer review of the auditing firm, any inquiry or investigation by governmental or professional authorities within the preceding five years undertaken respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with any such issues.

C) Duties and Responsibilities Related to Financial Planning

(a) Review and recommend to the Board for approval the Corporation's issuance and redemption of securities (including the review of all public filings to effect any of the issuances or redemptions), financial commitments and limits, and any material changes underlying any of these commitments;

(b) Review annually the Corporation's annual tax plan;

(c) Receive regular updates with respect to the Corporation's financial obligations, loans, credit facilities, credit position and financial liquidity;

(d) Review annually with Management the Corporation's overall financing plan in support of the Corporation's capital expenditure plan and overall budget/medium range forecast; and

(e) Review with Management at least annually the approach and nature of earnings guidance and financial information to be disclosed to analysts and rating agencies.

2. Internal Audit

(a) Approve whether the internal audit function should be outsourced and if outsourced, approve the audit firm to perform such internal audit service; provided that in no event shall the external auditor be retained to also perform the internal audit function;

(b) Review and consider, as appropriate, any significant reports and recommendations made by internal audit relating to internal audit issues, together with Management's response thereto;

(c) Review annually the scope and plans for the work of the internal audit group, the adequacy of the group's resources, the internal auditors' access to the Corporation's records, property and personnel;

(d) Recognize and advise senior Management that the internal auditors shall have unfettered access to the Committee, as well as the Committee to the internal auditors;

(e) Meet separately with Management, the external auditors and internal auditors to review issues and matters of concern respecting audits and financial reporting;

(f) Review with the senior financial members of Management and the internal audit group the adequacy of the Corporation's systems of internal control and procedures; and

(g) Recommend to the Human Resources Committee of the Board the appointment, termination or transfer of the lead individual responsible for internal audit, provided that if the internal audit function has been, or is being, outsourced to an audit firm, the Committee itself shall approve the appointment, termination or transfer of such audit firm.

3. Risk Management

The Board is responsible for ensuring that the Corporation has adopted processes and key policies for the identification, assessment and management of its principal risks. The Board has delegated to the Committee the responsibility for the oversight of Management's identification, and evaluation, of the Corporation's principal risks, and the implementation of appropriate policies, processes and systems to manage or mitigate the risks within the Corporation's risk appetite. The Committee reports to the Board thereon.

The Committee shall:

(a) Review, at least quarterly, Management's assessment of the Corporation's principal risks; discuss with Management the processes for the identification of these risks and the efficacy of the policies and procedures for mitigating and/or addressing these risks;

(b) Receive and review Managements' quarterly risk update including an update on residual risks;

(c) Review the Corporation's enterprise risk management framework and reporting methodology;

(d) Review annually the Corporation's Financial and Commodity Exposure Management Policies and approve changes to such policies;

(e) Review and approve the Corporation's strategic hedging program, guidelines and risk tolerance;

(f) Review and monitor quarterly results of financial and commodity exposure management activities, including foreign currency and interest rate risk strategies, counterparty credit exposure and the use of derivative instruments;

(g) Review the Corporation's annual insurance program, including the risk retention philosophy, potential exposure and corporate liability protection programs;

(h) Periodically consider the respective roles and responsibilities of the external auditor, the internal audit department, internal and external counsel concerning risk management and review their performance in relation to such roles and responsibilities; and

(i) Annually, together with Management, report and review with the Board:

(i) the Corporation's principal risks and overall risk appetite/profile;

(ii) the Corporation's strategies in addressing its risk profile;

(iii) the processes, policies, procedures and controls in place to manage or mitigate the principal risks; and

(iv) the overall effectiveness of the enterprise risk management process and program.

4. Governance

A) Public Disclosure, Legal and Regulatory Reporting

(a) On behalf of the Committee, the Chair shall review all public disclosure inclusive of material financial information extracted or derived from the Corporation's financial statements prior to dissemination to the public;

(b) Review quarterly with the Executive Vice President, Legal and Corporate Secretary, and, if necessary, outside legal advisors, significant legal, compliance or regulatory matters that may have a material effect on the Corporation's financial statements;

(c) Discuss with the external auditors their perception of the Corporation's financial and accounting personnel, any recommendations which the external auditors may have, including those contained in the Management letter, with respect to improving internal financial controls, choice of accounting principles or management reporting systems, and review all Management letters from the external auditors together with Management's written responses thereto;

(d) Review with Management, the external auditors and internal legal counsel (external counsel if necessary), any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Corporation, and the manner in which these may be or have been disclosed in the financial statements;

(e) Review annually the Insider Trading Policy and approve changes as required; and

(f) Review annually the Corporation's Disclosure Policy and Social Media Policy to ensure continued applicability with the law and the Corporation's disclosure principles.

B) Pension Plan Governance

(a) Review annually the Annual Pension Report and financial statements of the Corporation's pension plans including the actuarial valuation, asset/liability forecast, asset allocation, manager performance and plan operating costs, and reporting thereon to the Board annually; and

(b) Together with the Human Resources Committee of the Board, review annually, and as required, the overall governance of the Corporation's pension plans, approving the broad objectives of the plans, the statement of investment policy, the appointment of investment managers, and reporting thereon to the Board annually.

C) Information Technology – Cyber security and Artificial Intelligence

(a) Receive biannually a system status update with respect to the Corporation's core IT operating systems;

(b) Review annually the Corporation's cyber security programs and their effectiveness. Receive an update on the Corporation's compliance program for cyber threats and security; and

(c) Review periodically developments in respect of artificial and generative artificial intelligence, including opportunities, challenges and/or associated risks which could have a material impact on the execution of the Corporation's strategy or key business objectives.

D) Administrative Responsibilities

(a) Review the annual audit of expense accounts and perquisites of the directors, the CEO and the CEO's direct reports and their use of corporate assets;

(b) Establish procedures for the receipt, retention and treatment of complaints relating to securities law, accounting, internal accounting controls, or auditing matters;

(c) Review incidents, complaints or information reported through the Ethics Help Line addressed to the Committee or relating to securities law, accounting, internal accounting controls, or auditing matters;

(d) Establish procedures for the investigation of complaints or allegations, and, in respect of potentially material complaints or allegations, report to the Board thereon and ensure that appropriate action is taken as necessary to address such matter;

(e) Review and consider any related party transaction and to recommend, if necessary, the use of a standing committee or an ad hoc special committee to assist the Board in the evaluation of any such related party transaction;

(f) Review and approve the Corporation's hiring policies for employees or former employees of the external auditors and monitor the Corporation's adherence to the policy; and

(g) Report annually to shareholders on the work of the Committee during the year.

E. Compliance and Powers of the Committee

(a) The responsibilities of the Committee comply with applicable Canadian laws and regulations, such as the rules of the Canadian Securities Administrators, and with the disclosure and listing requirements of the Toronto Stock Exchange, as they exist on the date hereof. In addition, this Charter complies with applicable U.S. laws, such as the *Sarbanes-Oxley Act* and the rules and regulations adopted thereunder, and with the New York Stock Exchange's corporate governance standards, as they exist on the date hereof.

(b) The Committee may, at the request of the Board or on its own initiative, investigate such other matters as are considered necessary or appropriate in carrying out its mandate.

Appendix "B"

Glossary of Terms

"**AER**" – Alberta Energy Regulator

"**AESO**" – The independent system operator and regulatory authority for the Alberta Interconnected Electric System.

"**BC Hydro**" – British Columbia Hydro and Power Authority

"**BIA**" – *Bankruptcy and Insolvency Act* (Canada)

"**boiler**" – A device for generating steam for power, processing or heating purposes, or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes of the boiler shell.

"**capacity**" – The rated continuous load-carrying ability, expressed in megawatts, of generation equipment.

"**CBCA**" – *Canada Business Corporations Act*.

"**CER**" – Clean Electricity Regulations

"**CO_2e**" – Carbon dioxide equivalent.

"**cogeneration**" – A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating or cooling purposes.

"**combined-cycle**" – An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

"**ECCC**" – Environment and Climate Change Canada

"**FERC**" – Federal Energy Regulatory Commission.

"**GGPPA**" – *Greenhouse Gas Pollution Pricing Act* (Canada).

"**GHG**" – Greenhouse gases that have the potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and perfluorocarbons.

"**GW**" – Gigawatt – A measure of electric power equal to 1,000 MW.

"**GW/h**" – Gigawatt hour – A measure of electricity consumption equivalent to the use of 1,000 megawatts of power over a period of one hour.

"**IESO**" – Independent Electricity System Operator.

"**IFRS**" – International Financial Reporting Standards.

"**MSA**" – Market Surveillance Administrator.

"**MSHA**" – Mine Safety and Health Administration.

"**MW**" – Megawatt – A measure of electric power equal to 1,000,000 watts.

"**MWh**" – Megawatt-hour – A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

"**NEM**" – National Electricity Market

"**NERC**" – North American Electric Reliability Corporation.

"**net capacity**" – The maximum capacity or effective rating, modified for ambient limitations, that a generating unit or power plant can sustain over a specific period, less the capacity used to supply the demand of station service or auxiliary needs.

"**NWIS**" – North West Interconnected System

"**NYSE**" – New York Stock Exchange.

"**opt-in facility**" – A facility that satisfies the eligibility criteria for an opted in facility under Section 4 of the TIER regulation and is voluntarily choosing to participate in the regulation for the purposes of being able to generate emission performance credits.

"**SGM**" – Australian Government's National Safeguard Mechanism

"**TIER**" – Technology Innovation and Emission Reduction Regulation in Alberta.

"**TSX**" – Toronto Stock Exchange.

"**VWAP**" – Volume weighted average price

"**WEM**" – Wholesale Electricity Market

"**WTUC**" – Washington Transportation and Utilities Commission

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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 2-102:
Park Service Comments on BART Proposals (Nov. 2009)

United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

TAKE PRIDE IN AMERICA

IN REPLY REFER TO:

November 20, 2009

N3615 (2350)

Mr. Stuart A. Clark
Air Quality Program Manager
Department of Ecology
Air Quality Program
PO Box 47600
Lacey, Washington 98504-7600

Dear Mr. Clark:

Thank you for providing information on the Best Available Retrofit Technology (BART) proposals for facilities in Washington that are subject-to-BART. We recognize that much time and effort went into the analyses conducted by the Department of Ecology (Ecology), and we appreciate the time Ecology has taken to discuss the difficult and important issues inherent in this major effort. These comments supplement the statement made by Randy King, Superintendent of Mount Rainier National Park, at the October 13, 2009, public hearing.

In general, we found the Ecology BART analyses to be informative and well-presented. We also recognize that the BART program is relatively new, which presents several challenges to all of us in its implementation. As a national office which conducts BART analyses for all Class I areas in the National Park System, we are able to call upon a growing information base and wish to take this opportunity to make that information available to Ecology. The State of Washington is fortunate to have an extraordinary number of magnificent national parks and wilderness areas within its borders and accessible to its citizens, as well as to numerous visitors. There are many reasons that the law mandates our highest levels of environmental protection for these special areas. National parks and wilderness areas are our natural and cultural heritage. Sociology studies confirm their importance, as do our individual experiences of recreation and renewal. We share your interest in insuring that these magnificent natural areas are protected for the benefit of all. As mentioned in our testimony at the October 13 public hearing, over 1.1 million people visited Mount Rainier National Park in 2008 and visitation as of the end of August of this year is already above the 1 million mark.

Regarding the economic benefits of the national parks, for example, in 2000, when our last visitor surveys were conducted, we learned that visitors to Mount Rainier and Olympic National Parks spent over $120 million in the area. The total economic impact of visitor spending was $95 million in direct sales, $38 million in personal income, $58 million in direct value-added and 2,530 jobs. With multiplier effects, created by the re-circulation of the money spent by tourists, visitor spending generated about $135 million in local sales, and an associated $52 million in personal income, $82 million in value-added and 3,102 jobs. These figures do not include park admission fees or the impacts of the NPS payroll and operations in the area, nor do they include the economic benefits resulting from visitation to North Cascades National Park or to the nine Class I wilderness areas and the Columbia River Gorge National Scenic Area that are also suffering from visibility impairment as a result of emissions from the Washington BART sources.

Our detailed comments on Ecology's BART proposals are enclosed. Based on our review, we believe the following pollution control technologies are technically feasible, cost-effective, and will substantially improve visibility in one of more of the 12 protected areas (including Mount Rainier and Olympic National Parks) included in Ecology's analyses:

- Selective Catalytic Reduction (SCR) to reduce nitrogen oxides emissions from the Centralia Power Plant
- Sodium-based scrubbing to reduce sulfur dioxide emissions from the potlines at the Intalco primary aluminum smelter
- Additional particulate control on the No. 10 Power Boiler and a limit of 0.5% sulfur on fuel oil burned at the Port Townsend Paper Company
- Low-NO_x and Ultra-Low-NO_x Burners proposed by Tesoro (and accepted by Ecology) to reduce nitrogen oxides emissions at its Anacortes refinery. (We recognize the timing issues and suggest that we work together to develop a Reasonable Progress strategy that will achieve the emission reduction goals proposed by Tesoro in a cost-effective, yet expeditious manner.)

Therefore, we ask that you revisit your BART proposals. It appears that that the key issue in these reviews is whether or not to consider the cumulative benefits of reducing emissions for multiple Class I areas. We address that issue below and in our enclosed comments.

Cost-Effectiveness Metrics

BART is not necessarily the most cost-effective solution. Instead, it represents a broad consideration of technical, economic, energy, and environmental (including visibility improvement) factors. We believe that it is appropriate to consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of improving visibility across all of the Class I areas affected. It simply does not make sense to use the same metric to evaluate the effects of reducing emissions from a BART source that impacts only one Class I area as for a BART source that impacts multiple Class I areas. And, it does not make sense to evaluate impacts at one Class I area, while ignoring

others that are similarly significantly impaired. If we look at only the most-impacted Class I area, we ignore that the other Class I areas are all suffering from impairment to visibility "caused" by the BART source. It follows that, if emissions from the BART source are reduced, the benefits will be spread well beyond only the most-impacted Class I area, and that must be taken into account. .[1]

The BART Guidelines represent an attempt to create a workable approach to estimating visibility impairment. As such, they require several assumptions, simplifications, and shortcuts about when visibility is impaired in a Class I area, and how much impairment is occurring. The Guidelines do not attempt to address the geographic extent of the impairment, but assume that all Class I areas are created equal, and that there is no difference between widespread impacts in a large Class I area and isolated impacts in a small Class I area. To address the problem of geographic extent, we have been looking at the cumulative impacts of a source on all Class I areas affected, as well as the cumulative benefits from reducing emissions. While there are certainly more sophisticated approaches to this problem, we believe that this is the most practical, especially when considering the modeling techniques and information available.

One of the options suggested by the BART Guidelines to evaluate cost-effectiveness is cost/deciview. Compared to the typical control cost analysis in which estimates fall into the range of $2,000 - $10,000 per ton of pollutant removed, spending millions of dollars per deciview (dv) to improve visibility may appear extraordinarily expensive. However, our compilation[2] of BART analyses across the U.S. reveals that the **average cost per dv proposed by either a state or a BART source is $12 - $19 million**,[3] with a maximum of almost $50 million per dv proposed by Colorado at the Martin Drake power plant in Colorado Springs. For example, considering the 12 Class I areas impacted by Centralia, our calculations show that the cost per dv of installing SCR at Centralia would be $5 million, which is relatively cost-effective.

Please note that EPA is proposing to consider the cumulative benefits at multiple Class I areas approach in its own BART determinations. For example, in an August 21, 2009, Advance Notice of Proposed Rulemaking regarding BART for the Navajo and Four Corners power plants, EPA Region 9 discusses an approach to assess visibility improvement that considers multiple Class I areas. And, Oregon considered the cumulative benefits of adding SCR at the Boardman power plant in its determination that SCR would be installed there under the reasonable progress provisions of the Regional Haze Rule. Finally, the Wyoming Department of Environmental Quality explicitly cited[4]

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[1] For example, our analysis, which is described in detail in our enclosed comments, indicates that the cumulative benefits of reducing NO_x emissions from the Centralia power plant are seven times greater than the benefit at Mt. Rainier, the most-impacted Class I area, alone.

[2] Sent to Ecology on 11/13/09 and located at http://www.wrapair.org/forums/ssjf/bart.html

[3] For example, PacifiCorp has stated in its BART analysis for its Bridger Unit #2 that "The incremental cost effectiveness for Scenario 1 compared with the baseline for the Bridger WA, for example, is reasonable at $580,000 per day and $18.5 million per deciview."

[4] As stated by the Wyoming Department of Environmental Quality, "Tuning the existing LNB with OFA and installing SCR is determined to be BART for Unit 3 for NOx based, in part, on the following conclusions: 4. The cumulative 3-year averaged 98th percentile visibility improvement from the baseline

the cumulative benefits to the Bridger and Fitzpatrick Wilderness Areas in its conclusion that adding combustion controls plus SCR to the Naughton Unit #3 is BART.[5]

Over the past several months, we have worked with Ecology staff to evaluate the BART sources under EPA's BART Guidelines, and we are very appreciative of your expertise and assistance. We look forward to continuing this cooperative working relationship as this process advances. We believe that good communication and sharing of information will help expedite this process, and suggest that you contact Don Shepherd at (303) 969-2075 or email him at don_shepherd@nps.gov if you have any questions or comments.

Sincerely,

Christine L. Shaver
Chief, Air Resources Division

Enclosures

cc:
Janice Peterson
Air Resource Specialist
Forest Service
400 N. 34th Street, Suite 201
Seattle, Washington 98103

Rick Graw
Air Resource Management Specialist
USDA Forest Service
Pacific Northwest Region
Natural Resources
P.O. Box 3623
Portland, Oregon 97208-3623

Keith Rose
USEPA Region 10
1200 Sixth Avenue, OWW-130
Seattle, Washington 98101

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summed across both Class I areas achieved by tuning the existing LNB with OFA, SCR, wet FGD, and installing a new full-scale fabric filter, Post-Control Scenario B, was 1.849 Δdv."

[5] In addition, the Wyoming Department of Environmental Quality (WY DEQ) explicitly considered "visibility improvement from new [control options] summed across the [multiple] Class I areas" in its BART determinations for the Bridger, Johnston, and WYODAK power plants. WY DEQ also determined that SCR would be installed on Bridger units #3 & #4 under the Reasonable Progress provisions of the Regional Haze Rule.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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 2-103:
Park Service Comments on Proposed Haze State Implementation Plan (June 2010)

United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

TAKE PRIDE IN AMERICA

IN REPLY REFER TO:

June 11, 2010

N3615 (2350)

Ted Sturdevant, Director
Department of Ecology
P.O. Box 47600
Olympia, WA 98504-7600

Dear Mr. Sturdevant:

On April 1, 2010, we received Washington's draft regional haze implementation plan for review. We appreciate the opportunity to work with the State through the development and review of this plan to make progress toward achieving natural visibility conditions at our National Parks and Wilderness Areas.

This letter acknowledges that the U.S. Department of the Interior, National Park Service, in consultation with the U.S. Fish and Wildlife Service, has received and conducted a substantive review of the Washington draft Regional Haze Rule implementation plan in fulfillment of your requirements under the federal regulations 40 CFR 51.308(i)(2). Please note, however, that only the U.S. Environmental Protection Agency (EPA) can make a final determination regarding the document's completeness and, therefore, ability to receive federal approval from EPA.

Our review focused on eight key content areas that were outlined in a letter dated August 1, 2006, that we sent to each State. The content areas reflect priorities for the Federal Land Manager agencies, and our enclosed comments address these priorities. As we have discussed with your staff, we are concerned that the draft implementation plan as written does not meet all the regulatory requirements of the Regional Haze Rule. Washington has proposed reasonable progress goals without conducting the required four factor analysis of possible emission controls. The proposed reasonable progress goals do not reflect substantive improvement in visibility, and in the case of North Cascades National Park and Glacier Peak Wilderness Area, actually project a degradation in visibility by 2018 compared to the 2000-2004 baseline. We also have concerns with the determinations of Best Available Retrofit Technology (BART). Our BART comments supplement those that we provided on November 20, 2009.

We had a constructive discussion with your staff on May 18, 2010, and have offered our assistance in addressing our technical concerns. We look forward to continued dialog as you revise the implementation plan and respond to our comments per section 40 CFR 51.308(i)(3). For further information regarding our comments, please contact Pat Brewer of my staff, at (303) 969-2153.

Again, we appreciate the opportunity to work closely with the State of Washington to improve visibility in our Class I national parks and wilderness areas.

Sincerely,

for Christine L. Shaver
Chief, Air Resources Division

Enclosure

cc: Mahbubul Islam
Manager, State and Tribal Air Programs Unit
U.S. EPA Region 10
1200 Sixth Avenue
Seattle, WA 98101

Stuart Clark
Manager, Air Quality Program
Department of Ecology
P.B. Box 47600
Olympia, Washington 98504-7600

National Park Service Comments
Washington Draft State Implementation Plan for Regional Haze
June 11, 2010

General Comments

Washington Department of Ecology (Ecology) has provided a clearly written draft regional haze State Implementation Plan (SIP). The draft plan contains several, but not all, of the key policy elements that we outlined in our August 2006 letter to the States. Ecology has demonstrated using the IMPROVE monitoring data and technical analyses provided by the Western Regional Air Partnership (WRAP) that Washington understands the causes of visibility impairment at the Class I areas in Washington.

The draft SIP is missing the required analysis of the four statutory factors to set reasonable progress goals and lacks a substantive long-term strategy for improving visibility in Class I areas in Washington. Ecology is taking few actions beyond reporting existing federal or previous state actions. Ecology needs to do more to demonstrate its commitment to improving visibility.

Ecology's Best Available Retrofit Technology (BART) determinations addressed some of our procedural concerns, but made no changes in control requirements from the draft BART determinations.

We provide more detailed comments on these concerns below. We also agree with comments provided by the Forest Service. We are willing and would welcome the opportunity to assist Ecology to implement the recommended analyses prior to submitting the final SIP to EPA.

Specific Comments

Chapter 5 Baseline and Natural Conditions

It would be helpful to look at daily time series data for each IMPROVE monitor for each year to better understand the frequency of contributions from fire (e.g., few major events vs multiple smaller events) and to better characterize the seasonal variation in contributions from nitrate and sulfate. Daily time series plots can be generated from the VIEWS website (http://views.cira.colostate.edu/web/).

Chapter 6 Emissions Inventory

WRAP provided several inventories to the western states to support regional planning. Ecology has chosen to discuss only two of the available WRAP inventory versions, 2002 Plan d (Plan02d) and 2018 Projected Reasonable Progress version a (PRP18a). It would be helpful to report that a 2002 actual inventory was used for model performance evaluation for the 2002 base year and to clarify how those emissions differed from the 2000-2004 average emissions used in Plan 02d.

Ecology should provide more discussion of the basis for differences between the 2002 Plan02d and the 2018 PRP18a inventory. Please identify the specific On the Books controls that account for the reduction in point source sulfur dioxide (SO_2). Please define whether the PRP18a inventory includes all the controls determined to be BART for sources subject to BART in Washington.

Please discuss the basis for increases between 2002 and 2018 in emissions of SO_2 from area sources and increases in emissions of nitrogen oxides (NO_x), volatile organic compounds (VOC), primary organic carbon (OC), and elemental carbon (EC) from point and area sources. It is difficult to claim progress in improving visibility when Washington emissions are increasing rather than decreasing.

Please clarify why Ecology chose to use the earlier 2018 PRP18a inventory rather than the more recent 2018 PRP18b inventory. We recommend that Ecology use the PRP18b inventory and modeling results. At a minimum, Ecology should explain the significant differences between the PRP18a and PRP18b inventories and define which inventory is more accurate. For example, total projected SO_2 emissions from Washington point sources were 12,262 tons lower in the PRP18b inventory than in the PRP18a inventory. Total NO_x emissions from point sources were 5,250 tons lower in PRP18b than PRP18a. Are these differences due to emissions controls or changes in inventory methods? Did Ecology or WRAP generate these inventory changes?

Chapter 7 WRAP Modeling

Section 7.3 on model performance provides very little information to judge the confidence to place in the modeling results reported over the next 50 pages. It is preferable for Ecology to include model performance charts for sulfate, nitrate, and organic carbon. At a minimum, Ecology should discuss how well the regional models represent meteorology and air quality at the IMPROVE monitors in Washington.

The last sentence in section 7.3 is incomplete.

Section 7.4 accurately discusses the Particulate Source Apportionment Technology (PSAT) modeling and the Weighted Emissions Potential analyses (WEP). In Section 7.4.3 it is important for Ecology to clarify the significant differences between the inventory versions reported in Section 6 (WRAP 2002 Plan02d and 2018 PRP18a), the earlier inventories used for the PSAT modeling (2002 Plan02c and 2018 base b) and the later 2018 inventory used in the WEP analyses (2002 Plan02d and 2018 PRP18b).

Please correct the figure title for Figure 7-3 which refers to WEP results not PSAT results. The last two sentences in Section 7.4.3 appear contradictory.

Chapter 8 Source Apportionment

WRAP's PSAT results for sulfate and nitrate source apportionment and the WRAP WEP analyses are accurately reported. Residence time analyses can assist in defining source areas that

most frequently impact Class I areas. In addition to the residence time plots available on the WRAP Technical Support System (TSS) under the WEP analyses, residence time plots are also provided under the Causes of Haze technical archive:
http://www.coha.dri.edu/images/backtraj/wa_w20_0500m_backtraj_northcascades.gif.

Chapter 9 Reasonable Progress Goals

Ecology has not met the requirements of the regional haze rule Section § 51.308 (d) (1):

> "The reasonable Progress goals must provide for an improvement in visibility for the most impaired days…
>
> (i) In establishing a reasonable progress goal for any mandatory Class I Federal area within the State, the State must:
>
> (A) Consider 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 sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal."

Ecology set reasonable progress goals for the Class I areas in Washington the same as the WRAP PRP18a modeling results. DOE did not consider the four statutory factors. Modeled visibility in 2018 does not meet the uniform rate of progress for 2018. At North Cascades National Park and Glacier Peak Wilderness Area, visibility is projected to degrade by 2018. Both sulfate and organic carbon are projected to increase at North Cascades National Park in 2018 compared to 2002. This result does not comply with Section § 51.308 (d) (1). Ecology needs to explain the basis for these results.

It is difficult to see how Ecology can conclude that the existing controls are sufficient to demonstrate reasonable progress, especially when point and area source emissions in Washington are projected to increase by 2018.

Tesoro Refining and Marketing Company originally proposed to install and operate low NOx burners or ultra low NOx burners on process heaters by 2018 as part of their Best Available Retrofit Technology (BART) proposal. Ecology found the proposed controls to be technically and economically feasible. Since Tesoro proposed to install controls on two heaters during a regularly scheduled maintenance outage in 2017, these controls were determined to be too late to meet BART requirements and not required in Tesoro's permit. We ask Ecology to require by permit that these controls be operational by 2018 as part of the current reasonable progress demonstration.

The regional haze rule Section § 51.308 (d) (1) (vi) instructs:

> "The State may not adopt a reasonable progress goal that represents less visibility improvement than is expected to result from implementation of other requirements of the CAA during the applicable planning period."

Ecology is using the WRAP PRP18a inventory for reasonable progress goals, yet the more recent WRAP PRP18b inventory has lower emissions and the PRP18b modeling results project slightly better visibility at the Class I areas than the PRP18a modeling results. If the PRP18b inventory and modeling results provide a more accurate representation of visibility benefits from expected controls by 2018, then Ecology should cite the PRP18b modeling results.

For the reasonable progress analysis, Ecology should identify the major sources in Washington that may contribute to visibility impairment in Class I areas and potential future controls.

Using the WRAP Emissions Data Management System (EDMS), in the attached table we identified 37 individual units in Washington that have projected 2018 emissions greater than 350 tons per year of either SO_2 or NO_x in the WRAP PRP18a inventory. (Facility name is listed more than once if there are multiple processes at one facility.)

Ecology could use data available through the WRAP EDMS and WRAP WEP to qualitatively rank the potential contributions of Washington point sources to Class I areas. Emissions, distance from the source to the Class I area, and residence time of the grid cell where the source is located can be used to rank the relative importance of specific point sources for consideration in a reasonable progress analysis. Such an analysis is advisable to prioritize DOE's intended control analysis under the long-term strategy. We are available to assist in such an analysis.

Chapter 10 Long Term Strategy

The long-term strategy should include a discussion of the BART controls. Even if exempted from BART, industrial sources may still need to reduce emissions to make reasonable progress toward improving visibility.

Ecology indicates that Washington's silvicultural Smoke Management Plan was included in the 1999 SIP for Reasonably Attributable Visibility Impairment (RAVI). Please clarify if the Smoke Management Plan has been updated since 1999. Please provide additional discussion of the state's control requirements for agricultural burning. More discussion is needed to demonstrate how these smoke management programs restrict emissions.

Ecology discusses that Washington has already implemented a program to address residential wood combustion but does not discuss that the inventory provided by WRAP for this sector is increasing, not decreasing. Please clarify whether the WRAP PRP18a inventory accounts for Washington's residential wood control programs.

Chapter 11 Best Available Retrofit Technology (BART)

Ecology has not fully addressed our previous comments (November 20, 2009).

BART sources in Washington impact several Class I areas. Cumulative visibility impacts need to be considered when determining the appropriate level of control for BART. Ecology's response that there is no single clearly defined method to consider cumulative impacts does not

address our concern. The visibility benefits of controlling a source that impacts 12 Class I areas are greater than the benefits of controlling a source that impacts 1 Class I area, and Ecology's BART analyses should consider cumulative, multi-park impacts. We are willing to assist you in calculating cumulative impacts and multi-park benefits of control scenarios.

Our detailed comments on the proposed BART determinations are provided in the attached analyses and summarized below.

Alcoa Wenatchee: We strongly disagree with using an ultra fine modeling grid to exempt Alcoa Wenatchee from BART eligibility. Control options for this source should have been evaluated.

Centralia:

- We believe that Selective Catalytic Reduction (SCR) is both technically feasible and cost effective to reduce visibility impacts and should be determined to be BART for Centralia.
- TransAlta assumes that due to space constraints, SCR would have to be located on top of the electrostatic precipitator (ESP). TransAlta did not consider the feasibility of a downstream location. Ecology should not have eliminated low-dust and tail-end SCR with resized ductwork as feasible options.
- Ecology has underestimated the ability of SCR to reduce emissions. Ecology assumes that SCR can achieve an annual emissions limit of 0.07 lb/mmBtu or 70% NOx reduction. EPA's Clean Air Markets data base demonstrates that 19 units are achieving an annual emissions rate of 0.05 lb/mmBtu or 90% NOx removal. By underestimating SCR efficiency, cost effectiveness is underestimated.
- Costs of SCR installation are overestimated. The EPA Control Cost manual should have been used as recommended by EPA in the BART guidelines. Several cost items were included in the analysis that are not allowed in the Cost Manual.
- With higher removal efficiency and lower total costs, NPS estimated a reasonable cost effectiveness at $5622/ton, compared to $9091/ton estimated by TransAlta's consultant.
- TranAlta underestimated the visibility benefits of SCR. TransAlta has lowered sulfur dioxide emissions by burning low sulfur coal from Powder River Basin in Wyoming (called FlexFuel project). TransAlta evaluated the visibility benefits of Selective Noncatalytic Reduction (SNCR) with FlexFuel but evaluated SCR without the benefit of FlexFuel. Thus the benefits of SCR are underrepresented.
- We have previously asked Ecology to consider the cumulative visibility impacts of TransAlta on the 12 Class I areas that are within 300 km of the facility, and the potential visibility improvements in those areas from the various control alternatives.

Tesoro:

- Ecology found that NOx emissions controls originally proposed as BART by Tesoro are appropriate and cost effective to implement in the 2017-2018 timeframe. Because these controls cannot be installed by 2015, Ecology determined that they did not meet the BART requirements. Ecology should require these controls to be installed by 2018 as part of reasonable progress.

Port Townsend:

- Ecology must evaluate all technically-feasible and proposed options against the proposed BART limits if these are higher than current emissions limits.
- Ecology must evaluate the visibility impacts of switching to lower sulfur fuels.
- Ecology should have evaluated upgrades to existing control equipment.
- We believe a wet Electrostatic Precipitator for Power Boiler #10 is cost effective and represents BART.

Intalco:

- Costs of Limestone Slurry Forced Oxidation were overestimated.
- Intalco and Ecology should better explain why seawater scrubbing and sodium-based scrubbing were rejected for potline SO_2 emissions.

Conclusions

We would like to see Ecology make a more substantive effort to reduce emissions to improve visibility. We are willing to assist Ecology to address the concerns raised in this review.

Washington Point Source 2018 Emissions SO2 or NOx Greater than 350 Tons/Year
(from Western Regional Air Partnership; plant name is listed more than once if there are multiple units and/or processes at one facility)

Source Category	Source Category	Plant Name	2018 SO2 tons/yr	2018 NOx tons/yr
Primary Metal Production	Aluminum Ore (Electro-reduction)	Aluminum Co Of America Wenatchee Works	3,026	56
		Goldendale Aluminum	433	63
		Intalco Aluminum Corp Ferndale	4,734	29
Pulp and Paper and Wood Products	Sulfate (Kraft) Pulping	Boise Cascade	3,873	609
		Fort James Camas Llc	12	589
		Longview Fibre	125	815
		Pt Townsend Paper	448	374
		Simpson Tacoma Kraft	557	543
		Weyerhaeuser Co	67	839
	Sulfite Pulping	Fort James Camas Llc	8	480
		Weyerhaeuser Co.	284	572
Petroleum Industry	Process Heaters	Bp Cherry Point Refinery	904	1,684
		Conoco Phillips	744	640
		Puget Sound Refining Company	16	577
		Tesoro Northwest Company	1,100	761
	Flares	Puget Sound Refining Company	665	29
	Catalytic Cracking Units	Puget Sound Refining Company	1,571	
	Petroleum Coke Calcining	Bp Cherry Point Refinery	245	843
	Blowdown Systems	Conoco Phillips	559	393
Mineral Products	Cement Manufacturing (Wet Process)	Lafarge North America Inc	1,209	3,528
	Cement Manufacturing (Dry Process)	Ash Grove Cement Co, E Marginal	312	1,597
	Glass Manufacture	Cardinal FG	72	830
		Saint-Gobain Containers Inc	193	669
	Lime Manufacture	Graymont Western Us Inc Total	151	394
Chemical Manufacturing	Nitric Acid	Agrium Us Inc	0	415

Source Category	Source Category	Plant Name	2018 SO2 tons/yr	2018 NOx tons/yr
Electric Generation	Bituminous/ Subbituminous Coal	Transalta Centralia Generation	2,491	14,477
	Wood/Bark Waste	Avista	9	660
	Residual Oil	Daishowa America	412	71
Industrial Combustion Boilers	Process Gas	Conoco Phillips	1,223	103
		Longview Fibre	1,898	27
		Puget Sound Refining Company	4	629
		Tesoro Northwest Company	3,775	1,650
	Wood/Bark Waste	Kimberly-Clark Corporation	499	571
		Weyerhaeuser Co	821	1,666
	Residual Oil	Tesoro Northwest Company	707	117
	Natural Gas	Longview Fibre	1	499
Solid Waste Disposal - Government	Municipal Incineration	Waste To Energy	15	451

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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 2-104:
BART Order No. 6426 (June 18, 2010)

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
PO Box 47600 • Olympia, WA 98504-7600 • 360-407-6000
711 for Washington Relay Service • Persons with a speech disability can call 877-833-6341

June 18, 2010

Mr. Lou Florence,
TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, WA 9853

Dear Mr. Florence:

Regional Haze Best Available Retrofit Technology (BART) Determination
Order No. 6426

Best Available Retrofit Technology (BART) is required to reduce the regional haze impacts of emissions of your facility. The enclosed order #6426 contains our BART determination for your facility including a schedule for compliance.

If you have questions or requests relating to this order, please contact Alan Newman at (360) 407-6810 or by mail at the address above.

Sincerely,

Jeff Johnston, Ph.D.
Science and Engineering Section Manager
Air Quality Program

jj/lb

Enclosure

cc: Clint Lamoreaux, SWCAA
Alan Newman, Ecology
Richard DeBolt, TransAlta

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY

IN THE MATTER OF AN ADMINISTRATIVE ORDER AGAINST:	]	
	]	ORDER NO. 6426
TransAlta Centralia Generation LLC	]	
	]	

TO: Mr. Lou Florence,
TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, WA 98531

This is an Administrative Order requiring your company to comply with WAC 173-400-151 by taking the actions that are described below. Chapter 70.94 RCW authorizes the Washington State Department of Ecology's Air Quality Program (Ecology) to issue Administrative Orders to require compliance with the requirements of Chapter 70.94 RCW and regulations issued to implement it.

Ecology has determined that portions of your facility are subject to the provisions of the state visibility protection program (WAC 173-400-151), which is implemented consistent with the requirements of the federal visibility protection program (40 CFR Part 51, Subpart P). The rules require that the State determine what technologies and level of emission control constitute Best Available Retrofit Technology (BART) for the eligible emission units at your facility. The rules also require the installation and use of those emission controls on the BART-eligible emission units. The emission controls are to be installed as expeditiously as possible, but in no event may the State allow them to start operation later than five years after the State's Regional Haze SIP amendment is approved by the United States Environmental Protection Agency (EPA).

FINDINGS

A. The TransAlta Centralia Generation LLC ("TransAlta") Centralia Power Plant is a coal fired power plant larger than 750 MW output subject to BART.

B. BART emission limitations for sulfur dioxide and particulate were determined by the Environmental Protection Agency in 2003. The Centralia Power Plant's Operating Permit incorporates the BART emission limitations determined by EPA.

C. BART for nitrogen oxides at the Centralia Power Plant is based on:

   a. Use of low NO_x burners with separated and close coupled over fire air systems (aka LNC3).

   b. Use of a sub-bituminous Powder River Basin coal or other coal that will achieve similar emission rates.

c. Use and installation of additional boiler heat recovery equipment and boiler tube cleaning equipment to maximize the extraction of fuel energy into boiler steam.

Additional information and analysis is available in the BART Determination Support Document for the Centralia Power Plant, by the Washington State Department of Ecology, November 2008, and the BART Analysis for the Centralia Power Plant, June 2008 and the BART Analysis Supplement, December 2008.

YOU ARE ORDERED: To install and operate in accordance with the following conditions:

BART Emission Limitations

1. Nitrogen Dioxide Emissions

1.1. Starting no later than the date in Condition 2, emissions of nitrogen dioxide from the two coal-fired utility steam generating units at the Centralia Power Plant are limited to a maximum of:

1.1.1. 0.24 lb/MMBtu, 30 day rolling average, both units averaged together for days (i.e., midnight to midnight) when either unit's generating load is 360 MW gross or greater.

1.1.2. In the event that during a given 30 day period, only one unit operated, the average of both units will be the 30 day average emission rate for the operating boiler.

1.2. Compliance will be determined by use of a continuous emission monitoring system.

1.3. Coal used shall be a sub-bituminous coal from the Powder River Basin or other coal that will achieve similar emission rates.

Schedule for Compliance

2. Compliance with the 30-day rolling average nitrogen dioxide emission limitation begins on the date of issuance of this Order, based on emissions for the prior 30 day period.

3. Determination of compliance with the rolling annual average nitrogen and sulfur coal content limitation will commence at midnight on the 365th day after issuance of this Order, based on coal nitrogen and sulfur content testing during the prior year.

Monitoring and Recordkeeping Requirements

4. Nitrogen Dioxide

4.1. Nitrogen dioxide emissions are to be quantified by means of a continuous emission monitoring system, consisting of a continuous nitrogen dioxide monitor, and a continuous flow rate monitor.

4.2. The continuous monitoring system shall comply with Condition M9 of the Centralia Power Plant's Air Operating Permit, SW98-8- R3 (issued September 16, 2009) ("Air Operating Permit") and corresponding monitoring conditions in future renewals of the Air Operating Permit.

5. Missing data requirements for nitrogen dioxide emission monitoring required by this order

5.1. For a unit with less than 12 continuous hours of missing CEM data, the substituted hourly emission rate will be the higher of (a) the average of emissions during the hour before and the hour after the period of missing data or (b) the average of emissions from the previous 720 operating hours of quality-assured data.

5.2. For a unit with 12 or more continuous hours of missing CEM data, the substituted hourly emission rate will be based on the 90th percentile of the previous 720 operating hours of quality-assured data.

5.3. Those 30 day periods which include substitute data for calculating 30 day averages shall be indicated in the emissions information reported in Condition 7.

6. Coal Quality Monitoring

6.1. Coal nitrogen and sulfur content shall be determined by taking a sampling coal conveyed by the transfer belt between the coal pile and coal silos. An alternate location that provides a sample representative of the coal fired by the boilers may be proposed to Ecology by TransAlta for approval for use.

6.2. A sample of coal for nitrogen and sulfur content analysis will be taken at least once per week when at least one coal fired boiler is in operation. The sample shall be taken following ASTM Method D2234/D2234M-07.

6.3. Coal nitrogen and sulfur content will be determined using ASTM Method D3176-89 (as reapproved in 2002). Note, other ASTM methods related to sample collection and preparation may need to be followed in order to perform this test.

6.4. As an alternate to coal nitrogen and sulfur content testing at the plant, certified results of testing by the coal mine operator of coal actually sent to the Centralia Power Plant may be used. Testing frequency should be no less frequent than required above.

Reporting Requirements

7. Malfunction of the emission control system must, at a minimum, be documented in writing and submitted to SWCAA and Ecology with the emissions monitoring data per Condition 7. Additional recordkeeping and notifications related to excess emissions may also be required by SWCAA regulation.

8. Continuous emission monitoring data shall be submitted to Ecology and to the SWCAA in accordance with condition R3 of the Centralia Plant's Air Operating Permit; SW98-8- R3 (issued September 16, 2009). In addition to the information required in condition R3, the report will include the 30 day rolling average lb. NOx/MMBtu and tons of NOx emitted during the current calendar year. The submittal shall be sent electronically in a format acceptable to the SWCAA. Reporting to Ecology under this condition will end if the Order has been rescinded as provided in Condition 10, below.

9. Coal nitrogen and sulfur content information shall be submitted to Ecology and to the SWCAA in accordance with schedule in condition R3 of the Centralia Plant's Air Operating Permit; SW98-8-R3 (issued September 16, 2009).

    9.1. Coal nitrogen and sulfur reporting during the first year (Oct. 30, 2009 through Oct. 30, 2010) shall include the date each coal sample is taken, the nitrogen and sulfur content of each coal sample analyzed, the running average content and the maximum and minimum concentrations found.

    9.2. After the first year, the report shall include the rolling annual averages for nitrogen and sulfur content plus the maximum and minimum concentrations in the prior year.

    9.2.1. The weekly coal sample test results shall be retained for at least 5 years and available for review by Ecology or SWWCAA upon request.

10. TransAlta may request this Order be rescinded after all of the following occur:

    10.1. The emission limitations in this Order have been incorporated into an enforceable order or permit issued by SWCAA under the criteria of RCW 70.94.152 or 70.94.153 and SWCAA implementing regulations, provided that BART emission limits for the Centralia Power Plant will not be reanalyzed or reconsidered in connection with SWCAA's issuance of such enforceable order or permit.

    10.2. The emission limitations in the enforceable order or permit have been incorporated into the Air Operating Permit issued by SWCAA for the Centralia Power Plant.

    10.3. EPA has incorporated the Order into the Regional Haze State Implementation Plan.

Failure to comply with this Order may result in the issuance of civil penalties or other actions, whether administrative or judicial, to enforce the terms of this Order. Ecology shall enforce the terms of this Order only until such time as SWCAA incorporates the terms of the Order into the Centralia Power Plant's Air Operating Permit or except as provided by RCW 70.94.785.

You have a right to appeal this Order. To appeal you must:

- File your appeal with the Pollution Control Hearing Board within 30 days of the "date of receipt" of this document. Filing means actual receipt by the Board during regular office hours.
- Serve your appeal on the Department of Ecology within 30 days of the "date of receipt" of this document. Service may be accomplished by any of the procedures identified in WAC 371-08-305(10). "Date of receipt" is defined at RCW 43.21B.001(2).

If you appeal you must:

- Include a copy of this document with your Notice of Appeal.
- Serve and file your appeal in paper form; electronic copies are not accepted.

To file your appeal with the Pollution Control Hearing Board:

Mail appeal to:

The Pollution Control Hearings Board
PO Box 40903
Olympia, WA 98504-0903

OR

Deliver your appeal in person to:

The Pollution Control Hearings Board
4224–6th Avenue SE Rowe Six, Bldg 2
Lacey, WA 98503

To serve your appeal on the Department of Ecology:

Mail appeal to:

Department of Ecology
Appeals Coordinator
PO Box 47608
Olympia, WA 98504-7608

OR

Deliver your appeal in person to:

Department of Ecology
Appeals Coordinator
300 Desmond Drive SE
Lacey, WA 98503

And send a copy of your appeal packet to:

Alan Newman
Department of Ecology
Air Quality Program
PO Box 47600
Olympia, WA 98504-7600

For additional information, go to the Environmental Hearings Office website at http://www.eho.wa.gov.

To find laws and agency rules, go to the Washington State Legislature website at http://www1.leg.wa.gov/CodeReviser.

Your appeal alone will not stay the effectiveness of this Order. Stay requests must be submitted in accordance with RCW 43.21B.320. These procedures are consistent with Chapter 43.21B RCW.

DATED this 18 day of June, 2010 at Olympia, Washington.

Jeff Johnston, Ph.D.
Manager, Science and Engineering Section
Department of Ecology
Air Quality Program

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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 2-105:
Sierra Club Comments on Proposed Haze State Implementation Plan

EARTHJUSTICE

ALASKA CALIFORNIA FLORIDA MID-PACIFIC NORTHEAST NORTHERN ROCKIES
NORTHWEST ROCKY MOUNTAIN WASHINGTON, DC INTERNATIONAL

October 5, 2010

Email: AQComments@ecy.wa.gov
Doug Schneider
Department of Ecology
Air Quality Program
P.O. Box 47600
Olympia, WA 98504-7600

RE: Washington Proposed Regional Haze State Implementation Plan Comments by National Parks Conservation Association, Sierra Club, and Northwest Environmental Defense Center

Dear Mr. Schneider:

Earthjustice submits these comments on the Washington Department of Ecology's ("Ecology") Regional Haze State Implementation Plan ("Haze Plan") on behalf of the National Parks Conservation Association, Sierra Club—Cascade Chapter, and Northwest Environmental Defense Center (collectively "Conservation Organizations").

The National Parks Conservation Association ("NPCA") is a national organization whose mission is to protect and enhance America's National Parks for present and future generations. NPCA performs its work through advocacy and education. NPCA has over 340,000 members nationwide with its main office in Washington, D.C. and 24 regional and field offices. NPCA's regional Northwest office is located in Seattle where is works on a variety of issues affecting Northwest National Parks such as North Cascades, Olympic, and Mt. Rainier National Parks. NPCA is active nation-wide in advocating for strong air quality requirements in our parks, including submission of petitions and comments relating to visibility issues, regional haze State Implementation Plans, global warming and mercury impacts on parks, and emissions from individual power plants and other sources of pollutants affecting National Parks. NPCA's members live, work, and recreate in all the National Parks of the Northwest, including those directly affected by the TransAlta coal-fired power plant in Centralia, Washington.

The Sierra Club is a national organization founded in 1892, with more than 60 chapters throughout the U.S., including the Cascade Chapter located in Seattle Washington. The Cascade Chapter's membership resides and recreates throughout the state. Sierra Club is devoted to the study and protection of the earth's scenic and ecological resources—mountains, wetlands, woodlands, wild shores and rivers, deserts, plains, and their wild flora and fauna. An important part of Sierra Club's current work, at both the national and chapter level, is its Beyond Coal campaign which, among other things, focuses on retiring and reforming old coal-fired power plants that are significant contributors to health-harming soot and smog pollution, global warming pollutants, and hazardous pollutants such as mercury.

705 SECOND AVENUE, SUITE 203 SEATTLE, WA 98104-1711
T: 206.343.7340 F: 206.343.1526 E: eajuswa@earthjustice.org W: www.earthjustice.org

The Northwest Environmental Defense Center ("NEDC") is a regional non-profit organization, based in Portland, Oregon. NEDC works to protect the environment and natural resources of the Pacific Northwest, by providing legal support to individuals and grassroots organizations with environmental concerns, and engaging in litigation independently or in conjunction with other environmental groups. NEDC also provides valuable hands-on experience for students seeking to enhance their education in environmental law. NEDC is regularly involved in efforts to maintain or enhance the air quality of the Pacific Northwest, by serving as a watchdog over Oregon's Department of Environmental Quality, Washington's Department of Ecology and each state's respective permitting processes. Student volunteers regularly comment on proposals for new air permits and permit modifications, monitor current permits in search of violations, and stay on top of major air quality issues, such as changes in administrative regulations.

Ecology's proposed Regional Haze SIP fails to meet the legal requirements of the Clean Air Act and federal regulations, and fails to adequately control emissions that cause haze pollutions. As detailed below, the Conservation Organizations respectfully request that the proposed Haze Plan be revised to adequately control these pollutants.

BACKGROUND

Regional haze results from small particles in the atmosphere that impair a viewer's ability to see long distances, color, and geologic formations. While some haze-causing particles result from natural processes, most result from anthropogenic sources of pollution. Haze-forming pollutants, including sulfur dioxide (SO2), nitrogen oxides (NOx), particulate matter (PM), volatile organic compounds (VOCs), and ammonia (NH3), contribute directly to haze or form haze after breaking down in the atmosphere. These air pollutants contribute to the deterioration of air quality and reduced visibility in our national parks and wilderness areas. Visibility impairment is measured in deciviews, which is a measure of the perceptible change in visibility. The higher a deciview value is, the worse the visibility impairment.

The same pollutants that contribute to visibility impairment also harm public health. The fine particulates that cause regional haze, PM2.5, are a major public health concern because they can be inhaled deep into the lungs. Fine particulate can cause decreased lung function, aggravate asthma, and premature death in people with heart or lung disease. NOx and VOCs can also be precursors to ground level ozone, or smog. Ground level ozone is associated with respiratory diseases, asthma attacks, and decreased lung function.[1] The U.S. Environmental Protection Agency (EPA) has found that in 2015, the Regional Haze Rule also will provide substantial health benefits valued at $8.4 – $9.8 billion annually—preventing 1,600 premature deaths, 2,200 non-fatal heart attacks, 960 hospital admissions, and over 1 million lost school and work days.

[1] *See* http://www.nature.nps.gov/stats/index.cfm.

The total annual cost will range from 1.4 – 1.5 billion dollars.[2] These benefits are estimated under the assumption that the Regional Haze Rule will be implemented as intended. Unfortunately, these public health benefits will not be realized for the citizens of Washington if the State of Washington does not revise its plan to meet regional haze protection goals and requirements as set forth below.

Congress declared as the national goal, the "prevention of any future, and the remedying of any existing, impairment of visibility in the mandatory class I Federal areas which impairment results from manmade air pollution." 42 U.S.C. §7491(a)(1). "Manmade air pollution" is defined as "air pollution which results directly or indirectly from human activities." 42 U.S.C. §7491(g)(3). Congress adopted the visibility protection program to protect the "intrinsic beauty and historical and archeological treasures" of specific public lands.[3] To protect these treasures, the regional haze program establishes a regulatory floor and requires states to design and implement programs at least as stringent as the national floor to curb haze causing emissions located within their jurisdictions. In order to meet this goal, a state is required to design an implementation plan to reduce, and ultimately eliminate, haze from air pollution sources within its borders that may reasonably be anticipated to cause or contribute to visibility impairment for any protected area located within or beyond that state's boundaries. In creating and implementing the plan, a state has an unparalleled opportunity to protect and restore regional air quality by curbing visibility impairing emissions from some of its oldest and most polluting facilities.

Each state implementation plan ("SIP") must provide emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress towards meeting the national goal. 42 U.S.C. § 7491(b)(2). Two of the most critical features of a SIP are requirements for (1) the installation of BART for delineated major stationary sources of pollution and (2) a long-term strategy for making reasonable progress towards the national visibility goal. 42 U.S.C. § 7491(b)(2)(A) & (B).

THE WASHINGTON HAZE PLAN IS LEGALLY AND TECHNICALLY DEFICIENT

The Washington Haze Plan fails to require sufficient reductions in visibility-impairing pollutants from major polluting sources, falls far short of meeting reasonable progress goals, and fails to provide a long term strategy that would meet reasonable progress goals. Washington's Haze Plan shows visibility actually *degrading* at North Cascades National Park and Glacier Peak

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[2] EPA, Fact Sheet, *Final Regional Haze Regulations for Protection of Visibility in National Parks and Wilderness Areas* (June 2, 1999) at http://www.epa.gov/visibility/fs_2005_6_15.html.

[3] *See* H.R. REP. NO. 95-294, at 203–04 (1977).

Wilderness Area by the first 2018 milestone. Thus, the Haze Plan utterly fails to reflect *any* progress toward cleaning up visibility at these two Class I areas.

The plan also fails to provide for adequate reasonable progress toward cleaning up visibility impairment at most of its other Class I areas. Ecology found that, at the rate of emission reductions planned for or required by the state regional haze plan, it would take Olympic National Park *323* years to reach natural visibility conditions.[4] Ecology projects it would take *87* years for the Alpine Lakes Wilderness Area to reach natural visibility conditions and *86* years for Mount Rainier National Park.[5] And, amazingly, Ecology predicts it would take the Pasaytan Wilderness *698* years to reach natural visibility conditions.[6] These rates of progress are so ridiculously slow, they are not progress at all, much less reasonable progress.

As addressed below, the State can and must achieve much greater emission reductions in haze causing pollution with available control technologies and/or by imposing more stringent emission limits reflective of the best level of continuous emission reduction in its Best Available Retrofit Technology (BART) determinations. While it may be true that some of the pollution responsible for haze in the State's Class I areas is due to sources outside of Washington's control, that does not relieve Washington from the requirement to subject industrial sources within Washington to BART emission limits reflective of the best degree of continuous emission reduction achievable, nor does it relieve the State from adopting other measures to improve visibility in Washington.

In addition, the long-term strategy must ensure appropriate BART requirements and other measures are implemented to improve visibility in Washington and other downwind states' Class I areas to ensure that the Haze Plan will attain the goal of meet its share of the emission reductions needed to meet the reasonable progress goals for the area. Such additional measures must include consideration of source retirement and replacement. *See* 40 C.F.R. § 51.308(d)(3)(v)(D).

The National Park Service has submitted extensive comments to Ecology detailing the deficiencies in its regional haze plan on June 11, 2010 and on November 20, 2009.[7] Earthjustice submitted comments to Ecology on its Proposed Ecology/TransAlta Settlement Agreement

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[4] *See* Washington Proposed Regional Haze Plan, Chapter 9 at 9-7.

[5] *Id.* at 9-19 and 9-22.

[6] *Id.* at 9-30. Again, the requirement in the law is to reach natural conditions by 2064, 32 years sooner than Ecology apparently intends for Mt. Rainier National Park and 644 years sooner than Ecology apparently intends for the Pasayten Wilderness.

[7] *See* Exhibits 1 and 2 to this letter.

regarding best available retrofit technology (BART) requirements for the TransAlta-owned Centralia coal-fired power plant as well as mercury, and included expert comments by Dr. Ranajit Sahu that discussed the deficiencies in the BART requirements for the TransAlta Centralia Power Plant (the "TransAlta Centralia Plant").[8] EPA also submitted a comment letter to Ecology on June 30, 2010 identifying several deficiencies in the Washington Haze Plan and proposed BART requirements.[9] Ecology has failed to respond adequately to the majority of these comments. Those previous comments are incorporated herein and provide the following additional comments and information to Ecology regarding their deeply-flawed Haze Plan.

I. BEST AVAILABLE RETROFIT TECHNOLOGY REQUIREMENTS ARE NOT MET IN THE WASHINGTON HAZE PLAN.

States are required to submit SIPs if they host federally protected areas or the emissions of a facility located within a State "may be reasonably be anticipated to cause or contribute to any impairment of visibility" for a protected area located beyond their borders. 42 U.S.C. § 7491 (b)(2). A SIP must contain "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress towards meeting the national goal…," including BART requirements for all eligible sources and a long-term strategy for making reasonable progress towards meeting the national goal. 42 U.S.C. § 7491(b)(2)(A) &(B).

BART is defined as an emission limitation:

> **. . .based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility.** The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement invisibility which may reasonably be anticipated to result from the use of such technology.

40 C.F.R. §51.301 (emphasis added).

BART limits are required for major stationary sources that were in existence on August 7, 1977 and began operating after August 7, 1962 and that emit air pollutants that may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area.

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[8] A copy of our November 9, 2009 comment letter is included as Exhibit 3, and a copy of Dr. Sahu's expert report is included as Exhibit 4.

[9] See Exhibit 5 to this letter.

42 U.S.C. § 7491(b)(2)(A). The term "major stationary source" is defined as a source that has the potential to emit 250 tons or more of any pollutant and falls within one of 26 categories of industrial sources defined by the Act. 42 U.S.C. § 7491(g)(7). A BART-eligible source is one that meets the above criteria and is responsible for an impact on visibility in a Class I area of 0.5 deciview or more. 40 C.F.R. Part 51, Appendix Y. BART must be installed and operated no later than five years after the SIP approval. 40 C.F.R. § 51.302(c)(4)(iv).

As discussed in detail below, Washington has clearly not required emissions controls and limits that reflect BART for the BART-eligible sources.

A. BART for the TransAlta Centralia Coal-Fired Power Plant.

The TransAlta Centralia Plant is the largest emitter of regional haze pollutants of all of Washington's BART-eligible sources. Nonetheless, Ecology proposes nothing more than the status quo as BART at this facility. Given that the Washington regional haze plan so woefully fails to even come close to meeting its 2018 reasonable progress goals for any of its Class I areas, Ecology must conduct a proper evaluation of BART for the Centralia plant and require the installation of a selective catalytic reduction (SCR) system is BART for the NOx emissions at the TransAlta Centralia Plant.

1. The NOx BART determination for the TransAlta Centralia Plant is not at least as stringent as the presumptive NOx BART limits for tangentially–fired boilers.

Pursuant to 40 C.F.R. § 51.308(e)(1)(ii)(B), the determination of BART for fossil-fuel fired power plants with more than 750 MW generating capacity, such as the TransAlta Centralia Plant, must be made in accordance with the EPA's Guidelines for BART Determinations Under the Regional Haze Rule in 40 C.F.R. Part 51, Appendix Y. The EPA's BART Guidelines include presumptive BART limits for SO2 and for NOx. Therefore, these presumptive BART limits do not take the place of a case-by-case BART analysis. EPA has determined that these levels of emissions should be cost-effective, but lower emission limits may also be cost-effective. EPA's presumptive limit simply sets the minimum. For tangentially-fired boilers burning Powder River Basin coal, such as the TransAlta Centralia Plant's boilers, EPA's BART Guidelines identify 0.15 lb/MMBtu as the presumptive BART level for NOx. See 40 C.F.R. Part 51, Appendix Y, Table 1. Yet Ecology has proposed a NOx emission limit for the Centralia plant of 0.24 lb/MMBtu 30-day rolling average with both units averaged together. This is well in excess of EPA's presumptive NOx BART limit for similar boiler and coal types. Indeed, the fact that Ecology's determination of NOx emission limits achievable with current NOx controls is 60% higher than EPA's presumptive BART limit for similar boiler and coal types dictates the addition of post-combustion controls for NOx removal in the BART analysis.

2. The NOx BART analysis improperly took into account costs of the "Flex Fuels" project.

Ecology's BART determination for the TransAlta Centralia Plant treats the "Flex Fuels" project as one of the BART controls to be evaluated for costs. While it is true that the change to Powder River Basin coal appears to have lowered the TransAlta Centralia Plant's NOx emission rate, Ecology should not have considered the coal switch as a NOx BART option to be evaluated, because it should have been considered part of the base case for NOx control at the TransAlta Centralia Plant. Further, the costs of switching to Powder River Basin coal at the TransAlta Centralia Plant should not have been considered by Ecology at all in its BART determination.

TransAlta did not switch to Powder River Basin coal to meet BART. Rather, a clear record of evidence shows that the company switched to Powder River Basin coal because the Centralia coal mine was at the end of its economic life. According to a November 27, 2006 statement from TransAlta:

> "After exhausting all alternatives, we have made the difficult but necessary decision to stop mining at Centralia," said Steve Snyder TransAlta President and Chief Executive Officer. "The maturity of the Centralia mine, its rapidly deteriorating mining conditions and escalating costs from excessive overburden have combined to make the mine uneconomic. In order to produce competitively priced electricity from our Centralia coal-fired plant, we have to meet the fuel requirements for our plant from a more predictable and economic source."

See November 27, 2006 TransAlta press release entitled: "TransAlta Stops Mine Operations At Centralia, Switches To Powder River Basin Coal, And Announces Intention To 'Write Down' Centralia Gas Fired Plant."[10] TransAlta's press release did not indicate that this decision was made to meet regional haze requirements or to lower air emissions. The press release makes clear that the decision was economic one made independently of the BART requirements.

Until TransAlta's November 2008 submittal supplementing its BART analysis for the TransAlta Centralia Plant, the company did not include any discussion of its switch to Powder River Basin coal as an emission reduction project to meet BART. Instead, its earlier BART submittals simply stated that the units burn Powder River Basin coal. For example, TransAlta's July 2008 BART submittal simply states under the heading "Coal Characteristics" that "[t]he main source of fuel burned at CPP is being transitioned to be exclusively western sub-bituminous

[10] Copy attached as Exhibit 6; see also http://www.transalta.com/newsroom/news-releases/2006-11-27/transalta-stops-mine-operations-centralia-switches-powder-river-ba.

coal from the Wyoming Powder River Basin (PRB) by 2013."[11] In fact, based on the November 27, 2006 TransAlta press release discussed above, TransAlta had already secured Powder River Basin coal contracts with Rio Tinto Energy America and Peabody Energy's subsidiary COALSALES, LLC., as well as rail transportation contracts with BNSF Railway Company, by November 2006.[12]

Moreover, the fact that TransAlta had to make numerous changes to the boiler to accommodate the coal cannot be considered in a cost determination for the BART analysis. The following describes the reasoning for the boiler changes at Centralia with the switch to Powder River Basin coal:

> The boiler changes will reduce the boiler susceptibility to ash deposition. The major individual pressure part changes include: (a) reheater replacement to maximize sootblower cleaning effectiveness on the tube assembly surface areas, and (b) additional low temperature superheater and economizer heat transfer surface area to result in a lower flue gas exit temperature. Miscellaneous safety and nonpressure boiler changes include: (a) twenty new retractable steam sootblowers and eight new steam wallblowers for each unit to help reduce the slagging and fouling in the boiler furnace and convective heat transfer surfaces; (b) hydrojets cleaning system to maintain heat transfer effectiveness inside the furnace and lower the flue exhaust gas temperature.

See TransAlta's November 2008 Supplement to the BART Analysis for the TransAlta Centralia Power Plant at 1.

Most, if not all, of TransAlta's equipment replacement at the TransAlta Centralia Plant was due to the company's economic decision to switch to Powder River Basin coal and for the need to extend the life of the boilers. The TransAlta Centralia Plant's boilers were commissioned in 1971 and 1972. The components of the boilers , in particular the reheater and the sootblowers, were at the end of their useful life. While these components may have been replaced in part to help the boilers better utilize the Powder River Basin coal, it is entirely inappropriate to include the costs of life-extension work as the cost of a BART "Flex Fuels" project. TransAlta and Ecology are misleading the public through their representations that TransAlta is spending a significant amount of money to reduce NOx. Rather, TransAlta made

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[11] *See* BART Analysis for Centralia Power Plant, prepared for TransAlta by CH2MHill, Revised July 2008, at ES-3.

[12] *See* November 27. 2006 TransAlta news release entitled: "TransAlta stops mine operations at Centralia, switches to Powder River Basin coal, and announces intention to 'write down' Centralia gas fired plant," Exhibit 6.

the business decisions to switch to Powder River Basin coal and to replace worn out components of the boiler in order to extend the life of the boilers another 20 years or more.

Ecology also misrepresents its rationale for the NOx decrease with the switch to Powder River Basin coal by stating that there would be less fuel burned because of the higher heat value of the Powder River Basin coal.[13] Given that the characteristics of Powder River Basin coal increase the heat rate of the boiler[14] (i.e., the amount of Btu heat input it takes to produce one kW-hr), the tons of coal burned will not likely decrease with the change to Powder River Basin coal. Depending on the amount of increased heat rate with Powder River Basin coal, the total amount of coal burned at the Centralia units could even increase above the amounts of Centralia mine coal burned in prior years.

Thus, for all of the above reasons, Ecology cannot properly conclude that the "Flex Fuels" project constitutes BART for NOx at Centralia. Although the switch to Powder River Basin coal at Centralia did reduce NOx emissions to some extent, the reductions come nowhere near to what EPA has identified as presumptive BART levels for this plant. Instead the burning of Powder River Basin coal at Centralia should simply be considered part of base case emissions in the BART evaluation. The "Flex Fuels" technology is the plant's current mode of operation, and has been since at least 2006 if not earlier, it fails to conform to presumptive BART limits and thus it does not meet the haze reduction requirements of the Clean Air Act or EPA regulation.

3. Ecology failed to consider state of the art combustion controls, including Selective NonCatalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR).

Neither Ecology nor TransAlta evaluated any upgrades to the Centralia units' low NOx burners that were installed between 2000-2002 or any additional combustion controls that could be used to reduce NOx at the boilers. Ecology has proposed a plantwide NOx BART emission limit with the unit's existing combustion controls of 0.24 lb/MMBtu (30-day average, both units averaged together). State-of-the-art combustion controls can achieve much lower NOx emissions with Powder River Basin coal.

For example, the W.A. Parish Unit 6 facility was retrofitted with DRB-4Z™ ultra-low NOx burners with interlaced overfire air in 2000, and has achieved post-retrofit NOx emissions

[13] *See* Washington Regional Haze Plan, Appendix L at 8.

[14] *Id.* at 7.

of 0.17 lb/MMBtu or lower.[15] The W.A. Parish facility was emitting NOx at a rate of 0.40 lb/MMBtu before the retrofit.[16]

In addition, at Plant Scherer Units 3 and 4 which burn 100% Powder River Basin coal and are approximately 900 MW in size each, modifications were made to add separated overfire air ports and openings to provide deeper staging capabilities and distance from the combustion zone. Unit 3 had baseline NOx emissions of 0.22 to 0.33 lb/MMBtu and its post change NOx emissions decreased to 0.12 to 0.14 lb/MMBtu.[17] Unit 4 achieved even lower NOx emissions – 0.10 to 0.13 lb/MMBtu.

As discussed in Dr. Sahu's November 4, 2009 comments on the TransAlta Preliminary BART Determination, another option to further reduce NOx is the use of neural net controls such as NueCo. See Exhibit 4, ¶ 14. Dr. Sahu also provided examples of several existing Powder River Basin coal fired electrical generating units achieving NOx emission rates lower than Centralia through the use of combustion controls. *Id.*, Tables 1-6.

With more effective combustion controls, the TransAlta Centralia Plant could likely at least reduce its NOx emissions to meet presumptive BART limit of 0.15 lb/MMBtu. Further, with lower levels of NOx emitted from the boiler, the size of SCR equipment can be reduced because less catalyst would be required to remove NOx, meaning lower capital and operational costs. Thus, Ecology should have required TransAlta to evaluate various combustion control techniques to reduce NOx emissions from the TransAlta Centralia Plant boilers and also should have required evaluation of those combustion control techniques along with SCR at the TransAlta Centralia Plant.

4. TransAlta appears to have overstated the cost of hot-side SCR installation at the TransAlta Centralia Plant units.

As discussed in the National Park Service's comment letters from November 2009 and June 2010, as well as in EPA's June 2010 comment letter to Ecology, the determination of costs for SCR installation at the TransAlta Centralia Plant appears to be greatly overstated in TransAlta's BART analysis.

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[15] See Bryk, S.A. et al., First Commercial Application of DRB-4Z™ Ultra Low NOx Coal-Fired Burner, presented to POWER-GEN International 2000, November 14-16, 2000, Orlando, FL. (Exhibit 7).

[16] *Id.*

[17] *See* Whitfield, T. et al., Comparison of NOx Emission Reductions with PRB and Bituminous Coal in 900 MW Tangentially Fired Boilers, presented to EPRI-DOE-EPA-AWMA Mega Symposium, May 19-22, 2003, at 6. (Exhibit 8).

a. Total capital costs are higher than reported by others.

Capital costs for pollution control equipment are commonly reported on a dollar per kilowatt of capacity basis. TransAlta estimated the capital costs for SCR installation at each TransAlta Centralia Plant unit to be $580,290,872.[18] At 702.5 MW each, this equates to $413/kW based on the net MW production of each unit. Yet five industry studies conducted between 2002 and 2007 have reported the installed unit capital cost of SCRs,[19] or the costs actually incurred by owners, expressed in dollars per kilowatt. These actual costs are lower than estimated for the TransAlta Centralia Plant, and they call TransAlta's estimates into serious question.

The first study evaluated the installed costs of more than 20 SCR retrofits from 1999 to 2001. The installed capital cost ranged from **$116 to $233/kW,** converted to 2008 dollars.[20] It should be noted that 2008 dollars are used in these comparisons because of the fact that theCH2MHill Centralia BART cost analysis are in 2008 dollars.[21] Costs are escalated through using the Chemical Engineering Plant Cost Index (CEPCI).

Similarly, the second survey of 40 installations at 24 stations reported a cost range of **$83 to $265/kW**, converted to 2008 dollars.[22] The third study, by the Electric Utility Cost Group, surveyed 72 units totaling 41 GW, which represents 39% of installed SCR systems in the U.S. The study reported a cost range of **$145/kW to $321/kW**, converted to 2008 dollars.[23] A fourth

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[18] *See* July 2008 TransAlta BART Analysis, Appendix A, Table entitled "Capital Costs for Both Units 1 and 2."

[19] J. Edward Cichanowicz, Current Capital Cost and Cost Effectiveness of Power Plant Emissions Control Technologies, June 2007. Exhibit 9.

[20] Bill Hoskins, Uniqueness of SCR Retrofits Translates into Broad Cost Variations, Power Engineering, May 2003. Exhibit 10. The reported range of $80 to $160/kW $123 - $246/kW was converted to 2008 dollars ($116 - $233/kW) using the ratio of CEPCI in 2008 to 2002: 575.4/395.6.

[21] *See* July 2008 TransAlta BART Analysis at ES-3.

[22] J. Edward Cichanowicz, Why are SCR Costs Still Rising?, Power, April 2004, Exhibit 11; Jerry Burkett, Readers Talk Back, Power, August 2004, Exhibit 12. The reported range of $56/kW - $185/kW was converted to 2008 dollars ($83 - $265/kw) using the ratio of CEPCI for 2008 to 1999 (575.4/.390.6) for lower end of the range and 2008 to 2003 (575.4/401.7) for upper end of range, based on Figure 3.

[23] M. Marano, Estimating SCR Installation Costs, Power, January/February 2006. Exhibit 13. The reported range of $100 - $221/kW was converted to 2008 dollars ($130 - $286/kW) using the ratio of CEPCI for 2008 to 2004: 575.4/444.2.
http://findarticles.com/p/articles/mi_qa5392/is_200602/ai_n21409717/print?tag=artBody;col1

study, presented in a course at PowerGen 2005, reported an upper bound range of **$197/kW to $221/kW**, converted to 2008 dollars.[24] A fifth summary study reports recent applications that either become operational in 2006 or were scheduled to start up in 2007 or 2008 cost in excess of $200/kW on a routine basis, with the highest one slated for startup in 2009 at $300/kW.[25]

Thus, the overall range for these industry studies is **$83/kW to $300/kW**. The upper end of this range is for highly complex retrofits with severe space constraints, such as Belews Creek, reported to cost **$290/kW**,[26] or Cinergy's Gibson Units 2-4. Gibson, a highly complex, space-constrained retrofit in which the SCR was built 230 feet above the power station using the largest crane in the world,[27] only cost $275/kW in 2008 dollars.[28]

Further, the Centralia SCR cost estimates are much higher than other recent estimates. Wisconsin Electric estimated the cost to retrofit SCR on Oak Creek Units 5-8 to be **$205/kW**[29] for a cold-side SCR. This cost was certified in July 2008 for construction by the Wisconsin Public Services Commission.[30] Wisconsin Power and Light estimated the cost to

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[24] PowerGen 2005, Selective Catalytic Reduction: From Planning to Operation, Competitive Power College, by Babcock Power, Inc. and LG&E Energy, December 2005, Exhibit 14. The reported range of $160 - $180/kW) was converted to 2008 dollars ($197 - $221/kW) using the ratio of CEPCI for 2008 to 2005 (575.4/468.2).

[25] J. Edward Cichanowicz, Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies, June 2007, pp. 28-29, Figure 7-1 (Exhibit 9).

[26] Steve Blankinship, SCR = Supremely Complex Retrofit, Power Engineering, November 2002, Exhibit 15. The unit cost: ($325,000,000/1,120,000 kW)(608.8/395.6) = $290/kW. http://pepei.pennnet.com/display_article/162367/6/ARTCL/none/none/1/SCR-=-Supremely-Complex-Retrofit/

[27] Standing on the Shoulder of Giants, Modern Power Systems, July 2002, Ex. 8.

[28] McIlvaine, NOx Market Update, August 2004, Exhibit 17. SCR was retrofit on Gibson Units 2-4 in 2002 and 2003 at $179/kW. Assuming 2002 dollars, this escalates to ($179/kW)(608.8/395.6) = $275.5/kW. http://www.mcilvainecompany.com/sampleupdates/NoxMarketUpdateSample.htm

[29] Wisconsin Electric Power Company's Application to Install Wet Flue Gas Desulfurization and Selective Catalytic Reduction Facilities and Associated Equipment on Oak Creek Power Plant Units 5, 6, 7 & 8 for Control of Sulfur Dioxide and Nitrogen Oxide Emissions, Appendix C, Emission Reduction Study, Volume 1, Addendum August 20, 2007. Unit cost = ($190,500,000/1,135,000 kW)(608.8/499.6) = $204.5 kW

[30] Certificate and Order, Application to Install Wet Flue Gas Desulfurization and Selective Catalytic Reduction Facilities and Associated Equipment on Oak Creek Power Plant Units 5, 6, 7

retrofit SCR on the 430-MW Edgewater Unit 5 to be **$324/kW** in January 2008.[31] The Edgewater project is pending before the Wisconsin Public Services Commission. Similarly, American Electric Power (AEP) estimated that the average capital cost to install SCRs to remove 85-93% of the NOx from many of its units was **$162/kW**.[32]

The data from these studies and examples indicates that CH2MHill's estimates of capital cost to retrofit SCR at Centralia **($413/kW**) are higher than actual installment costs for SCR retrofits, including very difficult retrofits (which TransAlta and Ecology claim without support, will be the case with the TransAlta Centralia Plant).

b. TransAlta and Ecology used an improper cost method.

There are several ways to estimate cost, depending upon intended use. Costs for BART analyses typically use the total annual cost approach.[33] The total annual cost approach has been used for BACT cost effectiveness analyses since about 1977. That approach estimates costs of various control options by calculating costs equalized annually over the life of the control. These costs are real or constant-dollar estimates in that the effect of inflation has been removed.

A standardized approach is used to assure a level playing field and consistency in estimating costs, as the significance of cost effectiveness values is determined by comparing the costs for a given project to costs at other similar sources. This method was selected by EPA because it determines the "economic" cost of air pollution control, i.e., the true cost to society, it is simple to use, and it allows comparison of alternative control systems with different economic lives. EPA has adopted this approach for BART determinations, with the BART guidance specifically recommending the use of the EPA Control Cost Manual, which uses the total annual cost approach.[34]

& 8 for Control of Sulfur Dioxide and Nitrogen Oxide Emissions, Case 6630-CE-299, July 10, 2008.

[31] Wisconsin Power & Light Co., Certificate of Authority Application, Edgewater Generating Station Unit 5 NOx Reduction Project, Project Description and Justification, November 2008, PSC Ref#: 105618, p. 11. Exhibit 18. The unit cost was calculated from the total project cost minus escalation divided by gross generating capacity or: ($153,944,000 - $14,695,000)/430 MW = $323.8/kW.

[32] AEP, 2008 Fact Book, 43rd Financial Conference, Phoenix, AZ, p. 94. Exhibit 19.

[33] This method is also called the equivalent uniform annual cost method. See 70 Fed. Reg. 39104, 39166 - 39167 (July 6, 2005) which notes the EPA Control Cost Manual should be used where possible. This Manual uses the total annual cost approach.

[34] 70 Fed. Reg. at 39166.

TransAlta did not use the total annual cost approach, and thus its cost effectiveness values are not relevant for purposes of determining cost effectiveness of the various BART options, especially SCR. Further, TransAlta included costs for items that are not to be addressed according to OAQPS's Control Cost Manual.[35]

For example, TransAlta included 8% sales tax in its SCR costs, improperly inflating its costs by $26.8 million.[36] Pollution control equipment is typically exempt from property and sales taxes, which are usually assumed to be zero.[37]

TransAlta also improperly included an additional 10% of the capital costs as "owner's costs."[38] Owner's costs are not included in EPA's Control Cost Manual. Owners do not manage and implement capital projects, but rather retain engineering firms, called the "owner's engineer," to perform these functions. Other owner activities would be part of its overhead. Cost factors used to estimate capital costs are ordinarily reported, and would include these costs. Further, these costs, if not directly part of the project, are outside of the battery limits of a control project and would be part of the owner's overhead. Thus, they are not usually included in cost effectiveness analyses as a separate additional cost.

In addition, TransAlta included a general category of "contingency" and added 15% to the capital costs of SCR at both units.[39] It is not clear what TransAlta intended to fall under this category, and it is questionable whether the inclusion of an addition 15% to the capital costs for unspecific "contingency" is legitimate. TransAlta also included a cost category of "margin" and further added 10% to the capital cost of the SCR installations.[40] TransAlta failed to explain or justify either cost category.

TransAlta further included the cost of lost generation at $20/MWhr and 42 days per unit for SCR installation in the capital cost.[41] This is not one of the allowable items included in the Control Cost Manual. Further, it appears that TransAlta assumed the units would operate at a

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[35] See CH2MHill March 11, 2010 Submittal to Ecology, Table A.

[36] *See* July 2008 Centralia BART Supplement, Appendix A.

[37] OAQPS Control Cost Manual, 2002, Section 4.2, p. 2-48 ("In many cases property taxes do not apply to capital improvements such as air pollution control equipment...")

[38] *See* July 2008 TransAlta BART Analysis, Appendix A, Table entitled "Capital Costs for Both Units 1 and 2."

[39] *Id.*

[40] *Id.*

[41] *Id.*

95% capacity factor during those 42 days. Outages are generally scheduled for slow periods when demand is at the lowest. Also, due to hourly fluctuations in demand, units ramp down during evening hours and rarely would operate at 95% capacity. In addition, it appears that the cost of replacement power did not consider the reduction in the TransAlta Centralia Plant's operating costs during the shutdown for SCR installation. TransAlta identified the capacity factor of the TransAlta Centralia Plant units as 78% of TransAlta's NOx BART cost analysis, plainly an overstatement.[42]

In addition, TransAlta included "Allowance for Funds During Construction" ("AFDUC.") in the capital costs [43] This is not allowed by the EPA Control Cost Manual.

It also appears that TransAlta only assumed a 15-year life of the SCRs in its cost analysis.[44] The default useful life for an SCR system in EPA's Control Cost Manual is 20 years.

The overall result of TransAlta's free use of inflated figures not allowed by the Control Cost Manual is a gross overstatement of the costs of SCR pollutant control technology. The National Park Service raised many of these issues, in addition to other problems with the TransAlta SCR cost analysis, in its November 20, 2009 letter and attachments and in its June 11, 2010 comment letter and attachments. We incorporate those comments by reference into these comments and also have included these comments as Exhibits 1 and 2 to this letter.

c. TransAlta underestimated the NOx emission reductions that can be obtained with SCR.

TransAlta assumed that the installation of SCR for the Centralia units would only achieve a NOx emission rate of 0.07 lb/MMBtu and a 72% NOx removal rate, a rate far below the pollutant reductions SCR can achieve.[45] However, 90% NOx removal with an SCR system is readily achievable. With the current NOx rates the Centralia units are achieving (i.e., lower than

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[42] *See* July 2008 TransAlta BART Analysis, Appendix A, Table entitled "Input Calculations for Both Units 1 and 2."

[43] *See* July 2008 TransAlta BART Analysis, Appendix A, Table entitled "Capital Costs for Both Units 1 and 2."

[44] *See* July 2008 TransAlta BART Analysis, Appendix A, Table entitled "Input Calculations for Both Units 1 and 2." TransAlta assumed a 15 year "Plant Economic Life."

[45] *Id.* Note that Ecology incorrectly states in its BART Determination for TransAlta that the company evaluated 95% NOx removal in its SCR cost analysis. *See* Ecology's BART Determination Document for TransAlta's Centralia Power Plant, revised April 2010, in Appendix L of Washington Regional Haze Plan, at 12.

0.24 lb/MMBtu) and a 90% effective SCR, the units could meet a NOx BART limit as low as 0.03 lb/MMBtu. Achieving these lower levels would represent an additional 57% reduction in NOx emissions that could readily be achieved with SCR, as compared to the meager emission reductions evaluated in TransAlta's SCR analysis.

A review of recent SCR retrofits at other power plants definitively proves that very high levels of NOx removal are being achieved by recent SCR retrofit installations. NOx emission rates less than 0.05 lb/MMBtu are routinely achieved, and NOx removal efficiencies are typically around 90%.[46] Permitting agencies have required lower NOx limits in recent BACT determinations, with many proposed and required BACT limits of 0.05-0.06 lb/MMBtu. For example, the Plant Washington PSD permit, issued in April 2010, requires that unit to meet a 0.03 lb/MMBtu annual average NOx limit as BACT.[47] The Desert Rock PSD permit includes a NOx BACT limit as low as 0.035 lb/MMBtu.[48]

According to TransAlta's calculations, NOx emissions from the two TransAlta Centralia Plant units combined would decrease from 10,910 tpy to 3,055 tpy, for a reduction of 7,855 tpy based on an assumed NOx rate of 0.07 lb/MMBtu and a 72% NOx control efficiency with SCR.[49] Had TransAlta more appropriately assumed a NOx rate of 0.03 lb/MMBtu, which reflects 87.5% removal from current NOx emission rates, the NOx emissions from the units in total would decrease to 1,309 tpy for a reduction of 9,601 tpy from TransAlta's assumed base case emission level of 10,910 tpy. This level would reflect approximately 1,900 additional tons of NOx removed above and beyond the levels assumed in TransAlta's cost analyses. Without adjusting any of the other flaws in TransAlta's SCR cost analysis described above and in the attached exhibits, it is apparent that when more accurate assumptions for NOx emission reductions are evaluated, the cost of SCR at both units would decrease to $7,436/ton of NOx removed (as compared to TransAlta's estimate of $8,205/ton of NOx removed). When the costs of SCR installation at the Centralia units are more appropriately determined, the cost per ton will be even lower.

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[46] *See* Erickson, Clayton A. et al., Selective Catalytic Reduction System Performance and Reliability Review, The 2006 MEGA Symposium, Paper # 121, Exhibit 20.

[47] A copy of the Plant Washington permit is included as Exhibit 21.

[48] The Desert Rock Energy Facility permit requires the facility to achieve, after a NOx optimization period, a NOx emission rate of 0.035 lb/MMBtu on a 365 day rolling average and an emission rate of 0.05 lb/MMBtu on a 30-day rolling average. Exhibit 22. *See also* the National Park Service spreadsheet on BACT limits for New PC Power Plants, Exhibit. 23.

[49] *See* July 2008 TransAlta BART Analysis, Appendix A, Table entitled "Input Calculations for Both Units 1 and 2."

The National Park Service re-calculated the cost effectiveness of SCR at Centralia based on the Control Cost Manual and an assumed NOx emission rate of 0.05 lb/MMBtu in its November 20, 2009 comments and June 11, 2010 comments to Ecology. Those costs are much lower than the inflated capital and annual costs provided by TransAlta. Specifically, the National Park Service's recalculated cost effectiveness of SCR installation at both Centralia units of $5,622./ton which they found it to be a reasonable cost based on the cost of BART installation at other coal-fired electrical generating units.[50]

Ecology must require that the BART analysis of SCR at the Centralia units be based on achievable NOx emission rates, which would be lower than the 0.07 lb/MMBtu emission rate assumed by TransAlta. NOx emission rates of 0.03 lb/MMBtu should be achievable at the Centralia units given the current NOx emission rate, which is below 0.24 lb/MMBtu. The ceiling for the NOx BART limit evaluated should be no higher than 0.05 lb/MMBtu, which should be readily achievable with SCR at the Centralia units.

5. Neither TransAlta nor Ecology evaluated the cost-effectiveness of SCR in a low dust or tail end location.

TransAlta's NOx BART analysis raised issues with the tight space and duct arrangement for installation of SCR units at Centralia. Thus, TransAlta assessed the arrangement of the SCRs physically on top of the existing electrostatic precipitators, which they claimed "exponentially increased the capital costs."[51] Alternative arrangements include: an outboard arrangement; a low-dust SCR (located after the particulate control device); and a tail-end SCR located at the tail end, following all pollution control devices. These latter alternative arrangements are attractive as the SCR is located downstream of the air preheater, thus avoiding the space-constrained area between the boiler outlet and the inlet to the air preheater. Subsets of these alternatives include ducting together two or more units. There is no evidence that any alternative arrangements were considered by Ecology or TransAlta.

Only a high-dust SCR was evaluated for costs. However, retrofitting of a low- dust or tail-end SCR may be a more cost-effective retrofit—especially if combined with upgraded particulate matter controls for these units. Recently, for example, Wisconsin Energies decided it was more cost effective to retrofit Oak Creek Units 5-8 with low dust/tail-end SCRs, rather than

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[50] *See* June 11, 2010 National Park Service Followup Comments on Washington Department of Ecology's (Ecology's) Proposed Best Available Retrofit Technology (BART) Determination for TransAlta Centralia Generation (Exhibit 1) at 12. *See also* the National Park Service spreadsheet of NOx BART Limits and Costs (Exhibit 24).

[51] *See* July 2008 TransAlta BART Analysis at 3-9.

the more traditional high-dust SCRs.[52] Tail-end SCR units can be smaller than high dust units, have longer catalyst life, and can use less expensive catalysts.[53]

Ecology's BART analysis for Centralia is deficient without a cost analysis of alternative SCR locations.

6. Neither TransAlta nor Ecology adequately evaluated the other environmental benefits of SCR installation at the TransAlta Centralia Plant units.

As described above, if TransAlta were to install SCR systems along with combustion controls at the Centralia units, it could reduce NOx emissions by 90%. Not only would such installation improve visibility in the region's Class I areas, it would also likely improve the region's ozone pollution (i.e. O3) due to the fact that NOx is a precursor to ozone. One monitor in King County, to the north of Centralia, shows that emissions are violating the 2008 ozone NAAQS of 0.075 ppm, and Ecology has indicated they will recommend that area for nonattainment designation.[54] Further, data provided with EPA's January 2010 proposed revisions to the ozone NAAQS, which EPA has proposed to lower from 0.075 ppm to 0.060 to 0.070 ppm (8-hour average) (see 75 Fed. Reg. 2938, January 19, 2010), indicates that King County, Pierce County, and Thurston County could be in nonattainment for ozone depending on the level of the final ozone NAAQS that EPA adopts.[55] Reductions in NOx, which are achievable at the Centralia Plant with SCR, would likely help address those counties' ozone problems. Since vegetation damage has been found to occur even where ozone concentrations are below the ozone NAAQS, greater reductions in NOx emissions from the Centralia Plant, as would be obtained by the installation of SCR controls, could also benefit the vegetation of the region's Class I areas.

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[52] See August 24, 2007 letter from Wisconsin Energies to the Public Service Commission regarding the Oak Creek Power Plant, Appendix C August 20, 2007 Addendum Emission Reduction Study, and Appendix C NOx/SO2 Emission Reduction Study. These document are all included as Exhibit 25 to this letter.

[53] See January 2009 FGD and DeNOx Newsletter. Exhibit 26.

[54] *See* March 5, 2009 letter from Ecology to EPA, available at http://www.epa.gov/ozonedesignations/2008standards/rec/letters/10_WA_rec.pdf.

[55] *See* EPA Map Entitled "Counties with Monitors Violating Primary 8-hour Ground-level Ozone Standards 0.060 – 0.070 parts per million," available at http://www.epa.gov/air/ozonepollution/pdfs/20100104maps.pdf.

In addition, nitrogen deposition is also a significant environmental issue in the region. The significant adverse impacts of nitrogen deposition, which are caused by wet and dry deposition of nitrates derived from NOx emissions, on ecological systems is well known. Critical loads (*i.e.*, the amount of nitrogen deposition that an ecosystem can tolerate, above which the system become adversely impacted) are likely to soon be formally used to inform policy developments (*e.g.*, NADP-CLAD Meeting, Pensacola, FL Spring 2009). Further, National Park Service data shows significant concerns with nitrogen deposition in Mt. Rainier National Park, the closest Class I area to the TransAlta Centralia Plant, as well as in Olympic and North Cascades National Parks.[56] Thus, the potential to reduce nitrogen deposition-forming emissions is another compelling reason for requiring installation of the top NOx control measures as BART at the TransAlta Centralia Plant.

Reductions in NOx emissions achievable with SCR would also result in reduced fine particulate emissions. The use of ammonia injection before the electrostatic precipitator ("ESP") has also been shown to reduce sulfate formation by high levels, which would further benefit visibility as well as sulfate deposition and fine particulate concentrations.[57]

Finally, the use of SCR controls helps to oxidize the mercury emitted so it is more readily captured in a particulate control device.[58] SCR catalysts can act to oxidize elemental mercury (*e.g.*, to $HgCl_2$) making it easier to capture downstream in wet FGD systems or particulate matter collection devices. Currently, several industry improvements in SCR technology are being developed that would enhance mercury oxidation across an SCR catalyst for all coal types.[59] SCR would help TransAlta do much better mercury removal than the anemic 50% reduction goals that it has agree to with the state.

In summary, if the TransAlta Centralia Plant were subject to the best control technology for NOx reductions, *i.e.*, SCR (along with Powder River Basin coal and current or upgraded combustion controls), as compared to continuing with the current status quo at the TransAtla

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[56] *See* National Park Service's Air Quality in National Parks, 2008 Annual Performance and Progress Report at 10, available at http://www.nature.nps.gov/air/Pubs/pdf/AQ_Trends_In_Parks_2008_Final_Web.pdf

[57] R.K.Srivastava et al., Emissions of Sulfur-Trioxide from Coal-Fired Power Plants, *J. Air & Waste Manage. Assoc.*, 54: 750-762 at 758-759, June 2004, Exhibit 27.

[58] *See* EPA's Performance and Cost of Mercury and MultiPollutant Emission Control Technology Applications on Electric Utility Boilers, EPA-600/R-03-110, October, 2003, at 5, 9-15. Exhibit 28.

[59] June 29, 2004 letter from ICAC to EPA, pp. 15-17. Exhibit 29.

Plant, significant environmental benefits that would be obtained. Those benefits must be considered by Ecology in determining BART for NOx at the TransAlta Centralia Plant.

7. Ecology must determine the visibility benefits of the SCR plus Flex Fuels BART option.

Neither TransAlta nor Ecology modeled the visibility impacts of the Flex Fuels project (i.e., the lower SO2 emissions due to the lower sulfur coal) in addition to SCR at the TransAlta Centralia Plant units. Instead, TransAlta only modeled the visibility impacts based on a NOx emission rate of 0.07 lb/MMBtu with SCR, but keeping SO2 emissions at the level prior to the Flex Fuels change.[60] This is factually unsupportable. Rather than perform the required visibility analysis for this significant BART option, Ecology simply offered a qualitative statement that "…there would be additional visibility improvements were PRB coal continued to be used by the facility and SCR added."[61] Ecology has not fully evaluated the SCR option without such a visibility analysis, which is mandated by the Clean Air Act and EPA's regional haze regulations. *See* 40 C.F.R. §§51.301 (definition of "best available retrofit technology," 51.308(e)(1)(ii), Appendix Y, Section F.2.(c) and under Step 5; *see also* 42 U.S.C. §7492(g)).

Ecology's assumption that TransAlta would revert to burning Centralia mine coal if SCR was installed is faulty and unsupported. As Ecology has indicated in its BART analysis, he units have been physically modified to more efficiently burn Powder River Basin coal. The company has agreements in place to obtain coal from Powder River Basin mines. Such coal supply contracts cannot be readily cancelled. Thus, TransAlta cannot readily revert to burning Centralia coal.

EPA recently informed Ecology that a complete modeling analysis of the visibility impacts due to SCR along with use of Powder River Basin coal at the Centralia units is necessary in order for the Centralia BART analysis to be considered complete.[62] Yet, Ecology has not required or performed this modeling.

The modeling that TransAlta did for Flex Fuels plus SNCR is not adequate to represent the visibility assessment for Flex Fuels plus SCR. TransAlta only assumed a 25% reduction in NOx emissions with SNCR beyond the NOx levels achieved with Flex Fuels. SCR can achieve 90% NOx removal, which would mean 3-4 times more NOx removed or an additional 8,000-

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[60] *See* BART Determination Support Document for TransAlta Centralia Generation, LLC, Power Plant, Washington Department of Ecology, Revised April 2010, in Appendix L of Proposed Washington Regional Haze Plan, at 17.

[61] *Id.*

[62] *See* June 30, 2010 letter from EPA to Ecology, Exhibit 5.

9,0000 tpy of NOx removed with SCR plus Flex Fuels as compared to SNCR plus Flex Fuels. Such a big decrease in NOx emissions would have a significant impact on visibility.[63]

Ecology cannot adopt its regional haze plan and finalize BART requirements for the TransAlta Centralia Plant without requiring this analysis of the visibility benefits of Flex Fuels plus SCR at both the TransAlta Centralia Plant units.

For all of the above reasons, the BART analysis for the TransAlta Centralia Plant is flawed and incomplete. The Flex Fuels project, in which TransAlta switched to burning Powder River Basin coal for economic reasons, does not constitute BART because it essentially reflects the status quo for Centralia. Given that the Washington Regional Haze SIP does not show that improvements in visibility will be on track to meet the national visibility goal by 2064 at most of the state's Class I areas, the BART determination for the Centralia Power Plant (the largest source of regional haze pollution in the state) must reflect the best system of continuous emission reduction for NOx. TransAlta greatly overestimated the costs for SCR installation and failed to follow EPA requirements for conducting such cost analyses in a BART review. Further, TransAlta underestimated the NOx reductions achievable with SCR and the use of Powder River Basin coal.

The National Park Service analyzed costs of SCR at Centralia in its November 20, 2009 and its June 11, 2010 comments to Ecology using conservative assumptions and more reasonable emission rates, but following EPA's Control Cost Manual. The costs calculated by National Park Service are much lower than those provided by TransAlta. Specifically, the National Park Service's recalculated cost effectiveness of SCR installation at both Centralia units of $5,622./ton which they found it to be a reasonable cost based on the cost of BART installation at other coal-fired electrical generating units.[64]

Ecology has failed to require a modeling analysis that would show the benefits to regional haze in the state's national parks and wilderness areas due to installation of SCR along with the burning of Powder River Basin coal at the TransAlta Centralia Plant units. With that analysis, Ecology could then assess BART in terms of $/deciview of improvement, which would be a fair way to compare BART costs among different sources. Based on the available

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[63] *See* BART Determination Support Document for TransAlta Centralia Generation, LLC, Power Plant, Washington Department of Ecology, Revised April 2010, in Appendix L of Proposed Washington Regional Haze Plan, at 16.

[64] *See* June 11, 2010 National Park Service Followup Comments on Washington Department of Ecology's (Ecology's) Proposed Best Available Retrofit Technology (BART) Determination for TransAlta Centralia Generation (Exhibit 1) at 12.

information, Conservation Organizations submit that such an analysis would further demonstrate that SCR is the appropriate requirement for BART.

B. BART for Tesoro Refining.

The Tesoro Refinery in Anacortes, WA had the highest visibility impacts to Olympic National Park and in North Cascades National Park.[65] Ecology determined that the current emission controls and emission limitations for the Tesoro Refinery, with the exception of one heater, which will obtain new low NOx burners, constitute BART.[66] Ecology's reasoning for not requiring NOx BART installation at any other unit at the Tesoro Refinery was "[d]ue to time needed for the design approval process and the major maintenance cycle at the refinery…."[67] Specifically, for the CO Boiler 2 (F-304) and the catalytic reformer heaters F-6650 through F6653, Ecology determined that it was not cost effective for these units to install new ultra low NOx burners by the BART compliance date (5 years from the date EPA approves the regional haze plan).[68] Ecology determined it would be cost effective for these units to install new low NOx burners by the next scheduled turnaround in 2017.[69] These units are also scheduled for turnaround in 2012. Ecology did not explain why new low NOx burners could not be installed on these units in 2012.

Tesoro has had plenty of notice that BART would be required, and that compliance would be required as expeditiously as practicable, and no later than five years from the date EPA approves the regional haze SIP. EPA promulgated the regional haze rules, including the BART requirements, over 10 years ago. Tesoro first submitted its BART analysis to Ecology in February 2008, 4 years before the 2012 turnaround. Thus, both Tesoro and Ecology could have planned for the installation of low NOx burners at these units in 2012, if not by 2015. In addition, at this point, the BART compliance deadline could reasonably extend to the middle of 2016 if not later because EPA will not likely approve the Tesoro BART requirements any earlier than June of 2011.

In fact, Ecology has simply decided to give Tesoro an exemption from NOx BART, rather than require that Tesoro either change its turnaround schedule for these units (bumping it up by 6 months to year) or require Tesoro to install low NOx burners by 2012. Given that the

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[65] *Id.* at 11-11.

[66] *See* Proposed Washington Regional Haze plan, Chapter 11 at 11-15.

[67] *Id.* at 11-16.

[68] *See* Ecology's BART Support Document, Tesoro Refining and Marketing Company, Revised February 22, 2010, in Appendix L of Proposed Washington Regional Haze Plan, at 38.

[69] *Id.* at 39.

Washington Regional Haze plan utterly fails to meet reasonable progress milestones, showing visibility actually *degrading* in the North Cascades National Park in 2018[70] and estimating that it will take 323 years for Olympic National Park to reach the national visibility goal[71], Ecology cannot justify allowing the refinery to avoid having to meet BART for NOx simply because the compliance deadline does not fit the refinery's preferred maintenance cycle. At a minimum, Ecology should require Tesoro to install new low NOx burners in 2017 during the normal turnaround time for the CO boiler 2 (F-304) and the F6650 to F6653 heaters. Yet, Ecology has not specified *any* reasonable progress requirements for this (or any other) facility. There is simply no excuse for Ecology's failure to require the installation of cost-effective NOx controls at these units as part of its regional haze plan.

Further, Ecology did not require a complete evaluation of BART for SO2 emitted from the Tesoro refinery. Tesoro identified as a control option plantwide SO2 control by removing sulfur from refinery gas via a refinery gas sulfur removal system (which has already been installed at the facility) and recovering the sulfur via a sulfur recovery unit. The sulfur recovery unit currently used by the refinery is operating at capacity, so a new unit would need to be installed. Ecology did not require this control method to meet SO2 emissions. Ecology did not adequately explain the basis for rejecting the SO2 BART controls. If it rejected this control due to the costs, such rejection is not supported. The cost of the sulfur recovery unit evaluated for Tesoro was for a 50 ton per day unit. The BART analysis indicated between 395 to 451 tons per year of SO2 would be reduced from the facility.[72] A 50 ton-per-day sulfur recovery unit can recover 50 tons of sulfur per day, which would equate to a reduction of about 97 tons of SO2 removed *per day.* Yet, the BART analysis inexplicably indicates that 395 to 451 tons of SO2 would be removed *per year*. Thus, the sulfur recovery unit assessed is greatly oversized for the SO2 removal it has to obtain, and a larger sulfur recovery unit will have a higher capital cost than a smaller sulfur recovery unit. Also, based on the annual costs of $6,359,500/year,[73]stated for the assumed $58 million capital cost of a sulfur recovery unit, it appears the annual costs relied a higher interest rate than 7% and/or a shorter life of the sulfur recovery unit than 30 years.[74]

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[70] Washington Proposed Regional Haze Plan, Chapter 9 at 9-8

[71] *Id.* at 9-7.

[72] *See* Ecology's BART Support Document, Tesoro Refining and Marketing Company, Revised February 22, 2010, in Appendix L of Proposed Washington Regional Haze Plan, at 16.

[73] This was determined by multiplying the $14,100/ton cost by the 451 tons of SO2 reduced, as provided in Ecology's BART Support Document for Tesoro at 16.

[74] To annualize capital costs, the capital costs are multiplied by a Cost Recovery Factor. The Cost Recovery Factor is given by the following equation: CRF - $[i(1+i)^n]/[(1+i)^n -1]$

In addition, not only was the cost overestimated due to the size of the Sulfur Recovery Unit, but the stated cost even of a 50 ton-per-day unit seems high. In 2005, the capital cost for a 50 ton-per-day unit was approximately $15 million dollars.[75] That would be $16.5 million in 2008 dollars, which is significantly lower than the $58 million stated as the cost in the Tesoro BART analysis. A 10 ton-per-day sulfur recovery unit, which would still be oversized for the required SO2 removal, would cost only $7.8 million in 2005 dollars.[76] This would be $8.6 million in 2008 dollars. Applying a cost recovery factor assuming 7% interest and 30-year life equates to an annualized cost of $687,982 per year. If 451 tons of SO2 are removed per year, this equates to $1,525/ton of SO2 removed. This should be considered to be a reasonable cost of SO2 removal.

In summary, the NOx and SO2 BART determinations for the Tesoro Refinery are inadequate. As with the TransAlta Centralia Plant, Ecology has determined that the status quo constitutes BART, with the exception of one heater that will be required to install low NOx burners as BART. No additional SO2 controls have been proposed as BART, nor to meet reasonable progress requirements. Given that the SIP does not provide for reasonable progress toward the national visibility goal, it is imperative that Ecology require installation of cost effective pollution controls as BART, or at the minimum, to meet reasonable progress requirements.

C. BART for Alcoa-Wenatchee Works.

Ecology has proposed to find that the Alcoa plant in Wenatchee is not subject to BART because it does not significantly impact visibility in any Class I area. Unfortunately, Ecology's determination is based on a non-guideline model. EPA has informed Ecology that it must first obtain EPA approval for use of this non-guideline model.[77] The National Park Service "strongly disagree[s]" with the use of an ultra-fine modeling grid to exempt Alcoa Wenatchee from

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where i is the interest rate and n is the life of the pollution control equipment. In essence, annualization establishes an annual payment sufficient to finance the capital investment for its entire life. *See* EPA Control Cost Manual, January 2002, Section 1, p. 2-21. For the Sulfur Recovery Unit at Tesoro, assuming 7% interest and a 30 year life, the annualized costs should be $4,640,000.

[75] *See* Gary, James H. et al., Petroleum Refining, Technology and Economics, 5th Edition, 2007, Figure 13.8 at 288. An excerpt from this book with Figure 13.8 is included as Exhibit 30 to this letter.

[76] *Id.*

[77] *See* June 30, 2010 Letter from EPA to Ecology at 1 (Exhibit 5).

BART.[78] Until such approval for the use of a non-guideline model is obtained from EPA, Ecology cannot assume that the Alcoa Wenatchee Works plant is exempt from BART. Ecology should have evaluated BART options for this facility.

II. THE HAZE PLAN MUST PROVIDE FOR REASONABLE PROGRESS.

The Haze Plan must also provide a long-term strategy for achieving reasonable progress toward meeting natural visibility conditions at mandatory Class I areas by 2064. 40 C.F.R. § 51.308(d)(1)(i)(B). If a state's reasonable progress goals do not anticipate restoring visibility to natural conditions by 2064 the state must demonstrate why the goal of attaining natural conditions by the established date is unreasonable. 40 C.F.R. § 51.308(d)(1)(ii). The Haze Plan must provide for improved visibility on the most impaired days and ensure no degradation in visibility for the least impaired days. 40 C.F.R. § 51.308(d)(1)(i)(B). The long-term strategy is typically a 10-15 year plan containing enforceable measures designed to meet regional progress goals. In developing its plan, the State must document the technical basis for the SIP, including monitoring data, modeling, and emission information, including the baseline emission inventory upon which its strategies are based. 40 C.F.R. § 51.308(d)(3)(iii).

In developing its long-term strategy, a state must consider all anthropogenic sources of visibility impairment and evaluate different emission reduction strategies beyond those prescribed by the BART provisions. 40 C.F.R. §51.308(d). A state should consider "major and minor stationary sources, mobile sources and area sources." *Id.* At a minimum, a state must consider the following elements:

> (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) Emissions limitations and schedules for compliance to achieve the reasonable progress goal;
> (D) Source retirement and replacement schedules;
> (E) Smoke management techniques for agriculture and forestry management purposes including plans as currently exist within the State for these purposes;
> (F) Enforceability of emission limitations and control measures; and
> (G) The anticipated net effect on visibility due to projected changes in point, area, and mobile emissions over the period addressed by the long-term strategy.

40 C.F.R. 51.208(d)(3)(v)(A)-(G).

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[78] *See* June 11, 2010 Letter from NPS to Ecology, Attachment Entitled "Washington Draft State Implementation Plan for Regional Haze at 5 (Exhibit 1).

In addition to its failure to adequately assess and require BART, including SCR for the TransAlta Centralia Plant, Washington has not required any source emission reductions or source retirements other than its inadequate, proposed BART requirements to meet reasonable progress requirements. Regardless of its failure to properly assess BART of impacts that other sources outside of Washington may have on regional haze in Washington's Class I areas, Washington has a responsibility under the federal regional haze requirements to reduce haze-causing emissions from its own sources of air emissions in order to fulfill its legal duty to meet the reasonable progress goals. Under the Long Term Strategy regulations, Washington is required to demonstrate that "it has included in its implementation plan *all* measures necessary to obtain its share of the emission reductions needed to meet the progress goals for the area" even when sources from outside the state contribute to visibility impairment in the State's Class I areas. 40 C.F.R. § 51.308(d)(3)(ii) (emphasis added). Further, Washington has a responsibility to reduce emissions from Washington sources that are reasonably anticipated to impact visibility in other states' Class I areas. Idaho and Oregon are such states. Therefore, Washington must impose SCR on the TransAlta Centralia Plant and BART on Tesoro and Alcoa Wenatchee in order to meets is obligations on reasonable progress in Class I areas.

CONCLUSION

For all of the reasons given above, and as supported in the attached exhibits, the proposed Washington regional haze state implementation plan is technically and legally deficient. Conservation Groups urge Ecology to re-evaluate BART for the Centralia Power Plant and for the Tesoro Refinery, to require additional emission reductions beyond what these facilities are currently emitting. As the modeling for Washington's Class I areas shows, there is no way the state can show reasonable progress toward the national visibility goal without the adoption of additional emission reduction measures.

Thank you for considering these comments.

Sincerely,

Janette K. Brimmer
Earthjustice
Counsel for Conservation Organizations

Attachments
cc: Keith Rose, EPA Region 10