2026 MONTANA INTEGRATED RESOURCE PLAN

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1 EXECUTIVE SUMMARY

1.1 Introduction

NorthWestern Energy (NorthWestern or Company) continues to serve Montana's homes, businesses, and industries with safe, reliable, and affordable power. Today, we face new challenges: rising electricity demand, changing regional market structures, and the pressures to transition to lower-carbon resources while maintaining reliability during Montana's extreme winter conditions.

The 2026 Montana Integrated Resource Plan (IRP) provides a comprehensive, forward-looking framework to guide how NorthWestern will meet customer needs over the next 20 years. The IRP assesses future load growth, evaluates a wide range of resource options, considers evolving environmental regulations, and ensures compliance with the Western Resource Adequacy Program (WRAP).

1.2 Why the IRP is important

Resource planning at NorthWestern must balance affordability, reliability, and sustainability. The 2026 IRP examines multiple long-term futures and tests how changing fuel prices, environmental rules, technology costs, and load growth can affect a resource portfolio.

Key questions addressed include:

- How would early Colstrip retirement scenarios affect the overall portfolio costs?
- How do transmission investments, including the North Plains Connector (NPC), affect customer costs?
- What happens when large loads are added to the portfolio?

This IRP establishes a framework to evaluate different energy futures, supports regulatory transparency, and allows customers and stakeholders the opportunity to provide their input and insights.

1.3 About NorthWestern Energy

NorthWestern is a major, regional provider of electricity, natural gas, and related services to approximately 787,000 customers in Montana, South Dakota, and Nebraska. Our electric system has about 29,000 miles of transmission and distribution lines and associated facilities serving 341 communities and surrounding rural areas in Montana and eastern South Dakota. Our natural gas system includes approximately 10,000 miles of transmission and distribution pipelines and storage facilities serving 202 communities and surrounding rural areas in Montana, South Dakota, and central Nebraska. NorthWestern has approximately 1,585 full-time employees.

The Montana energy operations, which are based in Butte, provide regulated electric and natural gas transmission and distribution services to approximately 413,400 electric customers and 214,500 natural gas (and propane in limited areas) customers in the western two-thirds of Montana and Yellowstone National Park in Wyoming.

1.4 Our Service Territory

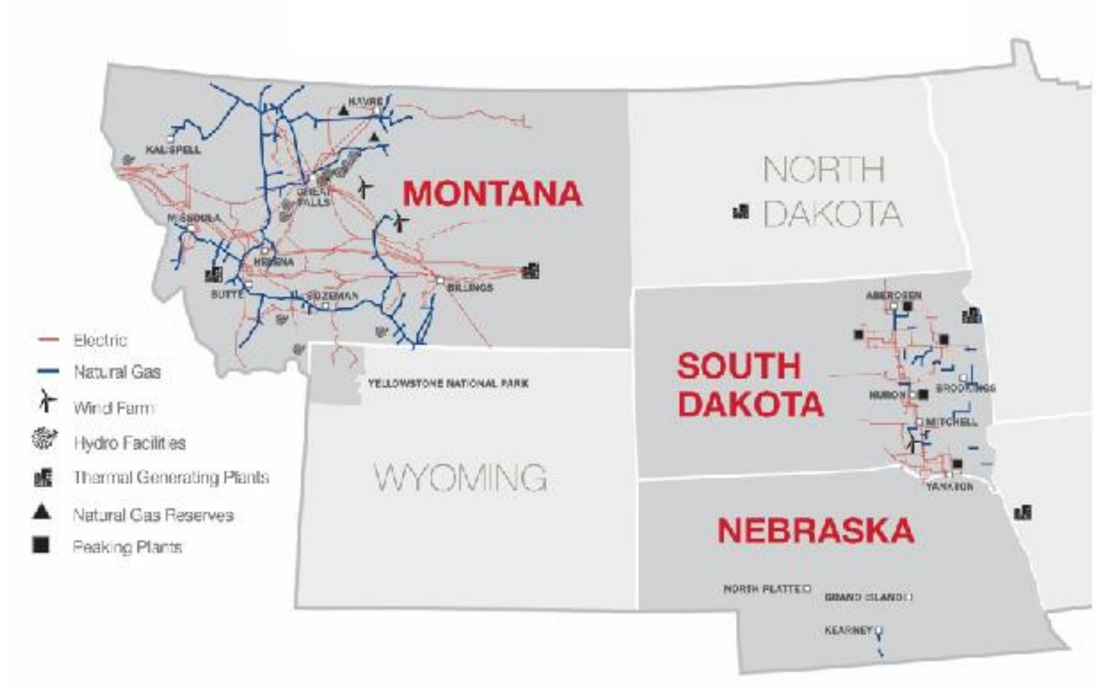

FIGURE 1: NORTHWESTERN'S SERVICE TERRITORY.

1.5 State of the Region

Montana's electric system is entering a period of accelerated change. Across the Western Interconnection, electricity demand is projected to rise more than 30 percent by 2035,[1] driven by large-scale data center development, transportation and building electrification, and steady native load growth. Yet, dependable firm generation additions are lagging. Regional studies by the Western Electricity Coordinating Council (WECC) and the Pacific Northwest Utilities Conference Committee (PNUCC) confirm that reliability risks are increasing as fossil-fueled generator retirements, prolonged drought, and extreme winter weather continue to stress the system.

Montana sits at the crossroads of this transformation. Its transmission corridors, renewable potential, cool climate, and relatively low energy costs are attracting industrial load growth, while its reliance on a small number of large, baseload units, including Colstrip Units 3 & 4, makes portfolio transitions complex. The challenge before NorthWestern is to maintain reliability and affordability amid this volatility while positioning Montana's system to participate in a more integrated, decarbonizing western grid.

1.6 Resource Planning Objectives

The IRP follows Montana statutes and Montana Public Service Commission (Commission) planning rules requiring a transparent, least-cost, risk-informed process. NorthWestern's planning objectives include:

[1] PNUCC 2025 Northwest Regional Forecast. https://www.pnucc.org/wp-content/uploads/2025-PNUCC-Northwest-Regional-Forecast-final.pdf

- **Reliability:** Maintain sufficient accredited capacity under WRAP to meet peak demand and planning reserve margin (PRM) targets.
- **Affordability:** Minimize long-term customer costs while accounting for risks.
- **Sustainability**: Advance a smart, phased transition toward lower-emission and more efficient resources, supported by sustainable and dependable fuel supplies. NorthWestern will adapt as new technologies mature, ensuring progress towards NorthWestern's Net Zero by 2050 Goal[2] without compromising reliability or affordability.

The IRP incorporates these goals through scenario analysis, stakeholder review, and portfolio optimization using the PowerSIMM™ Automated Resource Selection (ARS) and Production Cost Model (PCM) modeling platforms.

1.7 Key Inputs

Several emerging trends that shape the 2026 IRP:

1. *Load Growth*. Montana's electric load is projected to grow steadily, with significant uncertainty from potential data center development.
2. *Power Prices*: The power price forecast blends near-term futures with a long-term curve using a historical ratio between the Mid-Columbia trading hub (Mid-C) and Western Energy Imbalance Market (WEIM). With growing renewables, the model expects near-term price reductions followed by a gradual increase in average prices in later years as load and generation tighten along with increased natural gas costs. The historical ratio from Mid-C and the WEIM 15-minute locational marginal price (LMP) pricing is used to calculate forward pricing curves.
3. *Natural Gas Prices*: The natural gas price forecast is based on Intercontinental Exchange (ICE) forwards at Alberta Energy Company (AECO)/Colorado Interstate Gas (CIG)/Malin for the first two years, then escalates based on the U.S. Energy Information Administration (EIA) Henry Hub annual percent increase. The region is currently experiencing extremely low natural gas prices, so prices are lower in the early years and rise rapidly after 2030 and continue steady to a long-term escalation path.
4. *Environmental Policy*. The U.S. Environmental Protection Agency's (EPA) regulation of air emissions, including Mercury and Air Toxics Standards (MATS) and Greenhouse Gas (GHG) rules, could affect Colstrip operations and future thermal generation options. Recent federal actions to rescind or reconsider portions of these rules may ease near-term compliance pressures, providing temporary relief for existing thermal assets. However, long-term regulatory uncertainty remains.
5. *Technology Advancement*. Small modular reactors (SMRs) and long-duration energy storage (LDES) provide emerging opportunities to include those resource types in the portfolio post-2035 for SMR and post-2030 for LDES.
6. *Transmission*. Both NorthWestern's gas and electric transmission are constrained, so the model limits both imports and exports as well as considering both gas and electric upgrade costs when adding additional generation. Furthermore, major regional projects such as the NPC add transmission connectivity to other markets.

1.8 Resource Options

The IRP models a diverse set of candidate resources located in, or deliverable to, Montana. These candidate resources may not be the actual resources that NorthWestern will acquire. Rather, they are

[2] https://issuu.com/northwesternenergy/docs/netzero_0122_final

potential resource options modeled to evaluate future scenarios and inform a strategy for meeting future portfolio needs.

- Supply-Side Options:
  - Natural gas aeroderivative combustion turbine (CT), reciprocating internal combustion engine (RICE), frame CT, combined cycle (CC)
  - Renewable energy (solar, wind, hybrid solar-storage, and hybrid wind-storage)
  - Energy storage (lithium ion (Li-ion) 4-hour batteries, pumped hydro)
  - Emerging technologies (SMR nuclear, iron-air 100-hour storage)
- Demand-Side Options:
  - Increase in demand-side management (DSM) and net energy metering (NEM)

1.9 Capacity Need and Portfolio Evaluation

The Base Case assumes Colstrip retires according to its project book life on December 31, 2042, and includes NorthWestern's acquisition of Avista's 222-megawatt (MW) Colstrip share starting on January 1, 2026.

Based on conservative long-term planning assumptions and illustrated in the Base Case Capacity Forecast in Figure 2 and Figure 3 below, NorthWestern remains capacity long through summer 2027, after which a winter need emerges in 2027–2028 due to the expiration of the Powerex contract, followed by summer needs in 2032 after the Heartland contract ends. A significant winter shortfall appears in 2042 when Colstrip retires. More information can be found in Section 7.3.

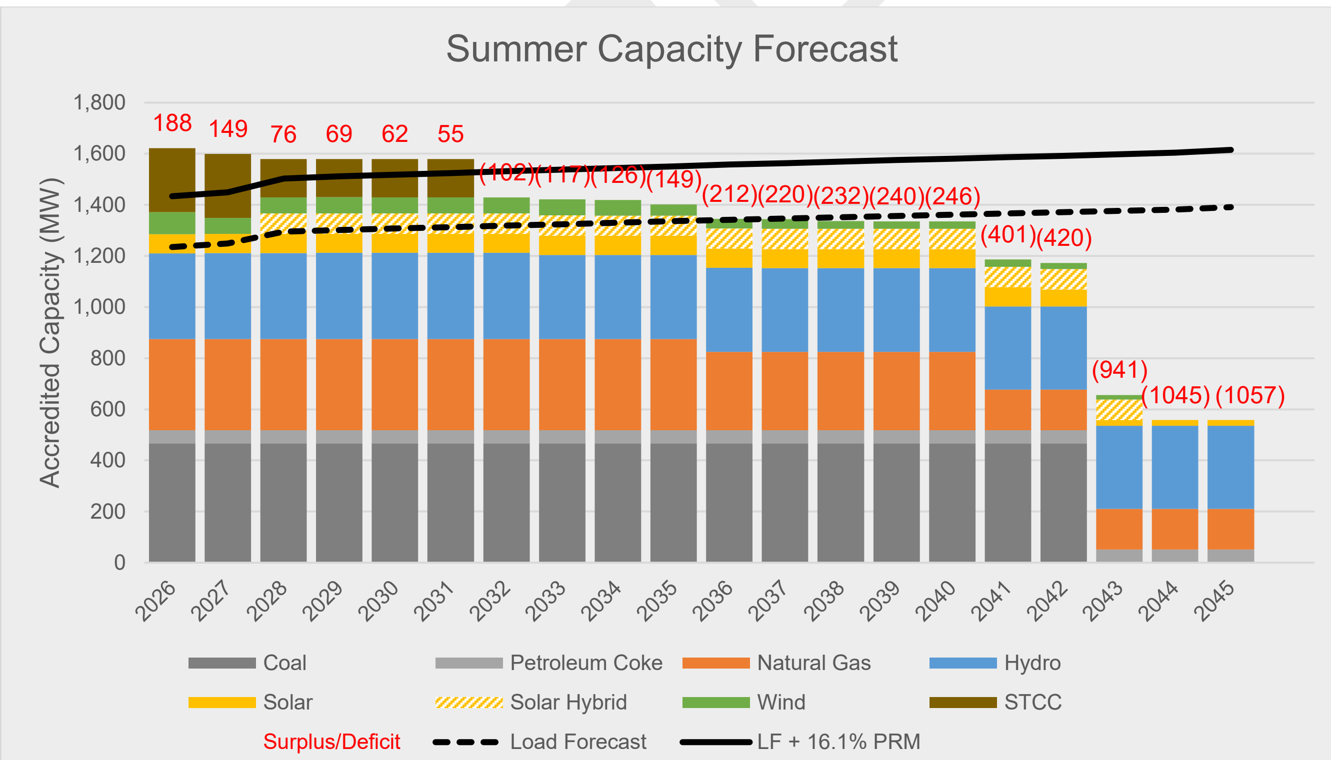

FIGURE 2: NORTHWESTERN'S SUMMER CAPACITY FORECAST.

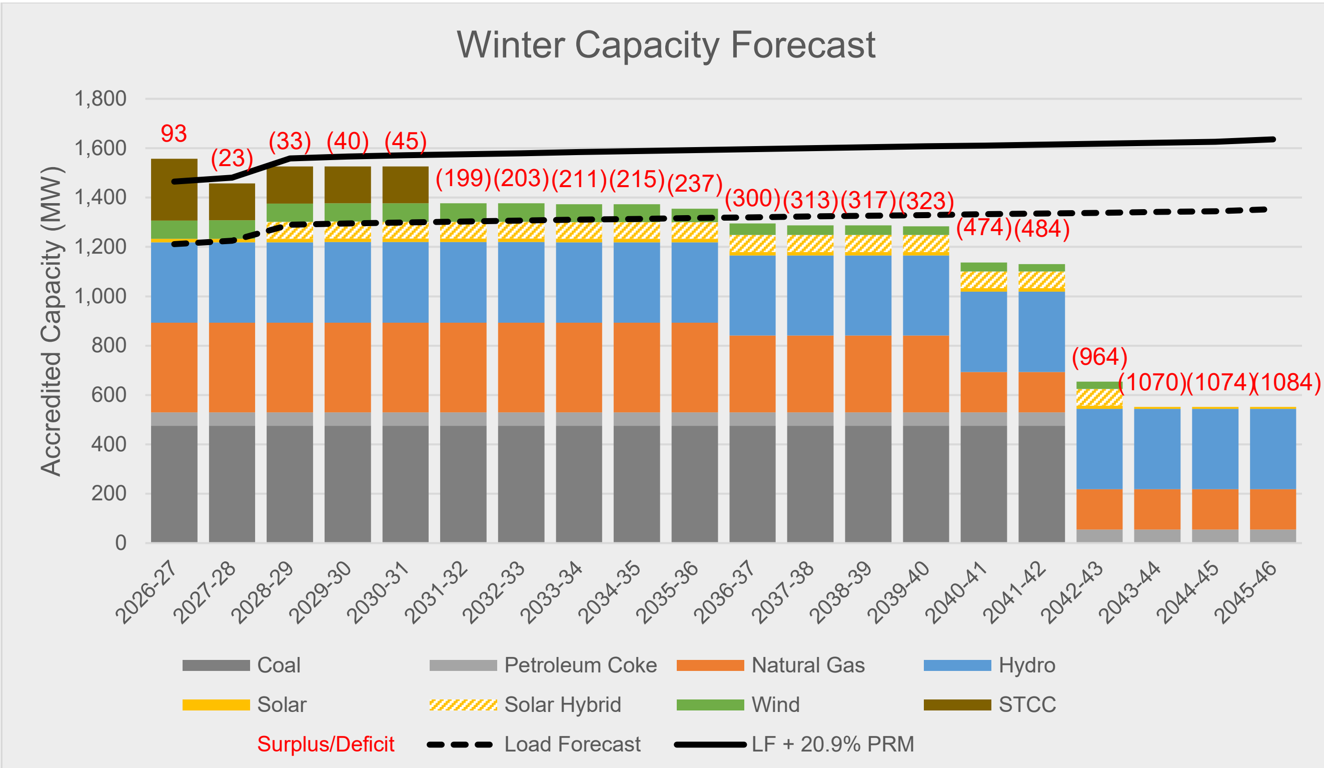

FIGURE 3: NORTHWESTERN'S WINTER CAPACITY FORECAST.

To capture the uncertainty of future MATS and GHG regulations, NorthWestern evaluates three Colstrip early-retirement scenarios: retirement in 2029, 2031, or 2035. NorthWestern also modeled a compliance case that allows Colstrip to operate through 2042 with the addition of a baghouse. These scenarios demonstrate that an earlier Colstrip retirement accelerates and deepens reliability needs. The IRP also tests a wide range of Base Case sensitivities, including ±50% power prices, ±50% natural gas prices, additional ownership interests in Colstrip, fossil fuel optionality, expanded interregional transmission (North Plains Connector), higher DSM/NEM, and multiple data center growth cases ranging from 150 MW to over 1,100 MW. Across these cases, winter peaks remain the primary driver of WRAP capacity deficits and the timing of new generation builds.

1.10 Summary Of Results

Category	Case	Total Added Nameplate Capacity % Difference from Base Case	20-yr NPV Cost ($M)	20-yr NPV Cost per Total Load (% Difference from Base Case)	20-yr CO_2 Intensity of Generation (% Difference from Base Case)
Base Case & Main Scenarios	A-BaseCase	0%	$5,658 M	0%	0%
	B-CSretMATS	-8%	$6,706 M	19%	-30%
	C-CScompMATS	0%	$6,092 M	8%	0%
	D-CSretGHG	16%	$6,170 M	9%	-26%
	E-CSret2035	-4%	$6,221 M	10%	-18%
Commodity	F-Power50	-7%	$6,467 M	14%	-4%
	G-Power150	-8%	$4,304 M	-24%	-3%
	H-NatGas50	-4%	$5,192 M	-8%	-3%
	I-NatGas150	1%	$6,124 M	8%	0%
Data Center	J-DC150	5%	$5,804 M	-13%	18%
	K-DC650	84%	$9,515 M	-2%	11%
	L-DC1160	119%	$13,288 M	4%	3%
Resource	M-NoCO2Lim	-12%	$5,528 M	-2%	5%
	N-CO2Free	27%	$5,955 M	5%	-3%
	O-wPseCS	27%	$4,812 M	-15%	18%
	P-NoAvaCS	8%	$6,303 M	11%	-17%
Other	Q-AddNPC300	3%	$5,557 M	-2%	2%
	R-IncDsmNem	16%	$5,090 M[3]	-4%	1%

TABLE 1: SUMMARY OF SCENARIO AND SENSITIVITY RESULTS IN UNITS OF PERCENT DIFFERENCE.

1.11 Major Findings

Capacity Need in 2027 and Early Colstrip Retirement

NorthWestern's current portfolio meets 2026 WRAP planning-reserve obligations, aided by the addition of the Yellowstone County Generating Station (YCGS) and the acquisition of Avista's 222-MW Colstrip shares (Avista 222 MW) and existing capacity contracts. Under NorthWestern's 2025 planning assumptions, a winter capacity shortfall of approximately 23 MW emerges in the 2027–2028 period, increasing to nearly 200 MW following the expiration of a capacity contract.

Over the 20-year planning horizon, the capacity need increases further as generating units reach the end of their book lives, particularly if Colstrip retires earlier than expected and/or large loads materialize faster than expected. Delays in constructing replacement resources could create reliability exposure even if total capacity appears adequate on paper.

Colstrip's Central Role

The modeling results confirm that early retirement of Colstrip is expensive to customers because replacing Colstrip's accredited capacity requires major capital investment. More specifically, as shown in Table 1, an early replacement of Colstrip in 2035 results in a 10% increase[4] in 20-year net present value (NPV) portfolio costs. Therefore based on the assumptions and scenarios modeled, maintaining Colstrip through 2042 remains the lowest-cost option to maintain reliability, noting there is uncertainty surrounding future MATS and GHG regulation.

Transmission and Regional Integration

[3] Modeled results reflect load-reduction benefits only; DSM and NEM program costs are not included.

[4] See portfolio E-CSret2035 in Table 1.

Transmission expansion, notably the NPC, adds value by increasing import capability and providing access to additional markets for purchasing and selling energy. Specifically, the NPC study resulted in a 2%[5] reduction in 20-yr NPV portfolio costs through energy market price variance in purchases and sales. Coordinated investment in additional interregional paths including NPC and the Montana to Idaho Project (M2I) could provide future benefits, including access to lower energy costs and potential regional reliability benefits, when studied through the Western Regional Adequacy Program.

Load Growth and Data Centers

Data center loads represent the most significant emerging source of uncertainty in load growth and an opportunity for Montana's energy system when coordinated with resource and infrastructure development. Modeling results indicate that under high-level, system-wide modeling assumptions, although additional generation is required to serve data center load, the resulting system-average cost per megawatt-hour generally declines or remains relatively stable relative to the Base Case portfolio due to economies of scale and improved asset utilization. Specifically, the modeling scenarios show a 13% reduction in cost per megawatt-hour (MWh) in the 150 MW scenario, a 2% reduction in cost per MWh in the 600 MW scenario, and a modest 4% increase in the 1,160 MW scenario.

Demand-Side Management and Distributed Resources

DSM and NEM programs show savings across the portfolio based on modeled load reductions. While DSM measures are modeled as a reduction to the load forecast and achieve the cost-effective programs recommended in the NorthWestern Electric EE and DR Market Potential Study (May 2024 - Revised October 2025) in Appendix H, the IRP also includes a sensitivity with increased DSM and NEM. The costs associated with increased NEM participation, including potential system and cost-shift impacts, as well as increased DSM participation costs are not reflected in this sensitivity and will need to be evaluated through a separate analysis outside of this IRP.

Emerging Technologies

The modeling selected LDES (e.g., 100-hour iron-air batteries) and SMRs in most scenarios and sensitivities. Each technology has the potential to play a future reliability role, but near-term commercialization timelines and cost uncertainties will need to be closely analyzed.

[5] See portfolio Q-Add NPC in Table 1.

1.12 Action Items

Action Area	Next Steps	Timeline
Address Near-Term Reliability Needs	• Align and document resource parameters, characteristics, and attributes to inform future resource evaluations • Evaluate extensions of contracts • Prepare for a competitive capacity Request for Proposals (RFP) if needed	Begin 2026; updates through 2029
Strengthen Data-Driven Planning	• Integrate AMI interval data into IRP modeling • Share insights with stakeholders	2026–2028
WRAP Binding Season & Accreditation	• Continue WRAP accreditation and methodology • Prepare for Winter 2027/2028 binding readiness • Quantify benefits of WRAP	2026–2028
Continue Transmission Analysis	• Evaluate NPC and potential M2I intertie • Engage with potential WRAP regional transmission analysis(s). • Assess transmission needs for access to WRAP resources.	2026–2028
Day-Ahead Market Participation	• Continue evaluation of CAISO EDAM and SPP Markets+ • Maintain participation optionality	2026–2028
Manage Data Center & Large-Load Growth	• Coordinate with developers and regulatory • Evaluate required firm capacity and transmission needs • Protect existing customers	Ongoing 2026–2029
Nuclear Resource Evaluation & Technology Readiness	• Monitor SMR and advanced nuclear development and licensing • Participate in regional and industry initiatives • Assess siting, cost, and feasibility; revisit readiness and portfolio role in 2029 IRP	2026–2029
Monitor Emerging Technologies (LDES, Advanced Geothermal)	• Monitor performance, demonstration projects, and cost trends • Reassess readiness and potential application in 2029 IRP	2026–2029
Support Continued Operation of Colstrip	• Monitor environmental regulatory requirements and compliance pathways	2026–2029
Transition Toward Integrated Resource Planning	• Develop more coordinated planning across distribution, transmission, generation, and DSM. • Improve cross-functional modeling tools and data systems. • Enhance stakeholder engagement and alignment across processes.	2026–2029

TABLE 2: NORTHWESTERN'S ACTION ITEMS.

1.13 Conclusion

NorthWestern is committed to delivering safe, reliable, and affordable energy to the customers and communities we serve. As Montana's energy landscape continues to change, we must balance three priorities that are sometimes in opposition with one another: keeping energy affordable for families and businesses, maintaining reliability during Montana's harsh winter conditions, and supporting a responsible transition toward cleaner and more sustainable resources.

The 2026 IRP shows that NorthWestern has enough capacity to meet reliability requirements today but identifies a near-term capacity need emerging in the winter of 2027, driven by expiring contracts and growing customer demand. Addressing this need will require thoughtful planning and continued evaluation of resource options to ensure we maintain dependable service during extreme weather events.

Looking ahead, we must also prepare for larger structural changes, including the future of Colstrip, evolving environmental policies, and the potential for rapid data center growth. These factors create real uncertainty, and they reinforce the importance of continuing to evaluate new technologies such as LDES and SMRs as they become commercially viable.

This IRP does not select a preferred resource portfolio today. Instead, it establishes a transparent foundation for future decisions, encourages open dialogue with customers, stakeholders, and policymakers, and ensures that every decision moves Montana's energy future forward responsibly.

NorthWestern remains committed to planning proactively, investing wisely, and upholding the values that guide our work: reliability, affordability, and sustainability.

2 PLANNING AND PROCESS HISTORY

2.1 Purpose and Methodology

NorthWestern developed this IRP in compliance with Montana's Integrated Least-Cost Resource Planning and Acquisition Act (Act) found in Montana Code Annotated (MCA) § 69-3-1204 through § 69-3-1209 and the Commission's resource planning rules implementing the Act found in the Administrative Rules of Montana (ARM) 38.5.2020 through 38.5.2025. The Act and rules establish requirements for resource planning by electric utilities operating within the state and can be found in Appendix B. An index that relates specific sections of the IRP to compliance with the Commission rules is found in Appendix C.

Pursuant to the Act and the implementing rules, the planning methodology encompasses the following key elements:

- **Resource Adequacy (RA) and Reliability Assessment**
  - The planning process assesses future load obligations and RA by projecting customer demand and energy requirements over a 20-year planning horizon. This assessment involves load forecasting, including peak and energy load forecasts, energy efficiency impacts, and consideration of DSM programs.
- **Resource Analysis**
  - Resource analysis integrates costs, reliability impacts, environmental considerations, regulatory compliance, and technological feasibility.
    - Transmission resources require physical generation to meet WRAP RA obligations. Therefore, transmission resources are evaluated based on economic impact through market assessment in addition to transmission-related import and export constraints but are not modelled to meet RA requirements within this IRP.
- **Scenario and Sensitivity Analyses**
  - In addition to the Base Case, as defined in Section 7.5, NorthWestern modeled five scenarios to analyze the effect of possible compliance costs or early retirement for the Colstrip plant on the portfolio. NorthWestern then conducted 13 sensitivity analyses to consider the effects of factors such as changing power and natural gas prices, additional data center load, changes to the portfolio due to carbon emissions, and additional transmission availability.
- **Public and Stakeholder Engagement**
  - Stakeholder involvement is a fundamental component of the IRP process. NorthWestern consulted with the Electric Technical Advisory Committee (ETAC), stakeholder working group, and the broader public to solicit input, promote transparency, and ensure the planning process reflects stakeholder concerns and community priorities.
- **Reporting and Recommendations:**

  The IRP includes comprehensive documentation of modeling assumptions, data sources, analysis methodologies, and results. This detailed information can be found in Chapter 7. Recommendations and near-term goals can be found in the action plan in Chapter 9.

2.2 Changes in the Planning Process and Content

This is NorthWestern's first IRP since the Commission's 2023 overhaul of its resource planning and acquisition rules.[6] In the new rules, the Commission emphasizes transparency, standardized documentation, and public and stakeholder engagement.

[6] The Commission's rulemaking docket was Docket 2021.01.077.

Major changes NorthWestern has made to its plan contents and planning process in response to commission recommendations are detailed below:

Action Plan

Developed a robust action plan that includes an estimated timeline and defined next steps to achieve the stated objectives. See Section 9.3 in the 2026 IRP and Chapter 10 of the 2023 IRP for comparison.

Net-Zero Goals

Modeled a sensitivity excluding NorthWestern's net-zero goals to enhance transparency and illustrate the potential cost implications of this commitment for customers. See Section 7.8.5 for more information.

Document Consolidation

To improve readability and navigation issues from the 2023 MT IRP, this IRP is organized into one consolidated volume, with appendices and supporting documentation provided as attachments.

Base Case Update

Refined the base-case scenario to include existing resources and only reflect future resources with executed power purchase agreements or final commission orders. See Section 7.5 in the 2026 IRP and Section 8.6 of the 2023 IRP for comparison.

Public Review

Facilitated greater public and stakeholder engagement by providing ample public review time for the draft IRP and hosting four public sessions across the service territory. See Section 2.2.1.4 for more information.

Environmental

Narrowed the scope of the environmental section to concentrate on how environmental considerations directly affect long-term energy supply planning. See Section 8.1 in the 2026 IRP and Chapter 4 of the 2023 IRP for comparison.

Risk

Introduced a new chapter to evaluate and discuss potential future risks associated with energy supply planning. See Chapter 8 for more information.

150% energy limit

Eliminated the 150%-of-load generation constraint for this IRP. See Section 8.3 of the 2023 IRP for reference.

2% Colstrip fuel escalation costs

NorthWestern implemented a more realistic escalation based on the historical performance of the Colstrip coal contract indices. See Section 7.4.1 in the 2026 IRP and Section 8.4.2 of the 2023 IRP for comparison.

Colstrip transmission

NorthWestern included the Colstrip transmission delivery assumptions in this IRP. See Section 5.5.4 and Section 7.5.1 for more information.

ETAC and Stakeholder Engagement

NorthWestern overhauled its ETAC and stakeholder engagement procedures. A description of the ETAC and stakeholder engagement procedures is included in Section 2.2.1 in the 2026 IRP and Section 2.4 of the 2023 IRP for comparison.

NorthWestern explains how it addressed Commission comments on the 2023 IRP in Section 2.3.2 of this IRP.

NorthWestern's changes to its planning process and the content result in an IRP that satisfies the Commission's rules adopted in 2023. The IRP reflects increased stakeholder engagement and contains more information about the current portfolio, additional transmission modeling constraints, costs, and evaluations, and clearer explanations of modeling for addressing future portfolio needs.

2.2.1 Technical Advisory Committee, Stakeholders, and Public Input Process

NorthWestern follows an open and transparent planning process designed to incorporate feedback where possible from technical experts, stakeholders, and the general public. These efforts ensure that a diverse range of perspectives are reflected in the planning process, including regulatory, environmental, consumer, and community interests.

NorthWestern's engagement began with the involvement of ETAC to advise on technical, economic, and policy issues related to the IRP. ETAC serves as the primary forum for detailed discussion of modeling assumptions, scenario development, and risk evaluation. In parallel, NorthWestern established a Stakeholder Working Group to provide early feedback from non-technical and community-oriented participants, enhancing transparency and inclusivity.

In addition to these structured groups, NorthWestern hosted four public information sessions across Montana, offering customers and interested parties an opportunity to learn about the IRP process, review results, and provide input before the plan was finalized. Throughout the planning process, NorthWestern maintained a comprehensive public website dedicated to integrated resource planning.[7] The website includes a Work Plan for preparing the IRP and a feedback form that enabled NorthWestern to receive input and comments during IRP preparation. A copy of the Work Plan is also included in Appendix D.

NorthWestern provided agendas, meeting materials, website updates, and meeting notes in advance to the greatest extent practicable. Stakeholder question summaries were formally updated and posted on a quarterly basis, while other materials were posted as they became available. Because the IRP modeling process is iterative and many discussions depended on evolving assumptions and scenario results, some materials could not be finalized significantly in advance; however, NorthWestern's objective throughout the process was to provide timely information sufficient to support meaningful participation.

2.2.1.1 Electric Technical Advisory Committee

The role of ETAC in NorthWestern's planning process is to work with NorthWestern to provide advice from a non-utility perspective. Through discussion, education, and collaboration on issues relating to portfolio planning and management and procurement of resources, ETAC strengthens resource

[7] https://www.northwesternenergy.com/about-us/gas-electric/montana-electric-supply-planning

planning efforts. NorthWestern selected members based on their expertise in relevant fields, representation of diverse interests, and ability to contribute constructively to the advisory process. NorthWestern sought members who were familiar with energy policy and long-term integrated resource planning in Montana and the broader region related to utilities. For the development of the Plan, ETAC consists of members from the following 7 entities:

- Haylee Gobert and Mike Dalton – Montana Public Service Commission
- Jeff Blend and Kyla Maki – Montana Department of Environmental Quality
- Jamie Stamatson – Montana Consumer Counsel
- Chuck Magraw – Natural Resources Defense Council
- Brian Dekiep – Northwest Power and Conservation Council
- Ben Bright and Kelli Schermerhorn – Southwest Power Pool
- Patrick Barkey – Bureau of Business and Economic Research

ETAC meetings were held at least quarterly in Helena or Butte, MT, with an option for members to join remotely. Additional meetings were scheduled on an as-needed basis. The schedule of meetings with major topics discussed is shown below in Table 3. Most meetings were available for the public to listen remotely and submit comments or feedback via the feedback form.

Meeting	Date	Topics
1	Dec. 5, 2023	Introductions, Overview, Expectations
2	March 27, 2024	IRP Workplan Development, ETAC Timeline, Stakeholder, Engagement Plan, PowerSIMM Modeling and ETAC
3	June 27, 2024	Review Final IRP Workplan, Stakeholder Engagement #1 Discussion, Modeling scenarios
4	Sept. 18, 2024	PowerSIMM Education, Price Forecasting
5	Dec. 18, 2024	Modeling Inputs, Load Forecasting, New Resource Cost Modeling, Modeling Scenarios, PowerSIMM Access
6	March 26, 2025	Stakeholder Working Group, Updated IRP Work Plan, WECC – Resource Adequacy Discussion, New Resource Cost Modeling, Modeling Scenarios, PowerSIMM
7	June 25, 2025	Stakeholder Working Group, Form Energy, PowerSIMM Login, Website Updates, Costs Discussion, Updates
8	Aug. 28, 2025	Asset Management VP Comments, Stakeholder Working Group, Scenario/Sensitivity updates, PowerSIMM Preliminary ARS Results
9	Oct. 29, 2025	Progress Update
10	Feb. 25, 2026	Public Session Presentation, Portfolio Results Summary, Public Comment Themes, Round Table Discussion

TABLE 3: ETAC MEETING SCHEDULE.

NorthWestern provided ETAC members with access to PowerSIMM via login credentials that grant access to the Montana schema which encompasses all the inputs, portfolios, and studies utilized for the modeling in the IRP. They were also given copies of the outputs from each scenario and sensitivity evaluated in the IRP. The process by which a stakeholder can obtain inputs electronically in order to conduct alternative modeling is located in Section 7.6.3.

2.2.1.2 ETAC Comments on NorthWestern's Planning Approach

During NorthWestern's meetings with ETAC, members participated in collaborative discussions during the development of this IRP. Some themes from the discussions and comments are: Colstrip uncertainty and retirement planning, market dependence, transmission constraints, regional interconnection, modeling inputs, data centers, candidate resource evaluation, cost assumptions, reliability and RA, demand response (DR) and DSM, and stakeholder engagement and communication. These are summarized below with NorthWestern's response of how ETAC's feedback was incorporated in this IRP.

Colstrip uncertainty and retirement planning

ETAC discussed the need for clearer assumptions around Colstrip retirement dates, including environmental compliance timelines, economic life, and ownership uncertainties. They advised a need for multiple retirement scenarios of the Colstrip facility to be modeled to show how timing affects reliability, resource needs, and customer costs. ETAC also discussed that Avista and Puget decisions should be incorporated into modeling.

NorthWestern's Response: NorthWestern evaluated multiple scenarios, A, B, D, and E, with different retirement dates of Colstrip. Sensitivity O added in the Puget share of Colstrip for customers, and sensitivity P analyzed the portfolio without the Avista share of Colstrip to illustrate the impact of each share on NorthWestern's portfolio. Detailed analysis on the modeling can be found in Chapter 7.

Market dependence, transmission constraints, and regional interconnection

ETAC discussed concerns about relying on market purchases, especially during severe weather events, and the need to model realistic import and export limits and firm transmission availability. Also discussed was a need for improved modeling of regional markets (primarily Mid-C, Southwest Power Pool (SPP), and Midwest Independent System Operator (MISO)) and more clarity about NorthWestern's intentions regarding major transmission projects like the NPC.

NorthWestern's Response: NorthWestern modeled transmission limits in this IRP rather than allowing infinite access as in previous IRPs. The NPC was modeled in this IRP as sensitivity Q. This sensitivity allowed connection to other regional markets, SPP and MISO, and the results show the potential benefits of access to these markets. Detailed analysis of the results of the NPC can be found in Section 7.8.6.

Modeling inputs

ETAC discussed the impacts of modeling inputs such as retirement dates, overbuild limit, and cost assumptions that may create unintended bias. They discussed the need for transparency into assumptions, constraints, and data sources for the modeling inputs used in NorthWestern's PowerSIMM modeling.

NorthWestern's Response: NorthWestern included a detailed description of the overbuild limit and cost assumptions in Chapter 7. The expected retirement dates and other details of each resource in NorthWestern's portfolio can be found in Chapter 5. NorthWestern provided ETAC members access to PowerSIMM as described in Section 2.2.1.1, and those seeking to perform alternative modeling can request the digital files through the process described in Section 7.6.3.

Data centers

ETAC members see rapid data center growth as an upcoming challenge facing NorthWestern. With load forecasts ranging widely and timing not clearly defined, ETAC members expressed concerns to address in the IRP, including how data centers may provide their own portfolios, how to plan for gas and transmission infrastructure, and how customers could be affected by data centers.

NorthWestern's Response: NorthWestern modeled data center sensitivities J, K, and L to show the impact of data centers on NorthWestern's system. The ARS results can be found in Section 7.7 and

PCM results can be found in Section 7.8. This analysis did not extend to scenarios in which data centers develop or supply their own resource portfolios or any potential tariff structures.

Candidate resource evaluation

ETAC discussed the need for modern cost assumptions, modular build sizes, and more representation of emerging technologies likely to be commercially available within the IRP horizon. Members wanted to see a broadening of the candidate technologies to include LDES, SMRs, enhanced geothermal, and hybrid configurations.

NorthWestern's Response: NorthWestern began evaluation of 28 different generation resource technologies, 19 of which were evaluated as candidate resources in the modeling. LDES, SMRs, solar-battery energy storage hybrid, and wind-battery energy storage hybrid systems were also modeled as candidate resources for this IRP. Candidate resources are discussed in greater detail in Section 7.1. Enhanced geothermal was not modeled, but it is identified as an emerging technology for future IRPs in Section 10.6.

Cost assumptions

ETAC discussed how to best align NorthWestern's cost assumptions with other available industry cost data, as well as how to be transparent in cost adders that are used in NorthWestern's modeling. ETAC had expressed a desire for NorthWestern to incorporate environmental externalities such as presenting the impact of a social cost of carbon on NorthWestern's portfolio. Members commented that they would like clarity on how carbon and regulatory risk are represented in dispatch and resource selection.

NorthWestern's Response: NorthWestern provides extensive details on cost assumptions used in the modeling in Chapter 7. The impact of a social cost of carbon was not presented in this IRP. Chapter 8, Risk and Uncertainty, was added to this IRP in order to identify and contemplate the risks related to uncertainty and changes in public policy, environmental regulations, supply chain, etc.

Reliability and Resource Adequacy

ETAC discussed the importance of winter reliability, firm transmission for remote resources, and the need to model stress events explicitly. ETAC members would like to see analysis for extreme weather, tight market conditions, and multi-day shortages, with an explanation of how portfolio choices mitigate those risks. Members also discussed WRAP, and they desired clarity on how it is utilized in NorthWestern's resource planning.

NorthWestern's Response: NorthWestern discussed markets and RA in greater detail in Sections 3.5 and 3.6. This IRP incorporates historical resource performance and WRAP's accreditation framework to reasonably manage weather-related reliability risk. Multi-day extreme-weather stress-test simulations were not evaluated within this IRP beyond PowerSIMM's stochastic weather simulation framework. This is further discussed in Section 8.2.

Demand Response and Demand-Side Management

ETAC members view DR as an underutilized resource. They would like to see NorthWestern explore better division by customer type, improved quantification of DR potential, and exploration of data centers as potential flexible or backup-contributing loads. ETAC members commented on their view that NorthWestern should use third-party DR aggregators and update DSM modeling to reflect current potential.

NorthWestern's Response:

While DR may play a role in portfolio diversification, the 2024 Market Potential Study indicates that total achievable DR reaches only 7–18 MW by 2027 and approximately 45 MW by 2044. Price-based programs such as time of use, critical peak pricing, peak time rebates, and real time pricing represent only about 26% of winter potential (≈11 MW by 2044) and provide uncertain, non-firm response. The remaining ~74% of winter DR potential relies on behavioral and direct load control (DLC) of space heating, domestic hot water, and other equipment, options that require significant customer enablement and are difficult to scale during Montana's extreme cold winters where safety is important. NorthWestern will continue exploring enhancements to pricing-based programs and evaluating opportunities to pair DR with large flexible loads such as data centers. However, DLC options for existing customers provide limited availability during winter peak conditions.

Stakeholder engagement and communication

ETAC discussed the need for earlier, clearer communication with stakeholders and the public in NorthWestern's planning process. They would like to see summaries of how feedback shaped modeling changes and a transparent record showing how stakeholder input influences IRP outcomes. They emphasized the need for consistent documentation and easily accessible information.

NorthWestern's Response: NorthWestern has strengthened and updated its presence on the public website. To better engage stakeholders, the Stakeholder Working Group was created in addition to ETAC. NorthWestern also released a draft plan for review prior to filing with the Commission and held four public sessions to present and receive input on the draft plan. NorthWestern highlighted how comments from different groups were incorporated into this IRP, including comments from the 2023 IRP, which can be found in this Section as well as Section 2.3.2.

2.2.1.3 Stakeholder Working Group

In addition to ETAC, NorthWestern established a Stakeholder Working Group to engage other stakeholders and customers, enhance transparency, and gather early input during the modeling process. This group brings together diverse perspectives, including non-technical voices from community members, customer groups, and environmental organizations, to ensure the planning process reflects broad public interests. Focused on inclusivity and the wider impacts of IRP decisions, the group provides valuable feedback to improve NorthWestern's planning efforts. Committed to continuous improvement, NorthWestern views this initiative as a foundation for expanding stakeholder engagement in future IRPs, with the goal of serving the best interests of its customers and Montana.

NorthWestern formed the Stakeholder Working Group by accepting applications for up to 20 members. NorthWestern received just 10 applications and established the Stakeholder Working Group of the following members:

- Nicholas Fitzmaurice – Montana Environmental Information Center (MEIC)
- Evora Glenn – City of Missoula
- Derek Goldman – Northwest Energy Coalition
- Ross Keogh – Parsons, Behle & Latimer
- Jack Leuthold – Northern Plains Resource Council

- Gary Matson – Retired (Matson's Laboratory)
- Sheryl Mayo – Quantica Infrastructure
- Robert Morris – Montana Technological University
- Makenna Sellers – Montana Renewable Energy Association (MREA)
- Kyle Unruh – Renewable Northwest

NorthWestern facilitated three in-person meetings with the group. The dates and major items discussed at the meeting are in Table 4.

MT 2026 IRP Stakeholder Working Group Meetings			
Meeting	**Date**	**Time**	**Topics**
1	June 9, 2025	9 - 4 p.m.	Introductions, What is an IRP?, Scenarios and Sensitivities, Candidate Resources, Activity, Load Forecasting, DSM, Transmission Overview Part I, Western Resource Adequacy Program, 2023 IRP feedback from stakeholders, 2026 IRP Workplan Review
2	July 10, 2025	10 – 4 p.m.	Balanced Portfolio, Transmission Overview Part II, Social Cost of Carbon, Scenarios and Sensitivities, Feedback Review
3	Nov. 10, 2025	10 – 4 p.m.	PowerSIMM Finalized ARS Results, PowerSIMM Preliminary PCM Results, Progress Update

TABLE 4: STAKEHOLDER MEETING SCHEDULE.

2.2.1.4 Community Engagement

In addition to the Stakeholder Working Group, NorthWestern posted a video and a recorded presentation on its webpage discussing the purpose of an IRP and overview of the 2026 IRP.[8] Additionally, after publishing the draft IRP in January 2026, NorthWestern conducted four public meetings shown in Table 5.

MT 2026 IRP Draft Presentation & Public Comment Sessions			
Location	**Date**	**Time**	**Approximate Public Attendance**
Great Falls Public Library	Jan. 27, 2026 Great Falls, MT	5:30-7:30 p.m.	30
Missoula College	Jan. 28, 2026 Missoula, MT	5:30-7:30 p.m.	89
Lewis & Clark Public Library	Feb. 3, 2026 Helena, MT	5:30-7:30 p.m.	50
Bozeman Public Library	Feb. 4, 2026 Bozeman, MT	5:30-7:30 p.m.	70

TABLE 5: PUBLIC ENGAGEMENT MEETING SCHEDULE.

2.2.2 Comments on the Draft 2026 IRP

During the review period, NorthWestern received comments from the ETAC, Stakeholder Working Group, and the public on the draft IRP. Themes from the comments and NorthWestern's feedback are summarized below.

2.2.2.1 ETAC Member Comments on the Draft 2026 IRP

1. <u>Rules compliance documentation</u>

The rules checklist in Appendix B is largely self-referential and does not always demonstrate that the cited sections "completely and thoroughly" document methods, assumptions, and alternative cases as required by ARM 38.5.2022(1)(g) – (j).

[8] https://youtu.be/wx9r_8LXDo8?si=XxQpTpUp1Yl01DOB

<u>*NorthWestern's Response:*</u> The checklist is intended to provide a reference to where the substantive content required in rule is located in the IRP. It is not intended to demonstrate anything.

2. <u>Colstrip retirement modeling approach</u>

The Colstrip analysis is framed primarily as a cost minimization comparison of a small set of early-retirement cases versus a 2042 book life case, with limited exploration of how a broader set of portfolios perform under different carbon/externality, capex, fuel price, or regulatory risk scenarios. This goes to the point that PowerSIMM is not capable of making an endogenous economic decision to retire a plant like Colstrip when it is no longer economic compared to alternatives.

<u>*NorthWestern's Response:*</u> Industry standard practice is to evaluate retirements through defined scenarios, as performed in this IRP, which allows for transparent comparison of least-cost, WRAP-compliant replacement portfolios under consistent constraints. NorthWestern evaluated key sensitivities including regulatory risks (MATS and GHG), power prices, and natural gas prices. All scenarios and sensitivities include non-monetized externalities, such as emissions.

3. <u>Externalities and societal cost treatment</u>

The treatment of environmental externalities and societal costs in the Draft IRP falls short of the Commission's rules. ARM 38.5.2021 defines cost to include externalities and societal cost to be all costs to a utility plus externalities. ARM 38.5.2020 states that the cost-effectiveness of all resource acquisitions will be evaluated with respect to long-term total costs, including scenarios based on societal costs. Environmental externalities are discussed qualitatively and a "No CO2 Limit" portfolio is modeled, but ARM 38.5.2020(2) requires scenarios based on quantified measures of externalities and societal costs. The Draft IRP doesn't reveal the risks for any of the scenarios if regulations change and a cost on carbon emissions is imposed, i.e., how do the relative costs of the various portfolios change if externalities are internalized and become actual costs. Quantifying externalities is speculative, but a certain degree of speculation is inherent in long-term planning and required by the planning statutes and Commission rules. NorthWestern could make a best guess at one or several societal cost values and use sensitivity analyses within the IRP to test the impact. Even if the values selected for environmental externalities and societal costs were not exactly accurate, it would still provide valuable information and make it clear to stakeholders that NorthWestern is not simply disregarding those types of costs in the IRP.

<u>*NorthWestern's Response:*</u>

Compliant with the Commission's rules, the 2026 IRP evaluated externalities and societal cost impacts through portfolio comparisons, including qualifying impacts through emissions intensity, annual emissions, early Colstrip retirement scenarios, and carbon free candidate resource sensitivities, rather than applying a single monetized carbon adder (Section 8.1.5). The portfolio cost differences serve as the proxy for monetizing societal costs by showing the total cost and percent increase for lower-emission pathways, without jeopardizing WRAP reliability. NorthWestern will continue working with stakeholders and the Commission on whether future IRPs should include multiple societal cost sensitives and additional alignment on externalities.

4. <u>Demand-side resources not modeled equally</u>

Demand-side resources continue to be overlooked by NorthWestern in its IRPs. Demand side resources are modeled as exogenous load reductions based on a potential study, rather selectable "candidate resources" in the capacity expansion model. This approach does not put demand-side resources on an even playing field compared to the supply-side counterparts. For example, NorthWestern could develop a hypothetical AC cycling program to test it within the model at varying levels of cost and penetration, to find out what the specifications of a program like that would be for it to be selected as an economic alternative within the model.

NorthWestern's Response: NorthWestern's DSM program reflects that demand-side resources are defined by achievable potential studies and are implemented through programs that meet total resource cost tests and are compensated through avoided cost frameworks. Consistent with WRAP requirements, only resources with clearly defined, demonstrated, and accreditable performance can be treated as accredited capacity, which supports representing DSM through load and peak reduction assumptions rather than as selectable resources within the IRP. Should any DR proposals be submitted in response to an RFP, NorthWestern would model the specific details of the DR proposal as a candidate resource, consistent with supply-side resources, noting a level of certainty around cost, performance, customer participation, and WRAP accreditation is required.

5. Insufficient DSM reporting detail

The description of existing demand-side energy programs and their cost-effectiveness (required by ARM 38.5.2022(1)(f) and MCA 69-3-1209) is aggregated at the portfolio level, and does not consistently provide the required data on a year-by-year and program-by-program basis (avoided cost used, cost of saved energy/capacity, and net economic benefits) in an easily auditable form.

NorthWestern's Response: NorthWestern provided program descriptions in Section 4.2.2, avoided costs in Section 4.2.4 for residential and non-residential/commercial year-by-year, and a summary since last plan of the DSM program costs, energy savings, estimated demands savings, cost of saved energy/capacity, and net economic benefits in Section 4.2.7. Also see the additional information in Exhibit H, Chapter 4.

6. Data center siting and transmission feasibility

Data center scenarios are presented as discrete changes in load, but the Draft IRP does not fully explore alternate siting, interconnection timing, or customer contribution arrangements. It would be helpful if the Draft IRP contained a more robust discussion of where on NorthWestern's transmission system it would be feasible to integrate data center loads of various sizes without the need for extensive transmission network upgrades.

NorthWestern's Response: Data center integration feasibility depends on location, timing, and project configuration, which is why the IRP evaluates large loads at a system level through load sensitivities rather than assumed site-specific interconnection scenarios. Hypothetical assumptions around siting, interconnection timing, customer contributions, and transmission upgrade responsibility vary significantly by project and do not provide a reliable basis for long-term planning. These issues are more appropriately addressed through site-specific feasibility studies and established interconnection, transmission service, and special contract processes to ensure costs and risks are properly assigned.

7. Load forecast transparency and reconciliation

Load-forecast documentation provides limited transparent reconciliation between historical load shapes, electrification assumptions, large-load additions, and class-level forecasts, making it difficult to test whether the "high" and "low" load scenarios reasonably capture load uncertainty.

NorthWestern's Response: NorthWestern updated section 4.1 to include more detail on load forecast considerations and uncertainty as well as added section 4.1.4 and updated 4.1.6 to include class level historic load shapes and class level peak forecasts, noting class level energy forecasts was already covered in section 4.1.2.

8. Preliminary AMI analysis disclosure

NorthWestern states it completed the deployment of AMI in 2025 (p. 209 of the Draft IRP) and will begin to integrate AMI interval data during the 2026-2028 time frame. In the final IRP NorthWestern should provide a preliminary analysis of the AMI data that it has collected for stakeholder review.

NorthWestern's Response: NorthWestern has provided preliminary AMI load shapes for stakeholder review in Section 4.1.4.

9. Transmission and generation co-optimization

The Draft IRP fails to fully integrate co-optimization of transmission and generation expansion. The final IRP should contain a section dedicated to discussion about how NorthWestern will co-optimize transmission and generation going forward, including specific timelines and any available workplans that will allow NorthWestern to accomplish this task.

NorthWestern's Response: NorthWestern recognizes the value of advancing this capability and is evaluating methodologies, tools, and data requirements to support more integrated planning in future IRPs. NorthWestern does not have a workplan and timeline, but is discussing how to align forecasts, methodologies, tools, and processes, and is actively leveraging AMI data to develop new forecasting tools.

10. Stakeholder input traceability

While the Draft IRP describes stakeholder engagement (ETAC, Stakeholder Working Group, public meetings) and summarizes changes from 2023, it provides limited detail on specific stakeholder recommendations, areas of disagreement, and how those comments altered modeling or portfolios, which falls short of best-practice expectations for traceable stakeholder influence.

NorthWestern's Response: NorthWestern has added a discussion of ETAC and stakeholder input to Sections 2.2.1 and 2.2.2.

Collectively, feedback resulted in changes in the IRP that includes clarification on NREL ATB vs. candidate resource costs in Section 7.1.6, inclusion of available AMI load profile data in Section 4.1.4, the addition of the 2035 retirement scenario in Section 7, and a discussion on the least-cost resource selection using different electrical network upgrade costs in Section 7.7.1.2. Note, much of the discussions and feedback focused on differences in methodological perspectives rather than discrete IRP changes.

11. Unexplained near-term peak load increase

There is a rapid increase in NorthWestern's peak load between the 2027-2028 and 2028-2029 planning years (in both the summer and winter seasons) that is not well explained in the Draft IRP. Absent such a rapid increase in the peak load it appears NorthWestern could be resource sufficient until the 2030-2031 planning year. The Draft IRP mentions that a WRAP-assigned forecast is used for 2027-2029 and that is the source of the increase, but the footnote referencing the WRAP short-term forecast methodology on page 114 of the Draft IRP does not return a valid page from the WRAP website.

Furthermore, the WRAP P50 forecast allows participants to make adjustments to the forecast under certain conditions. The Draft IRP does not explain if any adjustments were made to the short-term WRAP forecast and does not include workpapers showing how the forecast was derived. This is key information that is missing from the draft IRP and should be included in the final IRP.

NorthWestern's Response: See Section 7.3 that includes additional explanation on the change in slope of the load forecast. The broken hyperlink has also been fixed.

12. Transmission Reliability Margin clarification

NorthWestern states it uses Transmission Reliability Margin to account for import capacity availability. There should be more discussion surrounding this topic. Specifically: 1) how NorthWestern calculates transmission reliability margin, 2) how transmission reliability margin compares to available transmission capacity, and 3) if it is appropriate to use transmission reliability margin in long-range planning (is transmission reliability margin used as more of a short-term reliability metric?).

NorthWestern's Response: As explained in Section 6.2, Transmission Reliability Margin (TRM) is an amount of transfer capability held out of available transmission capacity (ATC). Allocating TRM is a step to ensure import capacity availability during peak times. NorthWestern does not include more discussion on this topic in the IRP because TRM is not directly applicable to WRAP Resource Adequacy requirements and is not incorporated into WRAP RA calculations. It is a short-term operational reliability margin used to manage real-time system Balancing Authority (BA) uncertainty and does not represent firm, planning-level transmission capacity for long-range resource adequacy purposes. For more information, please see the Transmission Reliability Margin Implementation Document posted on NorthWestern's OASIS site in the ATC Information folder.[9]

13. Natural gas upgrade cost transparency

Costs related to natural gas system upgrades to supply fuel for natural gas-fired resources are not well explained in the Draft IRP. NorthWestern mentions it estimates natural gas system costs for two different locations on the system to derive its final natural gas system upgrade cost that was applied to candidate resources, but it does not mention which two locations on the system it used, nor what the costs are for each of the locations. It might be worth using two cost profiles for each natural gas-fired candidate resource in the IRP – a cost for each location that NorthWestern examined.

NorthWestern's Response: NorthWestern updated Section 7.1.6.3 to include cost estimates of natural gas fuel delivery and locations. The natural gas infrastructure cost estimates for each location are similar, so an average cost was used rather than two separate cost profiles.

14. Uniform electric interconnection cost assumption

NorthWestern applies the same interconnection and network upgrade costs to all candidate resources. This is a crude way to estimate interconnection and network upgrade costs and could/should be improved. A potential solar farm, wind farm, or natural gas plant would likely locate differently, depending on resource type, and would face different interconnection and network upgrade costs. This aspect of the IRP could be improved.

[9] https://www.oasis.oati.com/woa/docs/NWMT/NWMTdocs/Transmission_Reliability_Margin_Implementation_Document_V23.4.pdf

NorthWestern's Response: The use of a uniform electric interconnection and network upgrade cost reflects an IRP planning-level screening assumption to ensure consistent comparison across resources. NorthWestern recognizes that costs will vary, and, as updated in Section 7.7.1.2, further evaluates how uniform transmission assumptions may influence resource selection.

15. Ancillary services modeling explanation

The Draft IRP does not appear to include a discussion of how ancillary service requirements are modeled. In NorthWestern's recent rate case it stated that it had modeled the same INC requirement in every hour of the year, regardless of the load-resource balance going into any given hour. See Data Request PSC-053 in Docket 2024.05.053. This approach significantly overestimated the amount of INC NorthWestern actually needed in each hour, and held back flexible resources to meet INC requirements that could be used to meet supply. Staff recommends against using that approach in the 2026 IRP. In any case, the IRP should include more explanation of how NorthWestern is modeling ancillary service requirements.

NorthWestern's Response: See Section 7.6.2.1 for the ancillary services modeling approach in PowerSIMM. NorthWestern expanded this section to include a statement on INC requirements.

16. Advance posting of stakeholder materials

The Draft IRP does not demonstrate compliance with ARM 38.5.2024(2) "A utility must…provide meeting materials in advance to the greatest extent possible." Providing meeting materials in advance allows both ETAC members and stakeholders to offer more substantive and in-depth feedback to the utility. Posting meeting materials on NorthWestern's website prior to meetings is more transparent than updating the website quarterly and fosters better engagement. If meeting materials aren't available to be posted ahead of the meeting, agendas should at least be more detailed to give ETAC members/stakeholders a better idea how to prepare for the meeting.

NorthWestern's Response: In this final IRP NorthWestern updated Section 2.2.1 to demonstrate that it provided meeting materials in advance to the greatest extent possible.

17. Storage constraints and effective load carrying capability (ELCC) treatment

Rather than constrain the 4-hour battery energy storage system (BESS) to 250 MW and LDES to 150 MW, it would be more transparent to model the resources unconstrained and then provide a detailed explanation why the results were unrealistic or untenable for NorthWestern's system/planning objectives.

NorthWestern's Response: NorthWestern added a new section 7.7.1.1 to the IRP and included a discussion on energy storage without limits.

18. Load shape and class-level demand presentation

The Draft IRP does not comply with the Commission's requirement that resource plans contain: A description and graphical presentation of daily and seasonal electric demand and energy requirements for each major rate or service class, the variability of those requirements, and how the utility assessed historical trends, and the potential for future changes in the timing and variability of electric demand and energy requirements in the development of the plan.

NorthWestern's Response: NorthWestern incorporated changes to the final IRP to comply with the requirement. See Section 4.1.4 and Section 4.1.6.

19. Action plan lacks concrete triggers

The plan identifies winter capacity deficits beginning in 2027–2028 and around potential Colstrip retirements but does not specify clear decision triggers or time-bound commitments for capacity procurement, leaving ambiguity about how identified needs will actually be addressed within the action plan period required by ARM 38.5.2022(1)(o). The action plan also offers relatively few concrete, measurable milestones (e.g., target dates for issuing any RFPs), which weakens its usefulness as a roadmap under ARM 38.5.2022(1)(o).

NorthWestern's Response: Consistent with ARM 38.5.2022(1)(o), the action plan is intended to provide directional guidance and near-term planning activities, rather than establish fixed procurement commitments or prescriptive decision triggers that may not remain appropriate as conditions change. NorthWestern's approach emphasizes maintaining optionality and flexibility, including continued monitoring of system conditions, advancement of resource development pathways, large load growth, and preparation for competitive solicitations where appropriate.

20. Puget and Avista Colstrip share evaluation

Greater attention and modeling should have been focused on the Puget and Avista Colstrip shares. If NorthWestern intends to bring them into the portfolio as contemplated by the base case and sensitivities, these resources will ultimately face a prudence review before the Commission. If such a filing occurs before the next IRP, this planning cycle will serve as part of NorthWestern's justification. Alternative modeling where these resources are selectable by the model, would help strengthen the premise the resources are least cost and in the public interest.

NorthWestern's Response: For clarification, the Avista share was modeled and discussed in NorthWestern's 2023 IRP, Section 6.8 and Section 8.11. In this IRP, NorthWestern did model the addition of Puget's Colstrip shares in Data Center Sensitivities as well as Sensitivity O. NorthWestern also modeled the portfolio without the Avista share of Colstrip in Sensitivity P.

2.2.2.2 Stakeholder Working Group Comments on the Draft 2026 IRP

1. Valuation of Wind, Solar, and Storage Resources

Stakeholder Working Group Members expressed concern that IRP modeling assumptions systematically undervalue wind, solar, and energy storage resources, which may prevent identification of portfolios that represent true least-cost options for customers.

NorthWestern's Response: The accredited capacity of all generators in NorthWestern's resource portfolio is assigned by WRAP; the accredited capacity is not calculated by NorthWestern. The accredited capacity of candidate resources is assumed to be the same as NorthWestern's existing resources. However, because NorthWestern's existing resources do not include hybrid resources, Section 7.2.2 includes information on the accreditation methodology of candidate hybrid resources.

Cost estimates for candidate resources are described in Section 7.1.6. Candidate resource costs are based on conceptual estimating, publicly available data, and attributes observed from actual project developments and RFP processes. Cost estimates do change over time due to many factors. Any changes in cost assumptions that are not captured in the 2026 IRP will be factored into the next planning process. Attachment H includes cost comparisons between NREL ATB Low, Medium, and High cases alongside cost estimates within this IRP.

Accredited capacity and cost assumptions are key inputs to evaluating which resources can reliably meet system needs at least cost within the IRP framework. However, the IRP does not choose resource acquisitions. The acquisition of new resources occurs through a competitive RFP process.

2. Demand-Side Management and Load Flexibility

Stakeholder Working Group Members noted that demand-side management, energy efficiency, and demand response are among the lowest-cost and fastest-to-deploy resources yet are underutilized in the IRP's core modeling framework.

NorthWestern's Response: Demand-side resources are incorporated based on achievable potential and participation constraints, rather than modeled as unconstrained build options. NorthWestern accounts for DSM and energy efficiency as a reduction to the peak and energy load forecast, as described in Chapter 4, which reduces the amount of capacity needed to reliably serve customers. DSM forecasts reflect estimated savings based on achievable participation; however, programs are fully funded for participating customers, and the measures offered are not capped by a fixed program limit.

To extend DSM capacity, additional cost-effective measures must be identified and evaluated through potential studies and tested against their cost effectiveness based on avoided costs. Note, an increase in the DSM forecast reflecting higher customer adoption of existing programs was modeled in Sensitivity R, which is described in Section 7.7.18.

Further discussion on including DSM and DR as selectable resources that result in meaningful decisions relies heavily on factors such as resource potential, program design, customer participation rates, response timing, measurement and verification protocols, WRAP accreditation requirements, and operational reliability during critical system conditions. Note, NorthWestern remains open to continued evaluation of DSM and DR through potential studies and cost-effectiveness analysis in future IRPs as methodologies and data evolve.

Additionally, see the response to ETAC Comment 4.

3. Portfolio Resource Modeling

Stakeholder Working Group Members stated that the IRP does not fully capture the combined value of portfolios that integrate renewable generation, storage, transmission, and flexible load, potentially understating system reliability and cost benefits.

NorthWestern's Response: See the response to Stakeholder Working Group Comment Theme 1.

Additionally in this IRP, NorthWestern did not model regional transmission as a capacity resource. This reflects current WRAP methodology, which does not assign capacity accreditation to transmission. However, the IRP does attempt to quantify the energy value of the North Plains Connector line in Sensitivity Q, which is discussed in Section 7.7.17.

NorthWestern has actively engaged in efforts to advance consideration of transmission within the WRAP framework. NorthWestern has submitted Change Request 2025-CRF-009[10] requesting that WRAP study how interregional transmission projects, such as the North Plains Connector, could reduce the PRM. WRAP has also received Change Request 2025-CRF-010[11] from Renewable Northwest,

[10] https://www.westernpowerpool.org/comments/change_requests/61/
[11] https://www.westernpowerpool.org/comments/change_requests/62/

GridLab, and the Interwest Energy Alliance requesting that WRAP directly assign accreditation value to transmission resources. NorthWestern will continue to monitor these efforts and participate in WRAP processes to better understand how transmission can contribute to resource adequacy. Should WRAP modify its approach, NorthWestern will incorporate any changes into future IRPs.

Flexible load, or demand response, may be considered to address peak capacity needs and is evaluated on a case-by-case basis. Additionally, see the response to Stakeholder Working Group Comment Theme 2.

4. <u>Constraints on Battery Storage Deployment</u>

Stakeholder Working Group Members raised concerns that arbitrary caps and restrictive operational assumptions applied to battery storage distort resource selection and limit the role of storage in supporting renewable integration.

NorthWestern's Response: Section 7.1.4 describes the short- and long-duration grid-charged energy storage resources modeled in the IRP. The fuel source for batteries is electricity generated by other resources in NorthWestern's resource portfolio or imported electricity from the region. Without reasonable charging limits for short-duration batteries, the charging demand can exceed the retail peak load, creating unrealistic system conditions that exceed operational and/or transmission constraints. For this reason, limits on short-duration storage were applied to ensure that modeled portfolios remain physically operable and consistent with system reliability requirements. NorthWestern will consider enhancements such as the use of declining ELCC curves in future IRPs.

As stated in Section 7.1.4, LDES technology is new and operational performance has not yet been proven at utility scale. The 150 MW LDES limit is a conservative modeling approach that prioritizes reliability. NorthWestern will continue to monitor this technology in the future. The LDES limit will be revisited and likely modified for the next IRP.

Additionally, see Section 7.7.1.1 that discusses ARS results that exclude energy storage limits.

5. <u>Treatment of Coal and Gas Resources</u>

Stakeholder Working Group Members indicated that coal and natural gas resources may be over-accredited for reliability, while risks related to fuel price volatility, environmental compliance, stranded assets, and public health impacts are understated.

NorthWestern's Response: As stated in Stakeholder Working Group Comment Theme 1, the accredited capacity of all generators in NorthWestern's resource portfolio are assigned by WRAP; the accredited capacity is not calculated by NorthWestern.

NorthWestern evaluated different commodity sensitivities to assess risks of lower or higher commodity prices, including power and natural gas prices. These sensitivities are described in Sections 7.7.6, 7.7.7, 7.7.8, and 7.7.9 and are intended to test portfolio performance under a range of market conditions.

Environmental compliance and policy-driven risks are evaluated in the IRP. The IRP evaluates environmental outcomes across portfolios, including emissions trajectories and associated portfolio costs, rather than relying on a single externality value. NorthWestern analyzed scenarios reflecting increased environmental compliance requirements due to MATS and GHG regulations that may result in an early retirement of Colstrip. These analyses are intended to capture the impact of regulatory uncertainty and additional costs for earlier portfolio transitions to recognize uncertainty in externalities, including societal costs as further discussed in Section 8.1.5.

6. Fuel Price, Climate, and Emissions Risk

Stakeholder Working Group Members emphasized that fuel price uncertainty, climate risk, greenhouse gas emissions, and the social cost of carbon are not sufficiently incorporated into long-term planning decisions within the IRP.

NorthWestern's Response: See the response to Stakeholder Working Group Comment Theme 5 for NorthWestern's comments on fuel price uncertainty.

The IRP evaluates emissions and environmental tradeoffs as outcomes of modeled portfolios (i.e. externalities including societal costs), allowing comparison of cost and emissions within a WRAP compliant portfolio without relying on a single externality value, including the Social Cost of Carbon, that may not reflect modeled system and/or market realities as further discussed in Section 8.1.5 and in the response to ETAC Comment 3.

7. Transmission Expansion and Interregional Connectivity

Stakeholder Working Group Members highlighted that transmission expansion and interregional connectivity provide measurable capacity and reliability benefits and should be more fully modeled as system resources in the IRP.

NorthWestern's Response: See the response to Stakeholder Working Group Comment Theme 3.

8. Regional and Day-Ahead Market Participation

Stakeholder Working Group Members noted that participation in regional and day-ahead energy markets can materially affect system costs and reliability and should be transparently reflected in IRP modeling and scenario analysis.

NorthWestern's Response: NorthWestern agrees that regional market participation does affect portfolio costs. Accurately modeling day-ahead market participation would require comprehensive representation of regional generation resources, transmission constraints, market rules, and regional load behavior, which are not fully available or practicable to model within the IRP framework. Additional information related to day-ahead markets is discussed in Section 3.5.2.

9. Load Forecasting and Data Center Impacts

Stakeholder Working Group Members expressed concern that load forecasts, particularly those related to potential data center development, are highly uncertain and may expose existing customers to undue cost and risk without appropriate safeguards.

NorthWestern's Response: NorthWestern agrees that there is a high degree of uncertainty of large load development from data centers. To help evaluate that uncertainly, NorthWestern modeled three different large load additions in Sensitivities J, K, and L that model a range of potential data center development scenarios. These sensitivities are intended to test how varying levels of large-load growth could affect portfolio outcomes and costs under different assumptions. NorthWestern recognizes the IRP growth scenarios may not capture the full extent of potential data center growth; however, the growth scenarios do demonstrate the need for additional accredited capacity when large customers, such as data centers, are added to the portfolio. NorthWestern will continue to monitor data center development trends and refine its load forecasting assumptions as more information becomes available.

10. Alignment with Climate Goals and Planning Transparency

Stakeholder Working Group Members stated that the IRP lacks clear alignment with climate science, stated net-zero commitments, and best practices for transparency and stakeholder engagement throughout the planning process.

NorthWestern's Response: NorthWestern is not attempting to deny climate science in the 2026 MT IRP. The IRP is aligned with Montana's integrated least-cost resource planning policy and regulations. Consistent with the Net Zero by 2050 goal, the 2026 IRP does not allow new carbon-emitting resources to be selected in the capacity expansion modeling after 2035. This modeling constraint represents a meaningful step toward reducing emissions while maintaining system reliability and affordability for customers. As stated in NorthWestern's goal, *"The technologies needed to reach this goal sooner are not currently available in a manner that is cost-effective for our company or our customers. Our needs require technologies and resources that are proven to be successful and cost-effective for both generation and capacity, especially for critical long-duration service. Additionally, regulatory and policy support will be critical in the speed of our transformation. For these reasons, we believe the year 2050 is the appropriate realistic timeline for our commitment to reaching Net Zero carbon emissions."*

NorthWestern continues to improve upon its IRP process related to transparency and stakeholder engagement. NorthWestern's 2026 IRP process included regular and separate ETAC and Stakeholder Working Group meetings, as well as four public comment meetings throughout the service territory. These forums provided opportunities for information sharing, technical discussion, and public input throughout the planning process. NorthWestern will continue to evaluate additional ways to strengthen engagement and clarity in future IRPs.

2.2.2.3 Public Comments on the Draft 2026 IRP

1. Least-Cost, Least-Risk Evaluation

Public commenters stated that the IRP does not demonstrate a least-cost, least-risk evaluation of available resource options. Commenters asserted that modeling assumptions and constraints appear to favor capital-intensive fossil fuel and nuclear resources, thereby limiting meaningful comparison with lower-cost and lower-risk alternatives.

NorthWestern's Response: NorthWestern's modeling assumptions and constraints were developed through an iterative process and discussed and reviewed during multiple ETAC and Stakeholder Working Group meetings. Feedback received during these sessions was considered by the planning team and, where appropriate, informed refinements to the analysis. All final assumptions and constraints are transparently documented in the IRP to allow stakeholders and regulators to fully understand the basis for the modeling results.

NorthWestern remains open to further discussion on how alternative approaches and sensitivities may inform future analysis.

2. Characterization of Coal and the Colstrip Facility

Public commenters challenged the IRP's characterization of coal resources, particularly the Colstrip generating facility, as low cost and low risk. Commenters cited concerns regarding plant age, declining reliability, escalating fuel and maintenance costs, regulatory exposure, and long-term financial liabilities to ratepayers.

NorthWestern's Response: The accredited capacity of Colstrip, as well as all other generators in NorthWestern's resource portfolio, are assigned by WRAP based on historic performance during capacity critical hours; the accredited capacity is not calculated by NorthWestern. Resource accreditation is discussed in Section 7.2. As shown in Table 17, Colstrip was the lowest-cost thermal resource in 2024 based on average variable costs, and Table 54 shows it remains one of the lowest-cost resources in the portfolio on the same average variable cost basis throughout the planning horizon. As the Colstrip plant ages, the owners of the plant, including NorthWestern, plan to ensure its reliable operation through routine maintenance and capital investments, as needed.

3. Public Health, Environmental Justice, and Climate Impacts

Public commenters stated that the IRP does not adequately account for public health impacts, environmental justice concerns, and climate-related damages associated with fossil fuel generation. Commenters emphasized that these impacts represent real economic and societal costs borne by the public.

NorthWestern's Response: NorthWestern recognizes that these issues are important to many stakeholders and are part of broader discussions about the role of externalities in resource planning.

Consistent with applicable statutes and Commission rules, the IRP evaluates resource portfolios based on quantifiable system costs, reliability performance, and compliance with existing regulatory requirements. The IRP also provides information on emissions and environmental characteristics of modeled portfolios to support transparency and inform stakeholder understanding.

In addition, the IRP evaluates scenarios that reflect earlier retirement of emitting resources, allowing for the assessment of the incremental system cost, or portfolio premium, associated with reducing emissions on an accelerated timeline. These portfolios are developed to remain compliant with WRAP, without introducing additional assumptions that directly alter the market price forecast assumptions and dispatch outcomes.

NorthWestern remains open to continued dialogue on how these considerations may be further incorporated into future planning efforts, consistent with evolving policy direction and regulatory guidance

Additionally, see the response to ETAC Comment 3.

4. Valuation of Wind, Solar, and Energy Storage

Public commenters indicated that wind, solar, and energy storage resources are systematically undervalued in the IRP. Concerns included inflated cost assumptions, conservative capacity accreditation, reliance on aging asset performance data, and insufficient recognition of technological advancement and declining costs.

NorthWestern's Response: See the response to Stakeholder Working Group Comment Theme 1.

5. Constraints on Energy Storage Deployment

Public commenters noted that artificial limits on short- and long-duration energy storage constrain the model's ability to select flexible and reliable clean energy portfolios. Commenters stated that restrictive assumptions regarding storage duration and charging behavior distort resource selection outcomes.

NorthWestern's Response: See the response to Stakeholder Working Group Comment Theme 4.

6. Treatment of Demand-Side Management

Public commenters emphasized that demand-side management, energy efficiency, and demand response are among the lowest-cost resources available. Commenters expressed concern that the IRP treats these measures primarily as load forecast adjustments rather than as foundational capacity resources.

NorthWestern's Response: See the response to Stakeholder Working Group Comment Theme 2.

7. Large Load and Data Center Assumptions

Public commenters raised concerns that assumptions regarding large load growth, including data centers, are speculative and may inflate projected demand. Commenters warned that such assumptions could justify unnecessary generation and transmission investments and expose existing customers to increased financial risk.

NorthWestern's Response: See the response to Stakeholder Working Group Comment Theme 9.

8. Framing of System Reliability

Public commenters stated that the IRP frames system reliability too narrowly around fossil fuel and nuclear generation. Commenters emphasized that reliability can also be achieved through diversified portfolios incorporating renewable generation, energy storage, demand-side management, transmission expansion, and regional coordination.

NorthWestern's Response: See the responses to Stakeholder Working Group Comment Themes 1, 2, 3, and 4.

9. Net-Zero and Sustainability Commitments

Public commenters found that the IRP lacks a clear and credible pathway to achieve stated net-zero and sustainability goals. Commenters noted limited discussion of climate change, absence of social cost of carbon analysis, and insufficient consideration of climate resilience and adaptation.

NorthWestern's Response: See the response to Stakeholder Working Group Comment Theme 10.

10. Transparency and Public Participation

Public commenters expressed significant concern regarding transparency and the effectiveness of public participation. Issues raised included redacted data, limited accessibility of meetings and materials, technical complexity, and a perception that public input did not meaningfully influence planning outcomes.

NorthWestern's Response: Since the 2023 planning cycle, NorthWestern has taken meaningful and reasonable steps to enhance transparency and public participation in its IRP process. These efforts included expanding the Company's public-facing website related to the IRP, establishing a Stakeholder

Working Group with capacity for up to 20 participants (of which only 10 stakeholders elected to apply), providing advanced access to the draft IRP prior to formally filing it with Commission, and conducting four public informational sessions across NorthWestern's service territory.

NorthWestern remains committed to considering relevant and actionable input received through these processes and will continue to evaluate opportunities to further enhance transparency and stakeholder engagement in advance of the next planning cycle.

Certain information has been redacted from the public filing because it constitutes confidential data subject to protective orders issued by the Montana Public Service Commission. Consistent with Commission requirements, NorthWestern filed both a redacted, public version and an unredacted, confidential version of the IRP. See Section 5.1 for more information on the confidential data.

While NorthWestern received a range of public comments during the informational sessions, some consisted of general statements or topics addressed outside the scope of long-term resource planning and the Draft IRP. As such, those comments did not provide specific, actionable changes to the draft IRP.

2.3 2023 IRP Action Plan and Stakeholder Comments

2.3.1 The 2023 Montana IRP Action Plan

The 2023 IRP concluded that NorthWestern was short of capacity to meet the PRM required by WRAP. In response, NorthWestern identified several key items in its action plan to improve its capacity position. Below is an update of the progress made on those items:

Participate in the ongoing development of WRAP.

NorthWestern remains actively engaged in the ongoing development of WRAP and anticipates joining the binding phase in the Winter 2027/2028 season. For this IRP, NorthWestern incorporated PRM requirements and resource capacity accreditations into its capacity expansion modeling. More information on WRAP can be found in Section 3.6. Additional details on resource accreditation and the PRM are available in Section 7.2 and Section 7.6.1, respectively.

Proceed towards the commercial operation of YCGS.

YCGS reached substantial completion on October 25, 2024. This 172 MW natural gas facility delivers essential, flexible capacity that strengthens NorthWestern's overall resource portfolio. More information on the facility can be found in Section 5.5.6.

Continue to monitor the need for an RFP, evaluate opportunity resources, and track Qualifying Facility (QF) development while working towards a resource adequate portfolio.

NorthWestern has not issued an RFP since the publication of the 2023 IRP but has taken steps, in addition to the completion of YCGS, to address RA. In December 2024, NorthWestern notified the Commission that it intends to extend the power purchase agreement (PPA) with Basin Creek Equity Partners, LLC. Effective January 1, 2026, NorthWestern added the Avista 222 MW Colstrip share to its portfolio. NorthWestern executed PPAs with Trident Solar and Colstrip Energy Limited Partnership (CELP). NorthWestern anticipates signing a PPA with Yellowstone Energy Limited Partnership (YELP) pending a final Commission decision. As a result, NorthWestern has sufficient capacity through summer 2027 as discussed in Section 7.3.

Evaluate the potential early closure of Colstrip.

NorthWestern continues to assess the potential early retirement of the Colstrip facility. This IRP evaluates several scenarios that consider the impacts of potential EPA regulations, such as the MATS and GHG emissions standards. These regulations could necessitate either substantial capital investment for compliance or potentially drive early closure of the plant.

Execute the DSM RFP

NorthWestern has completed the DSM Request for Proposals (RFP) process. The RFP resulted in new independent third-party analyses that provide updated insights into achievable energy efficiency and DR potential across the service territory. The following reports were delivered through this process and are now available for reference in Appendix H:

- NorthWestern Energy End-Use and Load Profile Study – Final (March 2024)
- NorthWestern Electric EE and DR Market Potential Study (May 2024 - Revised October 2025)

Monitor the acceleration of electrification

NorthWestern continues to analyze and forecast the impacts of increased electrification, including the adoption of electric vehicles (EVs) and electric equipment for space and water heating. These trends are incorporated in NorthWestern's peak load forecasting used in this IRP to the extent that the electrification has already been adopted for current load use. More information on the load forecast methodology can be found in Section 4.1.1.

Evaluate the development of new technologies

NorthWestern continues to evaluate the development and potential integration of multiple emerging technologies into its resource portfolio. In this IRP, NorthWestern modeled several new technologies as candidate resources that were not included in the previous IRP. These technologies are a 100-hour iron-air battery energy storage system (BESS), solar/battery hybrid, and wind/battery hybrid. While SMR generation was modeled in the last IRP, it remains an evolving technology and is again included for evaluation in this IRP. NorthWestern is committed to monitoring technological advancements and market trends to inform long-term resource planning. More information on emerging technologies under continuous evaluation can be found in Chapter 10.

Study the most effective transmission expansion opportunities

Expanding transmission infrastructure is essential to support additional supply and enhance grid reliability across the West, particularly as the integration of renewable generation continues to grow. On December 12, 2024, NorthWestern announced its intent to acquire 300 MW of capacity on Grid United's NPC. NorthWestern evaluated the potential energy benefits of the NPC as a sensitivity to the base case scenario. This analysis explores how increased transmission capacity could improve access to regional markets and enhance system flexibility. More information on the NPC is available in Section 6.5.1, and the corresponding modeling results can be found in Section 7.7.17.

2.3.2 Comments on 2023 MT IRP

2.3.2.1 Montana Public Service Commission Comments

The Commission provided extensive comments on NorthWestern's 2023 Montana IRP, focusing on several key areas: use of the PowerSIMM model, transparency, stakeholder and public engagement, analysis and explanation, DSM, Advanced Metering Infrastructure (AMI), and rate design. The

Commission also noted other concerns related to topics such as document organization and minor errors. These issues are summarized below with NorthWestern's response of how these concerns are addressed in this IRP.

Organization

The Commission commented that the organization of the 2023 IRP's content made the IRP challenging to review and recommended that future plans be organized around the statutory and regulatory requirements.

NorthWestern's Response: NorthWestern re-organized the document into one volume, considering the updated statutory and regulatory requirements in the organization.

Use of PowerSIMM

The Commission expressed concerns about the transparency of the PowerSIMM modeling tool. The Commission directed NorthWestern to develop a process that enables ETAC members to access and review PowerSIMM during the development of the 2026 IRP.

The Commission also noted that its consultant, Mitsubishi Electric Power Products, Inc. (MEPPI), expressed skepticism regarding whether the stochastic modeling process is beneficial and recommended that NorthWestern consult ETAC on this issue.

NorthWestern's Response: NorthWestern developed procedures that enabled ETAC members to access PowerSIMM during the planning process. Ascend Analytics, the developer of PowerSIMM, presented an overview of PowerSIMM including a slide on stochastic modeling to ETAC during the September 18th, 2024 meeting. Stochastic modeling is an industry-accepted best practice as shown in the guide "Best Practices in Integrated Resource Planning" developed by Synapse Energy Economics, Inc. and Berkeley Lab.[12]

Carbon Neutral by 2050 Commitment

The Commission stated that the 2023 IRP did not evaluate the feasibility of NorthWestern's carbon neutral by 2050 commitment. The Commission recommended that NorthWestern provide capacity expansion results without a net zero constraint so that any potential savings or costs from its net zero by 2050 commitment are transparent.

NorthWestern's Response – NorthWestern applied the net zero goal to the Base Case and all scenarios and sensitivities such that no fossil-fueled resources were selected after 2035, except for Sensitivity M. This sensitivity shows that selecting fossil-fueled resources after 2035 results in a total portfolio cost of 2% less than the Base Case.

Transparency and Accuracy

Throughout its comments, the Commission consistently emphasized a lack of transparency in both the IRP development process and the final document. While NorthWestern responded to a set of Commission questions in January 2024, the Commission noted that these clarifications should have been included in the original IRP. Additionally, errors and omissions in the document were highlighted as factors that diminished trust in the process and the IRP's credibility.

[12] https://www.energy.gov/sites/default/files/2024-12/best_practices_irp_nov_2024_final_optimized.pdf

NorthWestern's Response: NorthWestern increased transparency of the IRP development process by providing more information on its Electric Supply Planning webpage, utilizing both ETAC and a Stakeholder Working Group for greater stakeholder engagement, issuing a draft IRP, and holding four public meetings on the draft IRP. NorthWestern addressed the Commission's concerns about errors and omissions by devoting additional time to a review process.

<u>ETAC, Stakeholder, and Public Input</u>

The Commission called for a more meaningful and robust engagement process with ETAC members, stakeholders, and the public. The Commission expressed concern that stakeholder input was not adequately incorporated into the development of the IRP and that insufficient time was provided for public review and feedback on the final draft.

NorthWestern's Response: NorthWestern made multiple enhancements to our Electric Supply Planning webpage, developed a Stakeholder Working Group for greater stakeholder engagement, published all meeting materials and minutes for both ETAC and the Stakeholder Working Group on its website, utilized ETAC and the Stakeholder Working Group to provide input and develop a workplan which is available on the webpage, and held four public meetings prior to filing the IRP to gain insight. ETAC was also given the opportunity to access PowerSIMM. ETAC, stakeholders, and public comments have been tracked through the IRP process, and questions are posted publicly and updated quarterly on the website.

<u>Analysis, Data, and Explanations</u>

The Commission found the 2023 IRP lacking in both the depth of analysis and clarity of explanation. Specific examples included the use of a 150% energy level assumption, and the treatment of the Inflation Reduction Act (IRA).

NorthWestern's Response: NorthWestern explains its assumptions and analyses in greater detail in this IRP to better communicate the depth of its analysis.

<u>Action Plan</u>

The Commission commented that it would be helpful if the Action Plan is more substantive and includes details such as identified goals, relevant steps, and timelines associated with implementing those goals.

NorthWestern's Response: NorthWestern provides a more substantive Action Plan with this IRP.

<u>Demand-Side Management</u>

The Commission expects NorthWestern to incorporate the results of the energy efficiency potential study currently being conducted by AEG. Based on this study, the Commission expects NorthWestern to develop a concrete action plan for acquiring the identified DSM resources. A more comprehensive evaluation of DSM options is also expected.

NorthWestern's Response:

In 2024, AEG completed the Market Potential Study for Electric Energy Efficiency and Demand Response. NorthWestern reviewed and incorporated the findings of the study into its DSM planning and, as a result, developed and rolled out updated DSM programs for the 2025–2026 program year. These updates include revised savings assumptions, the addition of select new measures informed by the study's analysis of market potential and customer adoption. The study did not identify a broad set of new DSM program options that could be integrated cost-effectively. NorthWestern used the study results to refine existing offerings, establish updated acquisition targets, and optimize overall program performance.

NorthWestern will continue to monitor DSM opportunities, reassess program design options based on evolving technology and customer participation data, and evaluate additional measures as market conditions change.

AMI and Rate Design

The Commission directed NorthWestern to evaluate potential rate design options related to AMI and to provide a broader assessment of the system-wide impacts and benefits associated with AMI deployment.

NorthWestern's Response: Evaluating rate design options requires access to complete interval data and the analytical tools necessary to model potential structures. As NorthWestern's AMI deployment was substantially completed in June 2025, the Company is now entering the initial phase of analyzing interval data from AMI meters to support future rate design evaluations. The AMI data was not available for use with this IRP.

2.3.2.2 Stakeholder Comments

NorthWestern received many comments from stakeholders regarding the 2023 IRP. Some themes that were observed across the comments are described below as well as NorthWestern's response as to how these were addressed in this IRP.

Inaccurate Modeling and Cost Assumptions

Stakeholders expressed concerns about the accuracy of modeling and cost assumptions in the IRP. Numerous commenters stated that the IRA and Infrastructure Investment and Jobs Act (IIJA) incentives were either not properly modeled or inadequately explained. Cost assumptions for capital and operations and maintenance (O&M) were considered outdated or incorrect across multiple resource types. Stakeholders asserted that the Colstrip plant modeling understated costs and did not use a realistic escalation of costs. Additionally, stakeholders labeled the Mid-C price forecast as inaccurate. Finally, gas generation modeling was seen as inflating capacity accreditation.

NorthWestern's Response: NorthWestern engaged ETAC and stakeholders early in the 2026 IRP planning process to ensure an understanding of modeling inputs and cost assumptions. In Chapter 7, NorthWestern provides detailed modeling and cost assumptions for each candidate resource, as well as price forward curves and escalation percentages.

Resource and Technology Treatment Concerns

Several stakeholders criticized the IRP for its underrepresentation of clean and emerging energy technologies. Stakeholders expressed concerns that battery storage, particularly LDES, was undervalued or misrepresented, and hybrid resources, DSM, and DR programs were not adequately modeled or treated as generation resources. Stakeholders also found that NorthWestern did not adequately analyze enhanced geothermal, nuclear resources, or transmission.

NorthWestern's Response: NorthWestern introduced LDES and hybrid renewable resources as candidate resources in the 2026 IRP. For LDES, NorthWestern facilitated collaboration between the modeling software provider, Ascend, and a 100-hour storage vendor to ensure the modeling results were reasonable.

Furthermore, NorthWestern did not include conventional geothermal as a candidate resource due to high overnight costs and the small scale of the units. NorthWestern did not obtain cost estimates for enhanced geothermal technology.

NorthWestern considered transmission in its resource planning through its analysis of the NPC transmission project. DR was not included as a candidate resource in this plan and is further addressed in the Action Plan.

<u>Climate and Environmental Issues</u>

Stakeholders expressed strong concerns regarding the IRP's lack of attention to climate change and environmental impacts. Many criticized the absence of carbon pricing and the exclusion of the social cost of carbon from the modeling process. Climate impacts were generally seen as inadequately considered. Additionally, stakeholders perceived that the IRP failed to sufficiently incorporate several key regulatory and legal factors, such as the proposed EPA MATS and GHG rules, the implications of the Regional Haze Act, and the ongoing *State of Montana v. Held* climate case. Finally, stakeholders found that environmental remediation costs, particularly those related to coal ash, were inadequately contemplated.

NorthWestern's Response: In this IRP, NorthWestern discusses and models the effect of EPA MATS and GHG rules on the portfolio, specifically Colstrip. The risks associated with these rules, as well as the Regional Haze Rule (RHR), are addressed in Section 8.1. NorthWestern does not include carbon pricing or a social cost of carbon in its modeling, since Montana policy and legislation do not recognize carbon pricing or the social cost of carbon. The Commission addressed the effect of *State of Montana v. Held* in the MEIC's petition for rulemaking in Docket 2024.03.028. NorthWestern addressed the potential environmental impacts of candidate resources in Section 7.1 and Section 8.1.

In addition, environmental considerations are integrated through multiple components of the 2026 IRP, including emissions intensity comparisons and scenario sensitivities that evaluate resource selection that contribute toward reduced carbon intensity. For example, the IRP's resource modeling incorporates the base case that includes no additional fossil fuel builds as well as only selecting carbon free options after 2035.

NorthWestern remains committed to evolving its planning framework to more transparently integrate environmental and climate-related factors, consistent with Commission expectations, while maintaining its statutory obligation to provide safe, reliable, and affordable service to Montana customers.

<u>Stakeholder Engagement and Transparency</u>

The stakeholder engagement process received criticism, particularly the ETAC process, which was seen as lacking regular meetings and transparency in the sharing of materials. There was distrust in the modeling tool used, PowerSIMM, with several stakeholders advocating for alternatives to capture the value of storage technologies (e.g., BatterySimm, SmartBidder).

<u>*NorthWestern's Response:*</u> To enhance transparency in the IRP process, NorthWestern established a dedicated stakeholder group in addition to hosting regular ETAC meetings. ETAC members were granted access to the PowerSIMM modeling platform allowing participants to review assumptions, methods, and results in detail and helping to address broader transparency and stakeholder engagement objectives.

Market Participation and Policy Considerations

Stakeholders expressed broad support for NorthWestern's participation in the WRAP but requested improved modeling to reflect seasonal variations and accurate effective load carrying capabilities (ELCCs). There was also general support for participation in day-ahead (DA) and the WEIM, though the Montana Department of Environmental Quality (DEQ) recommended a cautious approach. Additionally, DEQ called for an analysis of how third-party loads, particularly those that do not obtain supply from NorthWestern but may rely on NorthWestern, could impact WRAP participation and the PRM.

NorthWestern's Response: NorthWestern is continuing to evaluate the DA market with more detailed information in Section 3.5. Updated WRAP accreditations can be found in Section 7.2.

WRAP performs its regional adequacy analysis using forecasted regional load and generation, which includes third-party loads located in Montana that may not be directly served by NorthWestern but are still part of the balancing authority's footprint. These third-party loads, along with associated generation, are incorporated into WRAP's modeling to ensure a comprehensive view of the region's supply-demand balance. While such loads can influence the overall PRM, the relationship is not one-to-one with Montana customers; rather, PRMs are calculated on a regional basis reflecting contributions and obligations across all participating entities. In this way, WRAP's analysis ensures that reliability requirements are shared proportionally across the region, rather than assigned solely to individual utilities or customer groups.

Methodological Issues in the IRP

Numerous methodological flaws and inconsistencies were identified in the 2023 IRP. A lack of explanation for key methodologies such as duration analysis, energy limits, and scenario modeling was noted. One particular modeling constraint, the 150% energy limit, was criticized as arbitrary or overly restrictive.

NorthWestern's Response: NorthWestern discussed inputs, methodologies, and modeling with ETAC and the Stakeholder Working Group. In this IRP, NorthWestern explains its assumptions and analyses in greater detail to better communicate its analysis and reasoning.

Tribal Concerns

Tribal representatives and advocates raised concerns about the lack of attention to equity and the omission of Tribal perspectives in the 2023 IRP. They assert that the renewable energy potential on Tribal lands was overlooked, while the harmful environmental and health impacts of continued coal use, particularly on the Northern Cheyenne Tribe, were not addressed.

NorthWestern's Response: Tribal representatives did not engage in the 2026 IRP stakeholder process; however, members were present in public meetings. NorthWestern's candidate resources for resource planning are not location specific. Rather, NorthWestern evaluates location-specific resources through a competitive solicitation process. NorthWestern did evaluate the environmental impacts of candidate resources in the 2026 IRP, which can be found in Section 7.1. Should there continue to be tribal interest, tribes are welcome to join the IRP stakeholder process during the next IRP as well as provide comment.

3 REGIONAL OUTLOOK

NorthWestern's system is integrated into the wider Pacific Northwest. Consequently, NorthWestern considers regional demand, supply, pricing, and policies in its integrated resource planning. This chapter reviews some of those regional factors.

3.1 Overview

The Western Interconnection is undergoing rapid change on several fronts. Load is climbing sharply, driven by data centers, policy-driven electrification, and native load growth. Planners must also navigate multi-day winter cold spells and ever-hotter summer heatwaves that push demand even higher. At the same time, increased variable energy resources (VER), fossil fuel retirements, and a growing threat of prolonged drought are squeezing dependable firm capacity. As captured by WECC in their 2024 Resource Adequacy Assessment,

> "The supply of electricity is not growing fast enough to keep up with demand growth. What was once a simple problem of supply and demand has become complicated by rapid change and increasing variability. Unless we prioritize reliability as the resource mix evolves and becomes more variable, we are at risk of serious and more frequent disruptions. The West must move quickly and more decisively to ensure resource adequacy over the next decade."[13]

To bolster reliability amid rising load and accelerating coal and gas retirements, the Western Power Pool (WPP) continues to enhance the WRAP, the West's first tariff-based program that requires every participating load-responsible entity to show enough accredited capacity and transmission six months ahead of each summer and winter season or pay deficiency charges while surplus holders stand ready to assist. This program is critical to assess the available generation to meet the region's reliability needs, instead of overbuilding or relying on a market that may not be resource adequate. More details on WRAP's current program status are in Section 3.6 and NorthWestern's WRAP accreditation in Section 7.2.

[13] WECC 2024 Resource Adequacy Assessment. https://feature.wecc.org/wara/

The Northwest Power and Conservation Council (NWPCC) develops long-range power plans for Montana, Idaho, Oregon, and Washington. According to the NWPCC High Growth – Climate A scenario,[14] the increase in demand is primarily driven by three factors: rapid expansion of data centers, policy-driven electrification (such as EVs and building electrification), and underlying native load growth, as illustrated in Figure 4 below. While data center load is expected to grow sharply through 2030, it levels off in the following years. In contrast, electrification of vehicles and buildings continues to accelerate beyond 2030, outpacing the rate of native load growth[14].

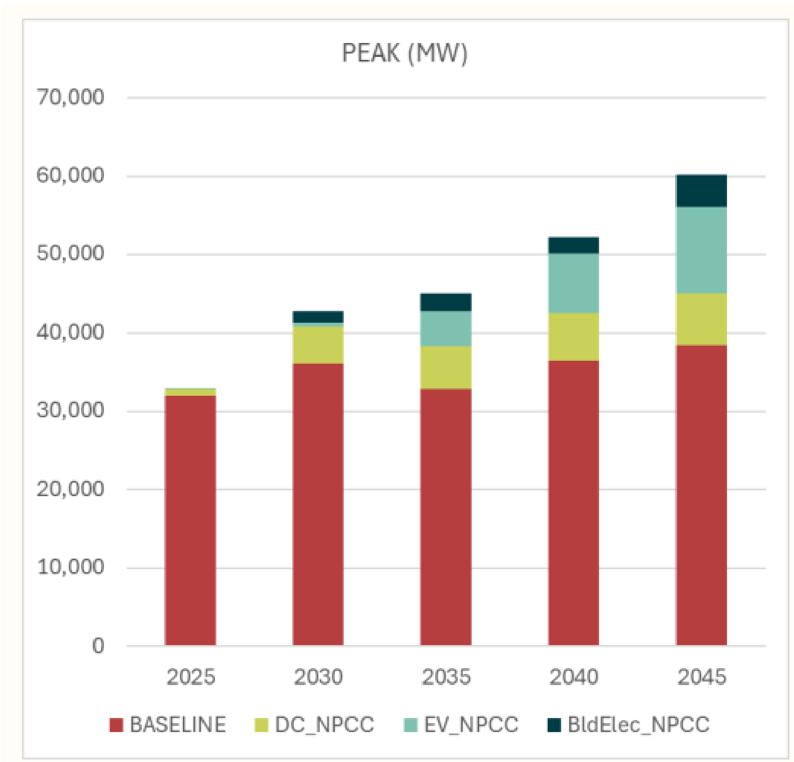

FIGURE 4: NORTHWEST POWER AND CONSERVATION COUNCIL REGIONAL FORECAST.[14]

[14] 9th Power Plan Demand Forecast. https://www.nwcouncil.org/fs/19380/2025_0429_2.pdf

3.1.1 Data Centers

Data center development is accelerating across the United States, driven by surging demand for digital services, cloud computing, artificial intelligence, and high-performance computing applications. These facilities are typically sited near major load centers or along corridors with access to abundant transmission capacity and robust fiber optic infrastructure. While the Midwest has comparatively fewer high-capacity fiber routes than the Eastern U.S., a major long-haul fiber line runs through Montana. This line connects Wyoming northward to Canada and west to Idaho and the Seattle metropolitan area, making Montana part of a strategic corridor for potential data center siting, as illustrated in Figure 5 below, published by the National Laboratory of the Rockies (NLR) (formerly the National Renewable Energy Laboratory (NREL)).

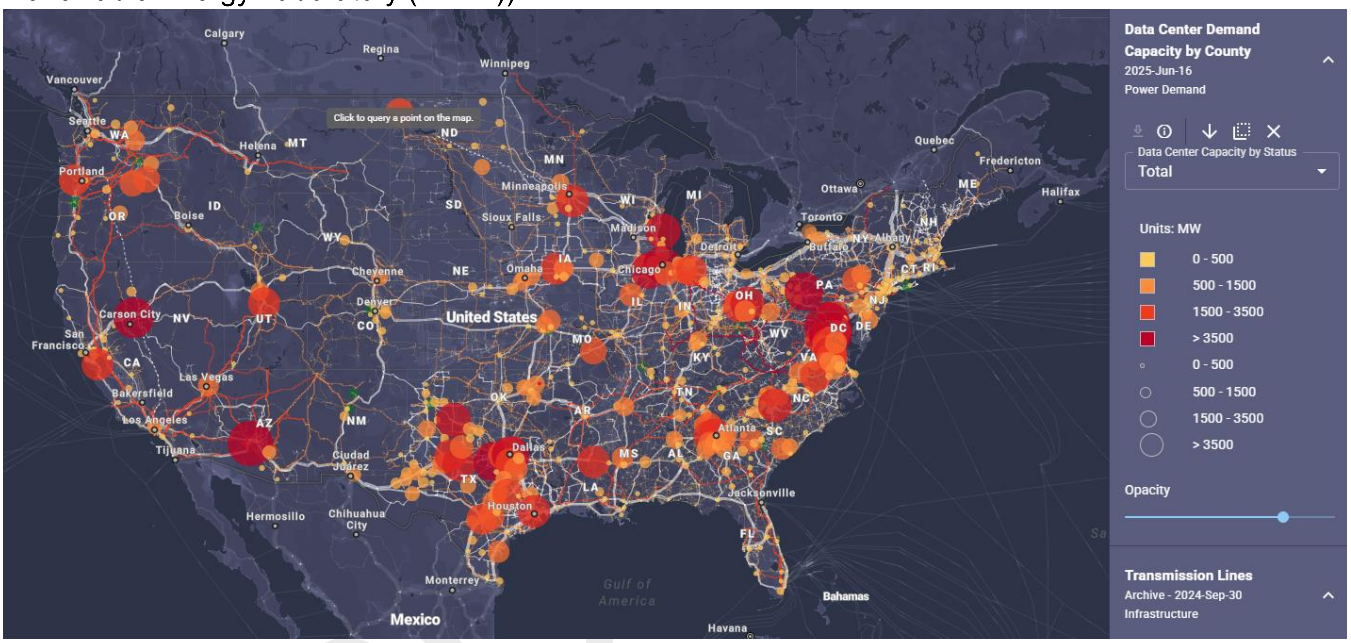

FIGURE 5: NLR DATA CENTER INFRASTRUCTURE MAP.[15]

According to recent projections, regional data center load could rise significantly depending on the pace of infrastructure buildout and investor commitments[14]. This represents an unprecedented rate of load growth concentrated in large, discrete increments. These loads are highly power-dense and potentially place additional stress on local and regional planning, permitting, and transmission systems.

Large data centers also represent a potential opportunity for Montana's energy system. When appropriately planned and aligned with infrastructure development, data center loads can support economic growth, increase utilization of existing assets, and improve overall system load factors. The scale and predictability of these loads may also enable innovative approaches to resource development, transmission investment, and demand flexibility that benefit both new and existing customers.

Montana's geographic position along the long-haul fiber route, relatively low land and energy costs, and a cool winter climate favorable to passive data center cooling, have begun attracting interest from developers. Reflecting this interest, from 2024-2025, NorthWestern entered into letters of intent with three data centers that are pursuing development in Montana. While current data center activity in

[15]NLR data center infrastructure map. Data Viewer | Accelerating Speed to Power

Montana remains limited compared to states like Oregon or Utah, large-scale proposals could materialize with minimal lead time. Although such growth introduces additional planning uncertainty, it also presents an opportunity to more efficiently utilize the system while supporting coordinated investment in infrastructure, flexibility, and clean energy resources.

3.1.2 Policy-Driven Electrification

Electrification of transportation and buildings is emerging as one of the most significant drivers of electricity demand growth in the Pacific Northwest. The PNUCC's 2025 Northwest Regional Forecast highlights increasing utility efforts to model electrification impacts, particularly from EVs, heat pumps, and industrial fuel switching.[1]

According to the NWPCC High Growth Climate A scenario from its 9th Power Plan demand forecast, EV charging alone could add approximately 1,000 average MW (aMW) by 2030 and grow to 6,500 aMW by 2046[14], surpassing even the long-term growth from data centers. Building electrification, including space and water heating, is also projected to increase steadily throughout the planning horizon. These forecasts assume widespread adoption driven by incentives, emissions standards, and state-level policies such as Washington's Climate Commitment Act[16] and Oregon's Executive Order 20-04.[17]

In Montana, where there are currently no statewide policies mandating transportation or building electrification, growth in electric load from these sectors is expected to lag regional trends. Additionally, the expiration of federal EV tax credits is expected to further slow EV growth; however, it is important to understand that the regional load shape, including demands on transmission, will change over time. Specific NorthWestern EV impacts are discussed in Section 10.1 and Appendix F.

3.1.3 Native Load Growth

Native load growth in the Pacific Northwest continues to follow a modest upward trend, primarily reflecting population growth, economic development, and evolving usage patterns across residential, commercial, and industrial sectors. According to the PNUCC's 2025 Northwest Regional Forecast, baseline electricity demand across the region is expected to grow steadily between 2025 and 2035. While the most dramatic demand increases are attributed to policy-driven electrification and data centers, native load defined as organic growth from existing customer classes is still projected to increase by approximately this historical rate of 0.5% to 1.0% annually over the planning horizon[14].

[16] Washington Climate Commitment Act https://www.commerce.wa.gov/cca/
[17] Oregon's Executive Order 20-04 https://www.oregon.gov/puc/utilities/pages/executiveorder20-04.aspx

3.2 Capacity Additions Required to Meet Load Growth

The combined drivers of load elevate the region's total projected growth rate to approximately 3%[1] per year, which is three times the historical native load growth of approximately 1%. Figure 6 illustrates the utility-planned capacity additions required to meet this growth, segmented by resource type:

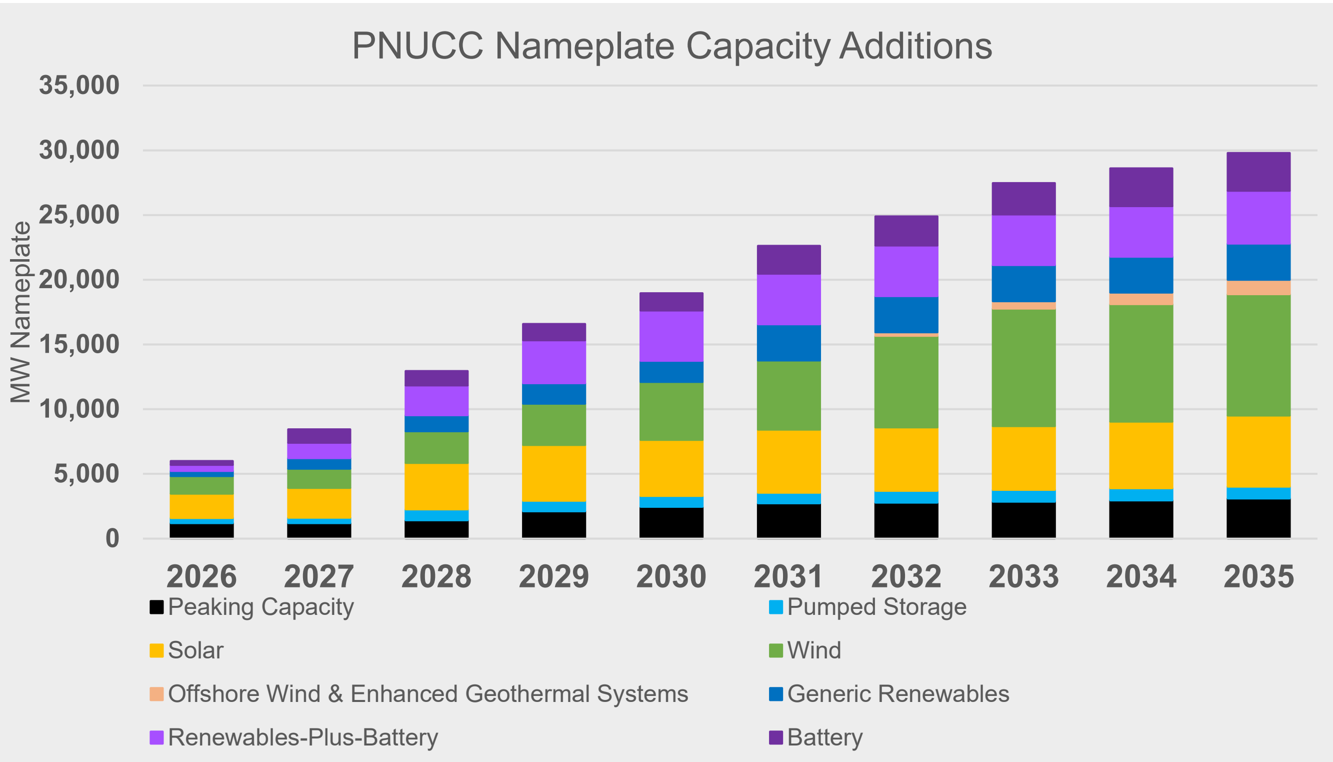

FIGURE 6: PNUCC NAMEPLATE CAPACITY ADDITIONS.

While wind, solar, and battery storage dominate planned capacity growth, firm peaking capacity additions are comparatively limited. By 2035, PNUCC projects approximately 29,798 MW[1] of cumulative nameplate additions which can be broken down as follows:

- 17,627 MW from variable resources (wind, solar, generic renewables)
- 7,945 MW from storage or hybrids
- 1,124 MW from geothermal or offshore wind
- 3,102 MW from peaking capacity, only 10.4% of total nameplate capacity added for reliability.

In the Pacific Northwest, if new resources keep arriving late and incomplete as they have over the past six years, with just 53% delivered on time in 2023[13], the region's load will surpass generation capability. Specifically, PNUCC expects a 13.7 GW winter demand deficit in 2035 without new resources.

3.3 Northwest Power and Conservation Council Needs Assessment

3.3.1 Background

The NWPCC plays a central regional-coordination role across Washington, Oregon, Idaho, and Montana, providing long-term electricity demand forecasts, RA analysis, conservation strategies, and policy. Established by the Northwest Power Act of 1980, the Council works in partnership with Bonneville Power Administration (BPA), utilities, and state energy offices to ensure an affordable, reliable, and environmentally sustainable power system for the Pacific Northwest. The region's electric demand is served by a diverse generating fleet anchored by one of the largest hydroelectric systems in the world, spanning the Columbia River Basin. This hydro backbone is complemented by thermal resources (natural gas and legacy coal units), a rapidly expanding portfolio of wind and solar generation, biomass and geothermal, and transmission-enabled market imports to balance variability and seasonal energy needs.

The Council also maintains a regional generator map[18] shown in Figure 7 to illustrate the resources contributing to reliable service across the four Pacific Northwest states. While its planning authority is focused on Washington, Oregon, Idaho, and Montana, the map includes generation outside the region because Northwest utilities own, contract for, or rely on resources across the broader Western grid. This reflects the interconnected nature of the power system and the important role regional transmission and market participation play in serving Northwest load.

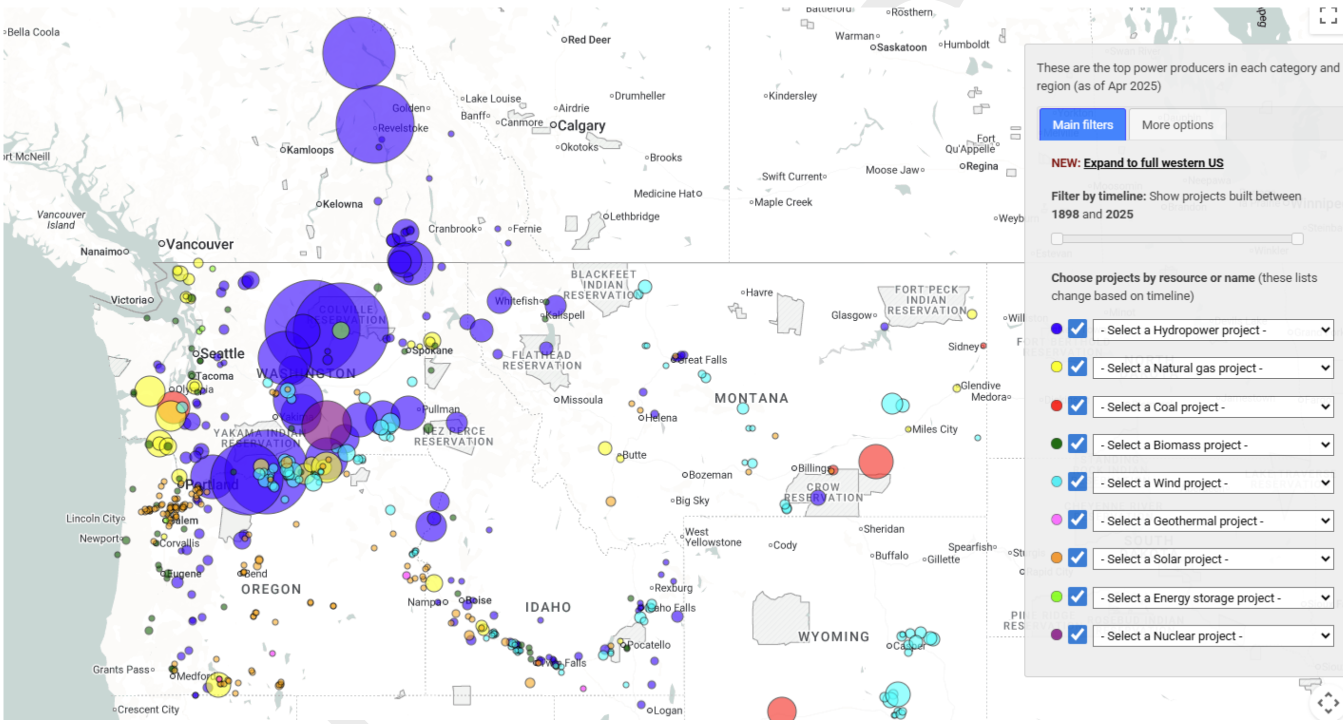

FIGURE 7: NWPCC MAPS OF PNW RESOURCES BY FUEL TYPE[18].

3.3.2 NWPCC Needs Assessment

As part of regional planning coordination, NorthWestern reviewed the Northwest Power & Conservation Council's Needs Assessment for Changing Hydro Operations[19] analysis, which evaluates how alternative Columbia River hydro system operating strategies could impact regional power system adequacy in 2031. The Council assessed four hydro-operation sensitivities (BiOp Flex Spill, 2023 RCBA Steady Spill, Minimum Operating Pool (MOP) with extended spill, and Limited Flex operational constraints) using the GENESYS RA model across 90 climate-driven hydro and load simulations.

The purpose of the Council's study is twofold:

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[18] https://www.nwcouncil.org/energy/energy-topics/power-supply/power-generation-map-overview/
[19] https://www.nwcouncil.org/fs/19637/2025_10_1b.pdf

- Support amendment discussions for the Fish & Wildlife Program by identifying power system implications of modified river operations, and
- Inform the Ninth Power Plan resource strategy by quantifying incremental reliability needs that arise under each operating condition.

Importantly, the Council's analysis does not select preferred hydro operating strategies nor prescribe resource additions; it frames system needs that could arise when fish-related operational modifications reduce hydro flexibility and generation. Their results provide relevant context for NorthWestern's IRP, particularly in understanding regional adequacy pressures, winter peak exposure, and the value of dispatchable resources and flexibility.

Key Findings Relevant to NorthWestern's IRP

The Council's assessment highlights several themes with direct relevance to reliability planning for the Northwest region, including Montana and the broader Western Interconnect.

1. Significant Adequacy Needs by 2031
   The Council's modeling shows material reliability shortfalls across all hydro-operation scenarios by 2031, even under average water conditions and current policy assumptions. Winter needs are most pronounced, with peak shortfalls reaching between 9,000 MW to 11,000 MW with a single operating case of 15,859 MW in the most extreme simulations, underscoring the region's vulnerability to extended cold periods.

2. Market Reliance During Stress Conditions
   All 90 simulation years tested by the Northwest Power & Conservation Council included one or more events exceeding the 1,200-MW adequacy threshold after applying assumed market imports of 2,500 MW, confirming exposure to winter peaks.

3.4 Variable Energy Resources

3.4.1 Resource Adequacy

While the total nameplate capacity in the Western Interconnection is projected to grow significantly over the next two decades, much of this growth comes from VERs, primarily wind and solar. These additions play a vital role in supporting state and federal decarbonization goals and offer abundant energy during certain times of the year. However, their contribution to RA, defined as the ability to meet load during the most critical reliability hour, is significantly limited. Unlike dispatchable resources, VER output is dependent on weather and time of day, which may not align with system peak demand periods. For example, a solar project with 100 MW of nameplate capacity might only provide 8%, or 8 MW of capacity. See Section 7.2 for more information on resource accreditation.

Figure 8 below shows the hourly output of VERs (% of nameplate) against the hourly demand (% of max demand) for the month of February 2022 for NorthWestern and the Northwest Region (which includes balancing authorities in Colorado, Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming). This data portrays that while there are times when there is a significant VER contribution to the max demand, there are multiple times that the VERs for both NorthWestern and the region contribute minimal capacity to demand. As the red boxes in the figure indicate, the percentage of VER output is mostly less than 5% when demand is 95% and above. Similarly, there are times when the Northwest region is near or at its peak; however, VERs are only contributing 15% of their overall nameplate.

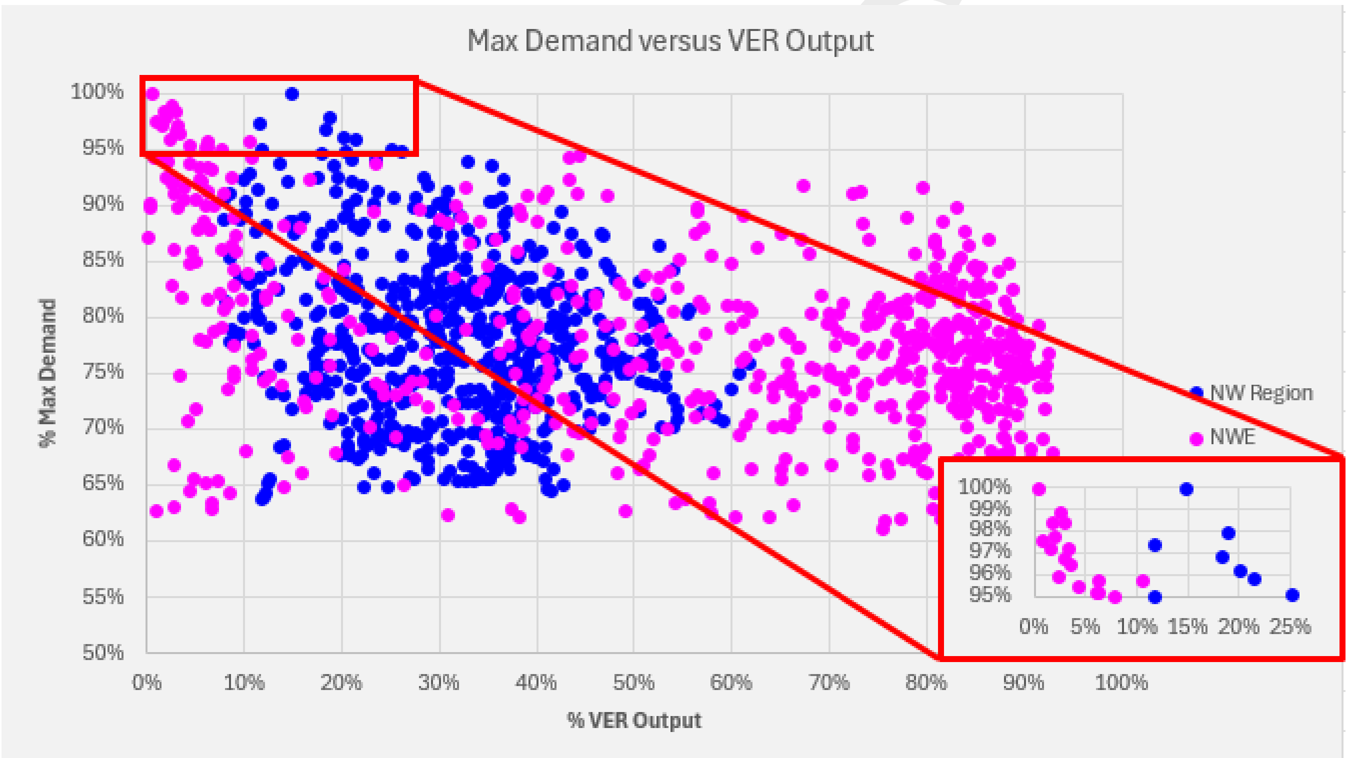


FIGURE 8: COMPARISON OF HIGH DEMAND AND VER RESOURCES IN NORTHWESTERN AND REGIONAL PORTFOLIO.[20]

During this February 2022 period, the entire Northwest region faced heightened reliability risks during multi-day winter cold snaps with minimal solar production and low wind availability, a prolonged VER drought.[21] Without sufficient firm resources including energy storage, these events can lead to capacity shortfalls, price spikes, or emergency reliance on external markets, which are facing similar challenges.

[20] Annual Electric Power Industry Report, Form EIA-860 detailed data with previous form data (EIA-860A/860B) - U.S. Energy Information Administration (EIA). Data was obtained from the Annual Electric Power Industry Report (Form EIA-860), including historical data from Forms EIA-860A and EIA-860B, published by the EIA. Nameplate capacity for each generation resource type was extracted from the EIA data and categorized by type for the NW region. Hourly total demand and total generation for the NW region were also obtained from the EIA and compared to the reported generation by type. Percentages of maximum demand and VER output were then calculated and compared to the NorthWestern Utility.
[21] https://agupubs.onlinelibrary.wiley.com/doi/epdf/10.1029/2024EF005313

Figure 9 below shows the same February 2022 period from Figure 8 in an hourly plot with percent of monthly max of NorthWestern's demand, percent of monthly max of regional demand, percent generation output based on nameplate for wind and solar in the region, and the percent generation based on nameplate for wind and solar for NorthWestern. Using the red boxes as indicators shown in Figure 9, during the two peak periods of demand for both NorthWestern and the region, VERs contributed between 0% to 60% of their total nameplate capacity. For the dates of the 21st to the 26th, a massive drop in generation from these resources is shown, indicating a winter renewable drought, where the generation is needed to fulfill demand, but cannot be provided due to low wind, and/or low solar coverage.

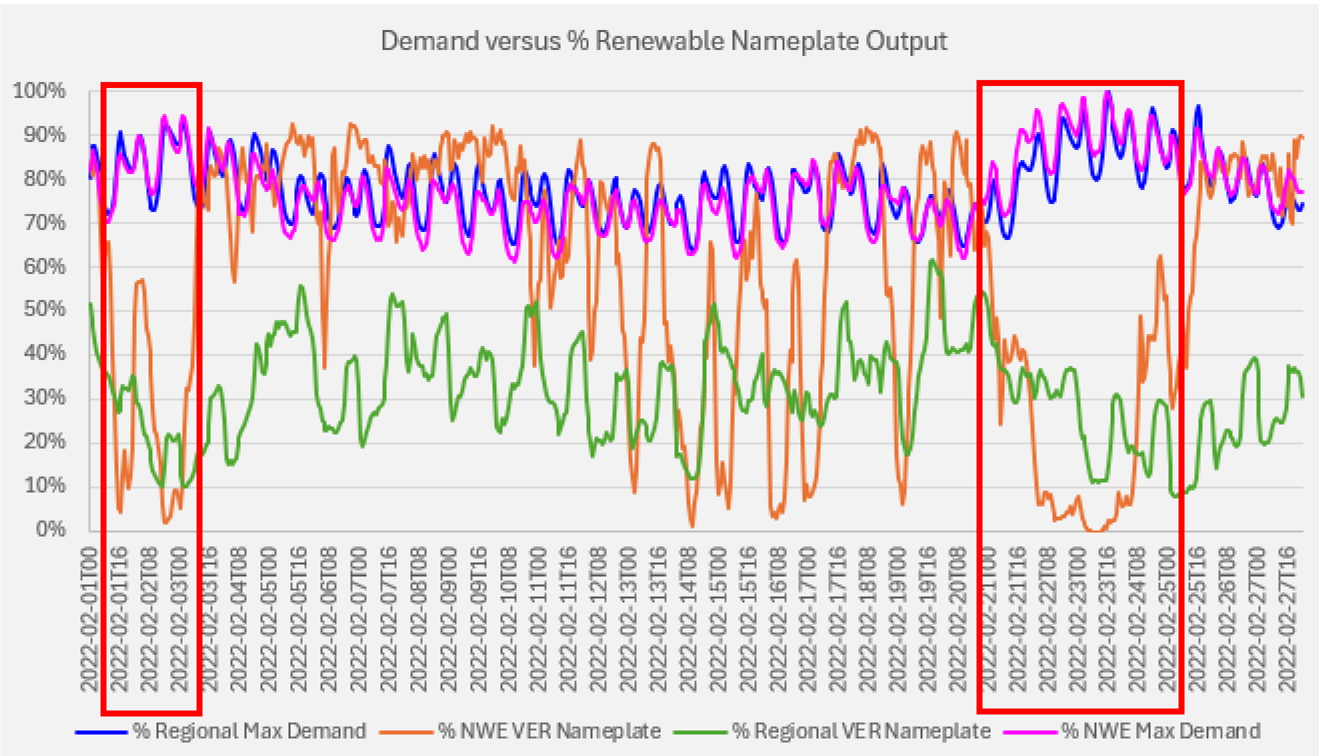


FIGURE 9: COMPARISON OF NORTHWESTERN RENEWABLES AND REGIONAL RENEWABLES DURING TIMES OF HIGH DEMAND.

Without significant storage, additional generation, or all utilities meeting regional planning reserve margins, these events could compromise the reliability of energy supply. This challenge has been repeatedly emphasized in regional adequacy assessments. The WECC's 2024 Resource Adequacy Report notes that "even with increasing amounts of renewable resources, there is a growing risk of supply shortfalls during extreme weather and high-load events."[13]

WRAP has formalized a response to this challenge by developing standardized accreditation metrics that distinguish between nameplate and accredited capacity. Under WRAP, participants must demonstrate sufficient accredited capacity to meet their PRM, including seasonal adjustments and firm commitments. In many portfolios dominated by VER additions, participants may be relying on transmission during peak times to access WRAP's regional resources when their VERs may be under-performing.

3.4.2 Firm and Balancing Generation

Resources that can rapidly respond to price signals, such as battery energy storage and fast-ramping gas turbines, are well positioned to extract value in this volatile environment. These assets can cycle multiple times per day, capturing spreads between off-peak and on-peak pricing. While average market prices may decline as low-cost VERs increase, the value of flexibility and responsiveness will grow, not only in economic terms but in maintaining reliability minute to minute.

For NorthWestern, this underscores the importance of investing in a balanced portfolio that includes firm, fast-ramping resources alongside VERs. Firm, fast-ramping resources are not only necessary for system stability but are also among the few resources capable of capturing value during both extreme, deep price troughs from oversupply and sharp spikes during scarcity through multi-day weather events.

Storage is unique, as it can enable a utility to buy negative-priced energy, store it, and sell it during higher price hours. The ability of energy storage to respond quickly allows it to not only stabilize price but also potentially participate as a balancing resource for VERs. Meanwhile, fast-ramping gas units can fill sudden gaps as solar dips, securing the value from peak price spikes.

3.5 Organized Market Development

3.5.1 Energy Imbalance Markets

Market coordination among entities in the West is continuing toward greater regional integration. The California Independent System Operator (CAISO) WEIM was created in 2014 and includes 22 members, with two more expected to join in 2026. NorthWestern joined WEIM on June 16, 2021. This market, which focuses on intra-hour or real-time optimization, has proven to be beneficial to customers from both resource management and financial perspectives.[22]

The WEIM is designed to discourage leaning on other participants for resources and imposes several Resource Sufficiency (RS) tests on participants so that issues are addressed prior to the operating hour. Failure to pass WEIM RS tests can lead to freezing transfers in the direction of failure as well as over- and under-scheduling charges for base scheduling errors. The WEIM RS requirements mean that NorthWestern needs to secure and maintain adequate capacity ahead of the operating hours to participate in the benefits of these markets and avoid penalties. Generally, a portfolio that is resource adequate and that has ramping capability makes it easier to pass WEIM RS tests and maintain WEIM participation.

SPP created a similar market, known as the Western Energy Imbalance Service (WEIS), in 2021. Participants include several utilities mainly in Eastern Montana, Wyoming, and Colorado.

3.5.2 Day-Ahead Market Development

Well-designed DA markets are expected to provide more value to customers than intra-hour markets such as WEIM because the range of resources that can be optimized in the DA timeframe is larger than the comparable set of resources that can be optimized in real time. The ability to commit resources with longer start times in a coordinated, optimized manner is expected to lead to a more efficient resource dispatch, with savings to customers.

The CAISO has been developing a DA extension to WEIM known as the Extended Day-Ahead Market (EDAM) since 2019. The EDAM tariff was approved by the Federal Energy Regulatory Commission (FERC) in December 2023. Seven entities have committed to EDAM by signing implementation

[22] https://www.caiso.com/Documents/NorthWestern-Energy-Joins-the-Western-Energy-Imbalance-Market.pdf

agreements. The first two of these – PacifiCorp and Portland General Electric – plan to go live in 2026, with the others following in 2027 and 2028.

The SPP is developing a competing DA market proposal known as Markets+. This initiative began in late 2021, and FERC approved the Markets+ tariff in early 2025. SPP has begun its Phase 2 development. Approximately seventeen potential participants, including the BPA, have committed to funding this phase of development, and several have committed to participating in Markets+. The initial launch date is expected to be October 2027, though BPA will not participate until 2028.

NorthWestern is continuing to evaluate both markets and expects to make a decision whether to join one of the markets in 2026.

3.6 Western Resource Adequacy Program

RA is the term used to describe an electric system's ability to meet demand under a broad range of conditions, subject to an acceptable standard of reliability. Currently, utilities in the Northwest individually plan for RA, typically through their resource planning processes. In 2019, the Northwest Power Pool, now known as the WPP, began the effort now known as WRAP, an initiative to develop a RA program for the region. This initiative was driven by recognition that the region could soon begin to experience power capacity shortages and that regional cooperation provides more efficiency than would be achieved by each energy company planning on its own. One of the program objectives is to leverage the geographic diversity benefits of the larger region to enhance planning and operations during times of peak energy demand. The ability of WRAP participants to pool and share resources during tight operating conditions is expected to lead to increased reliability and potential savings opportunities.

3.6.1 Program Status

NorthWestern has participated in WRAP as a founding member with representation on the Resource Adequacy Participant Committee as well as on a number of ad-hoc committees and work groups. FERC initially approved the WRAP tariff in early 2023, and in January 2025 approved tariff modifications related to the transition to the binding program provisions.

Some of the key design elements are:

- WRAP includes a Forward Showing (FS) program and an Operations program.
- Each entity will be required to demonstrate in advance that it owns or has contracted for the physical capacity needed to meet its forecasted peak load plus a reserve margin.
- The program is technology neutral, meaning that any resource that can help meet the peak load requirement can participate in the program.
- Resources are accredited based on their contribution to meeting peak load. An ELCC methodology is used for certain resource types.
- To qualify in the FS timeframe, resources must generally be accompanied by firm transmission.
- Contracts that are not linked to a specific resource or portfolio of resources do not qualify for RA.

The WRAP tariff contemplates compatibility for participants of both EDAM and Markets+ as well as those who do not participate in any DA market. WPP is collaborating with participants and both market operators to develop the details of how those interactions will occur. The Markets+ tariff requires participation in WRAP, but the EDAM tariff does not.

At the time of preparing this IRP, NorthWestern is committed to participating in the binding phase of the program beginning in winter 2027-2028.

3.7 Wholesale Market Observations

NorthWestern participates in the WEIM to optimize system operations in real time. The WEIM provides access to sub-hourly transactions that reduce the need for expensive balancing reserves and help integrate variable renewable generation. As the WEIM footprint continues to expand, its regional diversity enhances the ability to balance renewable variability across multiple balancing authorities.

3.7.1 Electricity Market Observations

Electricity markets across the Western U.S. have experienced increased volatility in recent years due to renewable integration, transmission constraints, and weather extremes. During periods of high wind and solar output, wholesale market prices can drop significantly, even becoming negative in some hours. Conversely, during cold snaps or heat waves, limited dispatchable resources and transmission congestion can drive prices sharply higher. This volatility underscores the importance of market participation, flexible resources, and regional coordination to maintain reliability and affordability.

3.7.2 Natural Gas Market Observations

Natural gas remains a critical component of wholesale electricity prices in the West. Following the 2021 winter storm events and ongoing infrastructure constraints, natural gas markets remain exposed to regional supply and transportation risks, especially during extreme weather when demand spikes across heating and electric generation sectors simultaneously.

Regional trading hub prices declined largely due to strong natural gas storage levels across all major regions, steady domestic production, and a mild winter. Warmer-than-normal temperatures, especially in the Northeast and Midwest, where heating demand is highest, kept storage inventories above the five-year (2019–2023) average for most of 2024.[23] This trend continued into 2025, with storage levels remaining well above average and continuing to exert downward pressure on prices as seen in the Figure 10 chart below from the EIA.

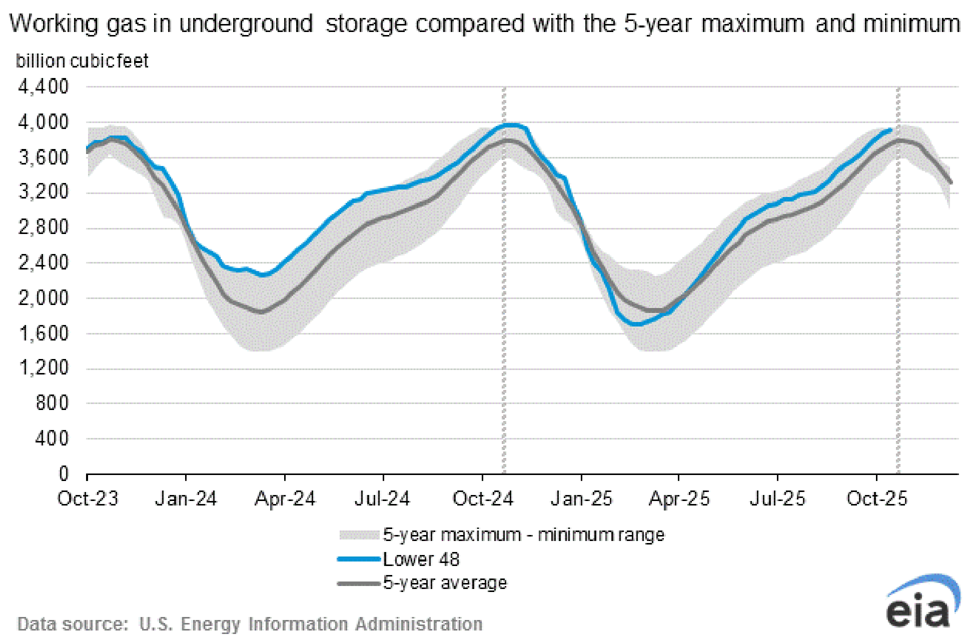


FIGURE 10: EIA UNDERGROUND STORAGE NOV. 14TH, 2025.[24]

[23] https://www.eia.gov/todayinenergy/detail.php?id=64445
[24] https://ir.eia.gov/ngs/ngs.html

4 LOAD FORECAST

4.1 Overview and Background

For the decade of 2010-2019, NorthWestern retail load grew at an average annual rate of 0.4% even though total customers grew at an average annual rate of 1.2%. The load serving obligation grew from 6.1 million MWh in 2010 to 6.4 million MWh in 2019 (or from about 700 average MW (aMW) to 730 aMW). However, after a decline during the COVID-19 year in 2020 of -1.7%, retail loads grew at over 3% in the next two years to reach a load-serving obligation of 6.7 million MWh or 765 aMW in 2022, where they remained through 2023 and 2024. From 2021-2024, total customers grew at an average annual growth rate of 1.6% driven by strong residential growth of 1.7% and GS1-Secondary of 2.0%. The strong customer growth has led to an increase in loads, but that increase has been limited by energy efficiencies, net-metering, and mild weather. Even with limited load growth, NorthWestern set records for retail peak demands for both summer and winter at 1,285 MW (2024) and 1,316 MW (2022), respectively – a reminder that although load growth may be low, the potential is always present for spikes in peak demands given the right conditions.

Examples of GS-1 Secondary customers include small commercial users such as convenience stores, grocery stores, restaurants, school districts, or hospitals. GS-1 Secondary customer usage is heterogeneous while residential usage is homogenous.

NorthWestern's DSM programs continue to be incorporated into the energy and peak demand forecasts. Prior year DSM acquisition is inherent in the energy and peak demand regression results, while future DSM acquisition is forecasted and applied to the regression results to reflect both a "gross" and "net" of DSM value for the energy and peak demand forecasts. The 2025-2026 DSM Acquisition Plan reflects approximately 3 aMW per year or 65 aMW in DSM energy savings over the next 20 years, excluding losses, with contributions to 2044 summer and winter peaks projected at 100 MW and 108 MW, respectively.

NEM on NorthWestern's system has grown significantly since the last IRP. From 2022 to 2025, residential solar-photovoltaic (solar-pv) NEM customers increased from 3,735 to 9,224, increasing installed solar capacity from 24 MW to 66 MW. Commercial solar-pv growth has not experienced the same significant increase as residential, with an increase from 581 to 765 customers and adding 4 MW of installed capacity to reach 13 MW total. Incremental NEM is forecasted to contribute 71 MW to the summer peak demand by 2050.

Data centers are a new topic in the long-term load forecast. In 2024 NorthWestern announced that the Company was working with data center entities to provide electric supply for their operations. The consistently high energy use by data centers means that there will be significant energy-serving needs throughout all periods of a normal day, putting emphasis and importance on both baseload and peak energy supply planning. Potential data center load is not included in NorthWestern's base load forecasts in this IRP. NorthWestern addresses potential additional data center load uncertainty by modeling different load growth sensitivities.

Overall, NorthWestern evaluated historical changes in both annual energy use and hourly load patterns, including customer growth, seasonal peak behavior, load duration trends, AMI-based customer class usage profiles, DSM impacts, and the increasing influence of net metering. This assessment was used to identify reduction of system peaks, sustained high-load events, and to inform the regression-based energy and peak demand forecasts as well as modeling sensitivities for forecast uncertainty that includes increased NEM and DSM growth and large load additions such as data centers.

4.1.1 Methodology and Energy Forecast

NorthWestern uses a combination of regression model analysis and known-change information to develop annual load and customer forecasts, which is the same methodology since the last IRP. Residential and GS-1 Secondary usage combined represents approximately 88% of the total energy load-serving obligation. These forecasts are based on more detailed regression models using the specific customer-class forecast and normal weather, defined as the 10-year average historical total degree days (heating plus cooling), as the explanatory variables that produce the annual load forecasts. Usage for all other customer classes, including GS-1 Primary, GS-2 Substation, GS-2 Transmission, Lighting, and Irrigation, are based on historical actual annual usage coupled with adjustments for known changes to future usage. In addition, transmission line losses are included in all customer classes' forecasts. For purposes of NorthWestern's ARS and PCM modeling, the total annual energy and peak forecasts are converted to monthly values using weather-normalized monthly energy and peak data. End-use data, such as average energy consumption per appliance, industrial motor counts or operating hours, etc, is not used in the forecasting methodology.

Expected DSM and NEM are also projected throughout the 20-year forecast period and subtracted from residential and GS-1 Secondary energy forecasts as well as the winter and summer peak forecasts. The projected DSM and NEM have a substantial impact on projected annual load; the forecasted average annual growth rate for the retail load-serving obligation excluding future DSM and NEM is 0.8%, while the average annual growth rate when including future DSM and NEM is 0.3%. Figure 11 illustrates the impact of DSM and NEM on future energy usage. Historical DSM and NEM energy and peak impacts are inherent in the regression results in that they are included in historical load figures, the basis for forecasting future loads. Figure 12 shows the energy forecast separated by customer class. Table 6 shows the actual and forecasted retail supply loads broken into commercial (both GS1-Primary and GS1-Secondary), residential, and "other"[25] categories.

[25] The "other" category includes substation, transmission, lighting, irrigation, and Yellowstone National Park loads.

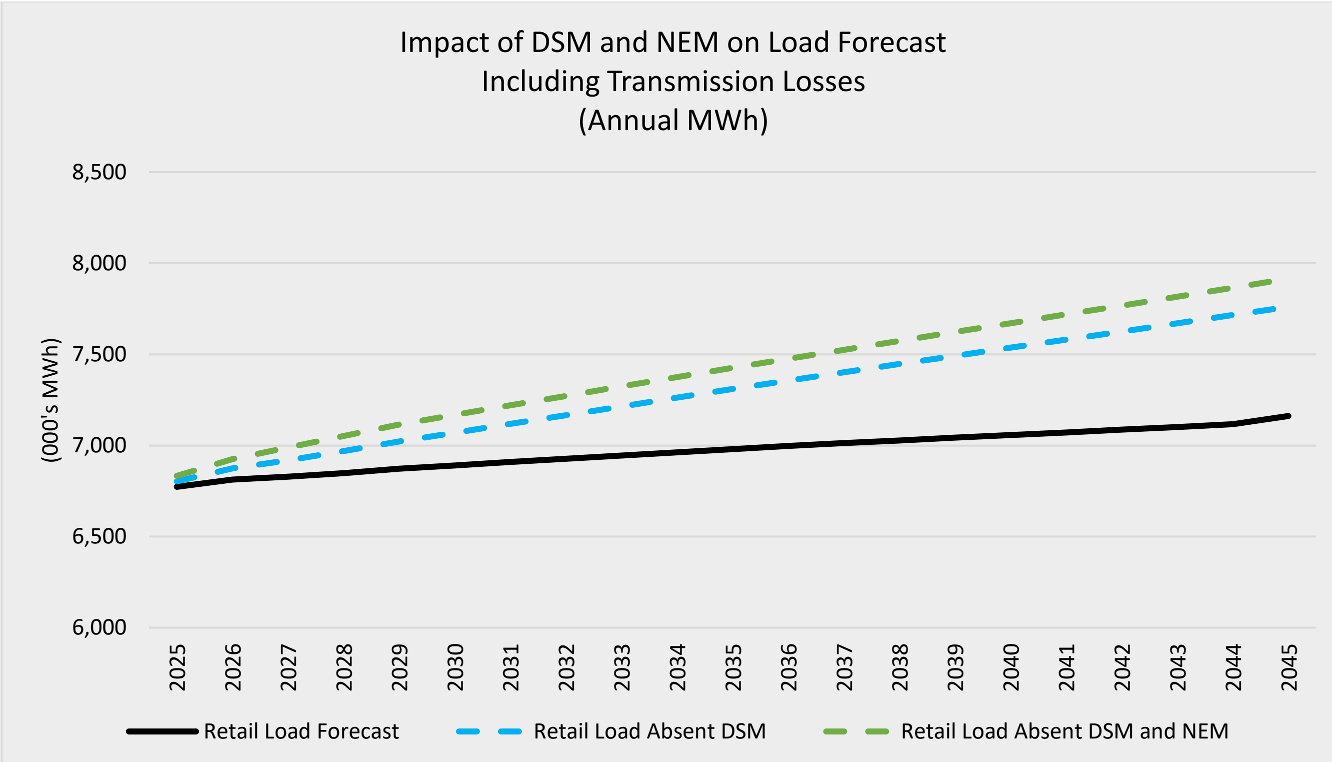


FIGURE 11: ENERGY FORECAST INCLUDING LOSSES, DSM AND NEM; EXCLUDING DATA CENTERS.

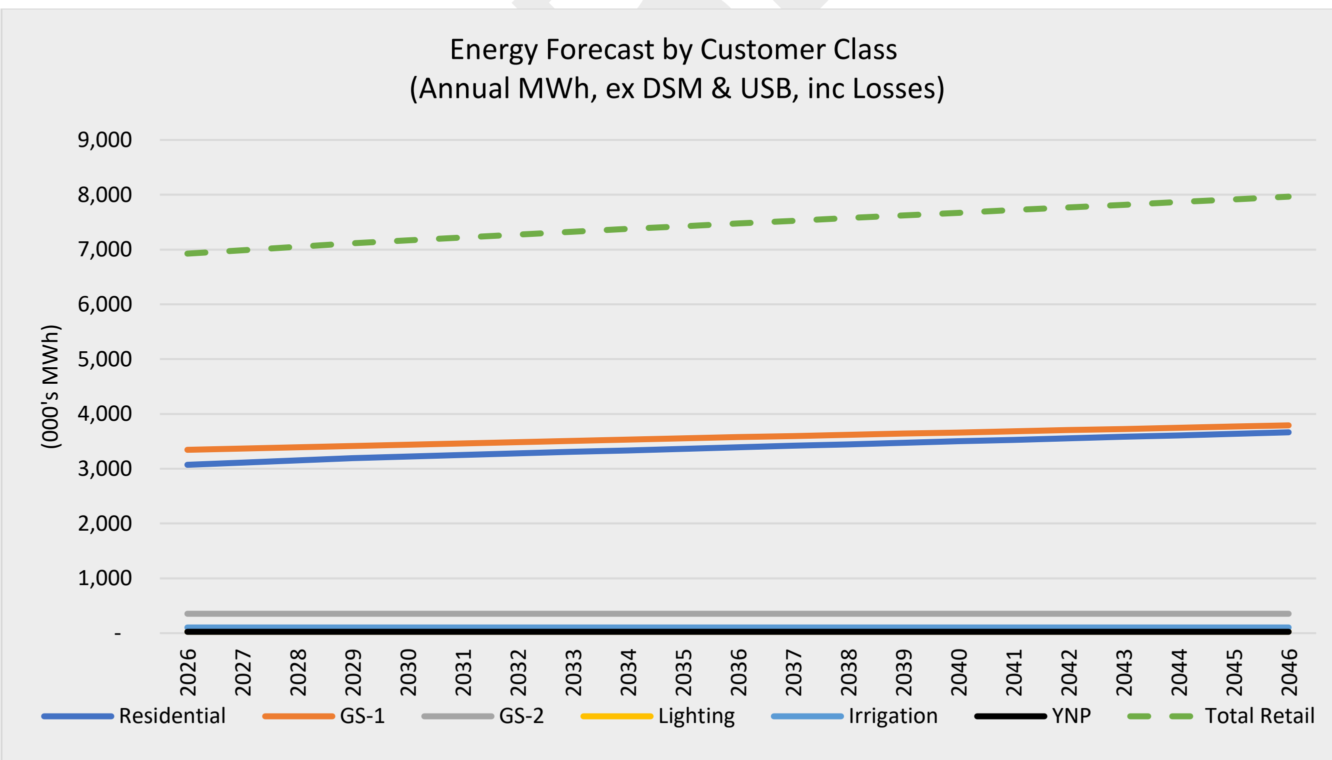


FIGURE 12: ENERGY FORECAST BY CUSTOMER CLASS INCLUDING LOSSES; EXCLUDING DSM, NEM, AND DATA CENTERS.

Year	Retail Load (MWh)	Annual Growth Rate	Commercial (MWh)	Annual Growth Rate	Residential (MWh)	Annual Growth Rate	Other (MWh)	Annual Growth Rate
2005	5,853,233		3,056,875		2,192,095		604,263	
2010	6,083,553	0.8%	3,176,584	0.8%	2,459,158	2.3%	447,811	-5.8%
2015	6,296,193	0.7%	3,258,127	0.5%	2,495,313	0.3%	542,753	3.9%
2020	6,325,688	0.1%	3,089,126	-1.1%	2,786,461	2.2%	450,101	-3.7%
2025	6,773,089	1.4%	3,299,239	1.3%	2,989,985	1.4%	483,864	1.5%
2030	6,890,535	0.3%	3,347,260	0.3%	3,059,411	0.5%	483,864	0.0%
2035	6,980,125	0.3%	3,364,263	0.1%	3,131,999	0.5%	483,864	0.0%
2040	7,057,501	0.2%	3,375,670	0.1%	3,197,967	0.4%	483,864	0.0%
2045	7,161,649	0.3%	3,404,790	0.2%	3,272,995	0.5%	483,864	0.0%
20-YR CAGR		0.3%		0.2%		0.5%		0.0%

TABLE 6: HISTORICAL AND FORECASTED RETAIL SUPPLY LOADS.

4.1.2 Customer Forecast

The customer forecast is developed similarly to the energy forecast in that regression models are used to project Residential and GS-1 Secondary customer counts, using population in NorthWestern's service territory as the explanatory variable and known-change information in all other classes. Table 7 shows the historic and forecasted populations for both the state of Montana and NorthWestern's service territory. Table 8 shows that total accounts are projected to grow at about a 0.9% annual rate, and Residential and GS-1 Secondary accounts are projected to grow at annual rates of 0.9% and 1.0%, respectively.

Year	Montana Population	Annual Growth Rate	NWE Service Territory Population	Annual Growth Rate
2000	903,773		705,765	0.8%
2005	940,102	0.8%	734,415	1.1%
2010	990,643	1.1%	774,995	0.8%
2015	1,030,475	0.8%	805,038	1.0%
2020	1,087,075	1.1%	847,005	1.2%
2025	1,150,090	1.1%	899,416	0.7%
2030	1,192,708	0.7%	932,745	0.7%
2035	1,233,965	0.7%	965,009	0.6%
2040	1,273,196	0.6%	995,690	0.6%
2045	1,312,337	0.6%	1,026,300	0.7%
20-yr CAGR		0.7%		0.7%

TABLE 7: HISTORICAL AND FORECASTED POPULATION.

Year	NWE Total Accounts	Annual Growth Rate	NWE Residential Accounts	Annual Growth Rate	NWE GS-1 Secondary Accounts	Annual Growth Rate
2000	292,437		235,784		49,759	
2005	315,755	1.5%	253,124	1.4%	55,491	2.2%
2010	338,804	1.4%	270,571	1.3%	60,872	1.9%
2015	359,565	1.2%	287,387	1.2%	64,554	1.2%
2020	385,230	1.4%	307,390	1.4%	70,014	1.6%
2025	440,226	2.7%	333,102	1.6%	77,162	2.0%
2030	466,172	1.2%	354,426	1.2%	81,784	1.2%
2035	486,833	0.9%	370,613	0.9%	86,258	1.1%
2040	506,480	0.8%	386,005	0.8%	90,513	1.0%
2045	526,082	0.8%	401,362	0.8%	94,758	0.9%
20-yr CAGR		0.9%		0.9%		1.0%

TABLE 8: HISTORICAL AND FORECASTED CUSTOMERS.

4.1.3 Average Hourly Demand

Figure 13 and Figure 14 below show the 2024 seasonal daily average hourly demand for all retail customers. The 2024 summer daily average is calculated using data from June, July, August, and September, while the 2024-2025 winter daily average is calculated using data from November and December of 2024, and January, February, and March of 2025. These daily average hourly demand shapes may change with more adoption of electrification and/or EV growth.

Figure 13 shows summer demand peaks in the evening, indicating higher energy consumption during the warmer parts of the day. July has the highest overall demand, while September has the lowest. Figure 14 shows a two-peak pattern for the winter season, with demand rising in the morning and again in the evening, matching the colder times of the day. February shows the highest demand during the winter season, while March shows the lowest.

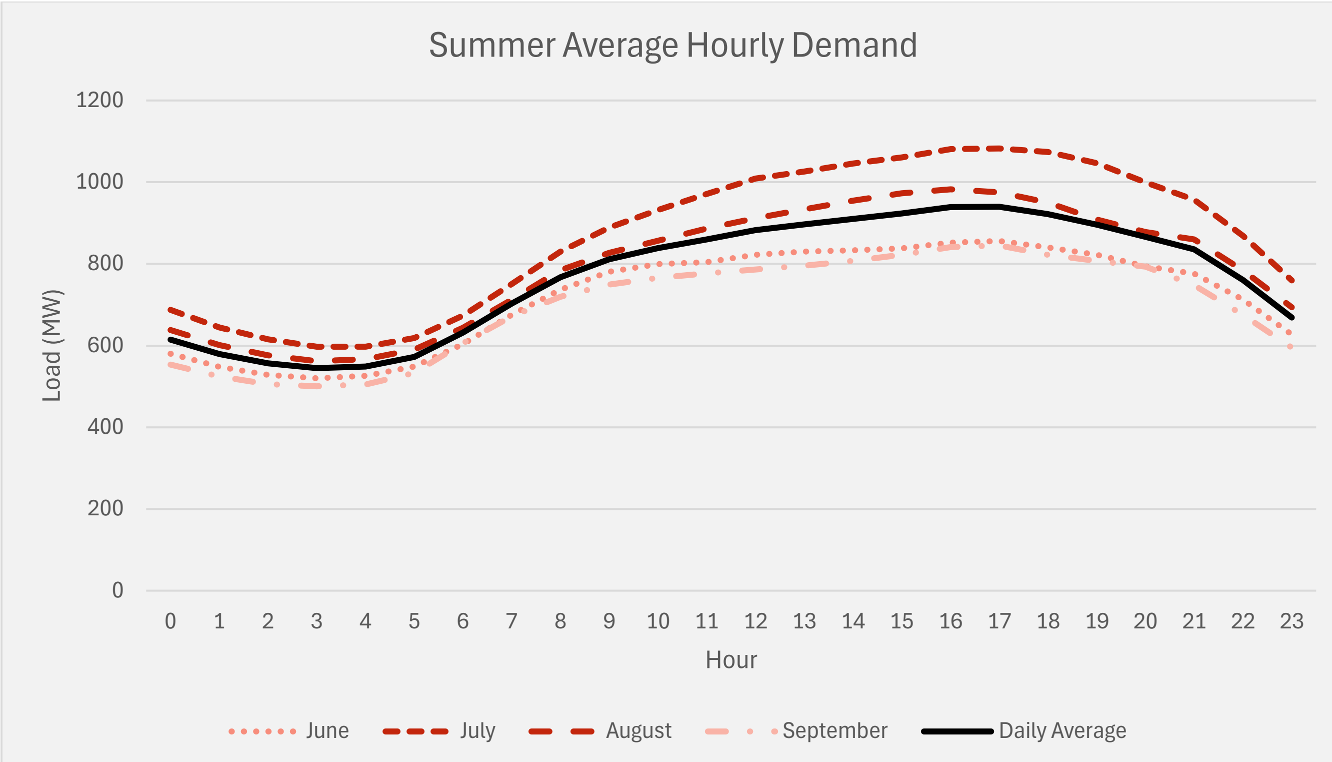


FIGURE 13: SUMMER AVERAGE HOURLY DEMAND FOR NORTHWESTERN CUSTOMERS.

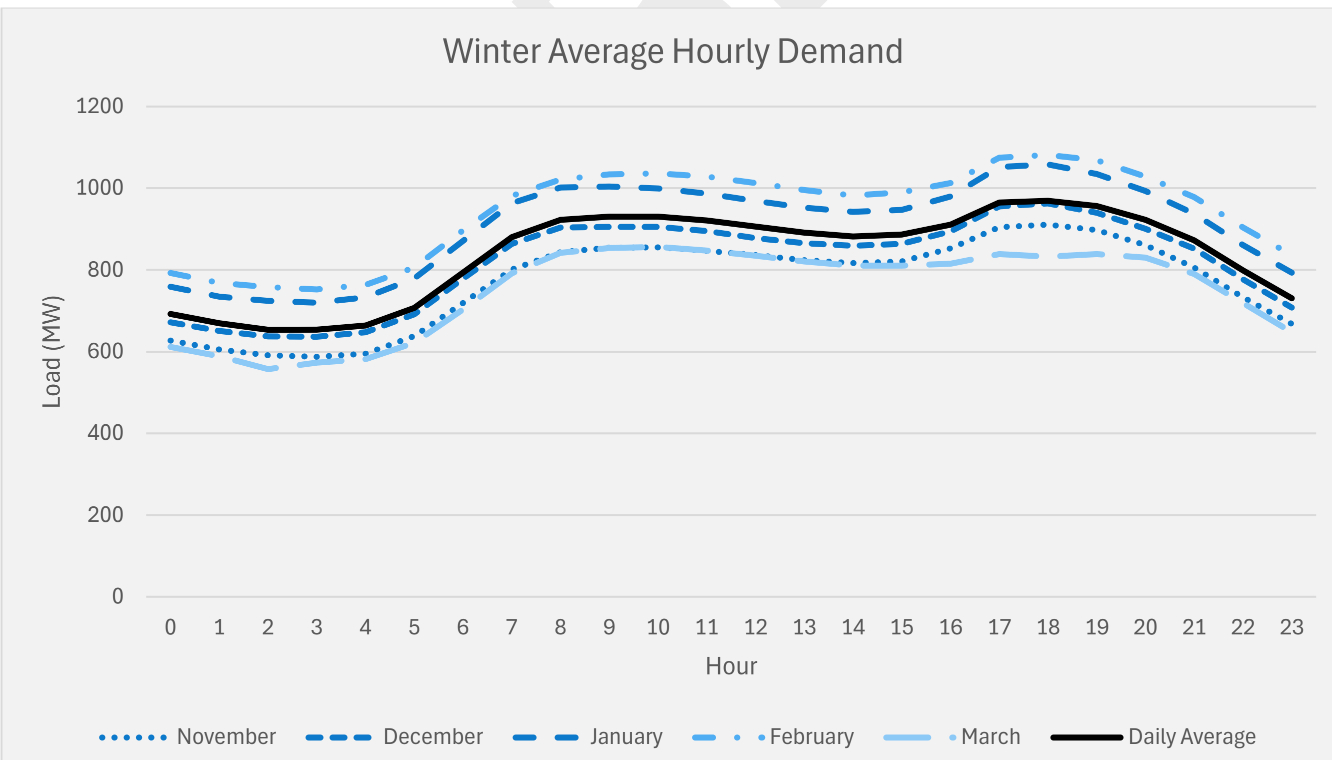


FIGURE 14: WINTER AVERAGE HOURLY DEMAND FOR NORTHWESTERN CUSTOMERS.

4.1.4 Customer Class Usage Profiles

NorthWestern currently collects AMI data for the following electric customer classes: Residential, GS-1 (Commercial), GS-2 (Industrial), Irrigation, and Street Lighting. The figures below characterize customer usage using percentile-based load shapes (P10, P50, P90) and average interval use for available AMI meters[26].

- P10 represents the lowest 10 percent of customer usage within a class.
- P50 represents the median customer.
- P90 represents the highest 10 percent of customer usage.
- Average Interval Usage reflects the mean usage across all customers in a class.

These metrics illustrate not only typical usage patterns, but also the diversity of behavior within each customer class.

NorthWestern evaluated hourly electric usage profiles for January and July 2025 as representative winter and summer season needs. In addition, NorthWestern developed annual average daily load shapes to illustrate longer-term patterns of customer class average energy usage.

The following sections present a detailed review of each major customer class (Residential, Commercial, Industrial, Irrigation, and Street Lighting) that NorthWestern analyzed, highlighting similarities and differences in seasonal load behavior, and summarizing annual average daily load profiles.

4.1.4.1 Residential

Figure 15 and Figure 16 below illustrate pronounced seasonal differences in hourly residential electricity consumption in January and July 2025. Residential load exhibits pronounced seasonal and daily variation throughout the year.

In January, residential usage remains elevated throughout the day, reflecting increased demand during early and later hours. The relatively sustained winter load indicates a greater reliance on electric end uses during cold conditions.

In July, residential usage increases steadily throughout the day and peaks in the early evening. Compared to winter, this spread between P10 and P90 usage widens during peak hours, reflecting greater variability in usage intensity among customers.

[26] Available AMI meters by customer class:

- Residential: ~321k meters
- GS-1 (Commercial): ~73k meters
- GS-2 (Industrial): ~50 meters
- Irrigation: ~3k meters
- Lighting: ~424 meters

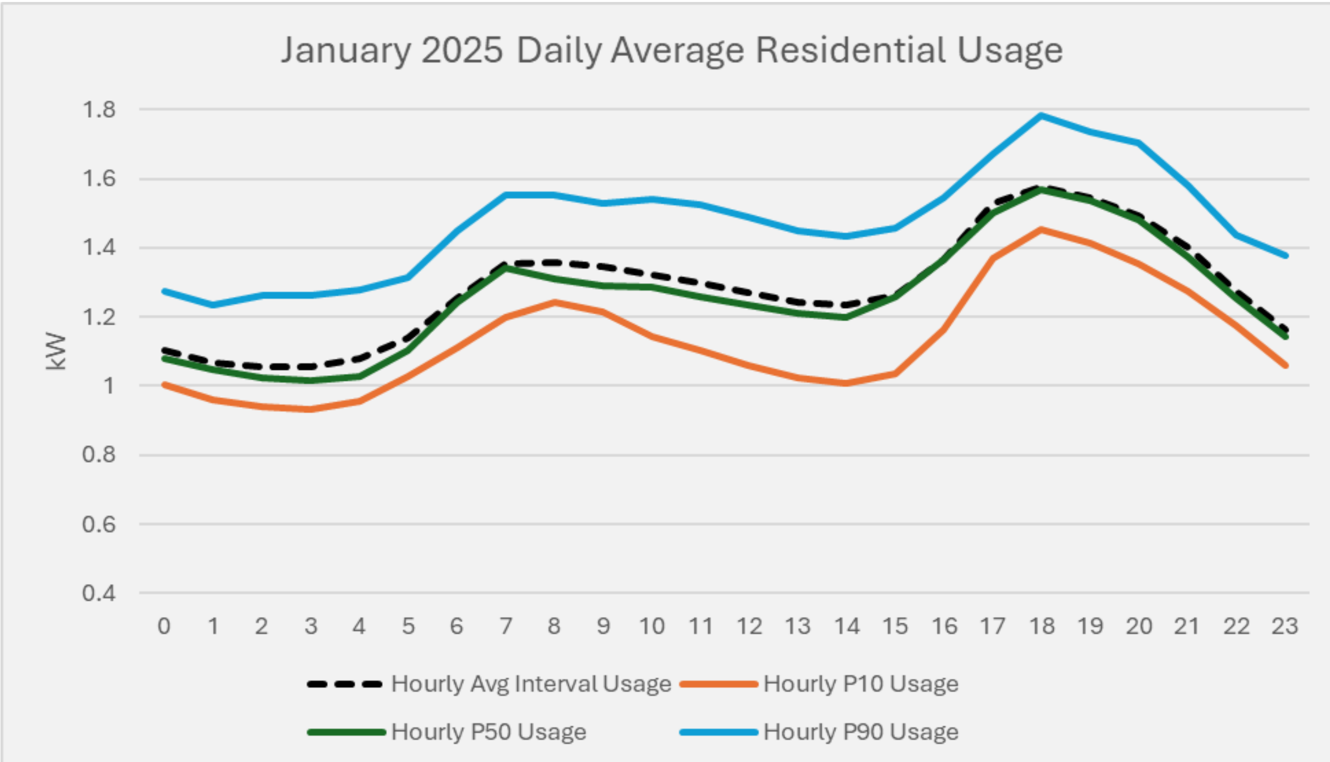


FIGURE 15: JANUARY 2025 DAILY AVERAGE RESIDENTIAL USAGE.

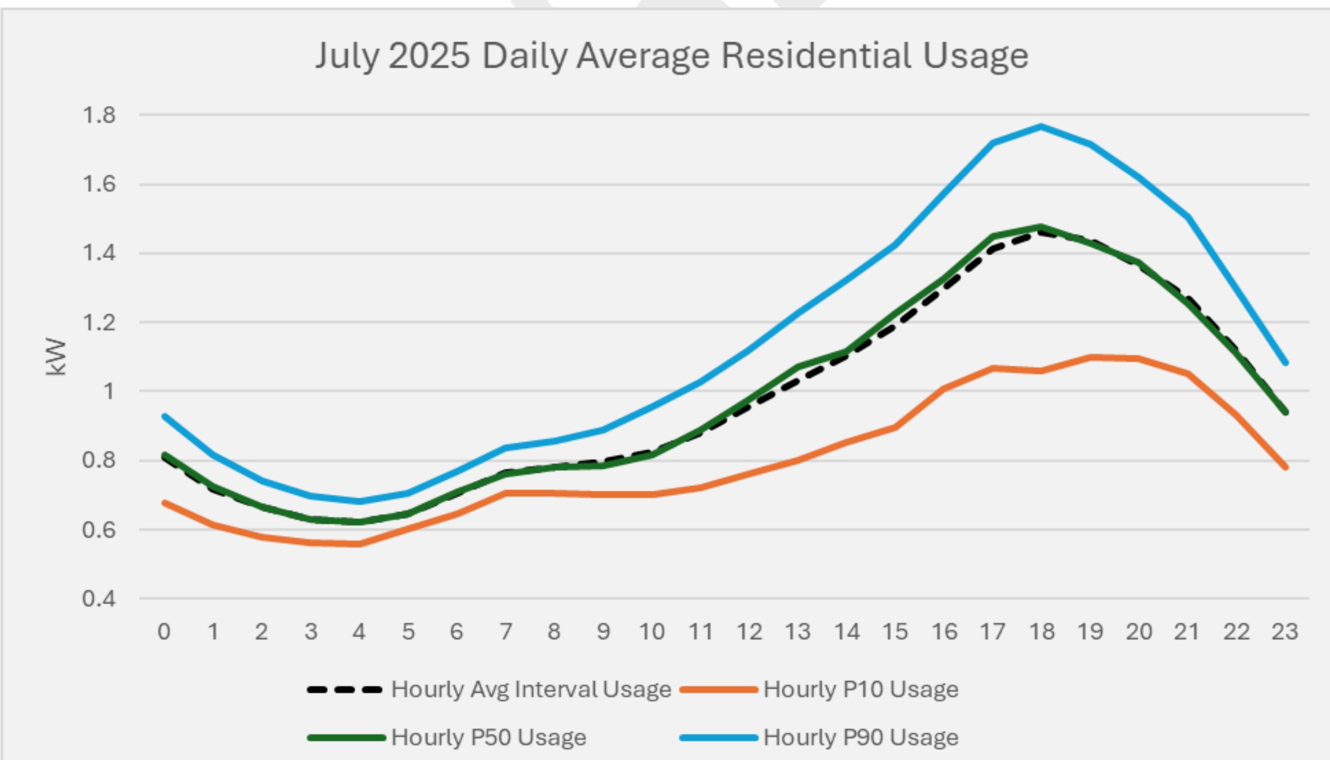


FIGURE 16: JULY 2025 DAILY AVERAGE RESIDENTIAL USAGE.

Figure 17 presents the annual average daily residential load shape, which smooths seasonal effects while preserving key behavioral patterns. The persistent morning ramp and evening peak highlight the consistency of residential electricity use across the year.

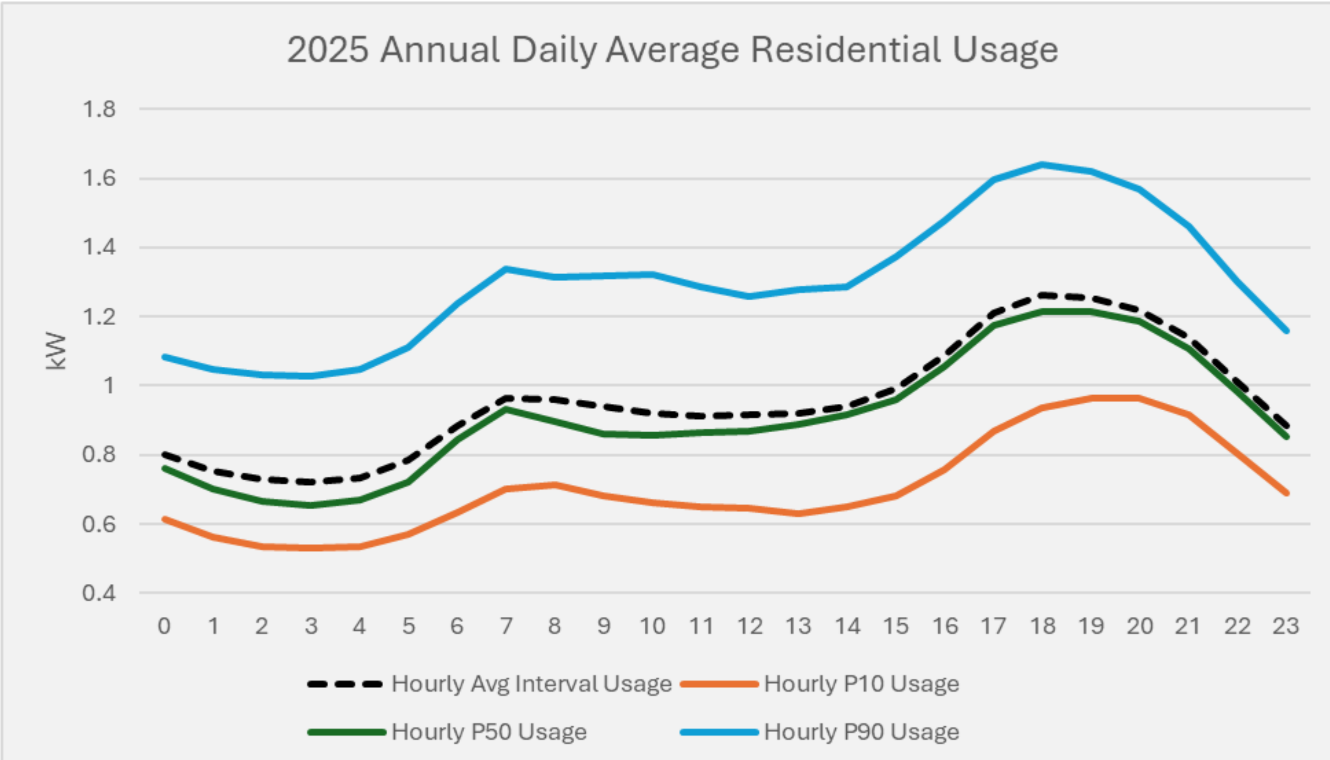


FIGURE 17: 2025 ANNUAL DAILY AVERAGE RESIDENTIAL USAGE.

4.1.4.2 GS-1 (Commercial)

Commercial customers display load shapes that differ from residential usage and more closely align with business operating hours.

For January, shown in Figure 18, commercial customers generally peak during the morning and midday, consistent with business startup and daytime operations. Figure 19 shows that in July, peak usage shifts towards late afternoon.

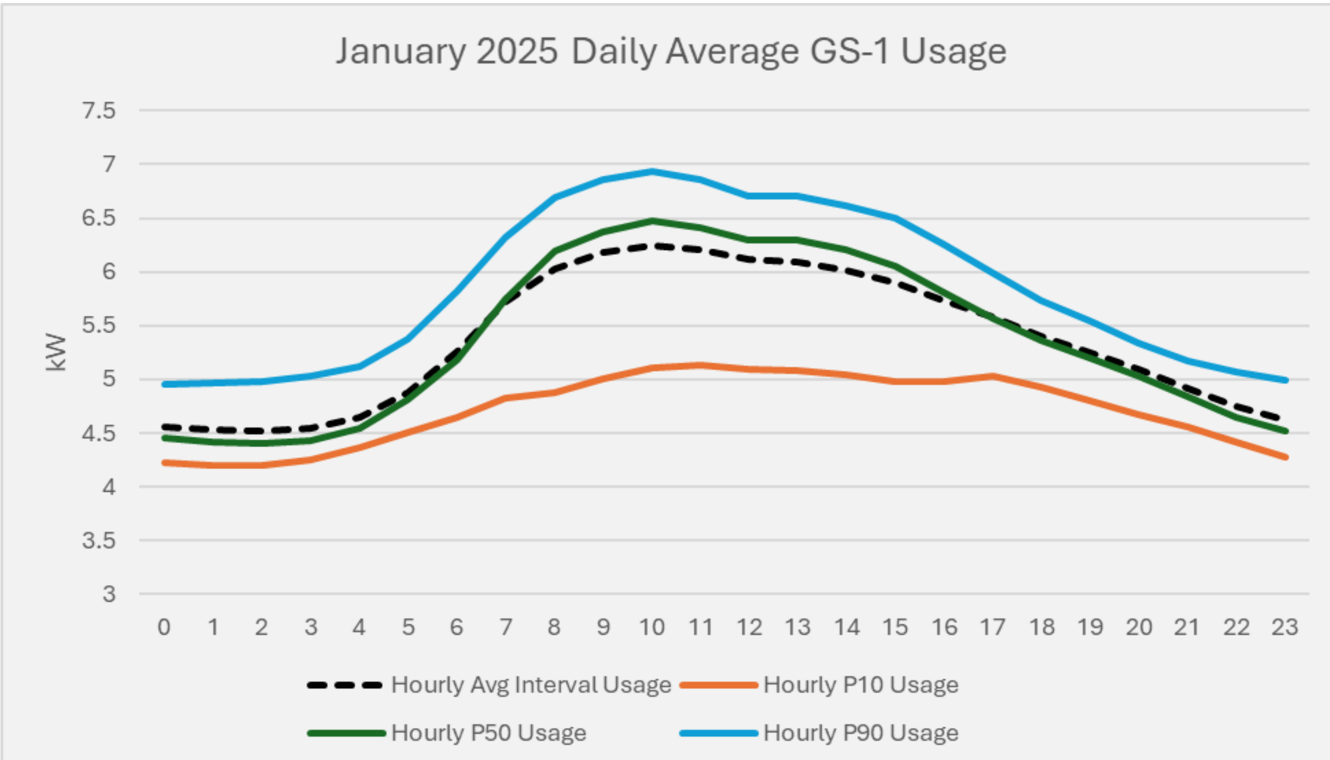


FIGURE 18: JANUARY 2025 DAILY AVERAGE GS-1 USAGE.

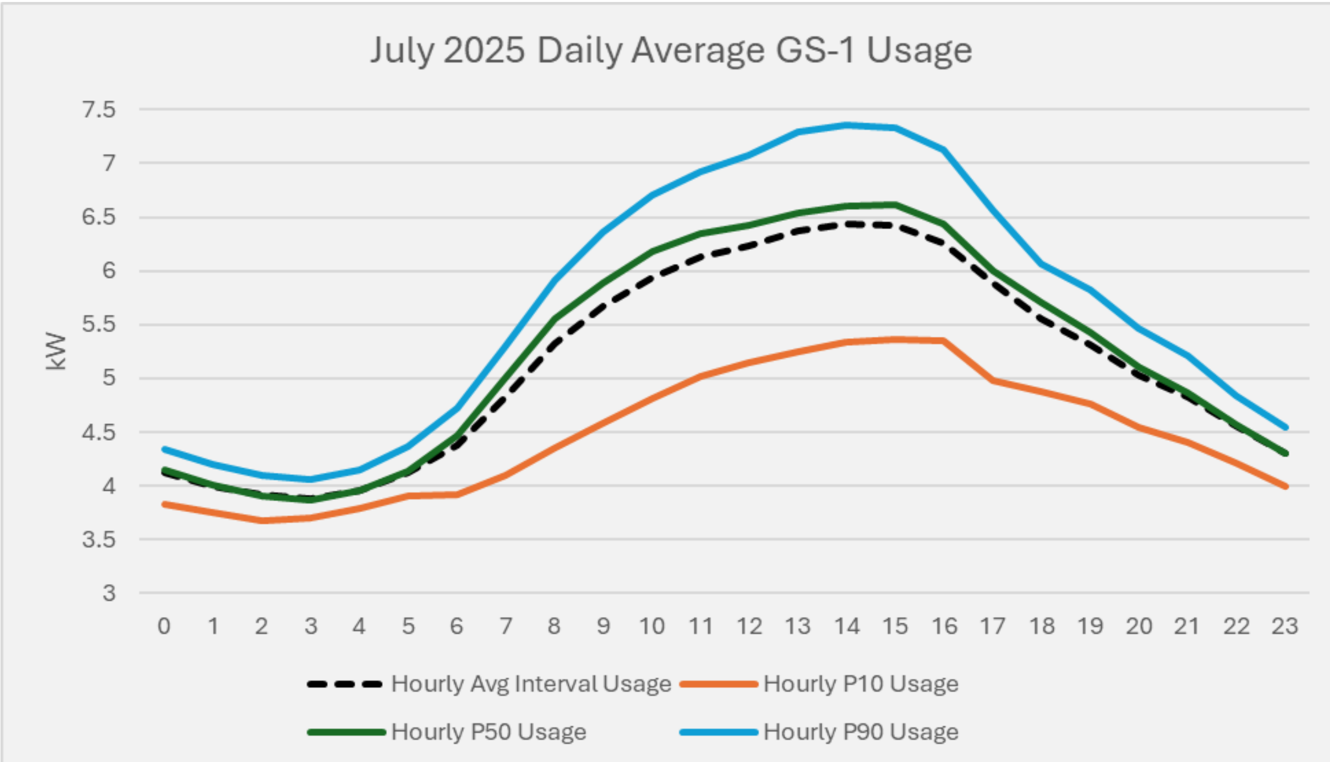


FIGURE 19: JULY 2025 DAILY AVERAGE GS-1 USAGE.

Figure 20 shows the annual average commercial customer daily usage profile. An interesting divergence appears between usage percentiles: P90 customers exhibit a later-afternoon peak, while the P50 and average customers tend to peak in the late morning. This indicates that more energy-intensive commercial facilities drive peak demand later in the day, while smaller businesses maintain more traditional daytime operating patterns.

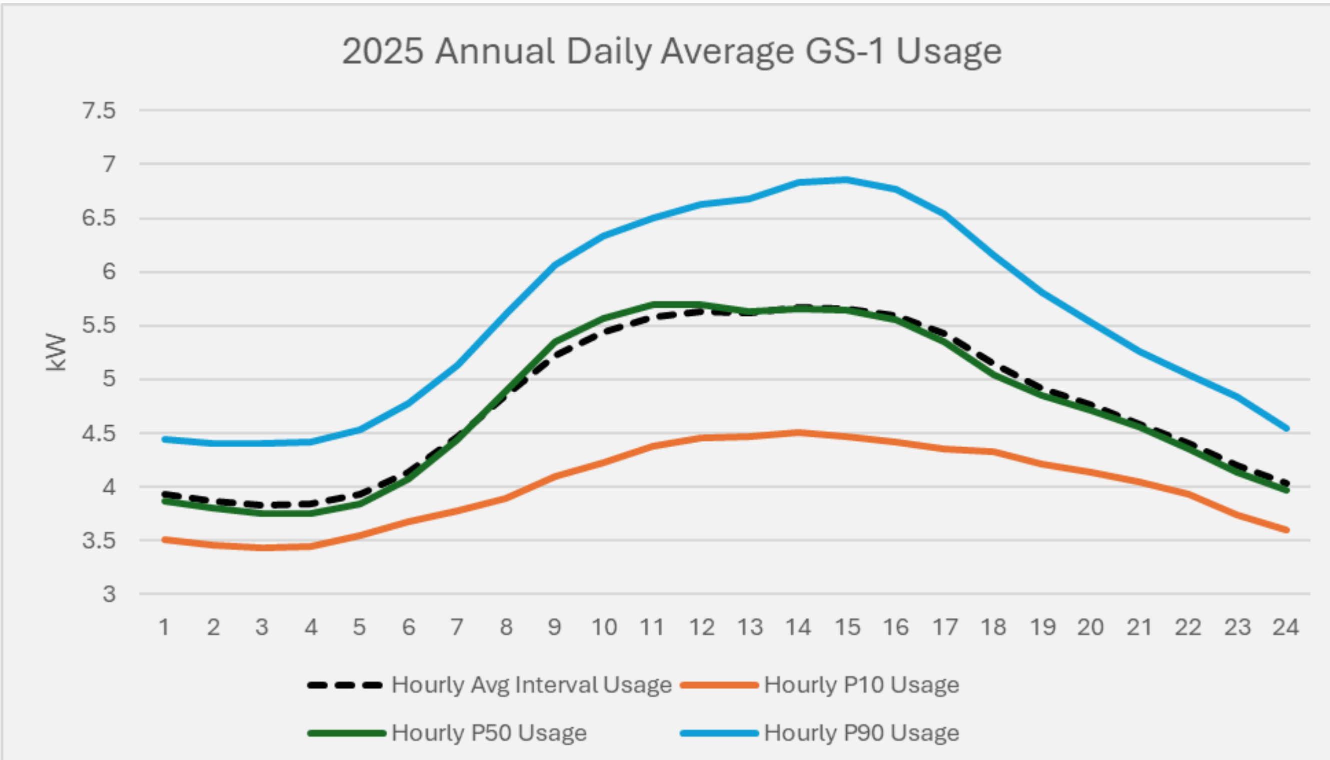


FIGURE 20: 2025 ANNUAL DAILY AVERAGE GS-1 USAGE.

4.1.4.3 GS-2 (Industrial)

Industrial customers exhibit largely non-conforming load behavior, with relatively flat usage throughout the day and limited seasonal variability. Figure 21 and Figure 22 demonstrate that industrial customer loads remain stable across hourly intervals in both January and July.

Winter usage is modestly higher than summer usage on an hourly basis. In July, a noticeable reduction in usage among P10 customers may reflect temporary operational shutdowns, maintenance periods, reduced seasonal production at certain facilities, or other external factors not under NorthWestern's control.

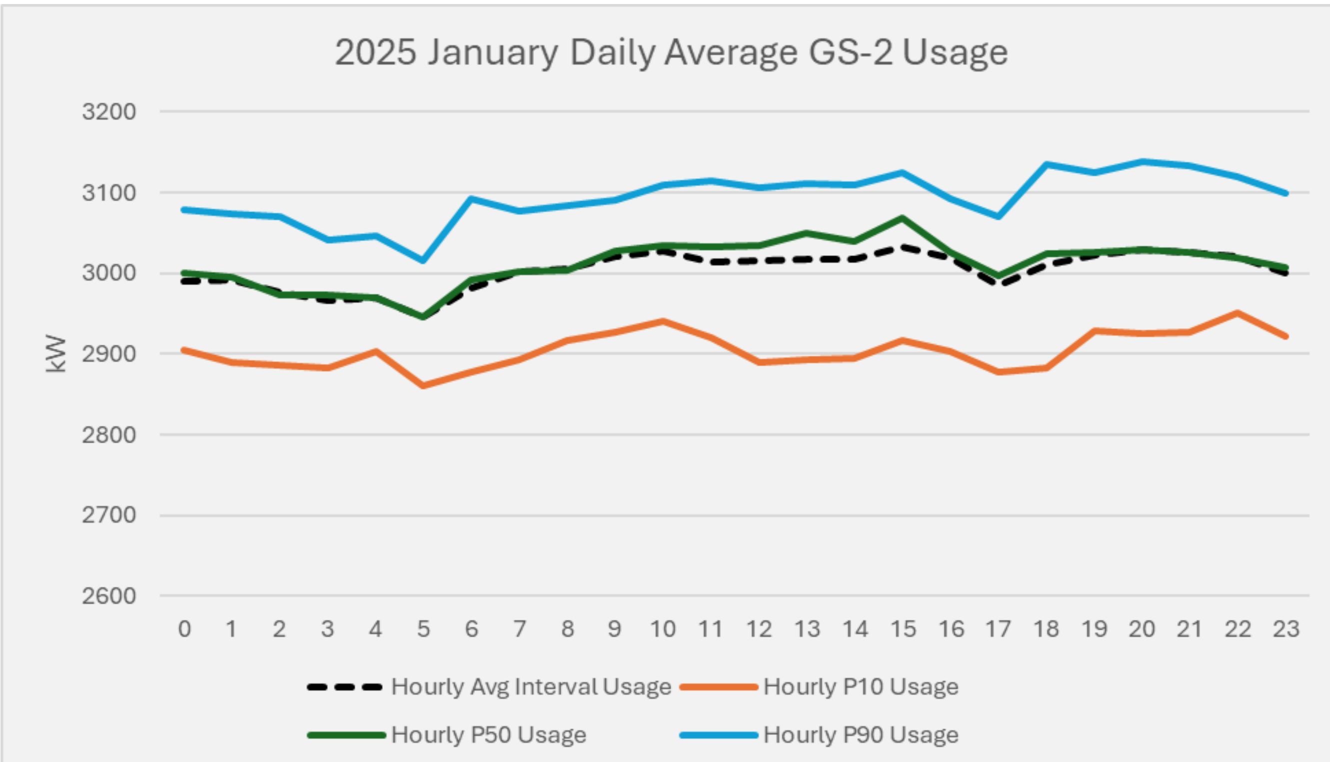


FIGURE 21: 2025 JANUARY DAILY AVERAGE GS-2 USAGE.

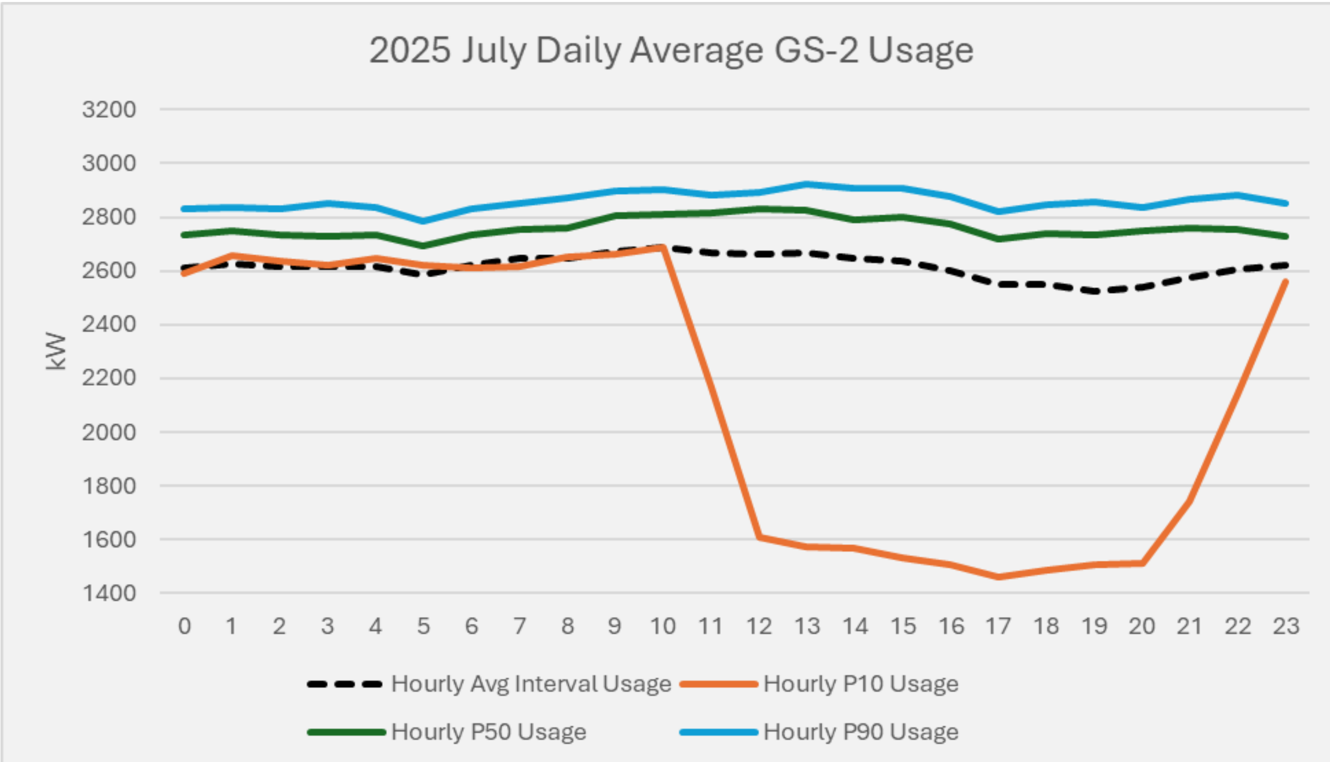


FIGURE 22: 2025 JULY DAILY AVERAGE GS-2 USAGE.

Figure 23 presents the annual industrial customer load profile, reinforcing the overall consistency of industrial demand.

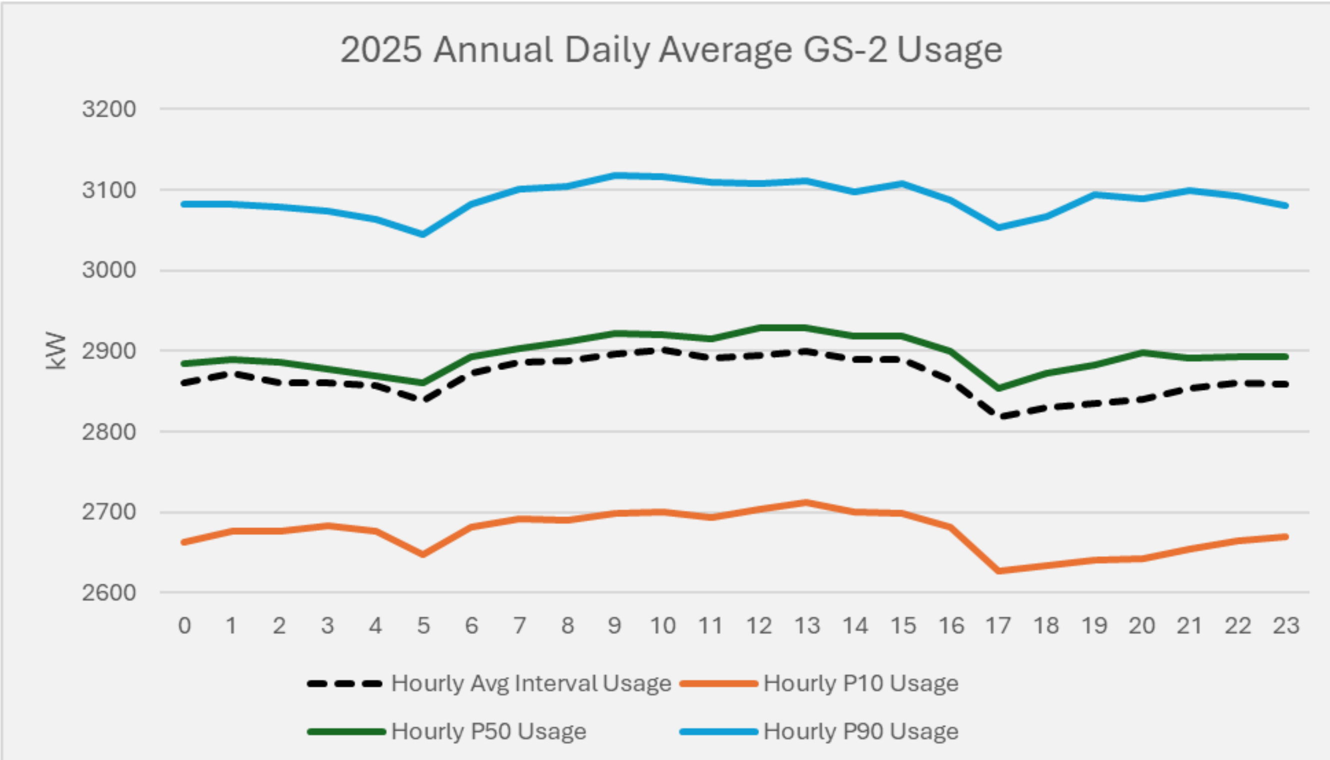


FIGURE 23: 2025 ANNUAL DAILY AVERAGE GS-2 USAGE.

4.1.4.4 Irrigation

Irrigation customer usage exhibits strong seasonal dependence. January usage, in Figure 24, is near zero across all percentiles, reflecting the absence of irrigation activity during winter months. In contrast, July usage, in Figure 25, is relatively flat across the day, indicating continuous or scheduled pumping operations.

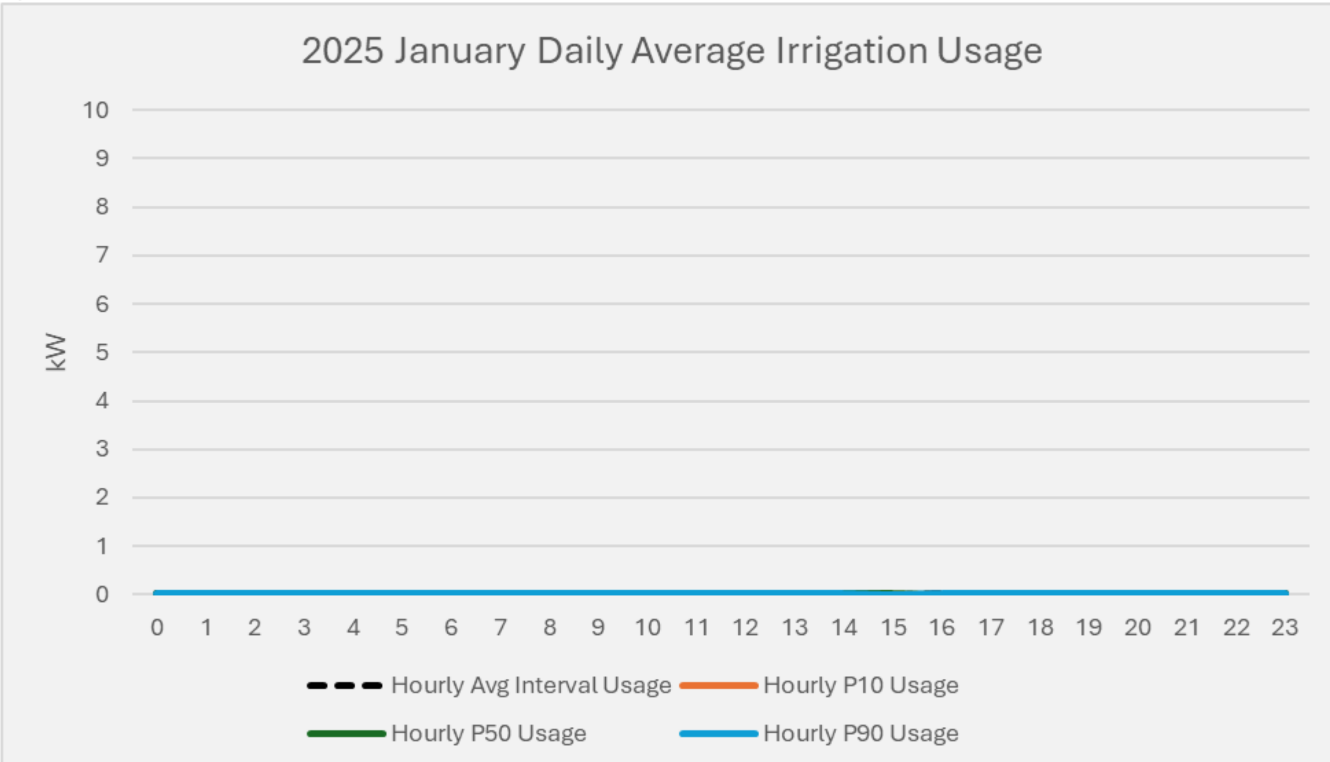


FIGURE 24: 2025 JANUARY DAILY AVERAGE IRRIGATION USAGE.

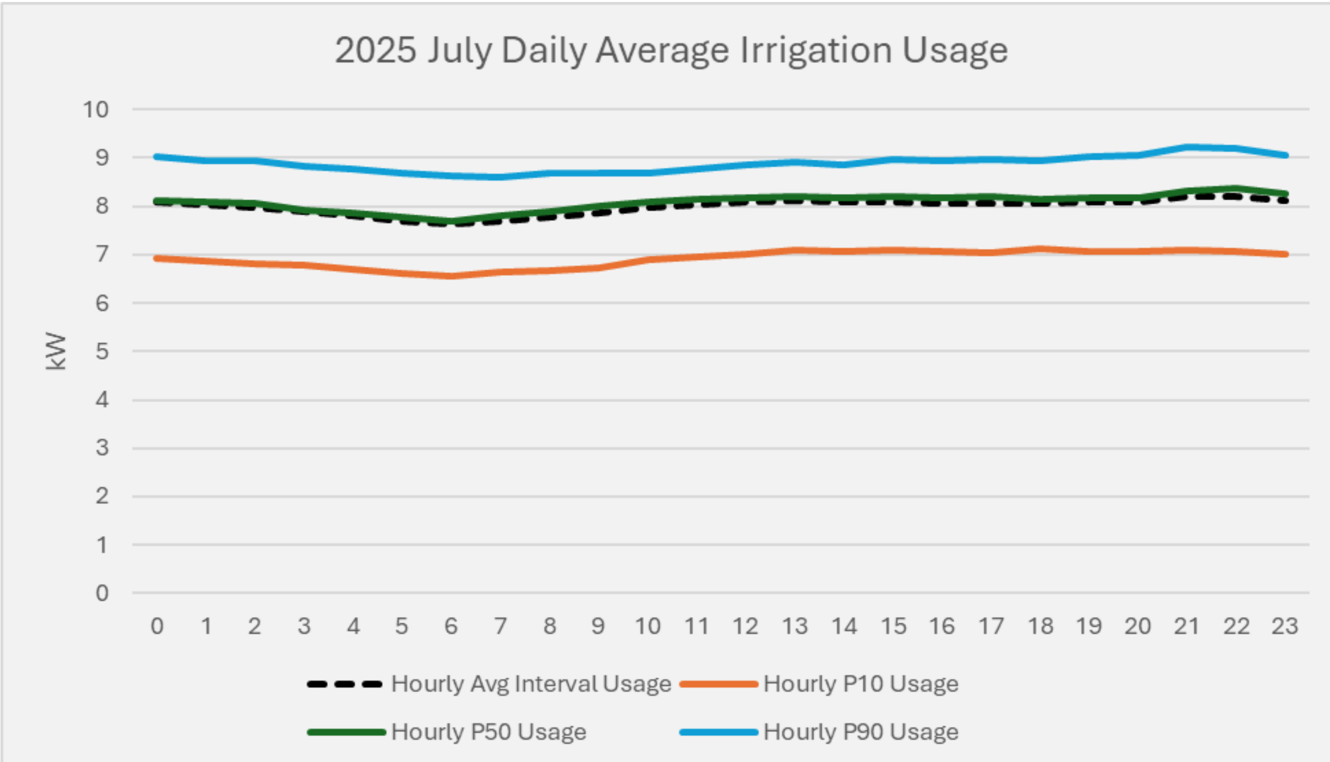


FIGURE 25: 2025 JULY DAILY AVERAGE IRRIGATION USAGE.

Figure 26 presents the annual Irrigation customer load profile, reinforcing the overall consistency of irrigational demand. As can be seen, P90 customers use higher overall energy than P50 and P10, raising the overall average by quite a bit.

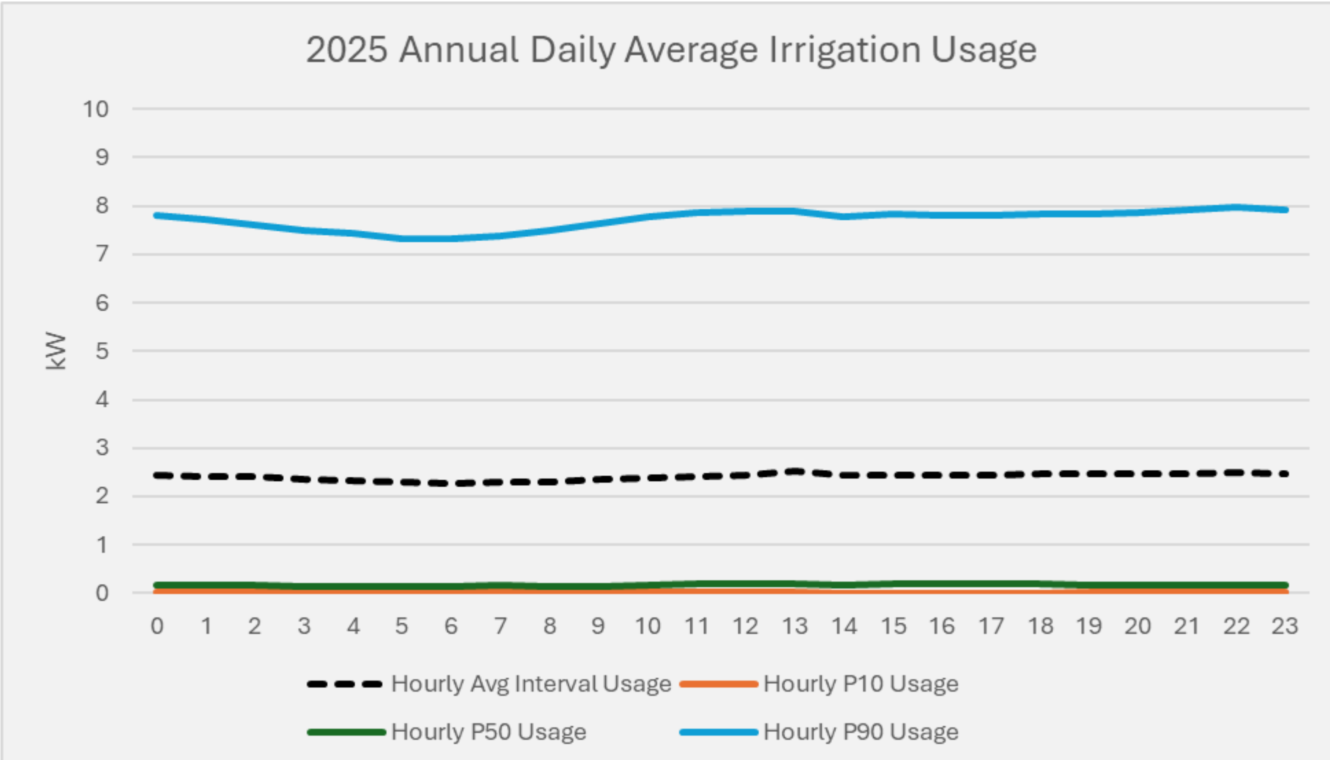


FIGURE 26: 2025 ANNUAL DAILY AVERAGE IRRIGATION USAGE.

4.1.4.5 Street Lighting

Street lighting customer usage is directly tied to daylight duration rather than customer driven behavior. In January, shown in Figure 27, shorter days result in longer lighting runtimes, while in July, shown in Figure 28, longer daylight hours substantially reduce operating hours. The hourly load shapes show predictable on/off behavior, with minimal variability across percentiles. Due to street lighting customer load being largely invariant and operationally controlled, it does not meaningfully influence system peak variability, reflecting a more non-conforming load.

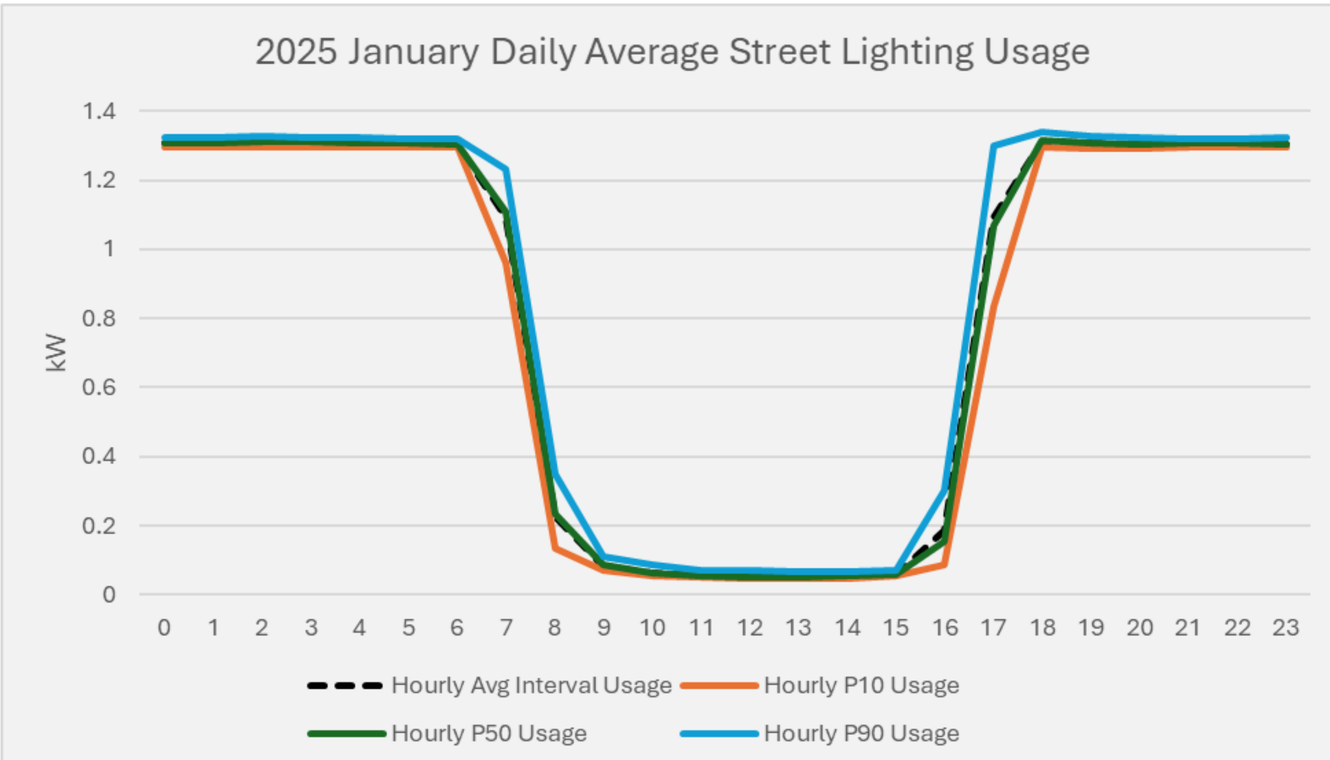


FIGURE 27: 2025 JANUARY DAILY AVERAGE STREET LIGHTING USAGE.

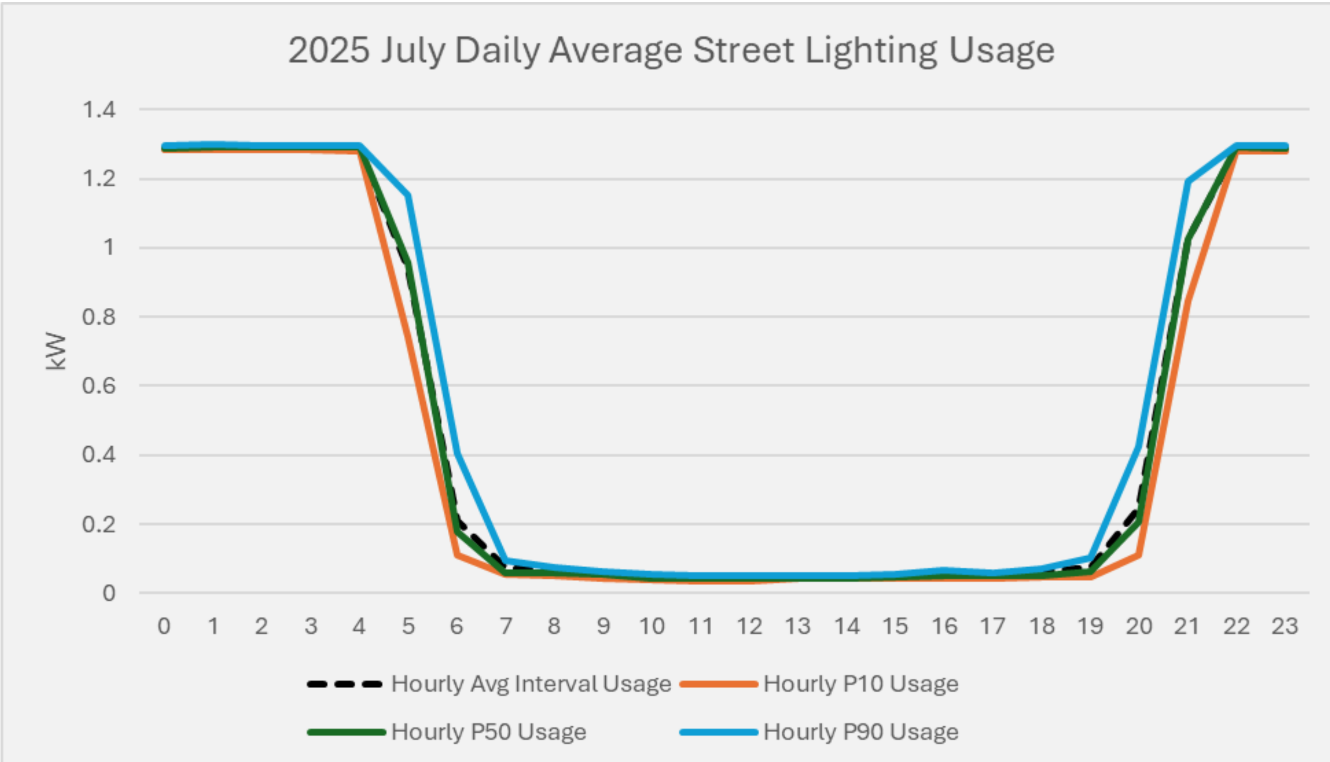


FIGURE 28: 2025 JULY DAILY AVERAGE STREET LIGHTING USAGE.

Figure 29 presents the annual Street Lighting load profile, reinforcing the overall consistency of this type of demand.

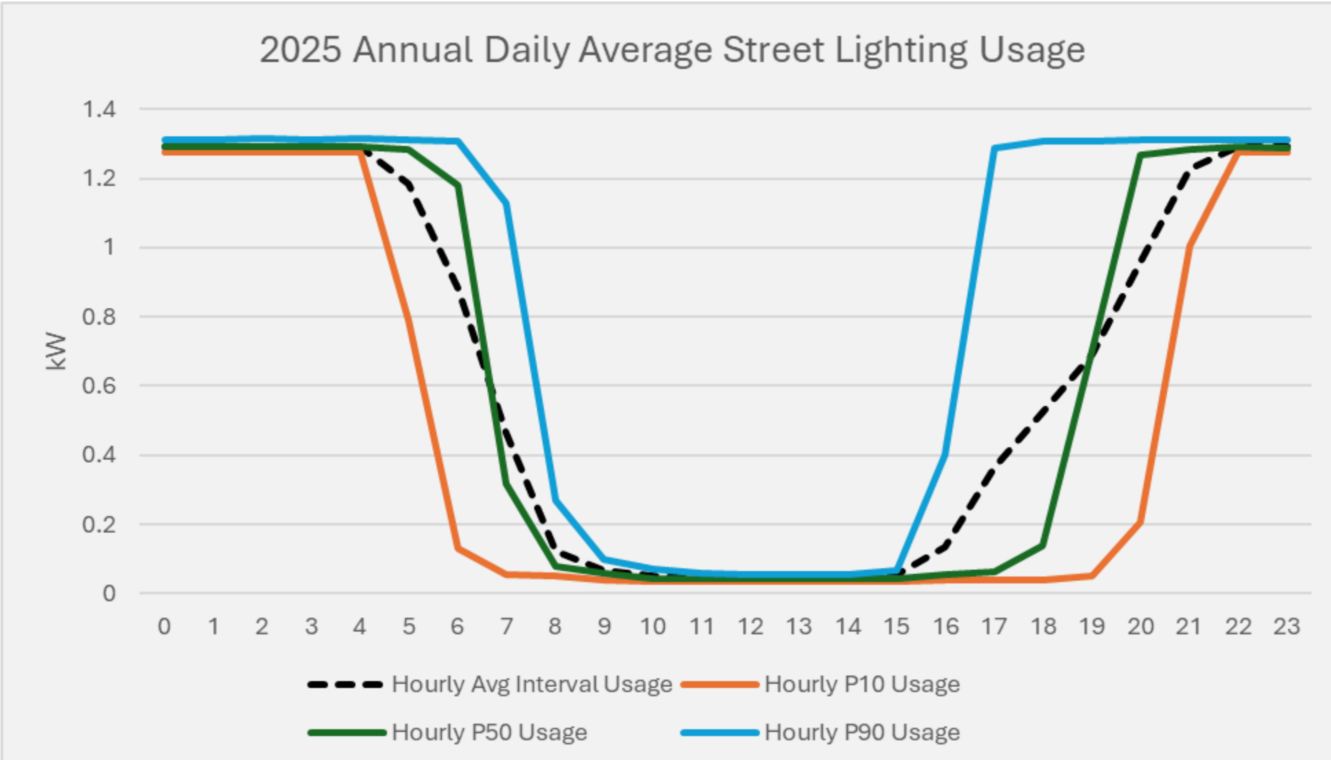


FIGURE 29: 2025 ANNUAL DAILY AVERAGE STREET LIGHTING USAGE.

4.1.4.6 Non-NEM vs. NEM Residential Comparison

Residential customers can be further subdivided into Non-NEM and NEM customers[27]. NEM customers are defined as those with a net metering system, typically rooftop solar, designed primarily to offset on-site electricity consumption.

As shown in Figure 30, January exhibits morning and evening peaks in both groups, although NEM customers show reduced midday net usage when solar generation is available. While NEM customers may reduce overall mid-day energy consumption, they do not reduce winter peak demand because peak winter load occurs during evening hours after solar production has declined.

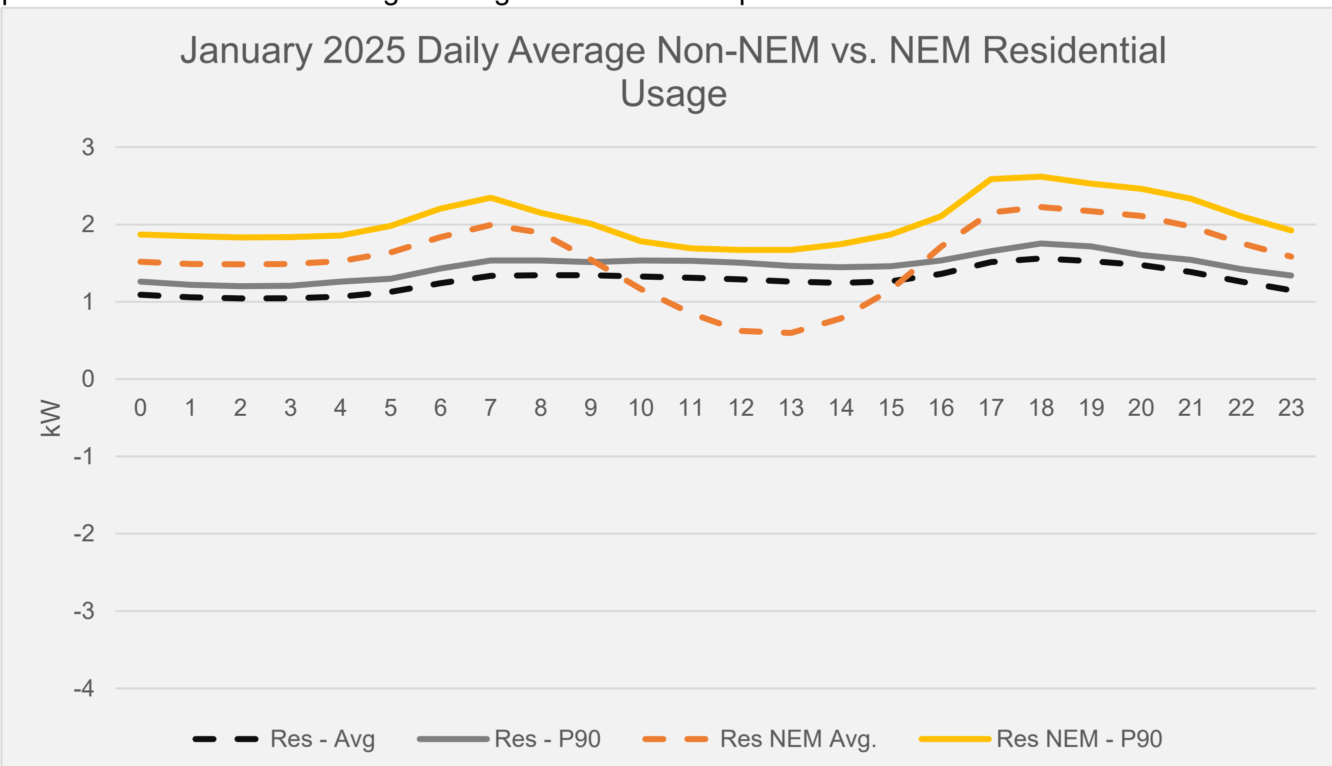


FIGURE 30: 2025 JANUARY DAILY AVERAGE NON-NEM VS. NEM RESIDENTIAL USAGE.

Figure 31, showing July usage, presents that NEM customers experience substantial reductions in net consumption during daylight hours, with some customers exporting energy back to the grid. Average NEM usage becomes negative consistently during the day, corresponding with peak solar production.

[27] Available AMI meters for Non-NEM vs NEM Residential Customers:

- Non-NEM Residential: ~315k meters
- NEM Residential: ~9k meters

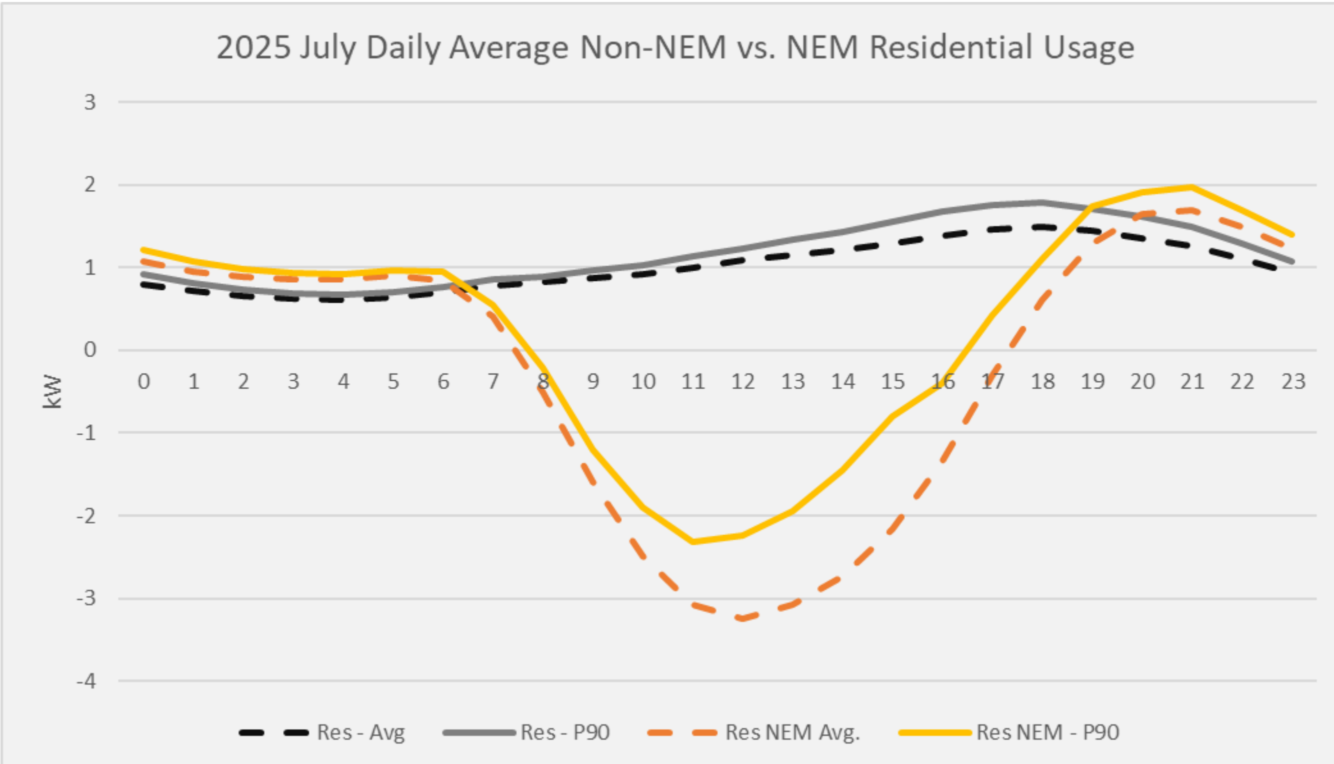


FIGURE 31: 2025 JULY DAILY AVERAGE NON-NEM VS. NEM RESIDENTIAL USAGE.

Figure 32 illustrates the annual average net usage, demonstrating that NEM customers consistently reduce mid-day system demand while maintaining evening consumption patterns similar to Non-NEM customers.

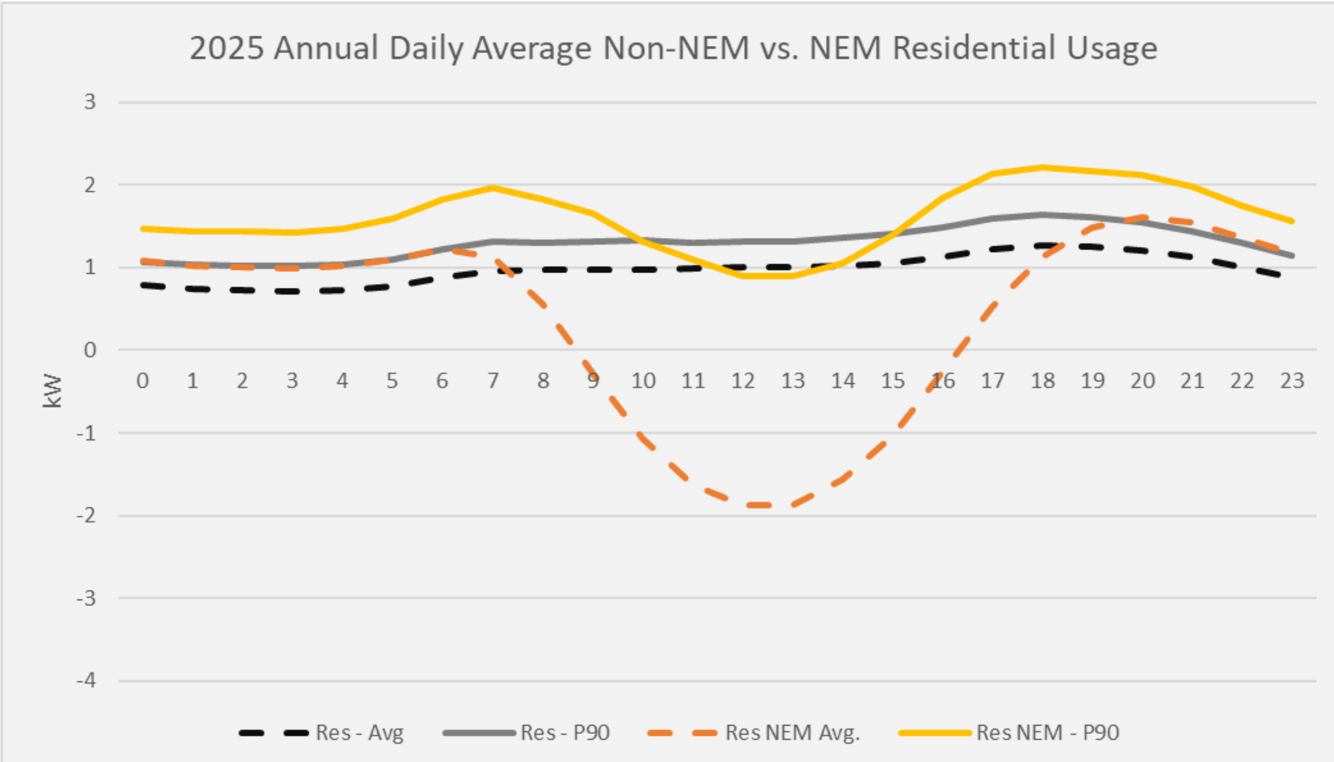


FIGURE 32: 2025 ANNUAL DAILY AVERAGE NON-NEM VS. NEM RESIDENTIAL USAGE.

4.1.5 Load Profile and Duration

Understanding the shape, frequency, and persistence of customer load provides context for how demand is experienced on NorthWestern's system over time. Rather than focusing on a single peak hour, the load profile and the duration analysis describes how often different load levels occur throughout the year and how long elevated demand persists once reached. This perspective distinguishes between common operating conditions and less frequent periods of higher demand, offering a more complete view of historical load behavior.

Load Profile

Figure 33 presents NorthWestern's hourly load magnitudes for the years 2020 through 2024. Rather than focusing on a single peak hour, the figure illustrates how often different load levels occur over the course of a year, providing a representative view of typical, low, and peak operating conditions.

As shown, the system's load is most frequently observed in the mid-range of the distribution, generally between approximately 725 and 800 MW. These load levels represent the most common operating conditions and account for the largest share of annual hours. Above this range, the number of hours decreases sharply, indicating that higher load levels occur less frequently and are concentrated around specific conditions, such as extreme cold or heat events.

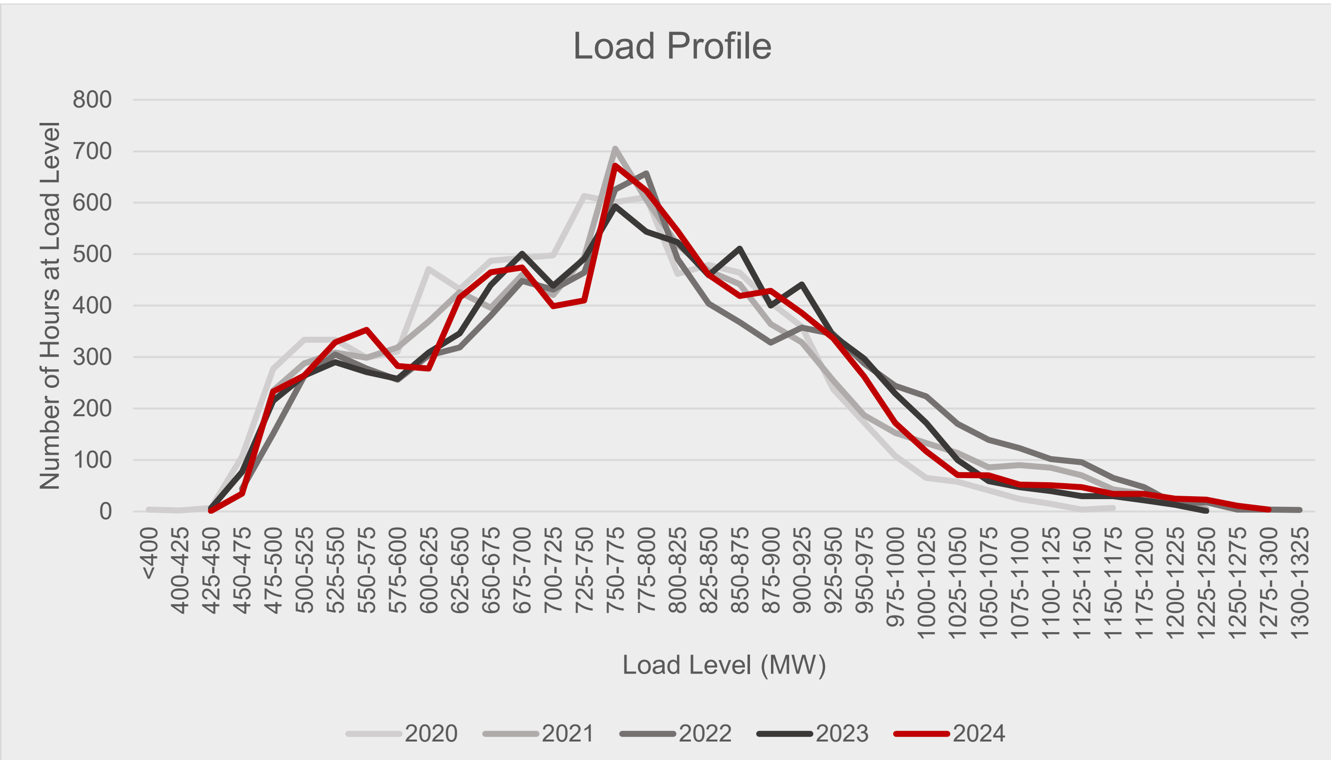


FIGURE 33: LOAD PROFILE 2020-2024.

Load Duration Analysis

To further characterize how long elevated load conditions persist, NorthWestern performed a load duration analysis using observed hourly data from 2020 through 2024. Duration analysis complements the load profile by quantifying not only how often specific load levels occur, but also how long those levels are sustained once reached.

Five load thresholds were evaluated, beginning at 800 MW. For each threshold, the analysis identifies:

- the number of discrete exceedance events,
- the longest continuous duration above the threshold, and
- the total number and percentage of hours at or above the threshold.

This analysis was conducted for both full retail load and for net load, defined as retail load adjusted for observed wind and solar generation. The net load view is included to illustrate how variable renewable output affects the observed load shape over time.

Table 9 summarizes the results for the full retail load. Loads at or above 800 MW occurred frequently, representing approximately 40% of the five-year interval. As load thresholds increase, both the number of events and total hours decline, indicating that higher load levels are less common, but still occur regularly. Finally, the top two tiers show fewer events and shorter event durations; however, these peak load times are the most critical. These top tiers coincide with more extreme weather conditions that pose higher risks to life and property. Consistent with historical experience, annual winter and summer peak loads occur during these periods and inform the peak load forecast.

Duration Analysis of Full Retail Load (2020-2024)					
Load Level (MW)	**800**	**900**	**1000**	**1100**	**1200**
# Events Exceeding Load Level	1,563	1,215	517	207	46
Longest Event (Hrs)	164	115	23	17	8
Total Hours At or Above	17,399	8,460	2,958	1,003	147
% of 5 Year Interval	39.68%	19.29%	6.75%	2.29%	0.34%

TABLE 9: DURATION ANALYSIS OF FULL RETAIL LOAD.

Table 10 represents the same duration metrics for net load. After adjusting for wind and solar generation, the frequency and duration of exceedances decrease, but the overall pattern remains consistent: elevated load conditions occur repeatedly and, in some cases, persist for extended multi-hour or multi-day periods. These results reinforce the importance of considering both the magnitude and duration of load when characterizing system demand.

Duration Analysis of Net Load (2020-2024)					
Load Level (MW)	**800**	**900**	**1000**	**1100**	**1200**
# Events Exceeding Load Level	795	425	193	76	8
Longest Event (Hrs)	112	70	19	8	5
Total Hours At or Above	5,439	2,510	957	253	26
% of 5 Year Interval	12.40%	5.72%	2.18%	0.58%	0.06%

TABLE 10: DURATION ANALYSIS OF NET LOAD.

4.1.6 Peak Demand Forecast

NorthWestern's retail load peak forecast was developed using a linear regression model with weather (heating degree day (HDD) for winter peak forecast and maximum temperature for summer peak forecast), monthly energy (including losses), and total customers serving as the explanatory variables. Projected DSM and NEM values were then subtracted from the regression results to calculate the peak demand forecasts. NEM is not a factor on the winter peak, but it does have a strong impact on the summer peak with incremental solar-pv installations expected to contribute 71 MW to the summer peak by 2050. The summer peak growth rate is projected to be 0.6% when factoring in DSM and NEM, while the winter peak growth rate is also projected to be 0.6% when factoring in DSM. Table 11 lists the historic, seasonal peaks for NorthWestern's retail load. Figure 34 shows observed historical loads and the demand forecasts for summer and winter. Figure 35 and Figure 36 show the summer and winter peak forecasts separated by customer class, respectively. The customer class forecasts are based on available AMI data.

Historical Summer Peak	Date	Hour Ending (MST)	Historical Winter Peak	Date	Hour Ending (MST)
1,146	8/13/2015	17	1,054	11/27/2015	18
1,147	7/21/2016	17	1,163	12/16/2016	20
1,210	7/13/2017	18	1,119	12/26/2017	19
1,196	8/10/2018	18	1,171	3/4/2019	9
1,119	7/23/2019	17	1,165	10/29/2019	9
1,171	8/17/2020	17	1,190	2/11/2021	20
1,248	7/27/2021	17	1,185	2/22/2022	19
1,250	8/1/2022	13	1,316	12/22/2022	20
1,224	8/15/2023	18	1,296	1/12/2024	20
1,285	7/23/2024	18	1,207	1/20/2025	20
1,233	7/8/2025	18	not available (NA)	NA	NA

TABLE 11: RETAIL LOAD HISTORICAL PEAKS.

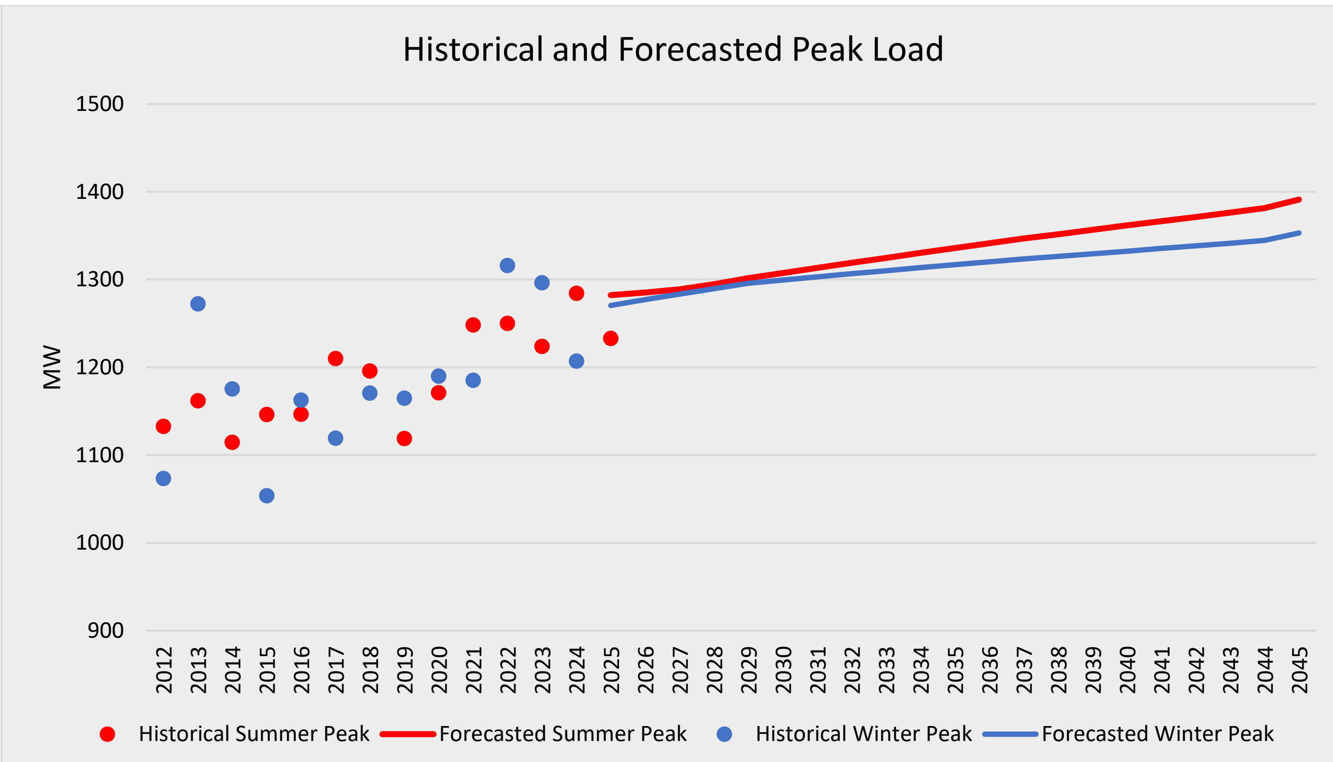


FIGURE 34: HISTORICAL AND FORECASTED SEASONAL PEAK DEMAND.

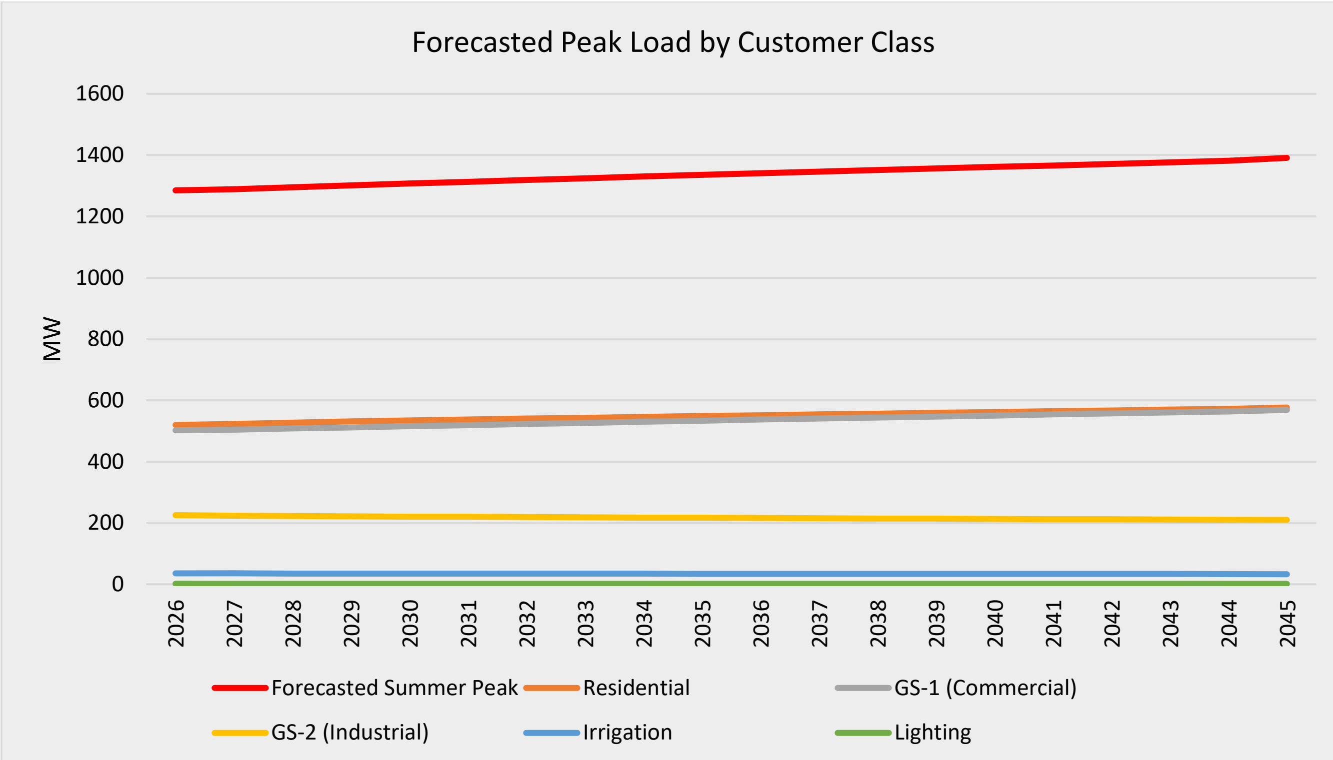


FIGURE 35: FORECASTED SUMMER PEAK DEMAND BY CUSTOMER CLASS.

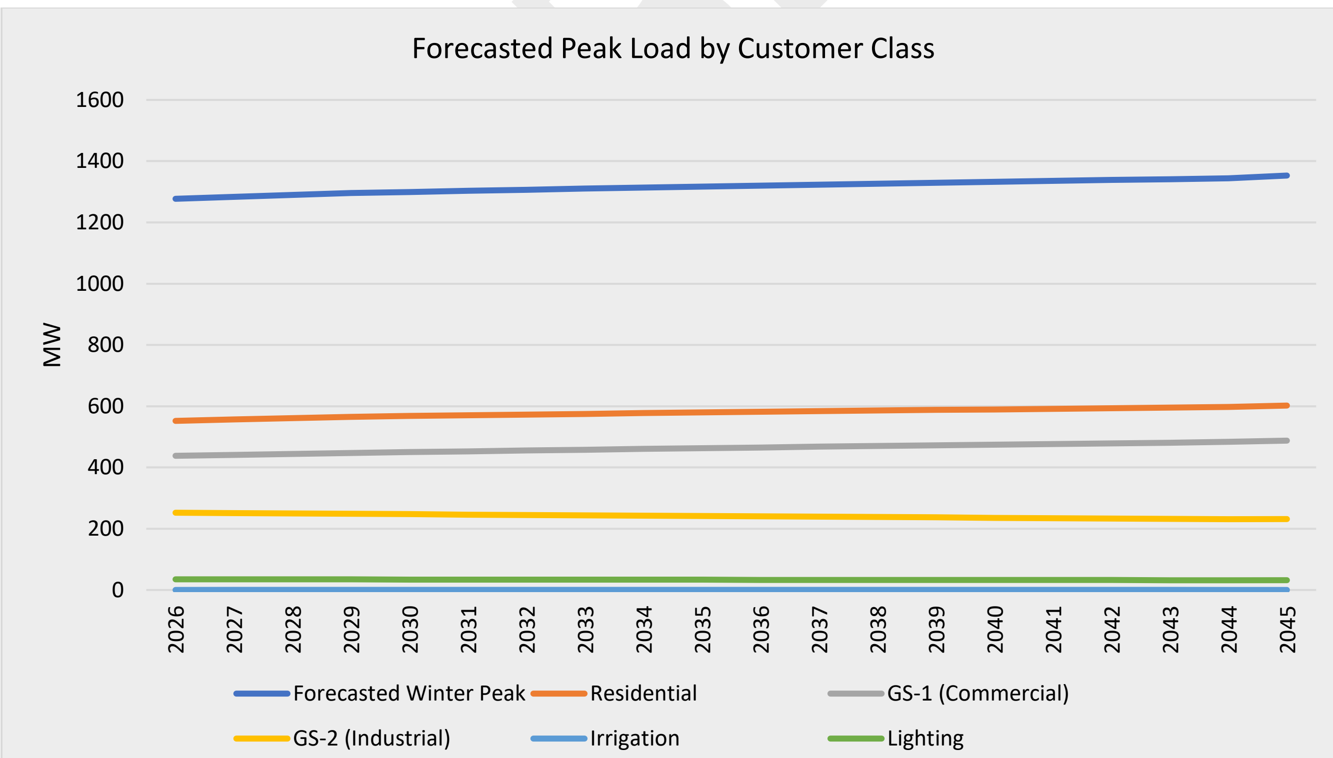


FIGURE 36: FORECASTED WINTER PEAK DEMAND BY CUSTOMER CLASS.

4.2 Demand-Side Management Acquisition and Programs

DSM refers to strategies and programs implemented by utilities to encourage customers to modify their electricity usage usually by reducing overall consumption or increasing energy efficiency. By including DSM in this IRP, NorthWestern treats demand reduction as a component of the load forecast - rather than a standalone candidate resource - that may help defer or avoid the need for new power generation, reduce system costs, and support resource goals.

4.2.1 2025-2026 DSM Acquisition Plan

NorthWestern invests in DSM pursuant to its 20-year 2025-2026 DSM Acquisition Plan, which is contained in Appendix H. As part of NorthWestern's 2025-2026 DSM Acquisition Plan, NorthWestern established an annual DSM acquisition goal of 3.225 average megawatts (aMW) per July 1 – June 30 year for program year 2025-2026 through 2045-2046. These annual aMW targets reflect estimated energy savings potential from measures and actions implemented through electric supply DSM programs, as well as savings achieved through the Northwest Energy Efficiency Alliance (NEEA). The annualized energy savings represent the full-year energy savings capability of installed conservation and efficiency measures.

NorthWestern retained a consultant, Applied Energy Group, Inc. (AEG) to conduct a study of potential electric energy efficiency and demand response to provide guidance to NorthWestern in developing programs. As reflected in the NorthWestern Electric EE and DR Market Potential Study (May 2024 - Revised October 2025), included in Appendix H, AEG's assessment of energy efficiency achievable potential found that there are opportunities for NorthWestern to deliver cost-effective energy efficiency programs. NorthWestern applied the results to update its list of qualified DSM program measures and offerings. The demand response portion of the study provides an initial basis for NorthWestern to consider the magnitude and value of potential demand response programs, and additional refinement of the various methods, data source, and inputs will be necessary before determining which options, if any, to pursue further.

Universal System Benefits (USB)-funded programs are not included in NorthWestern's 2025-2026 DSM Acquisition Plan, as their associated savings and expenditures are addressed separately through USB revenues and Montana Department of Revenue reporting. USB programs are typically designed to meet policy objectives—such as low-income assistance, renewable development, and market transformation—rather than to function as low-cost energy resources within the utility's planning portfolio. Furthermore, many USB programs (e.g., low-income weatherization or education and outreach initiatives) generate non-energy benefits or energy impacts that are not readily quantifiable in the same manner as traditional DSM or supply-side resources.

Table 12 presents the Electric DSM actual and forecasted acquisition goals, which include annual actual and forecasted energy savings estimates from both DSM and NEEA. The NEEA component reflects NorthWestern's expected electric savings from NEEA activities within its Montana service territory.

Actual or Forecast Electric DSM Acquisition			
Tracker Year	DSM Actual or Forecast Acquisition (aMW)*	NEEA Actual or Forecast Acquisition (aMW)*	Total DSM + NEEA Actual or Forecast Acquisition (aMW)*
2018-2019	7.35	1.98	9.33
2019-2020	7.1	1.72	8.82
2020-2021	5.92	1.01	6.93
2021-2022	7.41	1.07	8.48
2022-2023	5.92	1.01	6.93
2023-2024	4.63	1.25	5.88
2024-2025	5.01	1.62	6.63
2025-2026	2.37	0.85	3.225
2026-2027	2.37	0.85	3.225
2027-2028	2.37	0.85	3.225
2028-2029	2.37	0.85	3.225
2029-2030	2.37	0.85	3.225
2030-2031	2.37	0.85	3.225
2031-2032	2.37	0.85	3.225
2032-2033	2.37	0.85	3.225
2033-2034	2.37	0.85	3.225
2034-2035	2.37	0.85	3.225
2035-2036	2.37	0.85	3.225
2036-2037	2.37	0.85	3.225
2037-2038	2.37	0.85	3.225
2038-2039	2.37	0.85	3.225
2039-2040	2.37	0.85	3.225
2040-2041	2.37	0.85	3.225
2041-2042	2.37	0.85	3.225
2042-2043	2.37	0.85	3.225
2043-2044	2.37	0.85	3.225
2044-2045	2.37	0.85	3.225
2045-2046	2.37	0.85	3.225
Cumulative	**93.11**	**27.51**	**120.725**

*2018-2019, 2019-2020, 2020-2021, 2021-2022, 2022-2023, 2023-2024, and 2024-2025 are actual DSM + NEEA acquisition (aMW); 2025-2026 through 2045-2046 are forecast DSM + NEEA (aMW) which comes from the 2025-2026 DSM Acquisition Plan. Total DSM Acquisition (aMW) includes DSM program potential savings calculated from the AEG Electric Energy Efficiency and Demand Response – Market Potential Study and savings estimates from the Northwest Energy Efficiency Alliance (NEEA) initiatives. NEEA is a DSM-funded program held to the same cost-effectiveness tests as other DSM funded programs.

TABLE 12: DSM FORECAST ACQUISITION

4.2.2 Current DSM and NEEA Programs

NorthWestern continues to offer a variety of programs, services, and resources to help our Montana customers better manage energy costs. The following are current electric DSM Programs funded through energy supply rates:

- **Residential Electric Programs for Existing Homes and New Construction** – Cost effective electric energy savings measures are included in these programs. NorthWestern's programs implementation contractor, DNV, provides implementation services for these programs.
- **Commercial Lighting Programs** – Cost effective light-emitting diode (LED) offerings are included in NorthWestern's Commercial Lighting Program, where DNV provides implementation services for these lighting programs. Rebates to commercial customers encourage purchase and use of ENERGY STAR® LEDs and fixtures, and other energy-efficient lighting measures. Lighting is the most common opportunity for businesses to save energy. New technologies continue to become available. Rebates are available for qualifying lamps, fixtures, and controls.

  The U.S. (DOE) has issued several final rules significantly impacting general service lamps (GSLs). A 2022 rule expanded the definition of GSLs to include a wider range of lamp types, effective July 8, 2022. DOE also enforced a 45 lumens-per-watt (lm/W) minimum efficacy requirement for all GSLs beginning July 25, 2022.

  In April 2024, DOE adopted stricter efficiency standards—approximately 120 lm/W or higher—effective July 25, 2028, for newly manufactured or imported lamps. Additionally, DOE finalized updated testing procedures in January 2025, with compliance required starting July 15, 2025.

  NorthWestern continues to evaluate how recent federal lighting regulations impact its efficiency programs, particularly in the areas of product eligibility, program design, customer communication, and supply chain planning. As part of this process, NorthWestern is actively engaging with lighting experts and industry stakeholders across the country to better understand best practices and responses from other utilities. Based on these discussions, NorthWestern has determined that it does not need to lead the transition at this time, as many peer utilities have also not yet fully adopted or implemented programmatic changes in response to the new federal standards.

  NorthWestern serves a lagging market where lighting transformation is still underway. The 45 lm/W federal standard, while in effect, poses communication challenges for customers and does not easily align with the structure of a prescriptive incentive program. Notably, NorthWestern's commercial LED lighting program remains the most active and highest-performing efficiency offering in terms of both participation and energy savings. This continued engagement suggests that the lighting market in NorthWestern's service territory is not yet saturated or fully transformed, and that opportunities for impactful savings remain. As the market and regulatory landscape evolve, NorthWestern will continue to adapt its approach to ensure programs remain relevant, effective, and responsive to both customer needs and compliance requirements.
- **Commercial Electric Rebate Program for New or Existing Facilities** – Rebates are available to electric customers for qualifying electric measures. The Commercial Electric Rebate Program for Existing Facilities includes incentives for motor rewinding.
- **Business Partners Program** – Provides customized incentives to commercial and industrial customers for electric conservation, based on the metrics of the customer's specific project(s). Examples of projects include measures to improve lighting; heating, ventilating and cooling (HVAC) systems; refrigeration; air handling; and pumping systems. New and existing facilities are eligible.

- **Commercial Programs' Contractors** – NorthWestern continues contracting with firms to provide services in support of acquiring energy efficiency in the commercial sector. NorthWestern compensates these contractors on a performance basis, with payment based on a percentage of the energy conservation resource value of each individual project that is completed with the contractor's involvement.

  These contractors are supported by DNV employees who have responsibility for communication of E+ programs to commercial/small industrial customers in an effort to identify, qualify, and cultivate energy saving projects for follow-up by the contractors, along with implementation services for the prescriptive rebate programs. Services provided by these contractors include marketing to architect/engineering firms and trade/industry associations in Montana, direct contact with candidate businesses with energy savings potential, surveys and assessments of buildings and facilities, technical assistance for building owners, assistance with required engineering analysis and modeling, and assistance to customers with forms, contracts, and other paperwork used in and necessary for participation in these programs.

- **Northwest Energy Efficiency Alliance** – NEEA is a regional non-profit organization supported by utilities, public benefits administrators, state governments, public interest groups, and energy efficiency industry representatives. Through regional leveraging, NEEA encourages "market transformation" or the development and adoption of energy efficient products and services in Montana, Washington, Idaho, and Oregon. NEEA's regional market transformation activities target the residential, commercial, industrial and agricultural sectors. NEEA also funds some of the infrastructure development of ENERGY STAR Northwest and other above-code new home activities. NEEA is forecasting 0.85 aMW annually for NorthWestern as shown in Table 12.

4.2.3 DSM Demand and Energy Savings

Demand and energy savings for DSM are developed by AEG using measure-level engineering assumptions, program participation forecasts, and end-use load shapes to estimate both average and time-differentiated impacts on system load.

AEG estimates annual energy savings in MWh and converts those savings into an aMW value by dividing total annual savings by 8,760 hours.

AEG produces an aggregated 8,760-hour hourly savings profile that reflects when energy reductions occur throughout the year. These hourly profiles represent incremental annual savings associated with aggregated DSM measures acquired in a given program year and are used directly in calculating Avoided Costs.

The aMW values provide a transparent annual energy benchmark, while the 8,760-hour profiles enable avoided-cost modeling that captures hourly energy value, system dispatch impacts, and reliability contributions, ensuring DSM demand and energy savings are evaluated consistently with supply-side resources in both capacity and energy analyses.

For more information about AEG development of demand and energy savings for DSM, please refer to the NorthWestern Energy End-Use and Load Profile Study – Final (March 2024) and the NorthWestern Electric EE and DR Market Potential Study (May 2024 - Revised October 2025) in Appendix H.

4.2.4 Avoided Costs Calculations used for DSM

4.2.4.1 Net Cost of Capacity

Publicly available generator overnight construction costs, such as those published by NLR, EIA, and other national sources, provide a transparent foundation for resource valuation but are typically based on projects that reached commercial operation several years prior to publication. Because new generation projects generally require three to six years from early development to commercial operation, the underlying engineering, procurement, and construction (EPC) contract prices that define those costs are often established two to three years before a project's in-service date. Consequently, cost data published in 2024 may largely reflect contracts executed between 2019 and 2021, prior to the recent inflationary period and supply-chain constraints.

While these public datasets offer valuable benchmarking, they may not fully represent current market conditions. To improve accuracy, NorthWestern consults with Aion Energy, LLC (Aion), to provide forward looking overnight capital and operational costs for generation. The costs are provided in Section 7.1.6.

In applying overnight capital cost data to avoided-cost calculations, NorthWestern uses a net cost of capacity framework rather than a total annualized costs of a new resource. The net cost of capacity reflects the portion of that cost that must ultimately be recovered from customers after accounting for expected revenues. This distinction aligns the avoided-cost calculation with how customers experience costs in practice where generator revenues offset a share of capacity costs through market operations.

Using net cost of capacity provides an economically representative and transparent estimate of avoided capacity costs while maintaining consistency with NorthWestern's PowerSIMM-based energy modeling and WRAP accreditation metrics. Although the methodologies differ amongst utilities for calculating net cost of capacity, NorthWestern's resulting avoided-cost values for capacity and energy, as shown in Table 13, remain generally consistent with those of peer utilities, reinforcing that the overall outcomes are reasonable within the regional context. The 2025 DSM avoided costs calculations are derived from the capacity forecast as of June 20, 2025, along with overnight capital costs of a dual fuel CT from the 2023 IRP escalated to 2025.

Utility (Territory)	Year	Avoided Capacity Cost ($/kW-year)	Levelized Avoided Energy Cost ($/MWh)
NorthWestern Energy (Montana)	2025	$166.27 Net Capacity (DSM) $239.82 Total Resource Cost	$ 48.57 (DSM – Residential)
Idaho Power (Idaho)[28]	2025	$157.58	See Idaho Power's IRP for Avoided Cost Averages ($/MWh) (pg. 19)
Avista Utilities (Idaho)[29]	2025	$120.82 ($154.77 with T&D & Losses)	$42.71 (45.32 with losses)
Avista Utilities (Washington)[29]	2025	$120.82 ($170.25 SCGHG, Pref, Losses, Clean Prem.)	$43.97 ($74.21 w. GHG, Pref, Losses, Clean Premium

TABLE 13: DSM AVOIDED COSTS CALCULATIONS USED IN 2026 IRP[30]

[28] https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/2025IRP/2025%20IRP%20Appendix%20C.pdf

[29] https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2025/2025-avista-electric-irp.pdf

[30] NorthWestern's avoided cost values in Table 13 do not reflect the avoided cost rate paid to a QF, which is dependent upon NorthWestern's Electric Tariff, Schedule QF-1 rates, and other factors such as NorthWestern's capacity forecast and the QF's date of establishing a legally enforceable obligation.

4.2.4.2 Calculating DSM Avoided Cost of Capacity

Avoided capacity costs are calculated by first estimating the reliability contribution of DSM through an ELCC analysis performed by Ascend using PowerSIMM. ELCC quantifies the extent to which DSM reductions in load contribute to meeting system peak and maintaining RA. The resulting ELCC values, approximately 76.9% for non-residential DSM and 85.5% for residential DSM, were applied to NorthWestern's avoided-capacity rate of $166.27/kW-year, which is derived from the net cost of capacity shown in Table 13.

Applying the 76.9% and 85.5% ELCC values to the avoided capacity value of $166.27/kW-year results in an ELCC-adjusted avoided capacity rate of approximately $127.86/kW-year for non-residential DSM participants and $142.16/kW-year for residential DSM participants. These adjusted rates represent the portion of new resource capacity costs that are reasonably avoided by DSM. This approach ensures avoided capacity costs for DSM are calculated in a manner that is consistent with how supply-side resources are valued within NorthWestern's PowerSIMM modeling framework.

4.2.4.3 Calculating DSM Avoided Cost of Energy

Avoided energy costs were calculated separately using PowerSIMM's 8,760-hour production cost model. Non-residential and residential DSM measures were modeled independently using Nexant-derived hourly profile, with the Year 1 energy profile repeated over a 30-year analysis horizon consistent with the assumed useful life of DSM measures. This modeling captured the marginal energy value of DSM through avoided dispatch and market purchases, resulting in a levelized avoided energy cost of $48.57/MWh for residential as identified in Table 13 and $48.61 for non-residential.

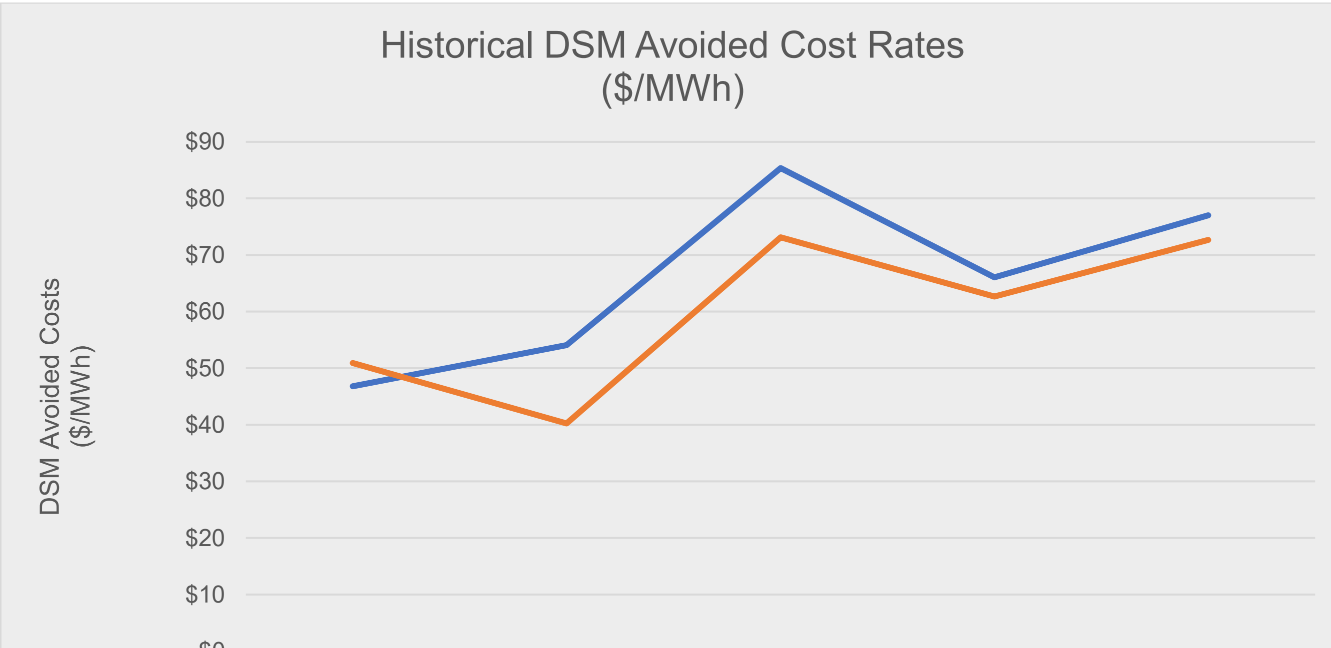
4.2.4.4 Blended DSM Avoided Cost Calculation

To calculate a single, blended DSM avoided cost rate, the avoided capacity and avoided energy values are combined on a levelized basis. Both value streams are first modeled as annual cash flows over the analysis horizon and discounted to a net present value (NPV) using NorthWestern's weighted average cost of capital (WACC). These NPVs are then converted to equivalent annual values and expressed on a $/MWh basis using the modeled DSM energy savings. This levelization process ensures the combined avoided cost reflects the full lifetime value of DSM in a manner consistent with how generation resources are evaluated in PowerSIMM.

For 2025, this methodology results in the following blended DSM avoided cost rates:

- Residential DSM: $77.01/MWh, consisting of a $48.57/MWh avoided energy value with the difference being the derived avoided cost of capacity of $28.44/MWh.
- Non-residential DSM: $72.65/MWh, consisting of a $48.61/MWh avoided energy value with the difference being the derived avoided cost of capacity of $24.04/MWh.

This approach ensures DSM avoided costs reflect both energy and capacity value using consistent modeling assumptions, economic valuation methods, and reliability metrics, and maintains alignment with NorthWestern's broader avoided-cost framework. Figure 37 shows the DSM avoided-cost rates over time, noting inputs and assumptions have changed year-to-year. In 2024, NorthWestern adopted a the net cost of capacity, which more appropriately represents customer avoided costs because customers are credited net energy revenues, offsetting the cost for a capacity resource.



	2021	2022	2023	2024	2025
Residential	$46.82	$54.11	$85.36	$66.04	$77.01
Commercial	$50.92	$40.25	$73.13	$62.64	$72.65

FIGURE 37: DSM AVOIDED COSTS

4.2.5 Program Cost Effectiveness

NorthWestern uses the Total Resource Cost (TRC) test to evaluate DSM opportunities for cost effectiveness. The TRC test is a ratio of benefits (the net present energy savings value based on the lifetime avoided energy and capacity costs) to total DSM program costs (utility program implementation costs and incremental customer costs). Historically, a TRC benefit-to-cost ratio of 1.0 or greater indicates that a DSM measure or program is cost effective. Consistent with the Commission's rule NorthWestern evaluates DSM cost-effectiveness using a TRC cost-to-benefit ratio of 1.10 or less[31].

[31] Admin. R. Mont. 38.5.2020(8) (2023) Evaluations of potential demand-side resources shall consider those resources cost-effective up to 110 percent of the utility's long-term avoided costs.

4.2.6 Historical Energy Acquisition

Table 14 summarizes historical DSM and NEEA acquisition performance from 2013–2014 through 2024–2025, including annual acquisition targets, reported acquisitions, and program expenditures. Acquisition is reported in aMW, reflecting the average annual load reduction achieved through DSM utility programs and NEEA regional market transformation efforts. Program expenses reflect DSM and NEEA costs incurred during each tracker period and exclude USB-related expenses.

Over the 2013–2025 period, NorthWestern's DSM programs consistently exceeded or closely tracked annual acquisition targets, while NEEA acquisitions provided an incremental contribution to overall energy efficiency performance. On a cumulative basis, DSM programs achieved 65.15 aMW, NEEA programs achieved 16.06 aMW, and combined DSM and NEEA efforts delivered 81.21 aMW of verified energy savings. Total cumulative program expenditures over this period equal approximately $96.2 million, consisting of $81.8 million in DSM program costs and $14.4 million in NEEA program costs.

DSM/NEEA Acquisition Target, DSM/NEEA Acquisition Reported, DSM/NEEA Expense							
(no USB Expenses included*)							
Tracker Year	DSM NEEA Acquisition Target (aMW)	DSM Acquisition Reported (aMW)	NEEA Acquisition Reported (aMW)	Total DSM + NEEA Acquisition Reported (aMW)	DSM Program Expense $	NEEA Program Expense $	Total DSM NEEA Expense $
2013-2014	5.41	4.9	1.14	6.04	7,526,764	1,812,813	9,339,577
2014-2015	5.62	3.99	1.32	5.31	4,399,366	1,015,012	5,414,378
2015-2016	5.42	3.41	1.14	4.55	4,831,958	1,219,625	6,051,582
2016-2017	4	4.25	1.23	5.48	5,303,406	1,221,149	6,524,555
2017-2018	4.08	5.26	1.54	6.8	6,283,806	1,523,720	7,807,527
2018-2019	4.11	7.35	1.98	9.33	7,744,933l	916,514	8,661,446
2019-2020	4.08	7.1	1.72	8.82	7,195,779	1,262,384	8,458,163
2020-2021	3.6	5.92	1.01	6.93	7,097,383	1,272,568	8,369,952
2021-2022	3.62	7.41	1.07	8.48	9,067,559	1,282,896	10,350,455
2022-2023	3.77	6.42	1.00	7.42	7,116,233	1,606,871	8,723,104
2023-2024	3.77	4.63	1.28	5.91	7,402,377	1,283,712	8,686,089
2024-2025	3.77	5.01	1.62	6.63	7,848,135	321,152	8,169,287
Cumulative	**51.25**	**65.15**	**16.06**	**81.21**	**81,798,849**	**14,404,113**	**96,202,962**

TABLE 14: HISTORICAL DSM/NEEA ACQUISITIONS

4.2.7 Historic Compliance Summary for DSM

Table 15 summarizes the historical performance, load-serving capability, and cost-effectiveness of NorthWestern's demand-side management ("DSM") programs for each year since the last Integrated Resource Plan, including program expenditures with incentive payments, achieved energy savings, estimated demand reduction, weighted average program life, annualized cost of saved energy and capacity, combined avoided cost of energy and capacity, and net economic benefits through the benefit-cost ratio. Program expenditures include DSM administrative costs, implementation costs, customer incentive payments, and general energy supply DSM expenses associated with energy efficiency and conservation programs across customer classes, as well as NorthWestern's participation in the Northwest Energy Efficiency Alliance ("NEEA").

Achieved energy savings represent the annualized full-year energy reduction from completed DSM measures installed during each tracker year and are shown both in MWh and average megawatts (aMW). Savings are developed using measure-level engineering assumptions, verified program participation, and end-use data provided by DSM consultants and program tracking systems. Weighted average program life reflects the expected useful life of installed measures and is used to annualize lifetime customer benefits and program costs for cost-effectiveness evaluation.

Note, NorthWestern's historical DSM tracking system recorded annual energy savings rather than both annual energy savings and peak demand reductions and also relied on existing measure-level end use data provided by consultants, which excluded MW savings per measure. In order to calculate historical demand savings ("MW") for DSM measures prior to 2026, NorthWestern estimated measure-level demand savings by applying the aggregated modeled peak capacity contribution ratio to modeled energy savings used in avoided cost calculations and applied the ratio uniformly to each program by class. Avoided costs include both levelized avoided energy and avoided capacity values as discussed in Section 4.2.4. These values are used to calculate estimates of net economic benefits through a benefit cost ratio for each program.

NEEA benefits are included in the DSM summary. NEEA provides regional market transformation savings by accelerating adoption of efficient technologies and building practices, with NorthWestern receiving attributed energy savings within its Montana service territory that are included in annual DSM acquisition. NEEA does not provide an 8760 profile of savings; however, the same combined energy and capacity savings as DSM avoided costs are used to provide a high-level estimate of net benefits. The NEEA program is also removed from the total in order to show only DSM program metrics.

Historic Compliance Summary for DSM								
	MWh	aMW	MW (Estimated)	DSM Expenditures w/ Incentives	Weighted Average Program Life	Annualized Cost of Saved Energy & Capacity ($/MWh)	Combined Avoided Cost of Energy & Capacity	Net Benefit Cost Ratio (>1 =benefit)
Programs - 2024-2025								
General Energy Supply DSM Expenses				$ 66,718				
Residential Lighting Programs	1.28	0.00	0.00	3,124	10	$ 342.04	$ 62.64	0.18
Residential EX Electric Rebate Programs	1,221	0.14	0.22	239,985	15	21.20	62.64	2.95
Residential NC Electric Rebate Programs	789	0.09	0.14	130,472	16	17.19	62.64	3.64
Commercial Lighting Rebate Program	29,698	3.39	3.86	4,793,344	14	18.15	66.04	3.64
Commercial EX Electric Rebate Program	5,065	0.58	0.66	969,674	16	19.89	66.04	3.32
Commercial NC Electric Rebate Program	6,495	0.74	0.84	1,539,204	16	24.62	66.04	2.68
Business Partners Program	605	0.07	0.08	105,615	12	21.64	66.04	3.05
Northwest Energy Efficiency Alliance (NEEA)	14,181	1.62	1.84	321,152	11	2.98	66.04	22.18
Total	58,055	6.63	7.64	$ 8,169,287	14	$ 16.04	$ 65.92	4.11
Total DMS without NEEA	43,874	5.01	5.80	$ 7,848,135	11	$ 23.51	$ 65.89	2.80
Programs - 2023-2024								
General Energy Supply DSM Expenses				$ 520,507				
Residential Lighting Rebate Program	2	0.00	0.00	111,260	10	$ 7,971.07	$ 85.36	0.01
Residential EX Electric Rebate Programs	891	0.10	0.18	130,849	15	16.03	85.36	5.32
Residential NC Electric Rebate Programs	182	0.02	0.04	35,900	19	18.97	85.36	4.50
Commercial Lighting Rebate Program	29,359	3.35	3.75	4,915,233	14	19.05	73.13	3.84
Commercial EX Electric Rebate Program	1,598	0.18	0.20	912,767	15	62.40	73.13	1.17
Commercial NC Electric Rebate Program	7,306	0.83	0.93	400,713	14	6.24	73.13	11.72
Business Partners Program	1,213	0.14	0.15	375,149	14	35.19	73.13	2.08
Northwest Energy Efficiency Alliance (NEEA)	11,225	1.28	1.53	1,283,712	39	8.54	73.13	8.56
Total	51,777	5.91	6.79	$ 8,686,089	17	$ 16.89	$ 73.38	4.35
Total DMS without NEEA	40,552	4.63	5.26	$ 7,402,377	10	$ 25.96	$ 73.45	2.83
Programs - 2022-2023								
General Energy Supply DSM Expenses				$ 87,945.30				
E+ Residential Lighting Programs	15,416	1.76	3.46	1,907,617	10	$ 17.55	$ 54.11	3.08
Residential EX Electric Rebate Programs	727	0.08	0.16	87,678	16	12.70	54.11	4.26
Residential NC Electric Rebate Programs	10	0.00	0.00	3,809	18	38.65	54.11	1.40
E+ Commercial Lighting Rebate Program	30,815	3.52	3.94	3,412,065	14	12.60	40.25	3.19
Commercial NC Electric Rebate Program	5,293	0.60	0.68	649,475	14	13.96	40.25	2.88
Business Partners Program	960	0.11	0.12	299,394	15	34.06	40.25	1.18
Commercial EX Electric Rebate Program	3,051	0.35	0.39	668,248	17	22.31	40.25	1.80
Northwest Energy Efficiency Alliance (NEEA)	8,754	1.00	1.12	1,606,871	30	14.67	40.25	2.74
Total	65,026	7.42	9.87	$ 8,723,104	17	$ 13.57	$ 43.69	3.22
Total DMS without NEEA	56,271	6.42	8.75	$ 7,116,233	13	$ 15.11	$ 44.23	2.93

TABLE 15: DSM COMPLIANCE SUMMARY

5 EXISTING RESOURCE PORTFOLIO

NorthWestern serves its retail customers with a diverse mix of hydro, wind, solar, and thermal generation resources. Resources in NorthWestern's portfolio are a combination of owned and contracted resources. The map in Figure 38 shows the location of most NorthWestern resources for the Montana territory denoted by resource name, fuel type, and magnitude of nameplate capacity in MW. NorthWestern uses this resource portfolio to serve retail load as well as provide ancillary services for NorthWestern's Balancing Authority Area (BAA). See Section 7.6.2.1 for more information on ancillary services modeling.

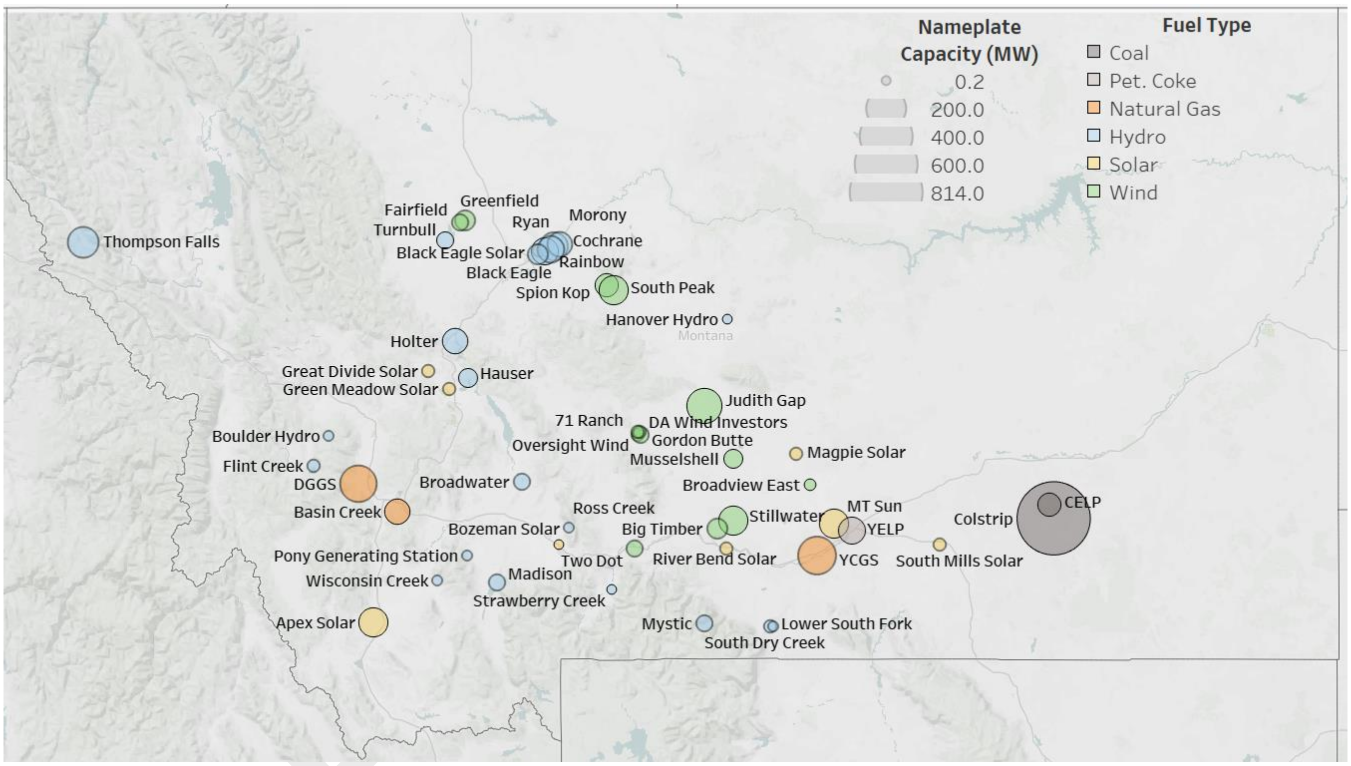


FIGURE 38: MAP OF NORTHWESTERN'S MONTANA OWNED AND CONTRACTED RESOURCES.

NorthWestern provides information about the fuel-source mix of its existing portfolio on its website.[32] The website provides the portfolio percentage of carbon-free generation and near real-time data of the output from the different fuel types of generation. Also the website hosts NorthWestern's Bright Magazine, which highlights stories about the communities we serve and showcases energy projects, sustainability efforts, and innovations across our service territory.[33] This 2026 IRP can also be found on the NorthWestern website, which discusses our long-term plan for the service territory, as well as different scenarios and sensitivities surrounding the planning process for that planning period.[34]

5.1 Confidential Data

The IRP contains third-party pricing and performance data that is subject to Commission-issued protective orders. To comply with these protective orders, the publicly available IRP contains

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[32] https://www.northwesternenergy.com/clean-energy/where-does-your-energy-come-from
[33] https://www.northwesternenergy.com/about-us/news-articles-events
[34] https://www.northwesternenergy.com/about-us/gas-electric/montana-electric-supply-planning

redactions. The confidential version of the IRP is available upon execution of the applicable non-disclosure agreement (NDA), which is the last page of the Commission's Protective Order 8021 available under this IRP Docket No. 2025.05.038 on the Commission's website.

5.2 Owned Generation Portfolio

NorthWestern currently owns approximately 1,060 MW of maximum delivered capacity as listed in Table 16. Traditionally, nameplate capacity is used to describe the total portfolio; however, due to historical upgrades to units, essentially increasing the nameplate capacity, NorthWestern has opted to use maximum delivered capacity in this IRP to better reflect, and more accurately define, these resources. NorthWestern's different resource types include dispatchable, baseload, and peaking generation as well as more variable resources including run-of-river (ROR) hydro and VERs like wind and solar generation. Several of NorthWestern's hydro sites—including Cochrane, Ryan, Mystic, and Thompson Falls unit 7—do have small amounts of storage, but the quantity is minimal and dependent on the upstream flows. While maximum delivered (or nameplate) capacity is a common measure of resource size, the accredited capacity provides information about the resource during peaking events. See Section 7.2 for more information about accredited capacity. The Anticipated Depreciation Date in Table 16 is the date the resource would have been fully depreciated at the time it was included in NorthWestern's rate base. NorthWestern uses these dates to represent the resource retirement dates for modeling purposes. However, the useful life of these resources may be extended through regular maintenance and/or capital projects. Historical energy production for NorthWestern's owned resources, capacity factors, and average variable costs for 2024 are provided in Table 17. The online dates shown in the tables below indicate when each resource began commercial energy production. Appendix H includes a comprehensive list of all resource information.

Resource	Maximum Delivered Capacity (MW)	Fuel Type	Online Date	Anticipated Depreciation Date	Prime Mover	Units	Designation
Colstrip	222[35]	Coal	1984	12/31/2042	Steam Turbine	2	Baseload
YCGS	172[36]	Natural Gas	10/25/2024	12/31/2054	RICE	18	Intermediate/ Peaker
DGGS	150	Natural Gas	2011	12/31/2040	Aero CT	3	Intermediate/ Peaker
Natural Gas Subtotal	**322**						
Black Eagle	25	Hydro	1927	12/31/2063	Propeller	3	ROR
Cochrane	62	Hydro	1958	12/31/2063	Kaplan	2	ROR
Hauser	21	Hydro	1911	12/31/2063	Kaplan, Z type	6	ROR
Holter	53	Hydro	1918	12/31/2063	Franis, vertical	4	ROR
Madison	12	Hydro	1906	12/31/2063	Franis, horizontal	4	ROR
Morony	49	Hydro	1930	12/31/2063	Franis, vertical	2	ROR
Mystic	12	Hydro	1925	12/31/2063	Pelton	2	ROR
Rainbow	64	Hydro	1910	12/31/2063	Kaplan	1	ROR
Ryan	72	Hydro	1915	12/31/2063	Franis, vertical	6	ROR
Thompson Falls	94	Hydro	1915	12/31/2063	U1-U6: Franis, vertical U7: Kaplan	7	ROR
Hydro Subtotal	**464**						
Spion Kop	40	Wind	2012	12/31/2036	Wind turbine	N/A	VER
Two Dot	11.3	Wind	2018	12/31/2042	Wind turbine	N/A	VER
Wind Subtotal	**51**						
Bozeman Solar	0.3	Solar	2017	12/31/2022	Solar	N/A	VER
Total	**1,060**						

TABLE 16: NORTHWESTERN'S OWNED RESOURCES (2024).

[35] NorthWestern acquired 222 MW of Avista's share of Colstrip effective January 1, 2026.
[36] The max delivered capacity for YCGS is 172 MW based on observed performance.

Resource	2024 Energy Production (GWh)	2024 Capacity Factor	2024 Average Variable Costs ($/MWh)
Colstrip	1,322[37]	68%[38]	[redacted]
YCGS	88	31%[39]	$51.20
DGGS	480	36%	$39.66
Natural Gas Subtotal	**569**		
Black Eagle	127	58%	N/A
Cochrane	228	42%	N/A
Hauser	134	73%	N/A
Holter	266	57%	N/A
Madison	76	72%	N/A
Morony	255	59%	N/A
Mystic	54	51%	N/A
Rainbow	329	59%	N/A
Ryan	435	69%	N/A
Thompson Falls	436	53%	N/A
Hydro Subtotal	**2,341**		
Spion Kop	110	31%	N/A
Two Dot	34	34%	N/A
Wind Subtotal	**144**		
Bozeman Solar	0.50	17%	N/A
Total	**4,375**		

TABLE 17: 2024 HISTORICAL PERFORMANCE OF NORTHWESTERN'S OWNED RESOURCES.

5.3 Power Purchase Agreements

NorthWestern uses PPAs, or contracts, with QFs and independent power producers (IPP) to supplement its owned resource portfolio when serving retail load, as shown in the tables below. Resource characteristics and contract dates for contracted thermal, hydro, solar, and wind resources are listed in Table 18, Table 19, Table 20, and Table 21, respectively. Historical information for 2024 production, capacity factor, and average contract price for contracted thermal, hydro, solar, and wind resources are listed in Table 22, Table 23, Table 24, and Table 25, respectively. Figure 39 shows the 2024 production separated by fuel type and by owned and contracted resources. Table 26 shows 2024 historical emissions for owned and contracted thermal resources. The online dates shown in the tables below indicate when each resource began commercial energy production. Appendix H includes a comprehensive list of all resource information.

37 Historical Colstrip production is measured net of 500 kV CTS losses.
38 Historical Colstrip capacity factor represents NorthWestern's share, not the entire unit or plant.
39 The 2024 capacity factor for YCGS was calculated from October 25, 2024, through the end of 2024.

Resource	Maximum Delivered Capacity (MW)	Fuel Type	Online Date	Contract End Date	Prime Mover	Contract Type	Designation
CELP	40.5	Waste Coal	1990	12/31/2042	Steam Turbine	QF	Base Load
YELP[40]	65	Petroleum Coke	1995	12/31/2028	Steam Turbine	QF	Base Load
Total QF Thermal	**106**						
Basin Creek[41]	52	Natural Gas	2006	6/30/2036	RICE	IPP	Intermediate/ Peaker
Total Contracted Thermal	**158**						

TABLE 18: CONTRACTED THERMAL RESOURCES.

Resource	Maximum Delivered Capacity (MW)	Fuel Type	Online Date	Contract End Date	Prime Mover	Contract Type	Designation
Boulder Hydro Limited Partnership(QF)	0.5	Hydro	1988	7/31/2030	Hydro	QF	Small hydro
State of MT DNRC (Broadwater Dam)	10.5	Hydro	1989	6/30/2026	Hydro	QF	Small hydro
Flint Creek Hydroelectric LLC(QF)	2.0	Hydro	2013	1/16/2037	Hydro	QF	Small hydro
Donald Fred Jenni (Hanover Hydro)(QF)	0.2	Hydro	1988	6/30/2034	Hydro	QF	Small hydro
Lower South Fork LLC(QF)	0.5	Hydro	2012	1/16/2037	Hydro	QF	Small hydro
Gerald Ohs (Pony Generating Station)(QF)	0.4	Hydro	1989	1/31/2027	Hydro	QF	Small hydro
Ross Creek Hydro LC(QF)	0.5	Hydro	1996	6/30/2032	Hydro	QF	Small hydro
Hydrodynamics Inc (South Dry Creek)(QF)	2	Hydro	1985	7/1/2041	Hydro	QF	Small hydro
Hydrodynamics Inc (Strawberry Creek)(QF)	0.3	Hydro	1987	11/30/2027	Hydro	QF	Small hydro
Wisconsin Creek LTD LC(QF)	0.5	Hydro	2021	8/31/2027	Hydro	QF	Small hydro
Total QF Hydro	**16.8**						
Turnbull Hydro LLC	13.0	Hydro	2011	12/31/2032	Hydro	IPP	Small hydro
Total Contracted Hydro	**29.8**						

TABLE 19: CONTRACTED HYDRO RESOURCES.

[40] Although YELP's PPA expires in 2028, NorthWestern included YELP in the Base Case starting January 1, 2029, for a term of 20 years because the Commission issued a final order approving terms for a new PPA in Docket 2024.04.047.
[41] The Basin Creek PPA expiration date reflects NorthWestern's notification in Docket 2024.12.116 that it will extend the PPA until June 30, 2031, and its right to extend to June 30, 2036.

Resource	Maximum Delivered Capacity (MW)	Fuel Type	Online Date	Contract End Date	Prime Mover	Contract Type	Designation
Apex Solar LLC (QF)	80	Solar	2023	8/31/2043	Solar	QF	VER
Black Eagle Solar LLC (QF)	3	Solar	2017	9/30/2042	Solar	QF	VER
Great Divide Solar LLC (QF)	3	Solar	2017	9/30/2042	Solar	QF	VER
Green Meadow Solar LLC (QF)	3	Solar	2017	3/31/2042	Solar	QF	VER
Magpie Solar LLC (QF)	3	Solar	2017	9/30/2042	Solar	QF	VER
MT Sun LLC (QF)	80	Solar	2023	1/31/2048	Solar	QF	VER
River Bend Solar LLC (QF)	2	Solar	2017	3/31/2042	Solar	QF	VER
South Mills Solar 1 LLC (QF)	3	Solar	2017	3/31/2042	Solar	QF	VER
Total QF Solar	**177**						

TABLE 20: CONTRACTED SOLAR RESOURCES.

Resource	Maximum Delivered Capacity (MW)	Fuel Type	Online Date	Contract End Date	Prime Mover	Contract Type	Designation
Big Timber Wind LLC (Greycliff) (QF)	25	Wind	2018	3/31/2043	Wind	QF	VER
Two Dot Wind LLC (Broadview East Wind) (QF)	1.6	Wind	2018	10/31/2043	Wind	QF	VER
DA Wind Investors LLC (QF)	2.7	Wind	2018	12/31/2043	Wind	QF	VER
Fairfield Wind LLC (Greenbacker) (QF)	10	Wind	2014	12/31/2033	Wind	QF	VER
Gordon Butte Wind LLC (QF)	9.6	Wind	2012	3/21/2036	Wind	QF	VER
Greenfield Wind LLC (QF)	25	Wind	2016	10/31/2041	Wind	QF	VER
Musselshell Wind Project LLC (QF)	10	Wind	2013	3/24/2036	Wind	QF	VER
Musselshell Wind Project Two LLC (QF)	10	Wind	2013	3/24/2036	Wind	QF	VER
Oversight Resources LLC (QF)	2.7	Wind	2018	12/31/2043	Wind	QF	VER
South Peak Wind LLC (QF)	80	Wind	2020	4/30/2035	Wind	QF	VER
Stillwater Wind LLC (WKN) (QF)	80	Wind	2018	10/31/2043	Wind	QF	VER
71 Ranch LP (QF)	2.7	Wind	2018	12/31/2043	Wind	QF	VER
Total QF Wind	**259**						
Judith Gap Energy LLC	135	Wind	2006	12/31/2026	Wind	IPP	VER
Total Contracted Wind	**394**						

TABLE 21: CONTRACTED WIND RESOURCES.

Resource	2024 Energy Production (GWh)	2024 Capacity Factor	2024 Average Contract Price ($/MWh)
CELP	288	81%	$70.78
YELP	382	67%	$107.79
Total QF Thermal	**669**		
Basin Creek	167	37%	$69.21
Total Contracted Thermal	**836**		

TABLE 22: 2024 HISTORICAL PERFORMANCE OF CONTRACTED THERMAL RESOURCES.

Resource	2024 Energy Production (GWh)	2024 Capacity Factor	2024 Average Contract Price ($/MWh)
Boulder Hydro Limited Partnership(QF)	1.22	27%	$44.97
State of MT DNRC (Broadwater Dam)	47.3	51%	$99.92
Flint Creek Hydroelectric LLC(QF)	11.0	63%	$63.05
Donald Fred Jenni (Hanover Hydro)(QF)	0.27	13%	$62.50
Lower South Fork LLC(QF)	0.68	17%	$63.24
Allen R. Carter (Pine Creek) (QF)[42]	0.97	37%	$65.74
Gerald Ohs (Pony Generating Station)(QF)	0.87	25%	$41.67
Ross Creek Hydro LC(QF)	1.36	35%	$37.69
Hydrodynamics Inc (South Dry Creek)(QF)	3.79	22%	$41.81
Hydrodynamics Inc (Strawberry Creek)(QF)	1.07	44%	$47.04
Wisconsin Creek LTD LC(QF)	0.616	16%	$31.29
Total QF Hydro	**69.1**		
Turnbull Hydro LLC	19.2	17%	$72.75
Total Contracted Hydro	**88.3**		

TABLE 23: 2024 HISTORICAL PERFORMANCE OF CONTRACTED HYDRO RESOURCES.

Resource	2024 Energy Production (GWh)	2024 Capacity Factor	2024 Average Contract Price ($/MWh)
Apex Solar LLC (QF)	158	23%	$42.70
Black Eagle Solar LLC (QF)	5.18	20%	$65.61
Great Divide Solar LLC (QF)	6.24	24%	$65.44
Green Meadow Solar LLC (QF)	5.64	21%	$65.55
Magpie Solar LLC (QF)	5.74	22%	$64.93
MT Sun LLC (QF)	174	25%	$42.74
River Bend Solar LLC (QF)	3.60	20%	$64.95
South Mills Solar 1 LLC (QF)	5.71	22%	$65.62
Total QF Solar	**364**		

TABLE 24: 2024 HISTORICAL PERFORMANCE OF CONTRACTED SOLAR RESOURCES.

[42] Pine Creek hydro and Cycle Horseshoe Bend Wind are shown in the 2024 historical production tables but not in the current contract tables due to the relative timing in which their PPAs were signed and the time in which the modeling was conducted.

Resource	2024 Energy Production (GWh)	2024 Capacity Factor	2024 Average Contract Price ($/MWh)
Big Timber Wind LLC (Greycliff) (QF)	80.0	36%	$45.49
Two Dot Wind LLC (Broadview East Wind) (QF)	4.09	29%	$54.33
Cycle Horseshoe Bend Wind[42]	29.2	34%	$64.67
DA Wind Investors LLC (QF)	11.7	50%	$54.42
Fairfield Wind LLC (Greenbacker) (QF)	26.0	30%	$62.54
Gordon Butte Wind LLC (QF)	39.1	46%	$69.21
Greenfield Wind LLC (QF)	82.5	38%	$53.99
Musselshell Wind Project LLC (QF)	23.1	26%	$69.21
Musselshell Wind Project Two LLC (QF)	26.5	30%	$69.21
Oversight Resources LLC (QF)	10.6	45%	$54.47
South Peak Wind LLC (QF)	259	37%	$22.44
Stillwater Wind LLC (WKN) (QF)	275	39%	$37.63
71 Ranch LP (QF)	11.4	48%	$54.44
Total QF Wind	**878**		
Judith Gap Energy LLC	413	35%	[redacted]
Total Contracted Wind	**1,291**		

TABLE 25: 2024 HISTORICAL PERFORMANCE OF CONTRACTED WIND RESOURCES.

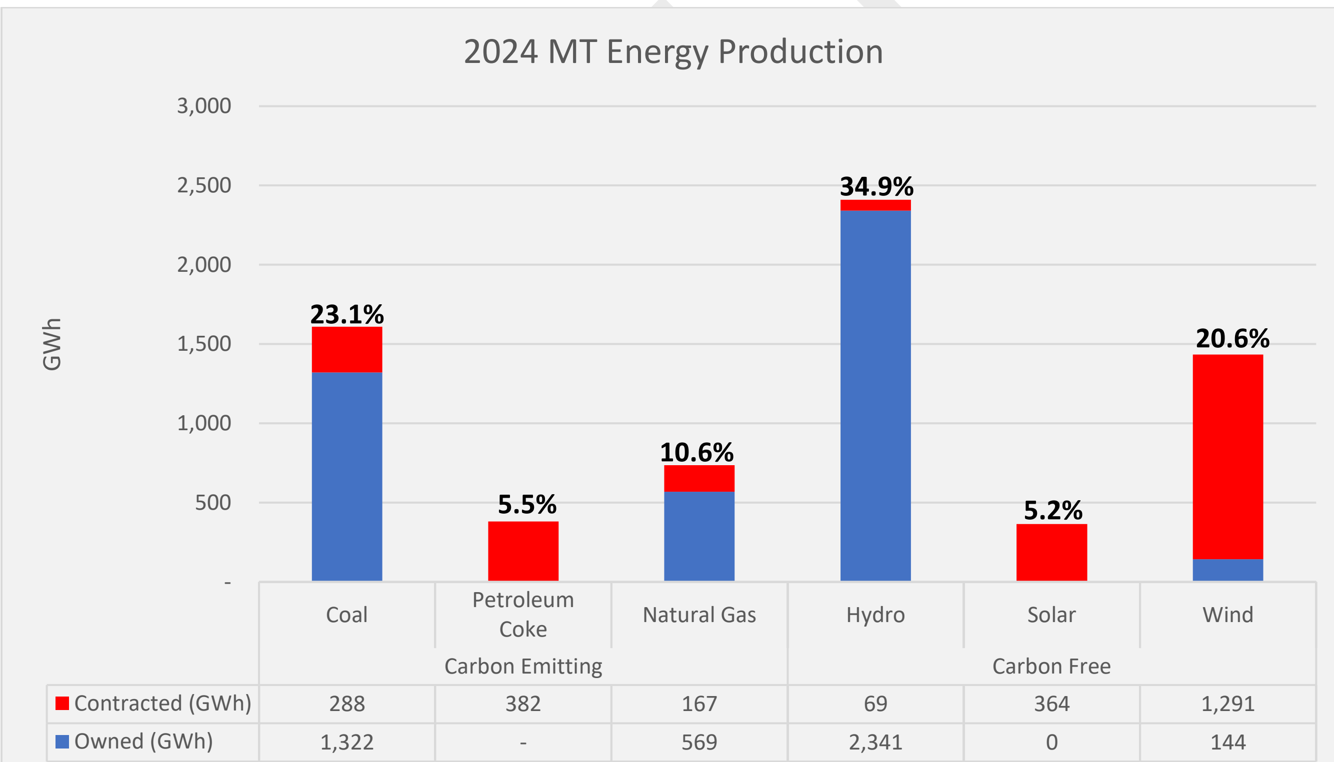


FIGURE 39: 2024 HISTORICAL ENERGY PRODUCTION BY FUEL TYPE AND OWNERSHIP.

Resource	CO_2 (Metric Ton)	Metric Tons of CO_2/MWh
Colstrip	1,364,993	1.03
CELP	391,171	1.36
YELP	673,731	1.76
YCGS	41,228	0.47
Basin Creek	82,795	0.50
DGGS	286,948	0.60

TABLE 26: 2024 HISTORICAL EMISSIONS.

5.4 Capacity Contracts

NorthWestern uses firm capacity contracts to keep the resource portfolio adequate. There are two capacity contracts in the portfolio that are listed in Table 27. NorthWestern calls on these capacity contracts less frequently than other resources, which is reflected in the PCM modeling described in Section 7.6.2.

Resource	Nameplate (MW)	Contract Start Date	Contract Term	2024 Energy Production (GWh)	2024 Capacity Factor	2024 Average Contract Price ($/MWh)
Powerex	100	1/1/2023	12/31/2027	280	32%	[redacted]
Heartland	150	2/1/2024	1/31/2032	28.6	2.17%	[redacted]
Total Capacity Contracts	**250**			**309**		

TABLE 27: CAPACITY CONTRACTS.

5.5 Near-term Portfolio Changes

The following sections describe the addition and removal of resources to the NorthWestern portfolio since the publication of the 2023 Montana IRP. These changes result in both operational and modeling changes since the 2023 IRP.

5.5.1 Hydro Capital Projects

NorthWestern continues to implement small, incremental upgrades[43] to its hydro fleet at various locations. These hydro upgrades are the result of replacing equipment that has operated beyond its useful life. Recent upgrades since the 2023 IRP include the following:

- 2 MW upgrade at Black Eagle unit 3 completed in 2023.
- 2.9 MW upgrade at Holter unit 1 completed in 2023.
- 2.9 MW upgrade at Holter unit 2 completed in 2025.
- 2.2 MW upgrade at Cochrane unit 2 completed in 2024.

Planned upgrades to the hydro fleet in the near term include the following:

- 1.4 MW increase at Hauser unit 1 in 2025.
- 2.9 MW increase at Holter unit 4 in 2026.
- 1.9 MW increase at Thompson Falls unit 6 in 2027.
- 0.4 NW increase at Hauser unit 6 in 2027.
- 1.4 MW increase at Hauser unit 3 in 2029.
- 2 MW increase at Black Eagle unit 2 in 2028.
- 1.9 MW increase at Thompson Falls unit 5 in 2029.
- 4 MW increase at Morony Unit 2 in 2029.

[43] Historical and planned hydro capacity upgrades are described in units of nameplate.

5.5.2 Broadwater Dam

The Broadwater Dam is owned by the State of Montana, Department of Natural Resources and Conservation (DNRC), and is approximately 10.5 MW of hydroelectric generation. Broadwater's PPA expires on June 30, 2026.

5.5.3 Colstrip Energy Limited Partnership

CELP is a QF that burns coal refuse, or coal waste, and has been in commercial operation since August 2, 1992. CELP began delivery under its current PPA on July 1, 2024, for a term of 18.5 years.

5.5.4 Colstrip

Effective January 1, 2026, NorthWestern added 222 MW of Colstrip to the existing 222 MW in the portfolio for a total of 444 MW. The additional 222 MW is comprised of Avista's former interests in Colstrip of 111 MW of Unit 3 and Unit 4, respectively. The 222 MW Avista share has firm transmission rights secured from January 2026 through December 2042.

The Colstrip ownership structure in 2026 consists of NorthWestern Energy, NorthWestern Colstrip 370Pu LLC, PacifiCorp, Portland General Electric, and Talen Energy. Colstrip Units 3 & 4 are operated by Talen Energy. The 2026 ownership structure of Colstrip Units 3 & 4 are shown in Table 28 below. See Section 7.5.1 for information about the 370 MW Puget share of Colstrip.

Ownership	Unit 3	Unit 4
NorthWestern Energy	111 MW	333 MW
NorthWestern Colstrip 370Pu LLC	185 MW	185 MW
PacifiCorp	74 MW	74 MW
Portland General Electric	148 MW	148 MW
Talen Energy (Operator)	222 MW	-

TABLE 28: OWNERSHIP STRUCTURE OF COLSTRIP UNITS 3 & 4

5.5.5 Trident Hybrid Solar and Battery

Trident Solar is a 160 MW solar plus 80 MW battery hybrid QF. While Trident is included in NorthWestern's resource capacity forecast and the IRP modeling because the project has a signed PPA, there is uncertainty as to whether or not the project will develop.

5.5.6 Yellowstone County Generating Station

YCGS is a fast-ramping reciprocal internal combustion engine (RICE) plant with 18 units delivering capacity of 172 MW.[36] YCGS began commercial operation and reached substantial completion on October 25, 2024. YCGS is a firm generation resource and has provided NorthWestern with more ability to balance large swings in variable generation, such as wind and solar. YCGS has provided value to NorthWestern customers through the WEIM due to its ability to quickly ramp its generation up or down depending on real-time prices.

5.5.7 Yellowstone Energy Limited Partnership

YELP is a QF that burns petroleum coke waste fuel and has been in commercial operation since September 12, 1995. YELP's current PPA is set to expire on December 31, 2028. On April 12, 2024, YELP filed a petition and supporting testimony asking the Commission to set terms and conditions for a renewal PPA. The Commission issued a final order on March 28, 2025. While a PPA renewal has not been executed at this time, NorthWestern considered the YELP PPA renewal to be included in the resource portfolio and IRP modeling starting on January 1, 2029, for a term of 20 years.

6 TRANSMISSION SYSTEM

6.1 Transmission and the IRP

Transmission is the bridge between resources and load, and therefore a core driver of reliability, affordability, and deliverability. NorthWestern's high-voltage transmission system links Montana load centers and connects NorthWestern's Balancing Authority (BA) to neighboring regions via key interties. Because real-world limits, based on available transfer capability (ATC), voltage/thermal constraints, contractual rights, and neighboring-system conditions, can bind at different times, resource choices must be evaluated alongside the transmission needed to move energy when and where it's required. The existing and anticipated transmission constraints along with the new proposed NPC project were utilized in the modeling of potential resource portfolios in this IRP.

Key Electric Transmission System Definitions:

- Open Access Transmission Tariff (OATT): the tariff on file with FERC that provides for non-discriminatory access to FERC-jurisdictional transmission systems, such as NorthWestern's, to all eligible customers.
- Total Transfer Capability (TTC): total designed and approved transfer capability of a transmission path.
- Available Transfer Capability (ATC): ATC is the amount of transfer capability left after taking into account the amount of firm commitments of the Transmission provider.
- Reliability: adequacy and security of the transmission system to operate properly under stressed conditions.
- Balancing Authority (BA): The responsible entity that integrates resource, plans ahead of time, maintains load-interchange-generation balance within a BAA, and supports Interconnection frequency in real time.
- Balancing Authority Area (BAA): 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.

6.2 Electrical Transmission System Overview

NorthWestern's transmission system comprises approximately 6,900 miles of 500 kV, 230 kV, 161 kV, 115 kV, and 100 kV systems that connect the various load centers in the state as well as 50 kV and 69 kV systems that serve many local areas. This transmission provides vital reliability service within Montana and also connects with Montana's neighboring regions. The most important interconnections to these regions, discussed below, are Paths 8, 18, 80, and 83.

NorthWestern's BA peaks in both the summer and winter. The winter peak was set during the January 2024 cold weather event at 2,079 MW and the summer peak was set in July 2024 at 2,016 MW. During these peak events, NorthWestern's BA imported approximately 42.0% and 56.6% of its needs, respectively. Table 29 shows this peak information as well as the corresponding NorthWestern retail load.

While there is a correlation between when the BA load and NorthWestern's retail load reach their peaks, they are not always on the same hours or days. For example, during the 2024 winter, the NorthWestern BA peaked in Hour Ending (HE) 18 on January 13, 2024, at 2,079 MW, while the retail load peaked in HE 20 on January 12, 2024, at 1,296 MW. During the 2024 summer, the NorthWestern BA peaked in HE 17 on July 23, 2024, at 2,016 MW, while the retail load peaked in HE 18 on July 23, 2024, at 1,285 MW.

2024 Peak Hours (Mountain Time)	Total BA Load MW	Total BA Imports	NWE Retail Load During BA Peak MW	NWE Market Purchases
Winter 1/13/24 HE 18	2,079	873 (42.0%)	1,248	666 (53.3%)
Summer 7/23/24 HE 17	2,016	1,141 (56.6%)	1,283	642 (50.0%)

TABLE 29: PEAK LOADS AND IMPORTS 2024

NorthWestern transmission serves 26 network customers[44], which represent approximately one third of the load in NorthWestern's BAA, in addition to NorthWestern Supply. These customers include electric choice customers, electric cooperatives, and federal power marketing agencies. The network customers and their 2024 peak loads are listed in Table 30. These customers have network transmission service to serve their loads, which totals approximately 858 MW. Some network customers are served with on-system resources and others are served with off-system resources.

Network Customer	2024 Peak (MW)
Ash Grove Cement Company	6.0
Aspen Air US, LLC	8.7
Atlas Power, LLC	69.5
Basin Electric Power Cooperative	168.0
Beartooth Electric Cooperative	22.2
Benefis Health Systems	6.1
Big Horn County Electric Cooperative	15.3
Bonneville Power Administration	205.7
Calumet Refining, LLC	20.0
CHS Inc.	44.7
City of Great Falls	3.7
Colstrip Steam Electric Station	6.1
Par Pacific	31.9
General Mills Operations, LLC	3.1
Great Falls Public Schools	1.7
GCC Three Forks, LLC	5.0
Magris Talc USA	4.0
Montana Resources	44.2
Phillips 66 Company	60.4
REC	79.5
Roseburg Forest Products	6.3
Suiza Dairy Group (Meadow Gold)	1.0
Stillwater Mining Company	35.5
Western Area Power Administration (WAPA) Irrigation	2.3
WAPA Bozeman MSU	3.0
WAPA Great Falls Malmstrom	4.0

TABLE 30: NORTHWESTERN'S TRANSMISSION NETWORK CUSTOMERS.

NorthWestern also provides point-to-point (PTP) service under its OATT, as approved by FERC. Currently, NorthWestern has approximately 30 to 40 PTP customers that are very active on NorthWestern's transmission system. Both short-term and long-term (i.e. yearly) PTP sales have grown

[44] The network customers are available on OASIS at https://www.oasis.oati.com/nwmt/index.html under Network Resource > List_of_Current_Network_Resources.

in recent years, with a notable increase in long-term PTP sales. New generation in Montana has contributed to approximately 400 MW of increased long-term PTP sales, along with other marketing use of the transmission system. The utilization of NorthWestern's transmission along with external regional systems for inter-regional transfers has contributed to increasing congestion and reduced the amount of ATC on NorthWestern's system.

Peak loads in NorthWestern's BA have grown considerably over recent years, and certain areas on the transmission system are experiencing capacity constraints. Both NorthWestern's retail load and cooperative loads reflect this increase. However, there continues to be great interest from potential new customers about interconnecting large transmission level loads such as data centers. As described below, the Billings, Butte, and South of Great Falls areas are severely constrained and will require additional capital improvements to the transmission system to maintain reliable load service. In addition, the closure of Colstrip would have a significant effect on the transmission system (discussed below).

NorthWestern has implemented Transmission Reliability Margin (TRM) to improve import capacity availability during peak times to improve reliability. TRM is an amount of transfer capability set aside or held out of ATC that can help manage uncertainties during the operation of the transmission system. TRM reduces ATC to ensure reliability. NorthWestern allocates TRM import capacity across Path 8 and Path 18 during peak months to ensure reasonable steps have been taken for customers to serve load and have access to import capacity. TRM is calculated in advance of the DA and pre-schedule based on planning studies. TRM is released for non-firm use at 11:00 AM each day during the pre-schedule window. For more information on TRM see the Transmission Reliability Margin Implementation Document posted on NorthWestern's OASIS site.

6.2.1 The Colstrip 500 kV Transmission System

Today, the 500 kV Colstrip Transmission System (CTS) is the backbone of the Montana transmission system, and it provides NorthWestern with a very strong path across the state to reliably serve all Montana customers. The CTS provides strong ties between the lower transmission voltage systems in the state at three substations – Colstrip, Broadview, and Garrison as shown in Figure 40.

The CTS runs 248 miles from the Colstrip transmission substation to just south of Townsend, Montana. The CTS is comprised of two 500 kV segments. The first segment runs from Colstrip to Broadview. The second segment runs from Broadview to Townsend, where the CTS interconnects with BPA's Eastern Intertie.

It is also important to note that there is no substation at Townsend. The ownership and construction type changes at this point just south of Townsend. NorthWestern contracts for firm transmission rights on the Eastern Intertie, in order to continue to deliver energy further west from Townsend to the BPA Garrison substation. The Garrison substation is also critical to NorthWestern as it is the largest contributor to the overall transmission interconnection to the West allowing for both import and export from and to the regional market. In addition, NorthWestern interconnects at Garrison with 230 kV facilities, adding another strong path to serve customers in western Montana. The CTS and the BPA Eastern Intertie are operated as one facility and are both within NorthWestern's BAA.

The CTS provides the greatest access to and from the regional market in the Pacific Northwest. Access to these markets west of Montana is extremely important to allow NorthWestern to import power into Montana from large energy markets located in the Columbia River region, which is also known as the

Mid-C market. This import capability has increased significantly as Montana's thermal generation retires and peak loads in Montana continue to grow.

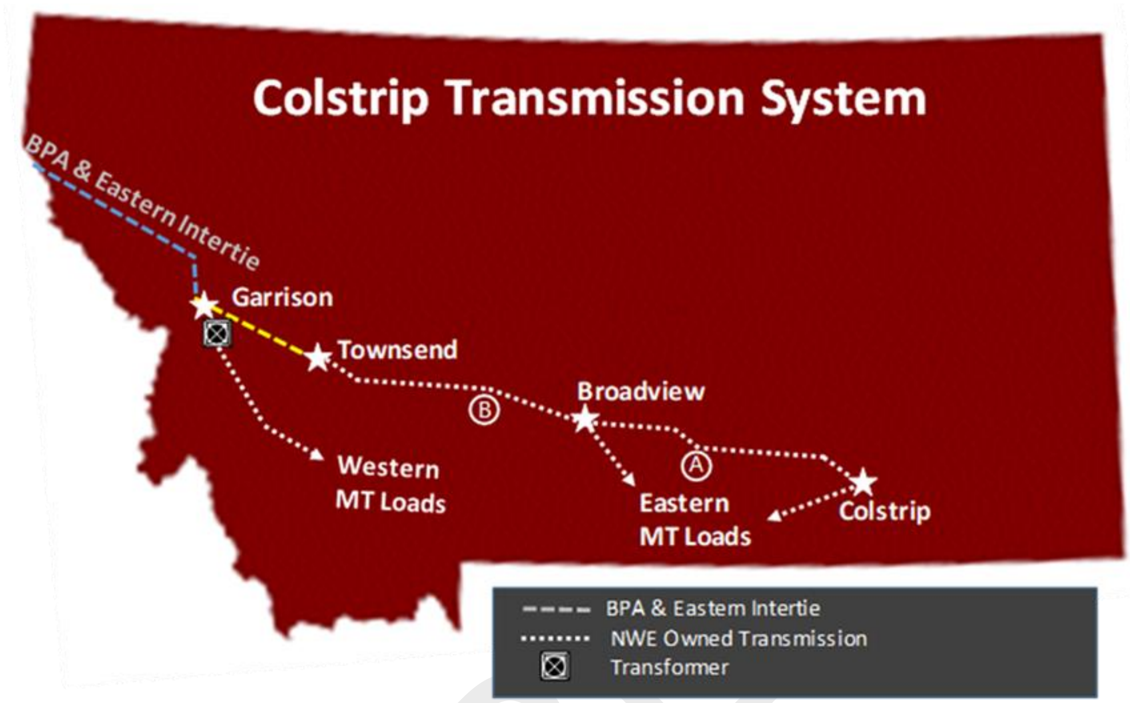


FIGURE 40: GENERAL LOCATION OF THE COLSTRIP TRANSMISSION SYSTEM AND BPA'S EASTERN INTERTIE.

The CTS is critical to NorthWestern and its customers because it is fully integrated into NorthWestern's transmission system and contributes to reliability through the balancing of resources and loads. The CTS serves the critical role of providing for both exporting energy from Montana and importing energy into Montana.

From a historical perspective, the 500 kV transmission lines were primarily constructed to export a portion of the Colstrip-generated power to load centers in Washington and Oregon and, importantly, to tie NorthWestern's lower voltage transmission system to the 500 kV transmission system from east to west across Montana, adding significant reliability benefits and assisting NorthWestern in supplying energy to western Montana loads. These lines provide NorthWestern with the added benefit of vital access to the regional market that is necessary to import power into Montana to serve customers. In addition, the CTS is fully integrated into NorthWestern's transmission system and BA. The CTS and BPA Eastern Intertie are fully integrated and operated as one system.

NorthWestern and the other CTS owners are evaluating the costs and benefits of upgrading the capacity on the CTS. Any CTS upgrades would be coordinated with BPA. Upgrades may also be required on BPA's Eastern Intertie, the Garrison Substation, and on BPA's system going west due to the integrated nature of CTS and the BPA transmission system. CTS upgrades would result in a higher Path 8 path rating, which would provide the CTS owners with incremental transfer capability to integrate additional generation and facilitate transfers from other regional transmission projects.

6.2.2 Transmission Interconnections with Other BAs

Figure 41 below depicts the amount, as rated by WECC, of TTC at the major interconnections of NorthWestern's system with other transmission systems. NorthWestern does not own all the transmission capacity shown on these paths. Since NorthWestern does not own all the transmission capacity, the capacity is not necessarily available to NorthWestern Supply to import energy onto the system to address peak loads. Further, there may not always be generating capacity outside of the BA available for import at the same time there is transmission capacity available. In other words, to import energy onto NorthWestern's system, there must be simultaneous generation capacity and transmission capacity. Consequently, relying solely on imports is a risky and expensive approach to addressing supply capacity shortages.

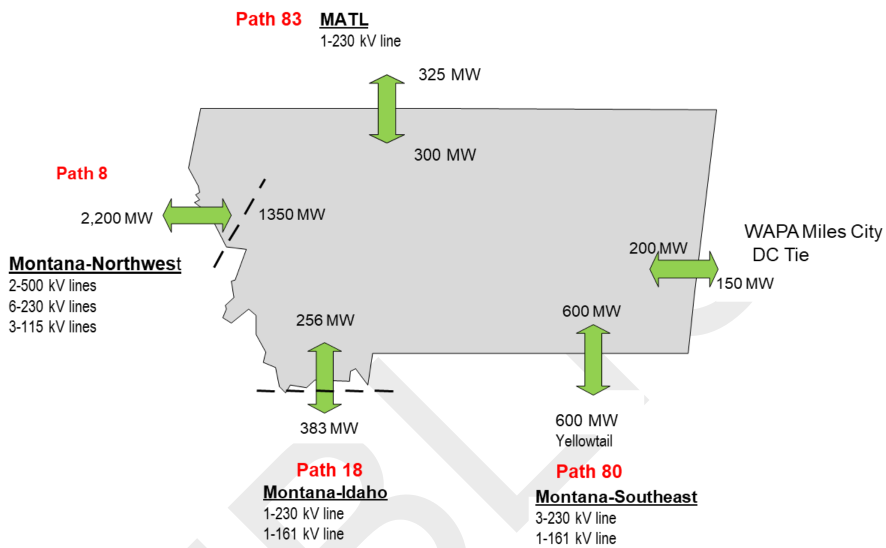


FIGURE 41: NORTHWESTERN PATH INTERCONNECTIONS TO WECC[45]

6.2.3 Interconnection Transmission Paths

This section explains the constraints on the paths that make up the interconnection between NorthWestern's BA and external entities. Transmission lines are constrained by stability, voltage, and thermal limits. Transmission system operators, like NorthWestern, use transmission line ratings to ensure that flows on transmission lines do not create risks of reliability events or damage to lines or equipment. In general, the issues that affect each of NorthWestern's interconnection paths fall into one of two categories: voltage and thermal limits. Voltage violations and thermal violations tend to occur when too much power goes through an undersized system. Voltage violations indicate that voltage on the system is below an acceptable level. These violations could be widespread or localized to a particular area. Thermal violations indicate that a transmission element has reached its thermal rating. Violations can occur when all lines are in service (steady state), or after an outage on the system (post-contingency). Voltage and thermal violations are not mutually exclusive and can cause other unwanted effects on the system that impact end-use customers and generators (such as transient instability).

6.2.3.1 Path 8 – Montana to Northwest

Path 8 consists of two 500 kV lines, six 230 kV lines, and three 115 kV lines. The two 500 kV lines (Broadview to Garrison) are part of the jointly owned CTS. The east-to-west (export) rating of Path 8 is 2200 MW. Path flows greater than the established rating could cause voltage violations and/or thermal violations depending on transmission outage conditions. The east-to-west (export) rating is currently protected by a Remedial Action Scheme (RAS) that will automatically take corrective actions by

[45] Path 8 imports to NorthWestern can be less than shown based on a nomogram.

shedding generation interconnected at Colstrip. In order to achieve a higher export, the transmission system would need upgrades on both NorthWestern's system and the neighboring BPA transmission system. NorthWestern has been exploring ways to increase the Path 8 capacity. Some of the expansion potential was explored under the Montana Renewable Development Actions Plan (MRDAP). NorthWestern and the other CTS owners are in the process of evaluating the path rating, cost, and incremental capacity associated with upgrading the CTS.

The west-to-east (import) rating on Path 8 is 1350 MW, and the TTC varies by season based on loading in the Flathead Lake area. Power flows greater than the established path rating could cause voltage violations and/or thermal violations depending on transmission outage conditions. An increase in Path 8 import capability and ATC would likely require reinforcements to either NorthWestern's and BPA's 230 kV transmission system or a new line interconnecting to BPA. It is unknown at this time if any upgrades would be required by Avista or BPA to allow increased transfers into Path 8.

A major part of Path 8 is the CTS and BPA's Eastern Intertie shown in Figure 40. To be clear, however, while critical, the ability to import on the Eastern Intertie and the CTS is limited. This is discussed in more detail below in Section 6.2.4. Finally, NorthWestern's contract with BPA that governs rates and available capacity on the Eastern Intertie, the Montana Intertie Agreement, terminates September 30, 2027. NorthWestern has contracted with BPA to extend this Eastern Intertie capacity for a 5-year term, with rollover rights, from October 1, 2027, to October 1, 2032.

6.2.3.2 Path 18 – Montana to Idaho

Path 18 consists of one 230 kV line and one 161 kV line in southwest Montana. Primary flows on Path 18 are in the north-to-south (export) direction. The TTC and rating of Path 18 is 383 MW in the southbound (export) direction and 256 MW northbound (import). Path flows greater than the established rating could cause thermal violations on the Mill Creek 230 kV phase shifting transformer. A phase shifting transformer is a device that acts like a valve to control power flow down a particular transmission line. In the case of Path 18, the Mill Creek phase shifting transformer allows NorthWestern to moderately control the power flow on the 230 kV line. The phase shifting transformer is critical to Path 18 operation. There are also outage conditions in Idaho and Wyoming that prevent Path 18 from exceeding 383 MW southbound. These outages can cause low voltage violations along the path. In order to increase the path rating and TTC in the southbound direction, upgrades may be required including new phase shifting transformers (PST) at Mill Creek and transmission reinforcements in southwest Montana to relieve voltage violations. Significant new northbound or southbound capacity would require the construction of a new transmission line from SW Montana to SE Idaho.

The south-to-north rating of the path (256 MW) is limited by the outage of the 230 kV Antelope to Brady (Idaho Power) line which would overload the Antelope to Goshen 161 kV (PacifiCorp) line. To prevent overloads on the line, a RAS has been installed to open up the south end of 230 kV portion of the path. Following the opening of the line, low voltage can occur in southwestern Montana and the RAS is in place to prevent any violations from occurring. In order to achieve higher imports on the path, upgrades on PacifiCorp's system and/or voltage reinforcements in NorthWestern's system may be necessary.

6.2.3.3 Path 80 – Montana Southeast

Path 80 consists of three 230 kV lines and one 161 kV line in southeastern Montana to northern Wyoming and the Western Area Power Administration (WAPA) and PacifiCorp's (PAC) systems. The primary direction of flow is from north to south. The three lines that terminate at Yellowtail, MT, are all controlled by PSTs; the PSTs are located at the other terminus, not Yellowtail. The tie at WAPA's

Crossover substation also has a connection to the Miles City DC line that transfers power to and from the Eastern Interconnect.

Path 80 is rated to 600 MW for both north-to-south (export) and south-to-north (import) flows. However, the transfer capacity on Path 80 is significantly lower due to transmission constraints in both Montana and Wyoming. The factors that limit Path 80 exports can include Miles City DC flow, system loading in the Billings area in NorthWestern’s system, and Yellowtail generation. The actual limit may be much less depending on those variables. The path is also constrained by the transmission system south of Yellowtail as well as transmission in Wyoming that make up Paths 38 and 85 (TOT 4A & 4B). For these reasons, Path 80 can be an unreliable path at peak and other times for firm transfers. To increase path capability in the north-to-south direction, major transmission upgrades are necessary in both Montana and Wyoming. Significant new north or south bound capacity would require the construction of a new transmission line from SE Montana to Northern Wyoming.

Like the north-to-south limits, the south-to-north path rating (600 MW) faces limitations that can result from Miles City DC flow and Yellowtail generation. To increase path capability in the south-to-north direction, similar transmission upgrades would be necessary in both Montana and Wyoming. Again, due to congestion and limitations discussed, Path 80 can be unreliable during peak and other times for firm transfers.

6.2.3.4 Path 83 – Montana Alberta Tie Line (MATL)

Path 83 consists of a single 230 kV line that connects Montana to Alberta, Canada. The path is rated at 325 MW southbound and 300 MW northbound. Path 83 flows cannot exceed the established ratings without causing a thermal violation to the phase shifting transformer at the north end of the path. Additionally, Path 83 is often limited by constraints in NorthWestern’s system on the South of Great Falls path (discussed below).

6.2.4 Available Transfer Capability

The ATC is the transmission that is available for customers' use after considering existing rights and obligations. Yearly Firm ATC on Paths 8, 18, and 80 is shown in Figure 42 below. ATC is the critical value for determining transmission capacity available for reliable operation. ATC is much less than TTC and can change from time to time. There is also competition for ATC from multiple types of transmission customers.

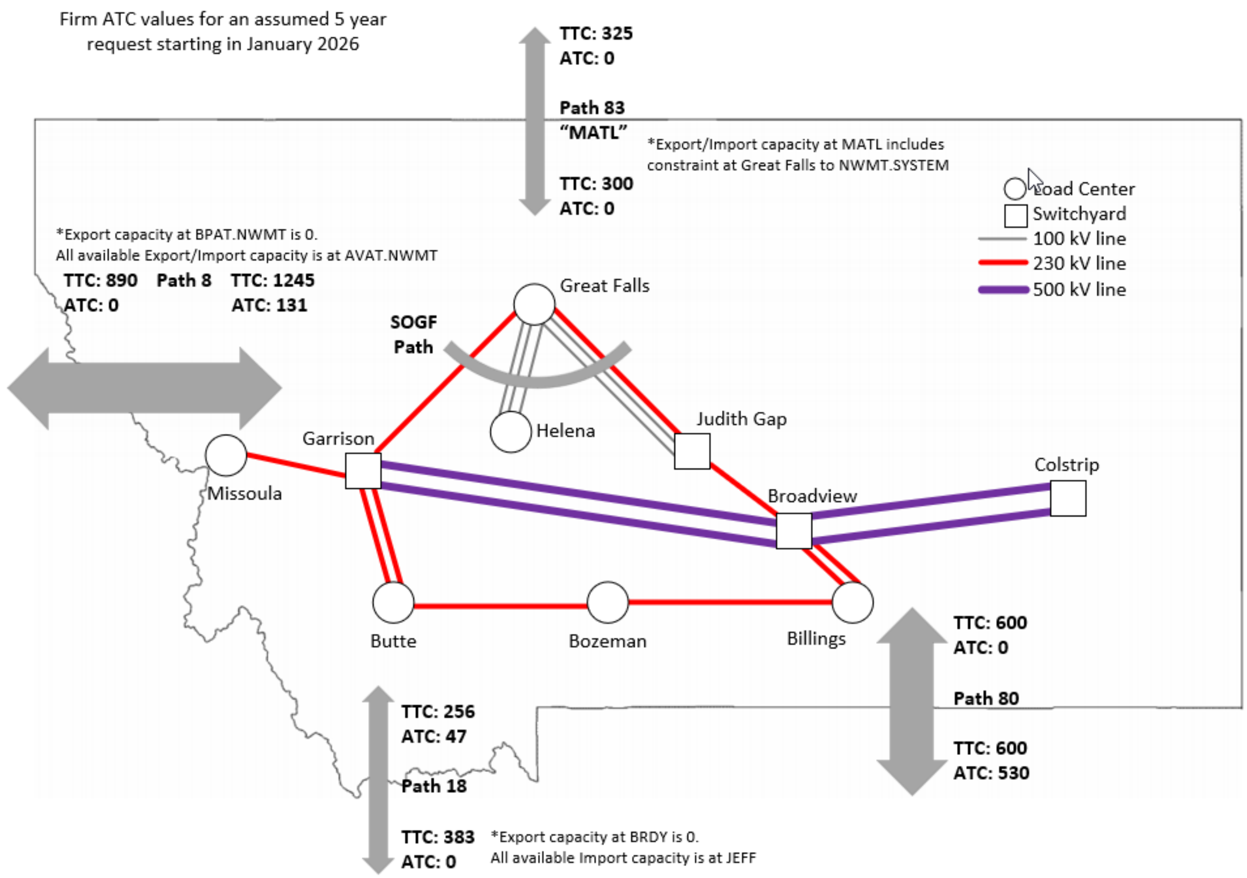


FIGURE 42: THE TTC AND ATC FOR TRANSMISSION PATHS THAT INTERCONNECT THE NORTHWESTERN SYSTEM WITH THE REST OF THE WESTERN INTERCONNECTION.

NorthWestern, under its FERC OATT, is required to provide transmission services to several types of customers, which means that there is significant competition for ATC among many potential users of the transmission system. NorthWestern's transmission system serves four types of customers – retail, network, interconnection, and PTP. In addition to NorthWestern's retail customers, our FERC customers include electric cooperatives, federal marketing agencies, and legacy choice customers that do not receive their supply service from NorthWestern.

This means that there are many non-NorthWestern entities within the NorthWestern BA that are competing for available transmission, constraining transmission of power at critical peak times when customers need that power the most.

This transmission competition is becoming much greater as in-state generation is shut down. It is important to note that transmission capacity is awarded on a first-come, first-served basis and that native load does not receive any preference over other eligible customers. In addition, there are rules governing what is a valid transmission service request or network service designation. For example, long-term network transmission service designation requests must be tied to legitimate network resources with valid contracts for service in place. Table 31 displays the firm import transmission that is reserved on a long-term basis by parties. Many of these reservations are not for service to NorthWestern's customers. This transmission capacity is reserved under NorthWestern's FERC OATT, which includes PTP customer wheeling into and out of NorthWestern's system, and Network customers, including some reservations by NorthWestern, importing energy from outside of Montana and into NorthWestern's transmission system to serve load.

Long Term Firm Reservations from Import Interface Paths (as of 7/14/2025)					
	Path 8 Imports	Path 18 Imports	Path 83 Imports	Path 80 Imports	Total
Network	770	0	175	4	949
Point to Point	76	34	0	49	159
Total	846	34	175	53	1,108

TABLE 31: LONG-TERM FIRM RESERVATIONS BY CUSTOMER TYPE

6.3 Loss of Colstrip Analysis

NorthWestern included a Loss of Colstrip Analysis in NorthWestern's 2023 IRP. The objective of the study was to determine whether imports from off-system resources could be utilized for a replacement of Colstrip generation serving Montana load. The study also analyzed the minimum generation within NorthWestern's BA needed to reliably operate the BA. NorthWestern analyzed the use of imports from off-system resources to make up for the lost supply. Paths 8 and 18 were assumed to provide the majority of the imports as they were deemed the most liquid and reliable import paths. NorthWestern's analysis concluded that imports from off-system resources cannot control voltage in the same way that the generation at Colstrip can control voltage, and an immediate loss of Colstrip would create high voltage problems on the entire transmission system. Replacing the voltage stability provided by Colstrip would be difficult, perhaps impossible, to do with off-system generation because of the limited capability of off-system resources to control voltage remotely. From a long-term perspective, reliance on off-system imports to completely replace the energy in the BA associated with Colstrip is not a reliable or realistic assumption.

The 2023 Loss of Colstrip study assumed that Colstrip capacity served 444 MW of designated load in Montana. If Colstrip capacity is used to serve more than 444 MW of designated load in Montana, the voltage control challenges across the entire NorthWestern transmission system would be further exacerbated if Colstrip becomes unavailable to serve such loads.

6.4 Internal Transmission System

Internal network capacity on NorthWestern's transmission system is currently reaching its limits, which could impact load service and reliability in the near future. This section discusses some of NorthWestern's key concerns and what it is doing about those concerns.

6.4.1 Billings Area

Billings is primarily fed by two 230 kV lines from the north. It also has two 230 kV lines connecting from the southeast that tie to Path 80 as well as a 230 kV and 161 kV line that head west to feed Bozeman. Billings and Path 80 are currently limited by the two 230 kV lines from the north as that is the predominate source that feeds both the Billings area and Path 80.

As loads grow, the ability to serve load in Billings and allow flow down Path 80 on a firm basis is diminishing. Even with minimal firm commitments down Path 80, the Billings area transmission system is currently challenged under peak loading conditions. System improvements in the Billings area are needed in the near future to continue to serve load in the Billings area. Planned system improvements include a new 230 kV transmission line north of Billings, upgrades to area substation capacity, and other related capacity upgrades. YCGS, which went online in 2024, as well as the new Rimrock Substation, have provided critical reliability support for the Billings area that has relieved certain area transmission constraints. However, as the Billings area continues to grow, additional transmission capacity upgrades in the Billings and SE Montana area will be needed within the next 5 years.

6.4.2 Butte/SW Montana Area

Butte and southwest Montana have similar constraints as Billings. Butte is primarily served by two 230 kV lines from the Garrison switchyard. It also has a 230 kV and 161 kV connection that heads east to feed Bozeman as well as a 230 kV and 161 kV connection that heads south and make up Path 18. The Butte area and Path 18 are currently constrained by the two 230 kV lines from the north.

As load in the Butte area grows, the reliability in the area and firm transmission on Path 18 are diminishing. Planned system improvements in the Butte area include the rebuild and capacity upgrades of area 230 kV & 100 kV transmission lines and substations. New dispatchable generation in the Butte area can relieve area transmission constraints and will be needed in the future with load growth.

6.4.3 South of Great Falls

South of Great Falls is an internal path on NorthWestern's transmission system that consists of two 230 kV lines and five 100 kV lines. The underlying 100 kV system is the primary limitation on the path because of the consequences that would occur with the loss of a single 230 kV line.

The constraints on South of Great Falls severely limit the ability to schedule power to and from the MATL, which makes up Path 83, as well as the ability to move power from generation in the Great Falls and surrounding area. NorthWestern has a 10-year PPA in place that is utilizing the remaining transmission capacity on the South of Great Falls path until 2032. In order to accept any new transfers across this part of the system or new generation in the area, new and/or upgraded transmission will be necessary.

6.5 Expanding Transmission Capacity and Interregional Electric Transmission Capacity

Expanding electric transmission capacity across NorthWestern's system is critical to being able to reliably serve the current growing load into the future and to be in a position to serve new on-system network loads and PTP loads. A robust and affordable electric transmission system is key to promoting economic development in the state of Montana. A state with reliable and reasonably priced energy tends to attract new business and industry, resulting in new jobs and additional tax base for that state.

A dynamic and reliable electric transmission system is required to consistently serve customer load. Transmission capacity expansion within NorthWestern's BA increases reliability by improving NorthWestern's ability to manage contingency events while maintaining load service. Having multiple transmission assets in place to transmit electricity from generation resources to load significantly improves reliability.

PTP service is generation that either (1) originates from outside NorthWestern's BA and is transported through NorthWestern's BA and then exits the BA or (2) originates from within NorthWestern's BA and then exits the BA. PTP load service is beneficial to NorthWestern's on-system customers and to the Montana economy because that service helps pay for the electric transmission cost of service with funds that are paid by customers from outside of the state. For example, PTP loads help pay Montana property tax included in the transmission cost of service that would otherwise be paid for by NorthWestern on-system customers.

Interregional energy transactions can occur between two different BAs or between a BA and a Regional Transmission Organization (RTO), or between two different RTOs. Interregional import transmission capacity would allow NorthWestern on-system customers to have access to out-of-state generation resources that would otherwise be unavailable. For example, interregional transmission capacity expansion on Path 8 could allow NorthWestern on-system customers access to additional Pacific Northwest hydro capacity. Interregional transmission capacity expansion on Path 80 could allow NorthWestern on-system customers access to potential new Wyoming generation capacity. Interregional export capacity is valuable to a resource portfolio that is long capacity by creating the ability to market that capacity and energy off system to create value for customers.

New interregional transmission capacity would provide NorthWestern on-system transmission customers with new and potentially low-cost energy purchase options in times of energy shortages and an avenue to sell energy off system at times when there is excess energy. These new energy purchase and sale opportunities would not exist without the interregional transmission capacity to facilitate those transactions. New interregional transmission capacity would further improve both DA and real-time market optimization opportunities by increasing access to more diversified generation resources and loads. The diversification of resources and load can be described as a non-peaking region supporting the load service requirements of a different peaking region. The non-peaking region's load is medium to low, so there is excess generation capacity available for dispatch into the peaking region. Interregional transmission capacity is the key to unlocking interregional resource and load diversification benefits.

Interregional transmission capacity could assist NorthWestern in complying with the RA requirements for participating in DA and real-time balancing electricity markets. CAISO's EDAM requires that participants meet RS requirements as a condition of market participation. SPP's Markets+ requires that participants comply with WRAP requirements as a condition of market participation.

Additional interregional transmission capacity would provide NorthWestern on-system customers with an additional layer of reliability to manage planned transmission outages, unscheduled transmission outages, and other transmission system contingencies than would otherwise be possible.

6.5.1 Grid United's North Plains Connector Project

One such interregional transmission capacity expansion opportunity is Grid United's NPC Electric Transmission Line Project. NPC is intended to be a 3,000 MW capacity bi-directional HVDC electric transmission project spanning approximately 420 miles from the Colstrip MT substation to two separate delivery locations in ND: Center ND/Oliver County Substation (1,500 MW MISO RTO capacity) and St. Anthony ND/Morton County Switchyard (1,500 MW SPP RTO capacity). The NPC Project would interconnect three energy markets: MISO, SPP, and Northwest/MID-C. The NPC Project would link the Western and Eastern North American Electric Reliability Corporation (NERC) Interconnections. The NPC Project would allow the various members of the three energy markets to take advantage of the load & resource diversity and price differentials within the markets. Grid United, an independent transmission company, is developing the NPC. The North Plains Connector Interregional Innovation (NPCII) consortium consists of North Plains Connector/Grid United, the Standing Rock Sioux Tribe, the North Dakota Transmission Authority, and eight utilities: ALLETE Inc., Avista, Minnkota Power

Cooperative, Montana-Dakota Utilities Company, NorthWestern, Otter Tail Power Company, Portland General Electric, and Puget Sound Electric. As of July 1, 2025, NPC is entering the permitting phase and initiating regulatory filings, with approvals expected in 2026. Construction is expected to commence in 2028, and the line is expected to be operational in 2032.

NorthWestern is evaluating the benefits and costs of acquiring capacity on the NPC. The NPC would provide NorthWestern with a flexible asset that would allow NorthWestern to effectively manage its supply portfolio and BA needs in the future. The key benefit that the NPC Project provides NorthWestern with is flexibility. Within this IRP, NorthWestern modeled a scenario for 300 MW of additional transfer capability to understand potential energy price diversity benefits. PCM results are in Section 7.8.6.

In December of 2024 NorthWestern announced signing a memorandum of understanding with North Plains Connector to own 10% or 300 MW of the total NPC Project.

6.5.2 Path 18 Montana to Idaho Project (M2I)

Grid United is exploring a new transmission project to strengthen the connection between Southwest Montana and Southeast Idaho, known as Path 18. This effort is in partnership with NorthWestern leveraging both companies' expertise in regional transmission development and grid operations. NorthWestern and Grid United have entered into a letter of intent to explore transmission development through the southwest corridor of Montana to bolster grid reliability and allow for transfer capability necessary to enable customers to access and benefit from emerging energy markets in the West. The project is in the early feasibility assessment stage. No specific route or final project details have been determined yet.

6.6 Gas Transmission

6.6.1 Gas Transmission and the IRP

The Montana gas transmission and storage systems play a significant role in ensuring the reliable operation of the natural gas-fueled generation resources in NorthWestern's electric supply portfolio. Gas transmission and storage provide Firm Natural Gas Service to the YCGS. Gas transmission and storage provide Non-firm Natural Gas Service to the Dave Gates Generating Station (DGGS) and the Basin Creek plant. These flexible gas-fueled generating resources are critical for providing peaking energy and regulation service to NorthWestern's customers. Because deliverability drives performance during peak and multi-day cold events, the IRP modeling considers additional gas transmission upgrades within new gas-fueled generation. The sections below summarize the status of the current system, interconnections, storage, load trends, and planning considerations.

Key Gas Transmission System definitions:

- Base Load: The minimum amount of natural gas delivered or required over a given period of time at a steady rate.
- Billion Cubic Feet (Bcf): A unit used to measure large quantities of gas, approximately equal to 1 trillion Btu.
- British Thermal Unit (Btu): A basic unit used to measure natural gas; the amount of natural gas needed to raise the temperature of one pound of water by one degree Fahrenheit.
- Capacity: The maximum amount of natural gas that can be transported in a given period of time.
- Compression Unit: Machinery used to increase the pressure of natural gas on a pipeline system.

- Cushion Gas: The volume of natural gas required in a gas storage reservoir to maintain a pressure sufficient to permit recovery of stored gas.
- Dekatherm: A measurement of natural gas; ten therms or one million Btu.
- Firm Natural Gas Service: Providing the delivery of natural gas supply quantity at a delivery point to meet load demand on a twenty four hour-three hundred and sixty-five day basis.
- Horsepower: A power unit of measurement that work is done in reference to the output of a gas compressor unit.
- Thousand Cubic Feet per Day (MCFD): A common daily gas volume measurement. The amount of natural gas to fill a volume of a million cubic feet, under stated temperature and pressure conditions, during a twenty-four-hour period.
- Non-firm Natural Gas Service: Providing the delivery of natural gas supply quantity at a delivery point to meet load demand, which is subject to curtailment.
- Peak Load: A measure of the maximum amount of natural gas delivered at a point in time.
- Pipeline and Hazardous Materials Safety Administration (PHMSA): A United States Department of Transportation agency responsible for developing and enforcing regulations for the safe, reliable, and environmentally sound transportation of energy and other hazardous materials, including natural gas pipelines.
- Reliability: adequacy and security of the transmission system to operate properly under stressed conditions.
- Working Gas: Natural gas in a storage field that is injected at one point in time, stored and then withdrawn at another point in time to serve customer load.

6.6.2 Gas Transmission Overview

NorthWestern's natural gas transmission system consists of more than 2,100 miles of pipeline and serves more than 133 city gate and meter stations where pressure is reduced to distribution level and measured. Pipeline diameter ranges from 1 inch through 24 inches. NorthWestern provides retail service to approximately 247,296 customers, which includes approximately 33,000 new Energy West customers, located in 117 Montana communities. There are 84 individual compression units totaling over 85,000 horsepower dedicated to our Montana transmission, storage, and gathering operations. In addition, NorthWestern owns and operates a pipeline which crosses into Canada through our wholly owned subsidiary, Canadian-Montana Pipeline Company. This pipeline is critical to access Canadian gas as discussed in more detail below. NorthWestern owns and operates the Havre Pipeline Company (HPC) transmission line, which is connected to a network of gas production wells and gathering lines also owned by NorthWestern. NorthWestern owns and operates three working natural gas storage fields in Montana – Dry Creek in south-central Montana, Cobb Storage north of Cut Bank, and Box Elder Storage near Havre. In our three active storage reservoirs, we cycle about 13 Bcf of natural gas in and out of storage annually. A system map is included in Figure 43 below.

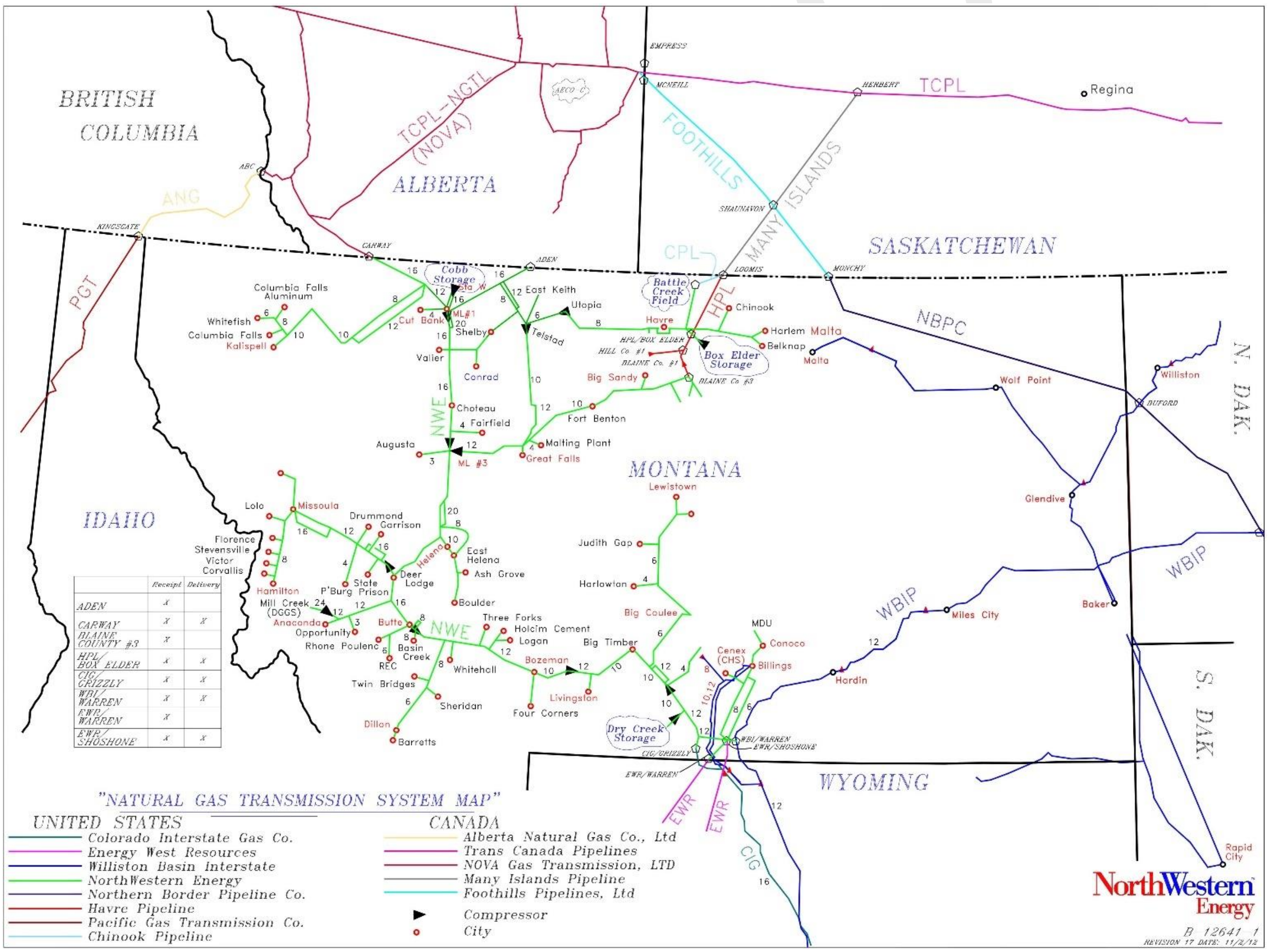


FIGURE 43: GAS TRANSMISSION SYSTEM MAP.

The natural gas supply provided to our customers during the heating season comes from three main sources, and the transmission and storage system is key to delivering this natural gas:

1. Flowing gas (on-system production), which is produced in Montana and has no other place to flow except onto NorthWestern's system;
2. Interconnect gas, which is produced outside of Montana but is delivered under contracts with interconnected pipelines to supply natural gas to NorthWestern's transmission system; and
3. Storage gas, which is brought onto the system typically in the "off season" and injected into NorthWestern's storage fields for use during the heating season.

Figure 44 below shows the sources of natural gas used to serve our transmission customers during the heating season from November 2024 through March 2025.

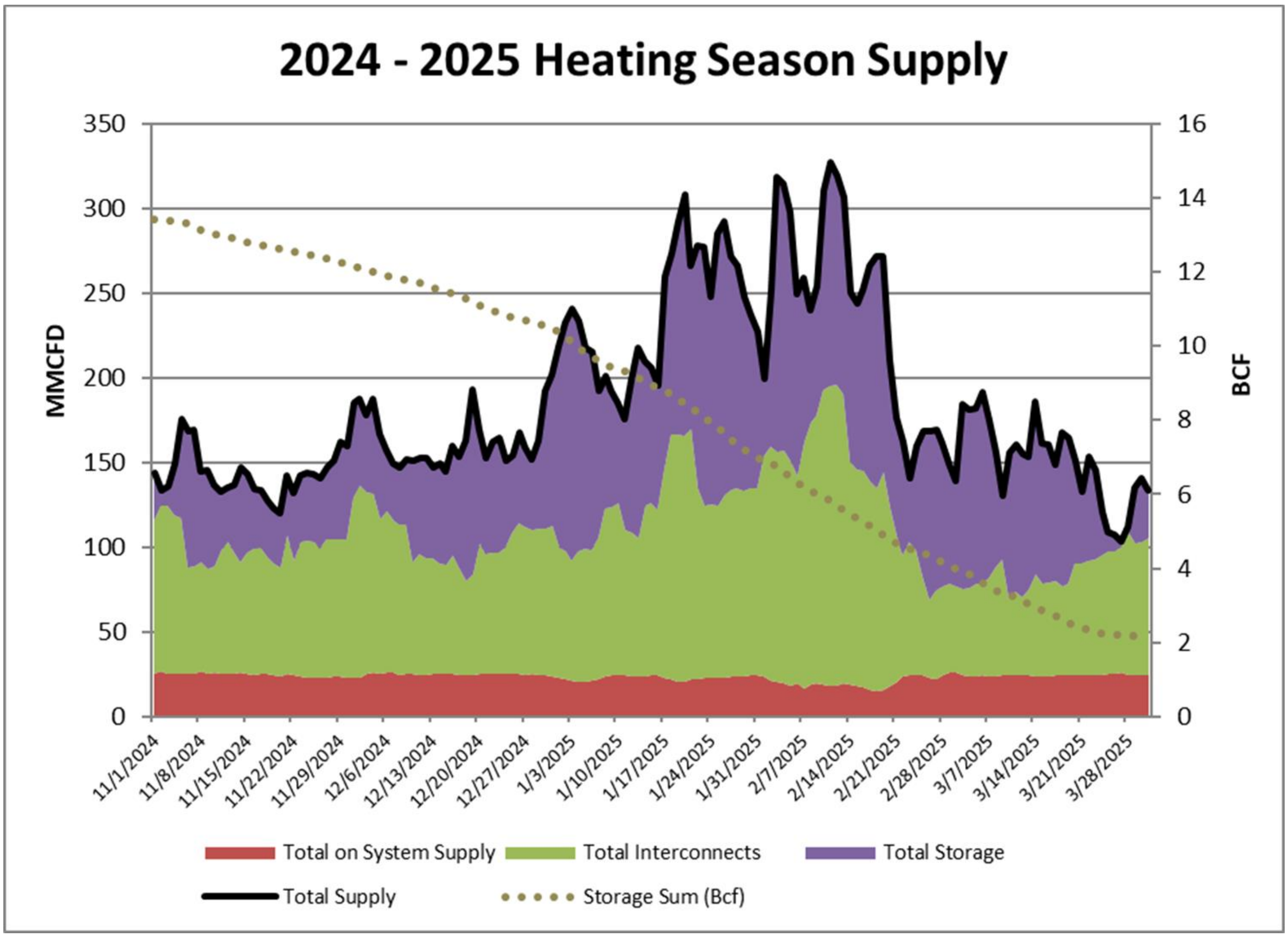


FIGURE 44: NATURAL GAS TRANSMISSION SYSTEM OPERATION.

There are four major pipeline interconnection points that NorthWestern has utilized: Carway (NOVA pipeline), Aden Boarder and Loomis in north central Montana, and Grizzly (Colorado Interstate Gas) in southeast Montana. The Carway interconnection point provides most of the interconnect capacity.

NorthWestern's natural gas transmission and storage system is regulated by the PHMSA. PMHSA develops and enforces regulations for the safe, reliable, and environmentally sound operation of NorthWestern's gas transmission pipeline system.

6.7 Gas Storage Fields

Natural gas storage is a physical tool that allows NorthWestern to accumulate and store natural gas. Gas storage fields use a certain amount of cushion gas, which is the minimum amount of gas constantly stored in a formation, such as salt cavern or depleted production reservoir, that will allow working gas to be injected, stored, and withdrawn. NorthWestern utilizes its natural gas storage to reliably meet physical peak day requirements and mitigate market price fluctuations through seasonal price diversity providing economic benefits to customers. Gas storage is a valuable asset to respond to regional gas demand while avoiding seasonal price spikes. Storage is filled in the summer during months of low demand. The low demand in the summer often leads to lower prices and provides a significant portion of economical supply to serve customers in the winter.

Gas storage improves gas-fueled generation resource reliability by ensuring a sufficient volume of gas is available during peak electric demand periods to operate gas-fueled generation resources. Gas storage also provides lower electric generation fuel costs for electric customers by purchasing lower-priced gas in the summer months for use during the winter months. It is important to account for incremental gas storage costs and benefits when including gas-fueled generating resources as candidate resources in the IRP analysis.

6.7.1 Cobb Storage

The Cobb Gas Storage Field is located in north-central Montana in the vicinity of the town of Cut Bank. The Cobb Storage Field is a depleted production reservoir storage field with total working gas capability of 12.75 Bcf and maximum daily withdrawal capability of about 115,000 dekatherms per day. The Cobb field is supplied from the north end of the system, from NorthWestern's interconnection with TransCanada's NOVA pipeline at Carway and from the north end of Montana natural gas production. NOVA provides access to the very liquid natural gas trading hub, AECO, which is located in Alberta.

6.7.2 Box Elder Storage

The Box Elder Gas Storage Field is located in north-central Montana in the vicinity of the town of Havre that stores natural gas from both AECO and on-system production. Box Elder is primarily used to augment deliveries to the Havre area during cold weather events. Box Elder has a total working gas capacity of 0.6 Bcf and maximum daily withdrawal capability of about 10,000 dekatherms per day. It is a critical resource for load balancing in the Havre area, though its total impact on the balance of NorthWestern's system is minimal.

6.7.3 Dry Creek Storage

The Dry Creek Gas Storage Field is located in south-central Montana in the vicinity of the town of Bridger. The Dry Creek storage field is a depleted production reservoir storage field with a total working gas capacity of 4.5 Bcf and maximum daily withdrawal capability of about 44,000 dekatherms per day. The Dry Creek field can be supplied from either the north end using AECO gas or the south end using CIG gas on the NorthWestern system.

6.8 Peak Load on the Natural Gas Transmission System

Table 32 below reflects NorthWestern's peak loads on our natural gas transmission system over the last several years. Note that many of the top ten days (measured in thousand cubic feet per day or

MCFD) occurred in the very cold weather during December 2022 and again in January 2024. In fact, five of the top ten days occurred during one cold weather event in January 2024.

Top Ten Flows		
	MCFD	Date
1	370,444	1/12/2024
2	360,273	12/22/2022
3	356,077	1/14/2024
4	352,410	1/13/2024
5	352,225	12/21/2022
6	349,432	1/15/2024
7	346,759	2/11/2025
8	343,116	2/22/2023
9	340,186	2/12/2025
10	337,831	1/11/2024

TABLE 32: PEAK LOADS ON NATURAL GAS TRANSMISSION SYSTEM

As a result, NorthWestern is continuing to plan for natural gas transmission upgrade requirements to meet the challenges ahead in the long-term planning horizon. The most difficult capacity needs are related to serving very rapidly growing service areas, reduced on-system natural gas supply, constraints at interconnections with other systems, and providing natural gas for gas-fired generation facilities. We must consider our delivery system design as we continue to search for the best natural gas supply sources to meet our core customers' and electric supply needs.

Accordingly, NorthWestern has analyzed and identified a number of options to increase natural gas transmission capacity including looping projects, compression additions, expansion of existing on-system storage, new on-system storage, and expanded interconnection capability.

6.9 Gas Transmission Loads and Growth

Natural gas is used primarily for retail residential and commercial heating, and as fuel for DGGS, Basin Creek, and YCGS. DGGS and Basin Creek operate using Non-firm Natural Gas Service sourced primarily from AECO. YCGS operates with Firm Natural Gas Service sourced from CIG. The demand for natural gas largely depends upon weather conditions. Our Montana retail natural gas supply requirements for 2024 were approximately 22.4 Bcf. Our Montana natural gas supply requirements for electric generation fuel for 2024 were approximately 8.0 Bcf.

As part of the overall planning process, NorthWestern performs hydraulic modeling to assess the pipeline capacity required to meet the expected customer growth on the system. This involves evaluation of the existing pipelines and compression to meet future demands and identify needed improvements. We have been experiencing steady and significant customer growth. Figure 45, below, indicates current load and load growth on a percentage basis across our natural gas transmission system.

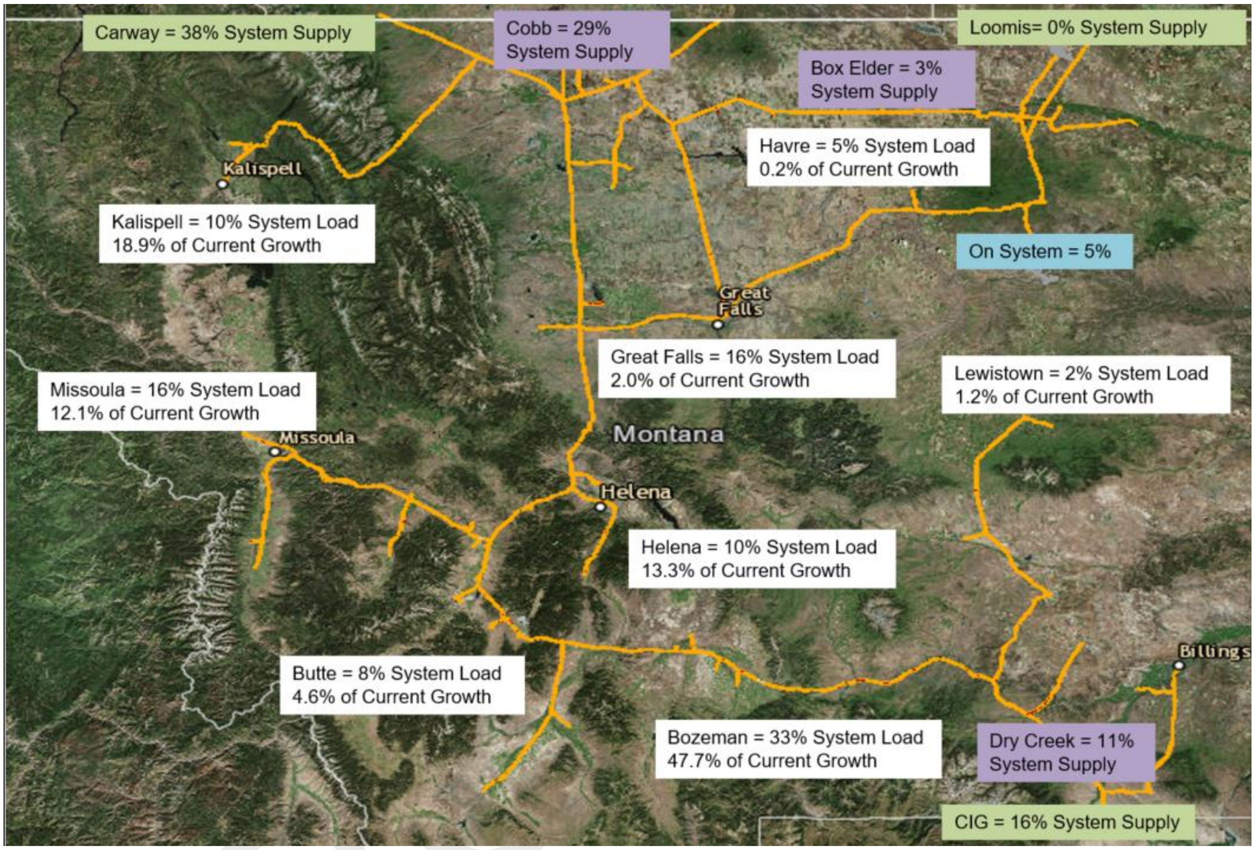


FIGURE 45: GAS TRANSMISSION LOADS AND GROWTH.

As indicated in the graphic, both the largest area load and fastest load growth rate is the Bozeman area, followed by Kalispell and then Missoula. The Bozeman area is a great distance from sources of natural gas and is growing very rapidly making it increasingly challenging to serve. Missoula and Kalispell are also more difficult to serve due to the radial nature of the system in those areas.

As NorthWestern's gas transmission becomes more constrained, it will need additional upgrades including loops, compressor stations, pipeline upgrades, and potentially new storage fields. NorthWestern included a fixed dollar per nameplate cost for expected gas transmission upgrades associated with new generation. This is further discussed in Section 7.1.6.3 Fuel Delivery Infrastructure.

7 RESOURCE PLANNING AND ANALYSIS

This chapter describes NorthWestern's modeling approach, assumptions, results, and implications to NorthWestern's resource portfolio. The IRP modeling identifies the energy and capacity needs of a resource portfolio given a load forecast. The IRP evaluates different scenarios and sensitivities to determine how particular change(s) in the base assumptions change the modeling results. The modeling results are dependent upon assumptions and inputs such as resource accreditation, capacity forecast, and price forecasts. At a high level, the modeling selects from the pool of generic candidate resources, as described in Section 7.1. The total costs of different scenarios and sensitivities are compared to the Base Case and are described in Section 7.8.

All capacity expansion and production cost analyses, collectively referred to as "modeling," were performed in PowerSIMM.[46] NorthWestern conducted the modeling in 2025 for the 20-year planning period of January 1, 2026, through December 31, 2045.

7.1 Candidate Resources

NorthWestern created a list of candidate resources for potential selection in capacity expansion modeling. Those resources are listed in Table 33 below and described in detail in the following sections. The capacity accreditation is addressed in Section 7.2. The candidate resources are assumed to be located in Montana and available for commercial operation starting on January 1, 2030. This commercial operation date (COD) allows approximately four years from the start of the planning horizon for a competitive solicitation and resource construction.

Thermal Candidate Resources
RICE 100 MW
Dual Fuel RICE 50 MW
Aero 100 MW
Dual Fuel Aero 50 MW
Frame CT 200 MW
CCCT 150 MW
CCCT 320 MW
Nuclear SMR 320 MW
Renewable Candidate Resources
Solar 300 MW
Wind 300 MW
Energy Storage Candidate Resources
BESS Li-ion 50 MW, 4h
BESS Li-ion 100 MW, 4h
BESS Li-ion 100 MW, 8h
Pumped Hydro 100 MW, 8h
Iron Air 50 MW, 100h
Hybrid Candidate Resources
Solar 100 MW, BESS 50 MW 4h
Solar 100 MW, BESS 100 MW 4h
Wind 100 MW, BESS 50 MW 4h
Wind 100 MW, BESS 100 MW 4h

TABLE 33: CANDIDATE RESOURCES.

NorthWestern reviewed the candidate resources that were modeled in NorthWestern's previous plans, as well as other integrated resource plans and discussed the maturity and feasibility of different technologies with Aion, the consultant that NorthWestern retained to develop cost estimates for candidate resources. NorthWestern selected candidate resources based on the described review and

[46] PowerSIMM is a product of Ascend Analytics.

NorthWestern's judgment of a particular technology delivering energy in Montana. The candidate resource options were reviewed both with ETAC and the stakeholder group. Interregional transmission is not considered a candidate resource on a standalone basis. Interregional transmission can provide greater market access to sell and purchase energy which can translate into increased grid reliability. However, interregional transmission alone does not guarantee resources are available during peak times. Therefore, interregional transmission is not considered as a candidate resource for fulfilling a capacity need. Other technologies that may be considered in future IRPs are discussed in Chapter 10.

7.1.1 Natural Gas Candidate Resources

NorthWestern included several different types of natural gas-fueled candidate resources. Smaller generating units such as aeroderivative simple cycle combustion turbines (Aero) and RICE were included as candidates to fill smaller capacity gaps. These smaller units are advantageous because when a forced or planned outage occurs on a single unit, the remaining units in the plant can still be used to produce energy. Dual-fueled options were also included to provide firm capacity via diesel backup fuel without the need to upgrade the natural gas transmission system. However, the quantity of dual fuel generators was limited to one 50 MW installation because the natural gas transmission system cannot supply an unlimited amount of non-firm natural gas generation.

Aero units are adopted from aviation use and are lighter, smaller, and more advanced when compared to frame installations that are generally designed for a specific site. Aero units handle a greater number of starts and stops compared to frame installations. Aero units require a higher gas pressure than RICE units, which adds construction and operations cost. The effective heat rate of Aero units increases significantly as the unit is dispatched at lower output levels below maximum capability and may not be able to run effectively below 50% of the nameplate capacity.

RICE units are internal combustion engines, similar to vehicle engines. They can operate with natural gas or be dual fuel with diesel backup. Similar to CT plants, RICE installations supply peaking power and operate in load following scenarios. Due to their wide range of operability and rapid response capability, RICE technology compares favorably for peaking applications. Generally, in utility power generation applications, RICE technology is smaller in scale and has better efficiency compared to simple cycle CT technology.

Larger natural gas-fueled generators such as Frame CT and CCCT were also included as candidate resources. These larger generators may be better suited to fill large capacity shortfalls that could occur in the planning horizon at a lower cost than smaller Aero or RICE units. Frame industrial gas turbines are somewhat slower in startup and have narrower operating ranges than Aero units. However, they can be less expensive than other turbine options and still provide peaking attributes. CC turbines generally have higher efficiency due to the extraction of more energy, or heat, from the CT.

For the base assumption, the last year in which natural gas units can be constructed in the model is 2035 in accordance with NorthWestern's Net Zero goal. The expected book life of all natural gas candidate resources is 32 years. For any natural gas resources that are selected in modeling, there is no accelerated retirement by 2050 assumption due to the Net Zero goal.

Table 34 below describes emission, water use, and land use characteristics of the thermal candidate resources. The emissions rates were provided by Aion based on feedback from original equipment manufacturers and reviewing performance attributes from RFP responses and regional IRPs. The land use for RICE and Aero generation projects are based on YCGS and DGGS land use, respectively. The land use for the Frame CT and the combined cycle combustion turbine (CCCT) projects were estimated from EIA's Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies[47] (EIA Capital Cost report). The water use estimate for RICE projects was based on YCGS, and the estimates for Aero and Frame CT projects were based on DGGS, which uses demineralized water to help reduce NO_x emissions. Demineralized water is required to prevent corrosion. The water use estimates for CCCT projects were also based on the EIA Capital Cost report.

Thermal Candidate Resources	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	CO2 (lbs/MMBtu)	Water Use (gal/MWh)	Land Use (acres)
RICE 100 MW	0.0017	0.0164	121	0	5
Dual Fuel RICE 50 MW	0.0017	0.0215	121	0	5
Aero 100 MW	0.0017	0.01	118	42	7
Dual Fuel Aero 50 MW	0.0017	0.01	118	42	7
Frame CT 200 MW	0.0017	0.01	118	42	20
CCCT 150 MW	0.0017	0.01	118	2,803	30
CCCT 320 MW	0.0017	0.01	118	2,803	30

TABLE 34: THERMAL CANDIDATE RESOURCE CHARACTERISTICS.

7.1.2 Small Modular Reactors

A SMR was included as a candidate resource. The 320 MW size of the SMR does not represent a specific technology but is similar in size to other SMRs modeled in other IRPs. The SMR is assumed to be unavailable until January 1, 2035, as nearly all SMR designs are still working through the design and Nuclear Regulatory Commission (NRC) approval processes. There are no SO_2, NO_x, or CO_2 emissions from an SMR to generate electricity. The projected water use for a water-cooled SMR, such as the Nuscale design, would consume approximately 740 gallons per MWh. However, the actual water use would be determined by the specific SMR design.[48] Different SMR designs may need different land requirements, but NuScale's SMR design can be located on as little as 35 acres.[49] The expected book life of an SMR candidate resource is 60 years.

7.1.3 VER Candidate Resources

NorthWestern included large, standalone solar and wind projects as candidate resources. The 300 MW project size was chosen for both wind and solar because the overnight costs[50] were cheaper than the 50 MW and 100 MW sizes. Also, the accreditation for wind and solar resources is small compared to the nameplate capacity so large projects would be needed to fill large capacity shortfalls.

PV cells are made of semiconductor materials and come in many sizes, shapes, and ratings. Solar cells produce direct current (DC) electricity and require inverters to convert the DC output to alternating current for grid-connected installations. Solar PV arrays are mounted on structures that can either tilt the PV array at a fixed angle or incorporate tracking mechanisms that automatically move the panels to follow the sun across the sky. The fixed angle is determined by local latitude, orientation of the structure, and electrical load requirements. Tracking systems provide more energy production. Single-axis trackers are designed to track the sun from east to west, and dual axis trackers allow for modules to remain pointed directly at the sun throughout the day. Data from NREL[51] shows that solar development potential in Montana is low compared to the southwest U.S. as shown in Figure 46. When

[47] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf
[48]https://inl.gov/trending-topics/carbon-free-power-project/faqs/
[49] https://inl.gov/trending-topics/small-modular-reactors/
[50] Overnight cost is the cost of a construction project if no interest was incurred during construction, as if the project was completed "overnight."
[51] https://www.nrel.gov/docs/libraries/gis/high-res-images/solar-annual-ghi-2018-usa-scale-01.jpg?sfvrsn=135d48b6_1

paired with native grasses and pollinator habitats or with sheep, utility-scale solar can still support agricultural production.[52] More specifically, a utility-scale solar power plant may require between 5 and 7 acres of land per MW of generating capacity[53] and has an expected book life of 25 years for a candidate resource.

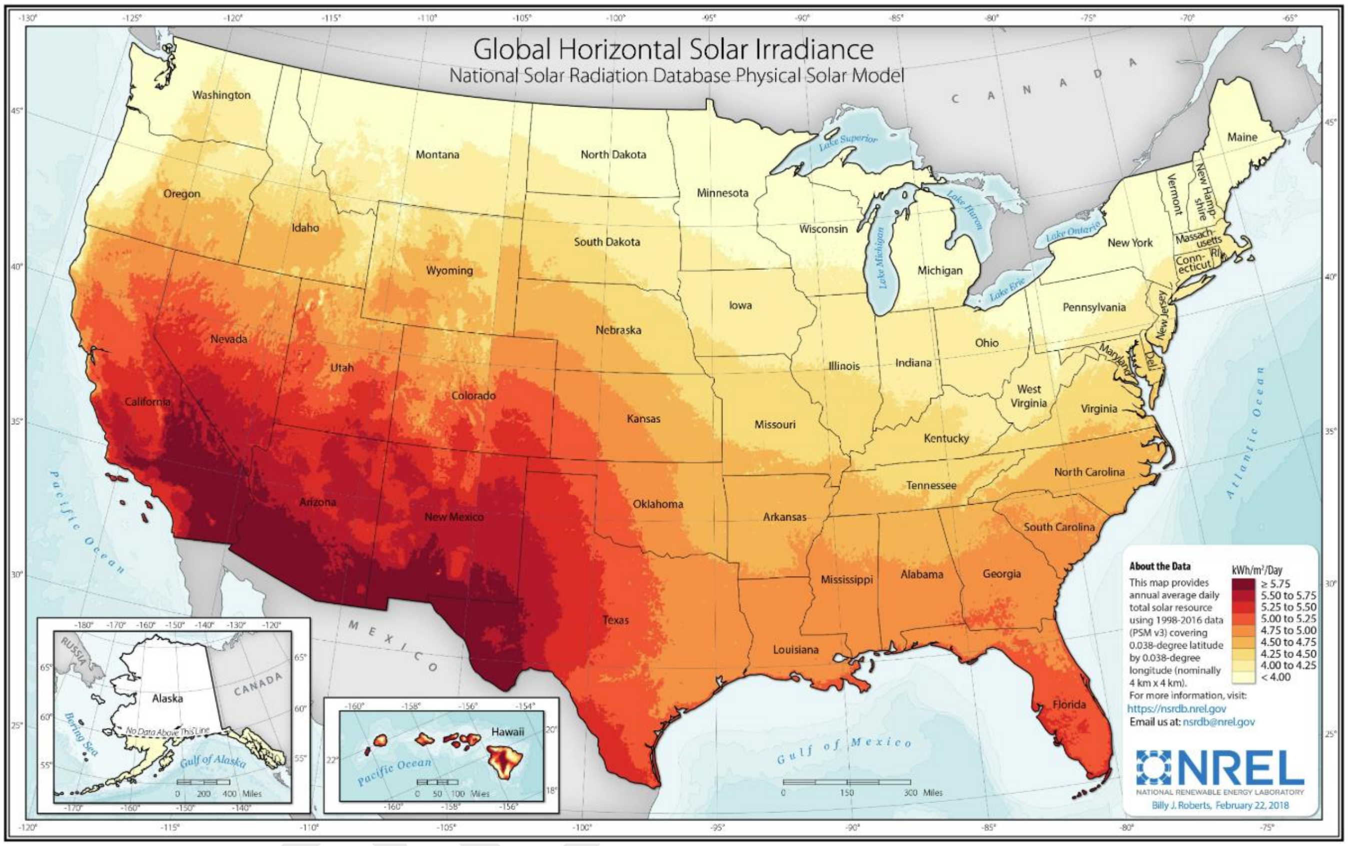


FIGURE 46: NREL'S SOLAR IRRADIANCE MAP.

[52] https://seia.org/wp-content/uploads/2019/09/Solar20Ag20Land20Usage20FactSheet202019-PRINT-1.pdf
[53] https://seia.org/initiatives/land-use-solar-development/#:~:text=A%20utility%2Dscale%20solar%20power,slopes%20and%20no%20water%20access

Individual wind turbines can be designed for sizes between 1.5 and 5 MW. Data from NLR[54] shows that wind development potential is favorable in eastern Montana as shown in Figure 47. Wind farms occupy only small areas for turbine pads, service roads, and related infrastructure, allowing farmers and ranchers to continue agricultural production and earn lease income, though developments can introduce considerations such as noise, visual impacts, and effects on wildlife.[55] The expected book life of a wind candidate resource is 30 years. The blades are large, durable pieces of fiberglass that are challenging to cut, bend, or otherwise repurpose and the majority of rotor blades are currently going to either landfills or incineration facilities.[56]

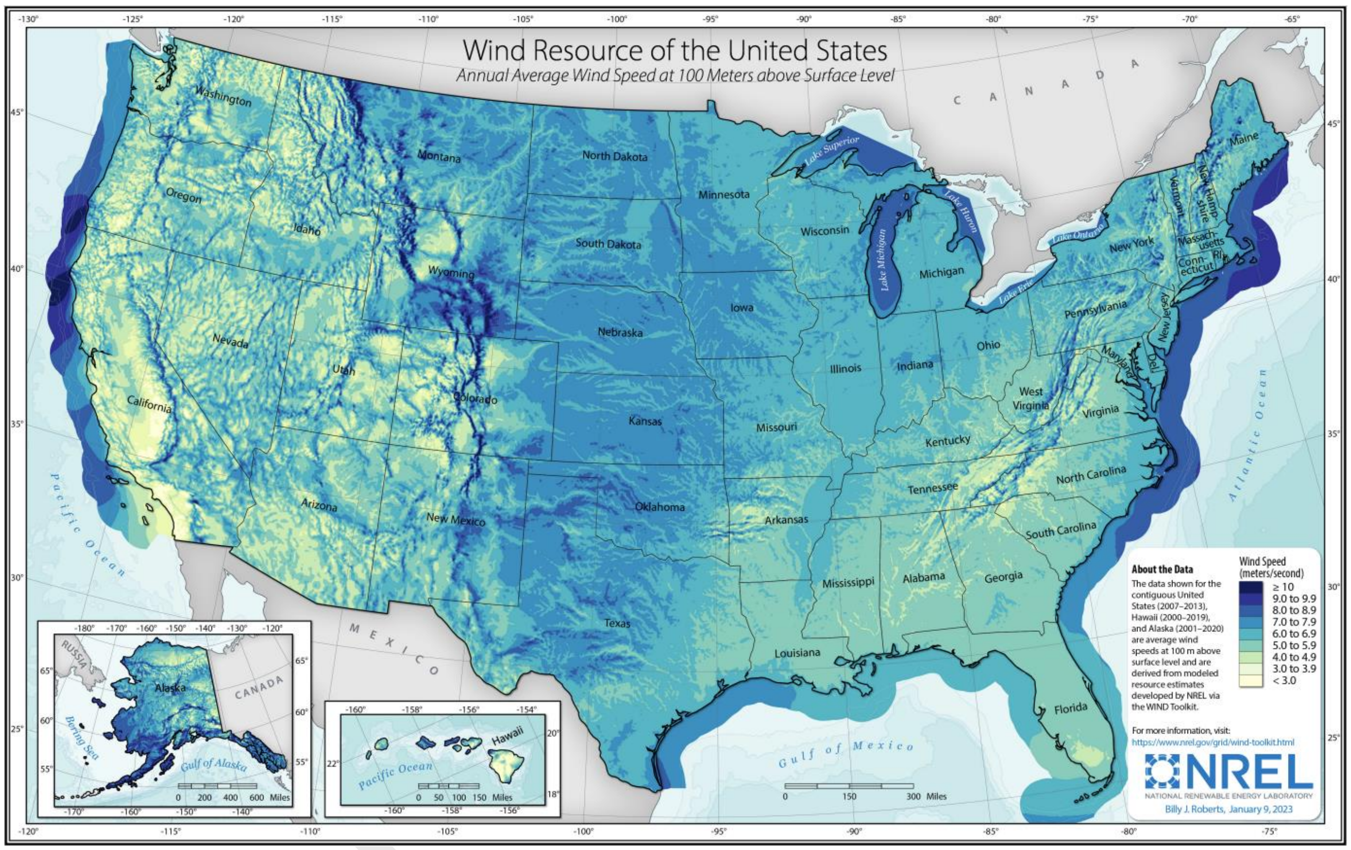


FIGURE 47: NREL'S WIND RESOURCE MAP AT 100 METERS.

7.1.4 Energy Storage Candidate Resources

NorthWestern reviewed several different BESS including Li-ion, iron air, and pumped hydro. The nameplate capacities for the Li-ion projects were 50 MW and 100 MW with four-hour durations as well as a 100 MW, eight-hour duration. Li-ion batteries are useful resources for intraday energy storage but typically are not as good for longer durations. Li-ion batteries provide a high energy storage density that has resulted in adoption across the transportation, technology, and power generation markets. Due to its characteristics, Li-ion technology is well suited for fast-response applications like frequency regulation and short-term spinning reserve. An important consideration of BESS is round-trip energy

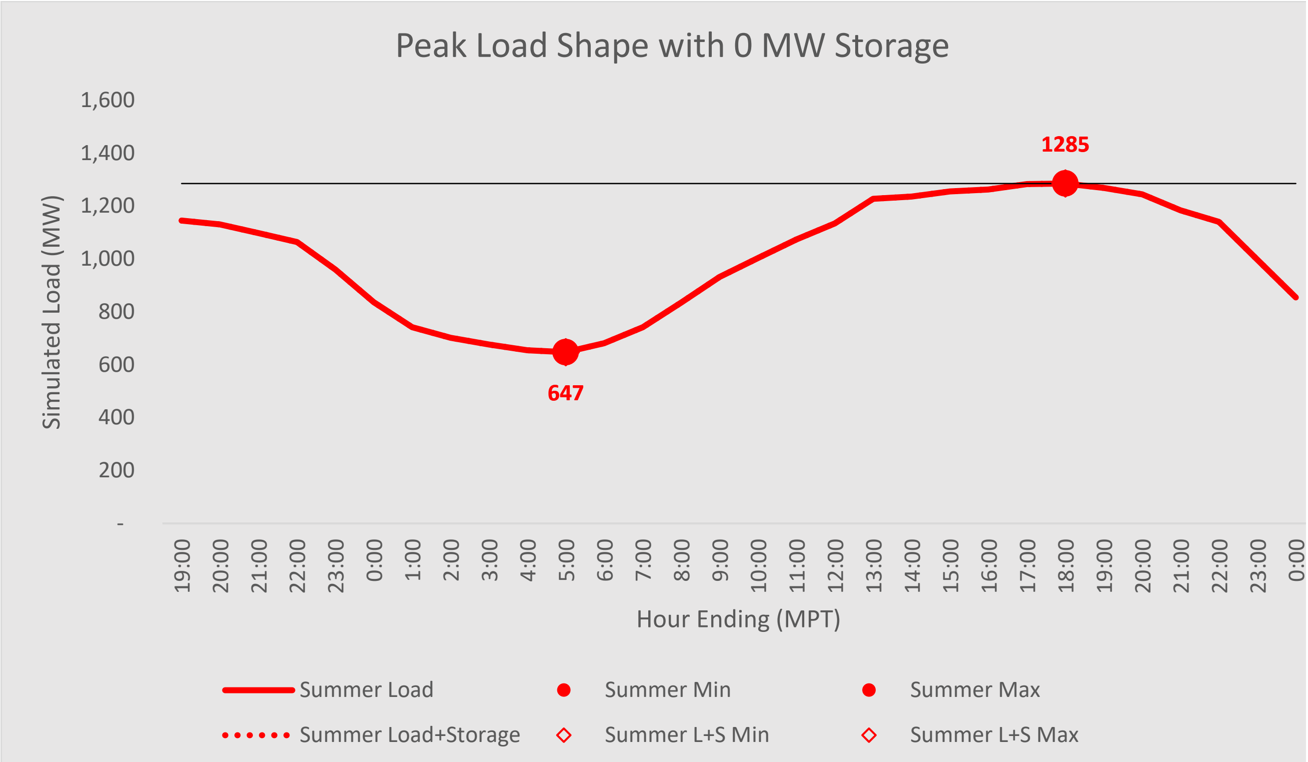
54 https://windexchange.energy.gov/maps-data/324
55 https://www.ers.usda.gov/amber-waves/2024/september/agricultural-land-near-solar-and-wind-projects-usually-remained-in-agriculture-after-development
56 https://cleanpower.org/wp-content/uploads/gateway/2023/01/ACP_BladeRecycling_WhitePaper_230130.pdf

efficiency (RTE). Losses experienced in the charge and discharge cycles include those from plant inverters, heating and ventilation, and associated control systems. Li‑ion technology experiences degradation both in terms of capacity and round‑trip efficiency with time due to a variety of factors, including number of full charge and discharge cycles as well as environmental exposure. The expected book life of a li-ion BESS candidate resource is 20 years. Utility-scale battery disposal is an ongoing question that is still being explored at the time of this IRP's publication.

Pumped hydro is relatively simple technology in which water is stored in an upper reservoir and can be discharged through a hydro turbine generator to a lower reservoir. The main consideration for pumped hydro energy storage is the hydraulic head, or elevation difference, between the upper reservoir and the hydro turbine generator in lower reservoir. Pumped hydro is still considered an intraday energy storage resource.

NorthWestern also modeled a 50 MW, 100-hour iron air BESS. This iron air BESS is distinctly different from Li-ion as it can store energy for extended periods of time, on the order of weeks or months. This type of energy storage can be advantageous for storing energy in the shoulder seasons when prices are low and discharging energy during long peaking events that could span multiple days when prices are high and renewable output is low. The expected book life of an iron air BESS candidate resource is 20 years. This type of BESS may also be referenced to as LDES. As this type of technology is new and operational performance has not yet been proven on a utility scale, the quantity of iron-air batteries was limited to the approximate equivalent of 10% of the annual peak load, or 150 MW.

It is assumed that intraday BESS can be charged and discharged once per day, including days when the load experiences a seasonal peak. BESS act like a load when they are charged from the grid. The number of stand-alone BESS that can be used to meet RA is limited based on the amount of charging demand that is added to the system. Figure 48 below shows NorthWestern's summer peak that occurred on July 24, 2024, and winter retail load peak that occurred on December 22, 2022. Notice that the winter peak shape is much flatter and shallower than the summer peak shape. These seasonal load shapes dictate how much BESS charging load can be added to the system. Ideally, BESS are charged across the lowest load period and discharged across the highest load period of the load shape. These same load shapes were applied to the highest summer and winter peaks over the 20-year planning horizon of 1391 MW and 1353 MW, respectively. Figure 49 shows a charging analysis of how the 20-year summer peak load shape changes with the addition of 250 MW and 300 MW of four-hour duration BESS, and Figure 50 shows the same analysis for the 20-year winter peak load shape. Notice that 300 MW of BESS creates a new winter peak load at 5 AM during the charging period of the BESS while the 250 MW of BESS is sufficiently decreasing the overall peak load for both the summer and winter peaks. Therefore, 250-MW 4-hour BESS was determined to be the maximum amount of 4-hour storage that is considered in the IRP. This same charging analysis could be performed for 8-hour BESS, as well. However, 8-hour storage will be further limited because of the longer charging durations as well as coordination with 4-hour storage. Both 8-hour BESS and pumped hydro are more expensive than 4-hour BESS so 4-hour BESS will always be selected by the model up to the charging limit. Therefore, 8-hour BESS applications, including pumped hydro energy storage, were not considered as an eligible resource in ARS.



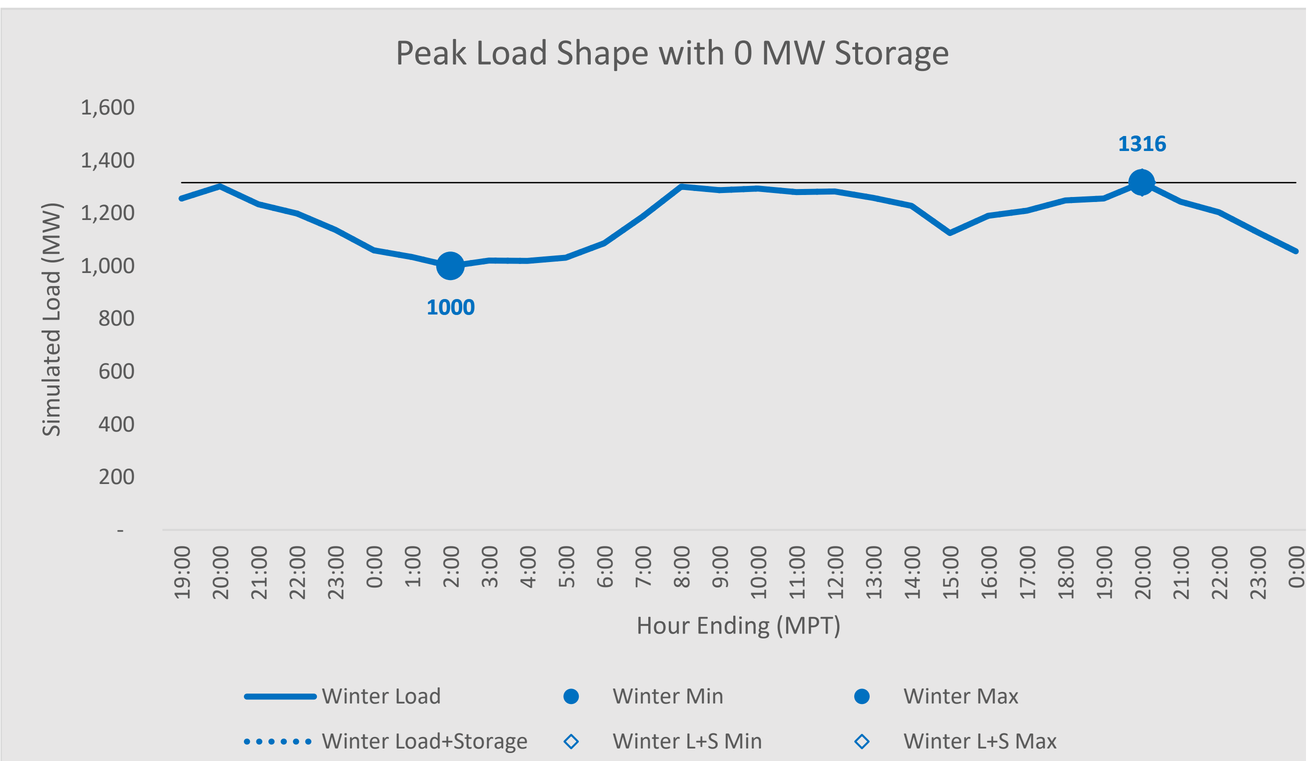
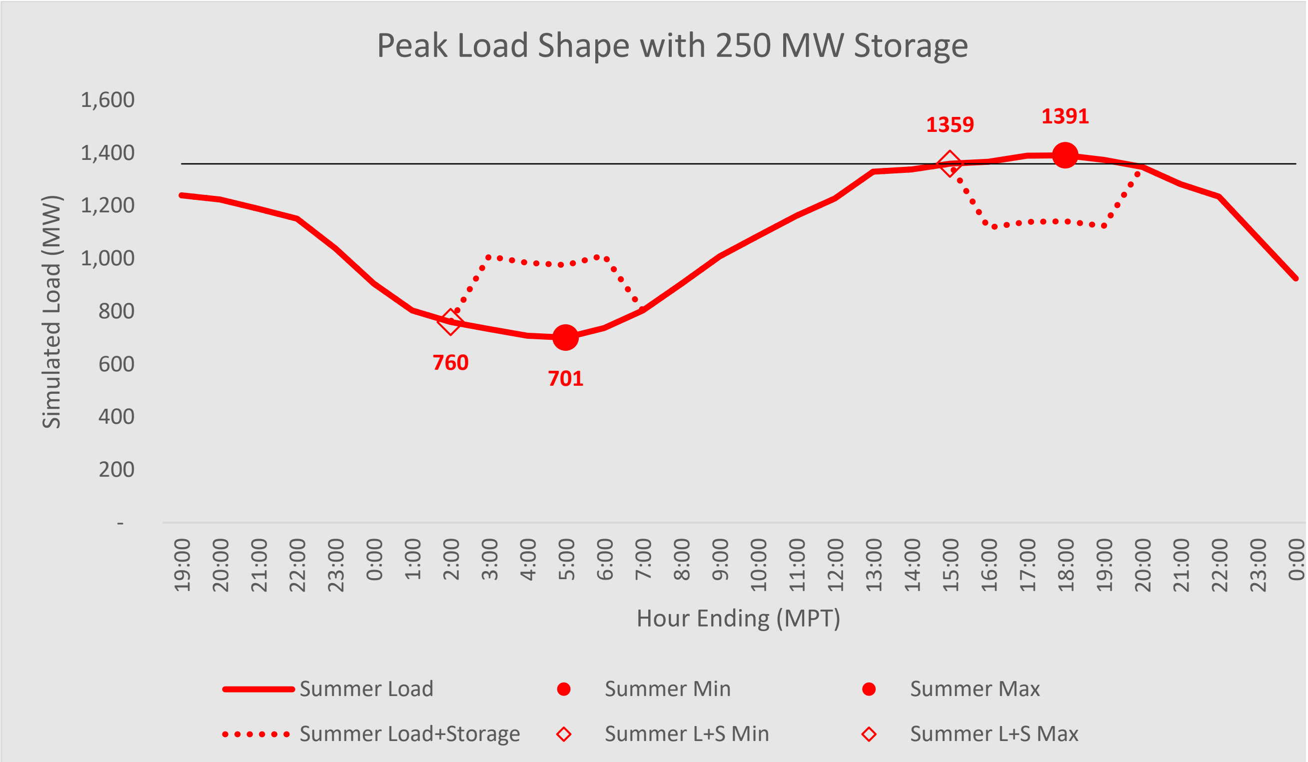


FIGURE 48: NORTHWESTERN'S HISTORIC SUMMER AND WINTER RETAIL PEAK LOAD SHAPE.



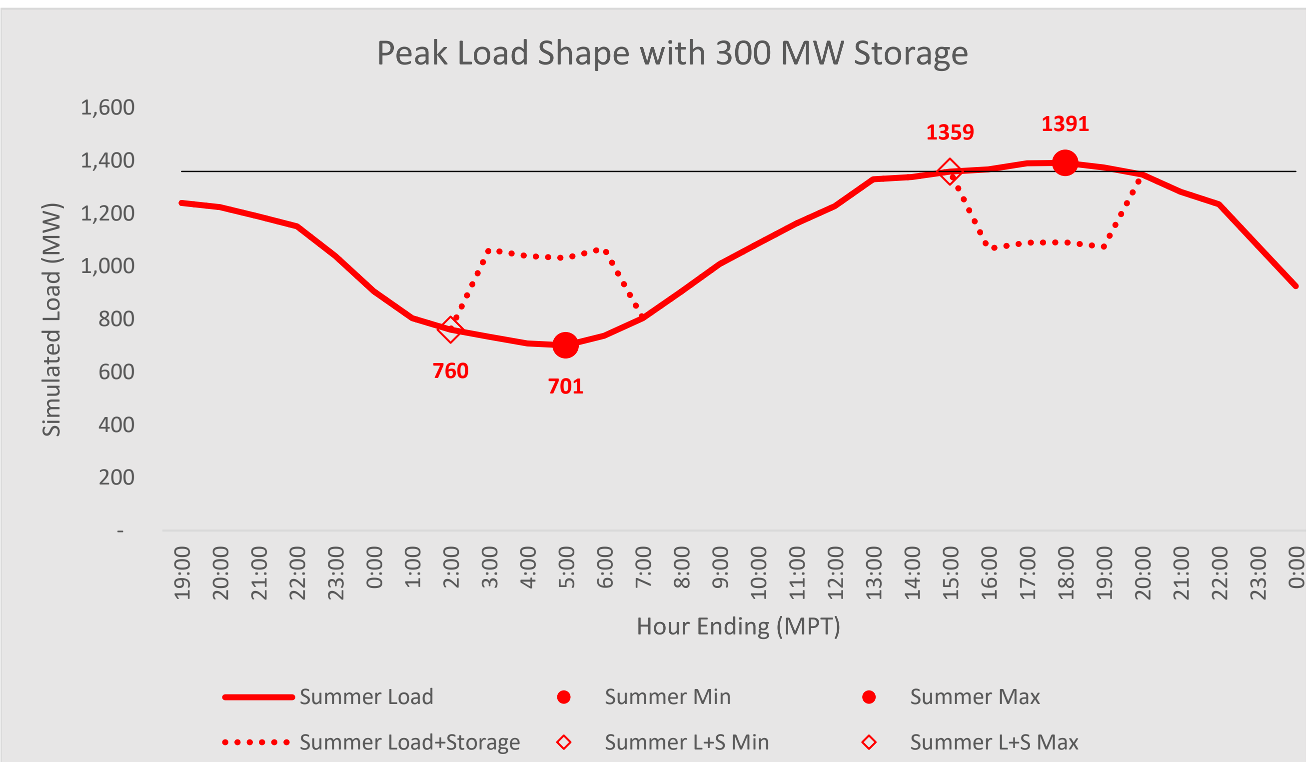
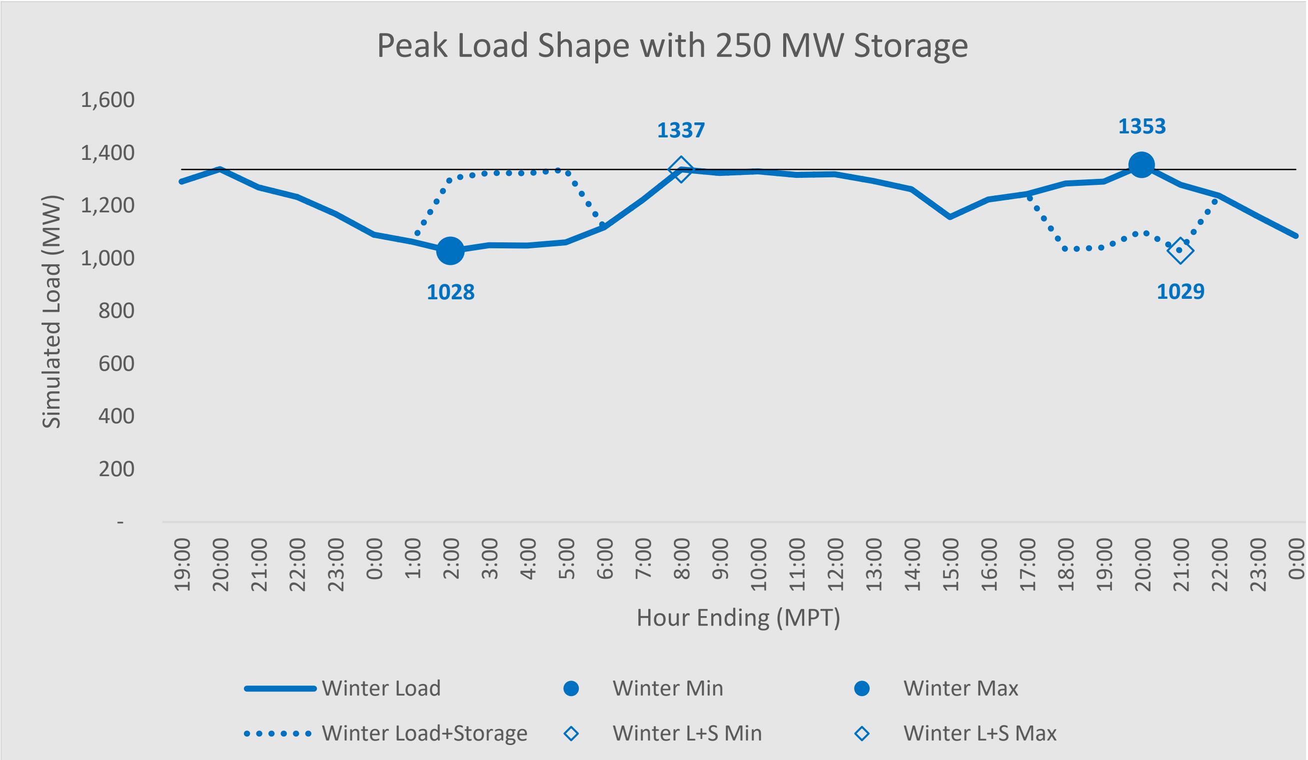


FIGURE 49: NORTHWESTERN'S PROJECTED SUMMER RETAIL PEAK LOAD SHAPE WITH 250 MW AND 300 MW, 4-HOUR BESS.



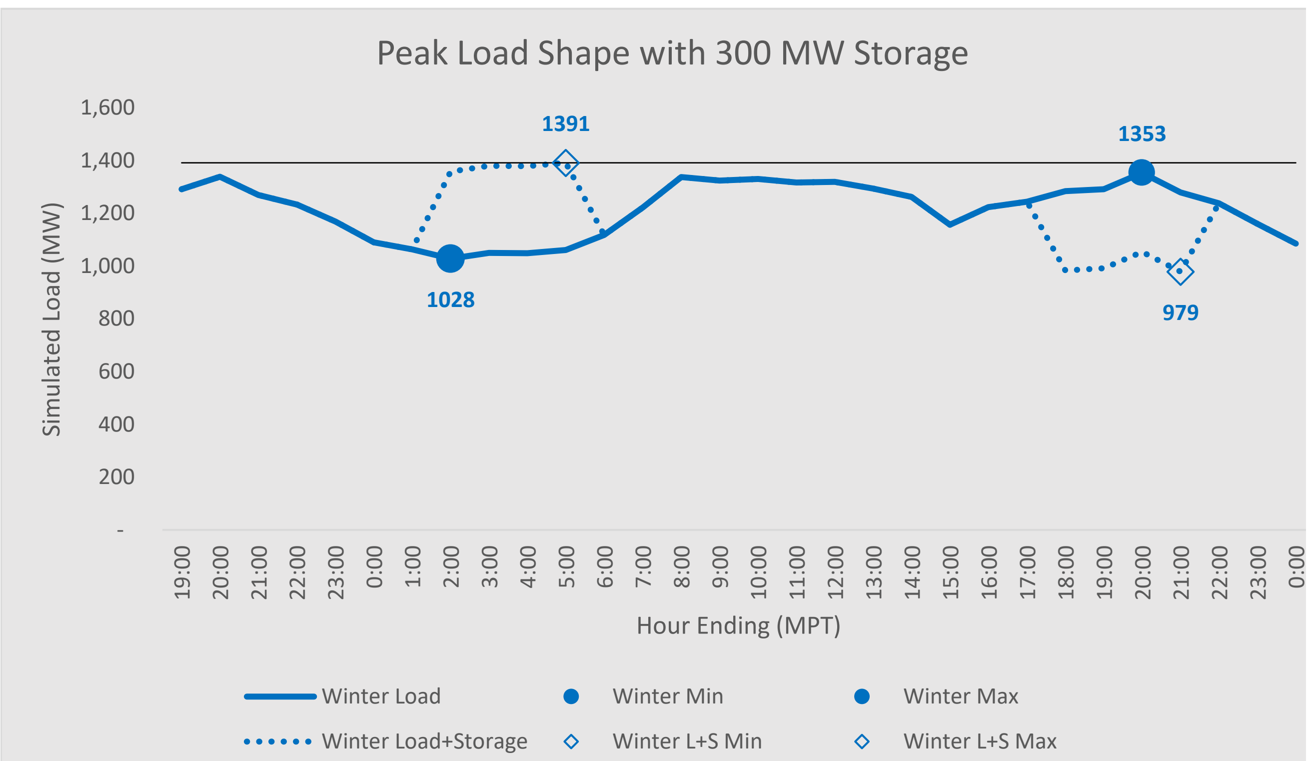


FIGURE 50: NORTHWESTERN'S PROJECTED WINTER RETAIL PEAK LOAD SHAPE WITH 250 MW AND 300 MW, 4-HOUR BESS.

The charging and discharging strategy for LDES is different than 4-hour BESS because LDES would not be required to charge in the same 24-hour period in which the resource is discharged. The LDES charging and discharging strategy goal would be to schedule enough charging hours during low demand periods to be ready to discharge for a multiday weather event that causes high system loading. The LDES charging hours may be short in duration, similar to 4-hour BESS, or the LDES charging hours may be continuous for multiple days if the system loading is low enough. Even though LDES would act as additional load during charging, that additional load would not create a new seasonal peak load, if properly scheduled, so it is assumed that the generation fleet and the transmission system could accommodate the charging condition. After the LDES is fully charged, it may sit idle for a period of time until the load demand starts to challenge the resource supply. As a multiday weather event approaches, the LDES project would have to be managed to spread out the discharging hours to try to cover the periods in which supply is most constrained. For example, if a 10 day weather event is forecasted to impact the load, then the 100-hour LDES may be managed to discharge for 10 hours of the highest load hours per day for those 10 days without requiring any additional charging hours during the same period. Each weather event will be somewhat unique along with different generation and transmission conditions that will influence the LDES operation. LDES would require continuous operational monitoring to optimally schedule charging and discharging periods.

ARS results that exclude four-hour duration BESS and LDES limits are discussed in Section 7.7.1.1.

7.1.5 Hybrid Candidate Resources

NorthWestern modeled four different hybrid projects in which either a 100 MW solar or 100 MW wind project was paired with either a 50 MW or 100 MW 4-hour BESS project. The hybrid project was constrained such that the BESS could only charge from renewable resources. This allows the hybrid project to avoid any intraday grid charging limitations discussed above. The output of the hybrid projects is limited to the size of the BESS. The expected book life of a hybrid candidate resource is limited to the BESS book life of 20 years. Hybrid projects that include a BESS paired with both wind and solar were not considered in this IRP.

7.1.6 Candidate Resource Cost Estimates

NorthWestern used the candidate resource capital costs, adjusted for tax credits and infrastructure costs, to create a partial revenue requirement (RR) for each candidate resource. The partial RR was then input to PowerSIMM's ARS module to model the least cost resource to fill a capacity deficit.

Candidate resource capital cost estimates are shown in Table 35 below, and are based on conceptual estimating, publicly available data, and attributes observed from actual project developments and RFP processes. The cost estimates typically consider proxy makes and models of technologies and site generic attributes, focused on the "inside-the-fence" project costs and do not include external costs such as electric, natural gas, and water supply system upgrades. NorthWestern retained Aion Energy, LLC, (Aion) to develop proxy candidate resources for use in the IRP. Aion's report is included in Appendix H. For more information on external costs, see Section 7.1.6.2 for electric transmission interconnection and network upgrades and Section 7.1.6.3 for fuel delivery infrastructure.

The capital and operating cost estimates represent typical utility-grade applications. Capital cost estimates for future years beyond 2025 were derived by escalating costs using the technology forecasts in the 2024 NREL Annual Technology Baseline (ATB). O&M costs are assumed to escalate at 2.5% per year consistent with the 2024 NREL ATB. Table 35 below lists the candidate resources modeled in ARS and the associated installed overnight and O&M costs in 2025 dollars.

Resource	Size (MW)	Storage (h)	Installed Overnight Cost (2025$/kW)	Fixed O&M (2025$/kW-year)
SC RICE	100	NA	$2,026	$23.56
SC Dual Fuel RICE	50	NA	$2,727	$41.71
SC CT - Aero	100	NA	$2,085	$18.44
SC CT - Dual Fuel Aero	50	NA	$2,379	$27.97
SC CT - F Class	200	NA	$1,817	$10.08
CCCT - Industrial 2x1	150	NA	$2,359	$17.27
CCCT - F Class 1x1	320	NA	$1,888	$9.43
Nuclear - SMR	320	NA	$11,015	$131.07
Solar PV	300	NA	$1,732	$26.26
Wind	300	NA	$1,871	$45.02
BESS - Li-Ion	50	4	$2,144	$31.75
BESS - Li-Ion	100	4	$2,071	$31.63
BESS - Li-Ion	100	8	$3,649	$58.28
PHES - Closed Loop	100	8	$4,800	$22.00
LDES - Iron-Air	50	100	$3,090	$19.58
Hybrid - Solar PV + BESS	50	4	$2,960	$43.27
Hybrid - Solar PV + BESS	100	4	$3,960	$58.99
Hybrid - Wind + BESS	50	4	$3,145	$66.64
Hybrid - Wind + BESS	100	4	$4,118	$82.40

TABLE 35: CANDIDATE RESOURCE CAPITAL AND O&M COSTS.

Table 36 below summarizes a cost comparison between IRP Overnight Costs vs. NREL ATB's 2024 Report. All resource cost assumptions can be found in Aion's report, which is included in Appendix H.

NREL ATB vs. IRP Overnight Cost Summary [2025$/KW]										
	Class 3 Wind [2025]	Class 7 Solar [2025]	4 hour Storage [2025]	8 hour Storage [2025]	Class 15 Pumped Storage [2025]	Hybrid Solar + BESS [2025]	Geo-thermal Flash [2025]	SMR – [2031*]	NG CT F Class [2025]	NG 2x1 CC [2025]
NREL Advanced	$1,571	$1,502	$1,437	$2,605	$5,105	$2,182	$5,171	$8,000	$1,255	$1,396
NREL Moderate	$1,598	$1,532	$1,796	$3,231	$5,210	$2,408	$5,278	$12,597	$1,255	$1,404
NREL Conservative	$1,667	$1,577	$2,297	$4,160	$5,210	$2,727	$5,427	$17,021	$1,255	$1,413
IRP Overnight Costs	$1,871	$1,732	$2,071	$3,649	$4,800	$2,960	$5,929	$12,899	$1,817	$1,888
% ATB Delta - Advanced	19%	15%	44%	40%	-6%	36%	15%	61%	45%	35%
% ATB Delta - Moderate	17%	13%	15%	13%	-8%	23%	12%	2%	45%	34%
% ATB Delta - Conservative	11%	9%	-11%	-14%	-9%	8%	8%	-32%	31%	25%
*SMR is not available until 2031 for NREL ATB Comparison										

TABLE 36: NREL ATB VS. IRP OVERNIGHT COSTS SUMMARY

Figure 51 below shows the installed overnight cost curves as they change over time. Note that the pumped hydro and SMR forward curves are excluded from this graph because those costs are higher than the rest of the candidate resources and make the graph difficult to read. More details can be found in Aion's report, which is included in Appendix H.

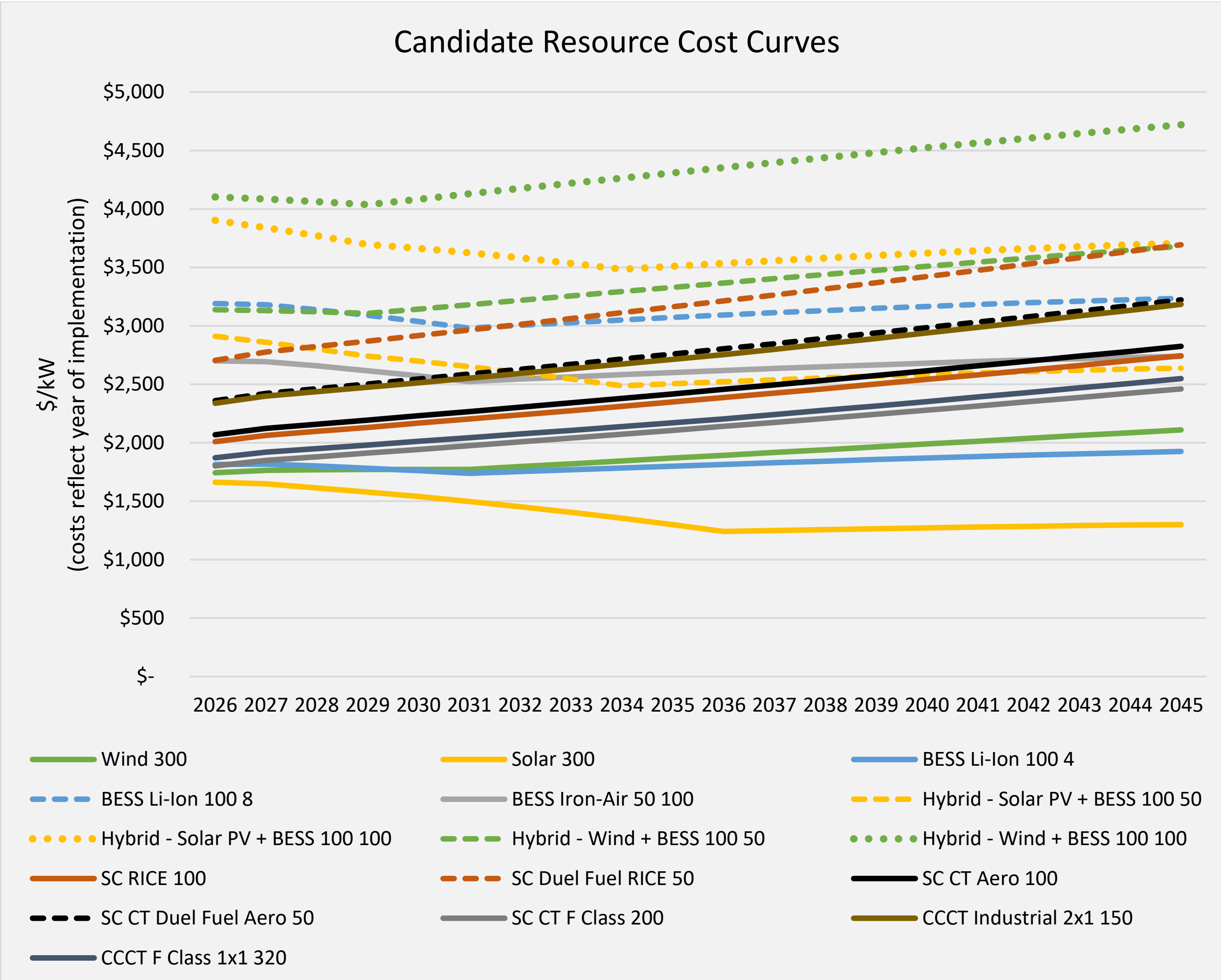


FIGURE 51: CANDIDATE RESOURCE COST CURVES.

7.1.6.1 Inflation Reduction Act Tax Credits

Although the 2022 IRA promoted renewable energy generation through production tax credits (PTC) and investment tax credits (ITC), it was modified by the Fiscal Year 2025 Reconciliation Bill. That 2025 legislation shortened tax credit eligibility for wind and solar resources but did not significantly impact energy storage and SMR resources. In addition, tariffs were implemented that will increase overall project expenses and could cause delays in construction. Figure 52 below shows the expected impacts of legislation and tariffs on resources costs.

Impacted by FY25 Reconciliation Bill (7/4/25)

	Solar PV	Wind	Li-ion Batteries	Geothermal	Nuclear	Thermal / CCS
Tax Credits	Final qualification year now 5 years earlier than previous minimum, and >10 years earlier than prior policy target year		Qualification preserved through 2032			45Q preserved, and 45X revision supports coal
Safe Harbor Provisions	Significant uncertainty present around ability of wind and solar to claim safe harbor, increasing risk of projects with 2029-2030 COD; Treasury guidance expected Q3/Q4 2025		Safe harbor timeline preserved and is incremental to tax credit phase-out timeline after 2032; Treasury guidance expected Q3/Q4 2025			No change
FEOC Impact	Compliance will look different across technologies and technologies more dependent on imports (solar, wind, li-ion batteries) are more exposed to FEOC risk, but novelty and severity of FEOC guidelines imposes near-term risk on all new projects seeking to claim tax credits					45Q risk is elevated but underlying technology is derisked
Depreciation	5-year MACRS preserved and 100% bonus depreciation restored			Bonus restored but heat pumps excluded from 5-year MACRS (legacy credits only)	5-year MACRS preserved and 100% bonus depreciation restored	45Q dynamics preserved but underlying technology unchanged
Tariffs	Significant risk, large impacts from multiple overlapping tariff policies	Difficult to de-risk but impacts likely to be small than for solar	Highest expected impact for any technology (high impact and high certainty)	Commodity risk during construction is minor, may depend on drilling equipment sources	Nuclear fuel (commodity risk) currently exempted	Little to no commodity risk during construction, and domestic supply chain is ramping up

FIGURE 52: E3'S EXPECTED IMPACT ON RESOURCE COST.[57]

The 2025 legislation also included more stringent rules prohibiting tax credits to taxpayers with a relationship with Foreign Entities of Concern (FEOCs) labeled as Prohibited Foreign Entities (PFE) under the new bill. For purpose of this IRP, NorthWestern assumed that the resources did not fall under this prohibition.

Section 45Q provides a federal tax credit for capturing and permanently storing carbon emissions, which can improve the economics of carbon-capture retrofits on existing fossil-fuel generation. While the credit is meaningful, the feasibility of carbon-capture technology is dependent on plant configuration, access to suitable geologic storage or transport infrastructure, and overall implementation and ongoing costs. For this IRP, NorthWestern did not model or evaluate the costs and solutions associated with carbon-capture technologies.

NorthWestern included PTCs and ITCs in its calculation of the partial RRs, where applicable. For the BESS resources, NorthWestern calculated the partial RR using a 30% ITC based upon the IRA's base credit of 6% that increases to 30%, assuming that prevailing wage and apprenticeship requirements are met. Due to income tax considerations, NorthWestern may transfer the credits to unrelated third parties, and has factored a discount of 10% into the computations.

NorthWestern evaluated the SMR partial RRs using the ITC and the PTC separately to understand which tax credit provided a lower overall cost. The NPV was compared between the two different tax credit assumptions over the planning period. NorthWestern's analysis showed that the PTCs were more

[57] https://www.ethree.com/wp-content/uploads/2025/07/2025.07_E3-RECOST.pdf

advantageous for SMRs than ITCs. NorthWestern calculated the partial RR using a PTC of $0.03 per kilowatt-hour, assuming that prevailing wage and apprenticeship requirements are met. Due to income tax considerations, NorthWestern may transfer the credits to unrelated third parties and has factored a discount of 10% into the computations.

7.1.6.2 Electric Transmission Interconnection and Network Upgrades

When analyzing the costs of candidate resources, NorthWestern considered the estimated costs of transmission system interconnection and network upgrades. Transmission system interconnection, or point of interconnection (POI) costs, include substation infrastructure and components including circuit breakers, air break switches, relaying equipment, etc. Estimating these costs can be challenging as they largely depend on the interconnection location and other generation projects considered in the interconnection study. NorthWestern estimated these costs by reviewing publicly available system impact study reports on NorthWestern's OASIS site[58] from newly proposed projects that applied for large generator interconnection from 2022 to June 2024. The technologies that made up these interconnection requests included stand-alone BESS, wind, solar, and solar hybrid projects. The reports for these projects are the most recent information available as the generation interconnection queue has been closed since June 10, 2024, while NorthWestern works to transition from a serial study process to a cluster study process as required by FERC Order 2023. Table 37 shows the interconnection and network upgrade cost estimates reflected in 2026 dollars. The interconnection and network upgrade cost estimates from the reviewed reports were chosen as the higher of the mean or the median. The POI costs were assumed to be 230 kV interconnection level, and the network upgrade costs were calculated on a dollar per megawatt basis. These cost estimates were used to calculate a partial RR, and the total interconnection costs were added to the capital cost of all candidate resources in the ARS process. The transmission interconnection and network upgrade costs were based on the project's nameplate size as this is the maximum injectable power. These additional costs are included in the RR for each resource.

Electric Transmission Related Cost Estimates	Estimate (2026$)
230 kV POI ($)	$9,226,207
Network Upgrades ($/MW Nameplate)	$1,291,137

TABLE 37: ESTIMATES OF 230 KV POI INTERCONNECTION AND NETWORK UPGRADE COSTS.

7.1.6.3 Fuel Delivery Infrastructure

NorthWestern estimated the cost of fuel delivery infrastructure for the candidate resources. Fuel delivery can come in the form of either electric infrastructure for grid-charged BESS or natural gas infrastructure for natural gas-fueled generation.

Electric infrastructure for fuel delivery of grid-charged BESS is highly dependent on location as well as system load. For example, the upgrades required for grid-charging are significantly less when BESS are charging during off-peak hours, such as in the middle of the night or during mid-day solar overgeneration. Charging BESS during on-peak hours is impractical as that is the time in which BESS would be used to serve the load. For this reason, it is assumed that all grid-charged BESS can charge during off-peak times and that this charging strategy will not require additional electric transmission system upgrades. See Section 7.1.4 for NorthWestern's grid charging analysis that limits the amount of grid-charged BESS.

Pipeline infrastructure for firm fuel delivery of natural gas generation faces the same challenges that come with estimating electric transmission system interconnection and network upgrade costs; the

[58] https://www.oasis.oati.com/nwmt/

natural gas infrastructure upgrades depend on location as well as other demands assumed in the study. NorthWestern used high-level upgrade estimates for firm natural gas fuel delivery to enable 150 MW natural gas facilities at two different locations on the system, assuming all scheduled gas upgrades are completed as planned and gas availability has not changed from the time of the original estimate. Upgrades for firm delivery from Stillwater County were estimated to cost approximately $85.7M and upgrades for firm delivery from Broadwater County were estimated to cost approximately $78.6M. These estimates were used to calculate a dollar per megawatt partial revenue requirement estimate required for firm fuel delivery of natural gas, shown in Table 38. The additional costs of fuel delivery were calculated for each natural gas candidate resource, except for the single dual-fueled project. The partial RR for the capital cost of the natural gas generation project plus the partial RR of the natural gas firm fuel infrastructure costs were included as an overall cost input to the ARS module. This means that when ARS is considering natural gas generation as the least cost resource to fill a capacity need, ARS will consider the total cost of the natural gas generation project, an estimate of the firm fuel delivery infrastructure, if applicable, and the electric interconnection costs.

Natural Gas Transmission Cost Estimate	Estimate (2026$)
Gas Transmission Upgrades ($/MW Nameplate)	$547,611

TABLE 38: ESTIMATE OF GAS TRANSMISSION UPGRADES FOR MODELING

7.2 Resource Accreditation

The nameplate capacity of a generator represents its maximum output under ideal conditions—such as ample fuel, wind, or sunlight. However, generators rarely operate at full nameplate capacity except under specific circumstances. From a resource planning and adequacy standpoint, nameplate capacity does not accurately reflect a resource's ability to serve load during critical periods. A more meaningful measure is accredited capacity, which reflects a resource's actual, demonstrated ability to deliver power during peak demand, based on historical performance. Thermal generators typically have high accredited capacities due to their reliability during peak hours, whereas wind and solar resources tend to have lower accreditations, given the variability and unpredictability of their energy inputs.

NorthWestern relies on the resource accreditations and PRMs that are used in the WRAP FS for long-term planning. The WRAP methodology for resource accreditation differs by fuel type including ELCC for VERs and Energy Storage Resources (ESR), Equivalent Forced Outage Factors (EFOF) for traditional generators that use conventional fuels such as coal or natural gas, and historical performance for ROR hydro. Historical performance during capacity critical hours (CCH) is a component in the accreditation methodology for VERs, traditional generators, and ROR hydro. CCH are those hours during which the net regional capacity need for the WRAP Region is expected to be above the 95th percentile. Using these different accreditation methods, a Qualifying Capacity Contribution (QCC) is determined for each resource for each binding season month. A resource's QCC is the amount of capacity in units of megawatts that qualifies to help satisfy a FS capacity requirement, i.e. accredited capacity. More information about the WRAP accreditation methodologies can be found in the WRAP Tariff[59] and the WRAP business practice manuals (BPM).[60]

The PRM is defined as the difference between the total resource accredited capacity and the peak load forecast, all divided by the peak load forecast[61].[60]

[59] WRAP_Tariff_Effective_3.16.25.pdf
[60] https://www.westernpowerpool.org/resources/wrap_bpms/
[61] https://www.westernpowerpool.org/resources/versioned/bpm-102-forward-showing-reliability-metrics (version 1.1)

The WRAP defines the summer season as June 1 through September 15 and the winter season as November 1 through March 15.[59] NorthWestern assumes the full month of September for the summer season and the full month of March for the winter season for simplicity in the model. Note that the WRAP PRM Task Force is proposing to change the winter season as November 20 to February 28/29, but that change has not been finalized at this time.

Specific information on the methodologies for calculating resource QCCs can be found in the WRAP 105 Qualifying Resources BPM.[62] The QCC for VER resources, including wind and solar, are calculated for each month of the binding seasons. The ELCC study will consist of analyses utilizing loss of load expectation (LOLE) metrics to determine the capacity provided by the VERs being analyzed. The LOLE benchmark metric to be used in the ELCC accreditation study will be a one-day event in 10-year threshold. Specific resource zones will be used in the ELCC study. The WRAP VER zones for solar and wind are shown in Figure 53. At least three years of hourly historical output will be used to calculate the QCC of VERs. Curtailed energy, if known, will be added to the historical output for purposes of the ELCC analysis. It is understood that as more VERs are added to a system, the capacity value provided by all similar VERs will decrease as a function of the nameplate value of those resources.

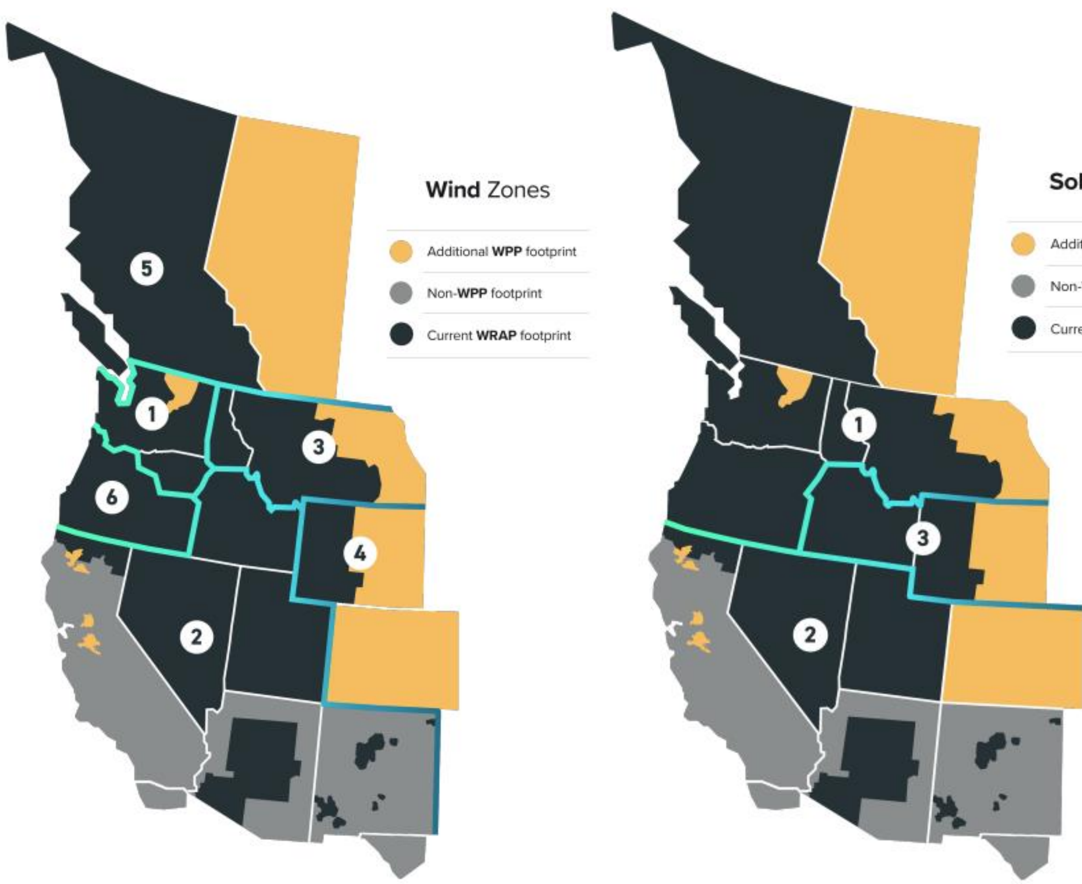


FIGURE 53: WRAP WIND AND SOLAR VER ZONES.

[62] https://www.westernpowerpool.org/resources/versioned/bpm-105-qualifying-resources (version 1.1)

The QCC for ESR such as BESS or pumped hydro will use the ELCC method similar to the VERs processes. Only storage devices with at least 4 hours of storage will be evaluated in the ELCC study. The QCC for 4-hour batteries will be scaled up or down for ESRs that have more or less energy storage capability. ESRs with eight-hour or longer durations are considered LDES, which use the same accreditation methodology as thermal resources.

WRAP calculates the QCC for hybrid resources by applying the appropriate methodology to each component of the facility, summing the two QCC values, and capping the total at the interconnection limit, i.e. “the sum of parts” method. For example, an ESR paired with a wind facility would use both the ESR ELCC methodology and the wind QCC, which will be determined according to the wind ELCC methodology. The QCCs for each component will be summed and capped, if needed, to the interconnection capacity. This sum of parts methodology assumes that the BESS can be grid charged. There is no WRAP accreditation methodology for BESS that are charged by the VER behind the meter. Because of this, NorthWestern performed its own loss of load probability (LOLP) studies to determine an appropriate accreditation for hybrid candidate resources.

The QCC for thermal units including coal, natural gas, nuclear, and LDES is calculated with a performance-based methodology. The methodology uses NERC GADS data and a seasonal EFOF equation. Six years of data are used for the calculation. The worst performing year is removed, allowing for a five-year average with equal weighting. Only forced outages or derates occurring during CCHs are used to calculate QCC. Outages during hours that are not deemed to be capacity critical will not negatively impact QCC. For new units that have been in service less than six years, class average data are used for accreditation.

For ROR resources, the QCC is set to the monthly average performance of the project during CCHs over the 10-year historical period.

WRAP calculates QCCs for capacity contracts, including NorthWestern’s Heartland and Powerex contracts. In order for a contract to be eligible to meet a participant’s FS capacity requirement, the participant is required to complete a Joint Capacity Attestation Form (JCAF). The JCAF is required to be executed by both the participant and the other parties to the contract for which QCC is being claimed. The intent of the JCAF is to ensure that a double counting of capacity does not occur.[63]

[63] https://www.westernpowerpool.org/resources/versioned/bpm-106-qualifying-contracts

As stated above, NorthWestern relies on the resource accreditations and PRMs in the WRAP FS for long-term planning. NorthWestern chooses the monthly PRM that results in the highest load plus PRM for a particular season. For resources that are accredited on a monthly basis including VER, ROR, and ESR, NorthWestern chooses the monthly QCC value for each resource that results in the lowest total portfolio accreditation for a particular season. For example, Table 39 below shows NorthWestern's 2025 Summer FS results for load, PRM, and total portfolio capacity. In this example, NorthWestern chooses the 16.1% PRM from the month of August because this results in the highest monthly load plus PRM, i.e. 1403 MW. For resource accreditation, NorthWestern chooses the QCCs calculated for the month of August because this results in the least amount of capacity in the portfolio, i.e. 1404 MW. While this example shows that both the PRM and the resource accreditations are chosen from the month of August, it is possible that different months are selected for the PRM and the resource accreditation. This practice of choosing the PRM that results in the highest load plus PRM and the monthly QCCs that results in the lowest total accredited capacity portfolio is a conservative approach. NorthWestern believes this approach is reasonable for long-term planning absent a long-term resource accreditation program for the region, noting that future portfolio capacity results may vary depending on which month produces the lowest accredited resource stack and the corresponding planning reserve margin.

	June	July	August	September
Monthly Load	1,090	1,224	1,208	1,083
PRM	26.2%	14.5%	16.1%	14.2%
Monthly Load plus PRM	1,375	1,401	1,403	1,236
Total Portfolio Capacity i.e. sum of QCC (MW)	1,519	1,423	1,404	1,427

TABLE 39: 2025 SUMMER FS TOTAL PORTFOLIO CAPACITY.

7.2.1 Existing Resources

NorthWestern's existing portfolio is described below in terms of maximum delivered capacity and summer and winter accredited capacity, or QCC, for the 2026 summer and 2026-2027 winter seasons in Table 40, Table 41, Table 42, Table 43, and Table 44 for thermal, hydro, wind, solar[64], and short-term capacity contracts (STCC), respectively. Figure 54 summarizes the total capacity of NorthWestern's portfolio in terms of maximum delivered and capacity accreditation. Note that Table 40 and Figure 54 reflect NorthWestern's acquisition of Avista's 222 MW share of Colstrip on January 1, 2026.

Resource	Fuel	Maximum Delivered Capacity (MW)	Summer WRAP Accredited Capacity (MW)	Summer WRAP Accreditation (%)	Winter WRAP Accredited Capacity (MW)	Winter WRAP Accreditation (%)
Basin Creek	Natural Gas	52	50.0	96.2	51.5	99.1
DGGS	Natural Gas	150	147.8	98.5	147.7	98.5
YCGS	Natural Gas	172	158.6	92.2	163.7	95.2
Natural Gas Subtotal		**374**	**356**		**363**	
Colstrip	Coal	444	436.4	98.3	441.8	99.5
CELP	Waste Coal	40.5	30.8	76.0	33.0	81.5
YELP	Petroleum Coke	65	51.4	79.1	55.2	84.9
Total		**924**	**875**	**94.7%**	**893**	**96.7%**

TABLE 40: NORTHWESTERN'S THERMAL RESOURCE ACCREDITATIONS.

64 NorthWestern's owned resource, Bozeman Solar, was not included in the model due to its size.

Resource	Maximum Delivered Capacity (MW)	Summer WRAP Accredited Capacity (MW)	Summer WRAP Accreditation (%)	Winter WRAP Accredited Capacity (MW)	Winter WRAP Accreditation (%)
Thompson Falls	94	62.1	66.1	69.0	73.4
Cochrane	64	57.8	90.0	48.9[65]	76.1
Ryan	72	58.0	80.6	55.2	76.7
Rainbow	64	39.5	61.8	41.8	65.3
Holter	54	29.6	54.4	37.7[65]	69.3
Morony	49	29.1	59.3	29.5	60.2
Black Eagle	25	14.1	56.4	12.2	48.8
Hauser	22	15.6	69.3	14.1[65]	63.0
Mystic	12	11.7	97.5	9.1	75.8
Madison	12	5.5	45.8	5.5	45.8
Turnbull Hydro LLC	13	8.1	62.0	0.9	7.1
Flint Creek Hydroelectric LLC(QF)	2	1.8	89.8	1.1	55.7
Hydrodynamics Inc (South Dry Creek)(QF)	2	1.5	75.6	0.0	0.0
Wisconsin Creek LTD LC(QF)	0.5	0.2	46.7	0.2	43.2
Boulder Hydro Limited Partnership(QF)	0.5	0.2	46.7	0.2	43.2
Lower South Fork LLC(QF)	0.5	0.2	46.7	0.0	0.0
Ross Creek Hydro LC(QF)	0.5	0.2	46.7	0.2	43.2
Gerald Ohs (Pony Generating Station)(QF)	0.4	0.2	46.7	0.0	0.0
Donald Fred Jenni (Hanover Hydro)(QF)	0.2	0.1	46.7	0.1	43.2
Hydrodynamics Inc (Strawberry Creek)(QF)	0.3	0.1	46.7	0.0	0.0
Total	**489**	**336**	**68.7%**	**326**	**66.7%**

TABLE 41: NORTHWESTERN'S HYDRO RESOURCE ACCREDITATIONS.

[65] Hydro Generation upgrades were assumed for the 2026-2027 Winter Season as shown in Section 5.5.1.

Resource	Maximum Delivered Capacity (MW)	Summer Accredited Capacity (MW)	Summer Accreditation (%)	Winter Accredited Capacity (MW)	Winter Accreditation (%)
Judith Gap Energy LLC	135	24.4	18.0	0.0[66]	0.0
Stillwater Wind LLC (WKN) (QF)	80	16.1	20.2	20.2	25.3
South Peak Wind LLC (QF)	80	17.0	21.2	18.0	22.5
Spion Kop Wind	40	6.4	16.0	8.8	22.1
Greenfield Wind LLC (QF)	25	5.3	21.3	6.3	25.2
Big Timber Wind LLC (Greycliff) (QF)	25	5.3	21.3	6.7	26.6
Two Dot Wind Farm	11	2.0	17.5	2.9	25.6
Fairfield Wind LLC (Greenbacker) (QF)	10	2.2	22.3	2.2	22.2
Musselshell Wind Project LLC (QF)	10	1.8	18.3	1.5	14.7
Musselshell Wind Project Two LLC (QF)	10	2.4	23.8	1.8	18.0
Gordon Butte Wind LLC (QF)	9.6	2.2	23.3	3.3	34.0
71 Ranch LP (QF)	2.7	0.6	23.5	0.8	30.8
DA Wind Investors LLC (QF)	2.7	0.5	19.0	0.8	31.1
Oversight Resources LLC (QF)	2.7	0.6	22.2	0.6	22.7
Two Dot Wind LLC (Broadview East Wind) (QF)	1.6	0.3	17.5	0.4	25.6
Total	**446**	**87**	**19.6%**	**74**	**23.9%**

TABLE 42: NORTHWESTERN'S WIND RESOURCE ACCREDITATIONS.

Resource	Maximum Delivered Capacity (MW)	Summer Accredited Capacity (MW)	Summer Accreditation (%)	Winter Accredited Capacity (MW)	Winter Accreditation (%)
Green Meadow Solar LLC (QF)	3.0	3.0	100	0.1	4.7
South Mills Solar 1 LLC (QF)	3.0	3.0	100	0.2	6.2
Black Eagle Solar LLC (QF)	3.0	3.0	100	0.1	4.6
Great Divide Solar LLC (QF)	3.0	3.0	100	0.2	6.2
Magpie Solar LLC (QF)	3.0	3.0	100	0.1	4.5
River Bend Solar LLC (QF)	2.0	2.0	100	0.1	5.9
MT Sun LLC (QF)	80.0	22.8	28.5	8.1	10.1
Apex Solar LLC (QF)	80.0	34.4	43.0	5.3	6.6
Total	**177**	**74**	**41.9%**	**14**	**8.1%**

TABLE 43: NORTHWESTERN'S SOLAR RESOURCE ACCREDITATIONS.

Resource	Maximum Delivered Capacity (MW)	Summer Accredited Capacity (MW)	Summer Accreditation (%)	Winter Accredited Capacity (MW)	Winter Accreditation (%)
Powerex	100	100	100	100	100
Heartland	150	150	100	150	100
Total	**250**	**250**	**100%**	**250**	**100%**

TABLE 44: NORTHWESTERN'S STCC RESOURCE ACCREDITATIONS.

66 Judith Gap's PPA expiration date is 12/31/2026. Judith Gap's capacity will contribute to the November and December 2026 monthly resource portfolio, but, on a seasonal basis for winter 2026-2027, it is considered to contribute 0 MW because it will be unavailable for January, February, and March 2027. Judith Gap's max delivered capacity was excluded for calculating the Total Winter Accreditation of wind resources.

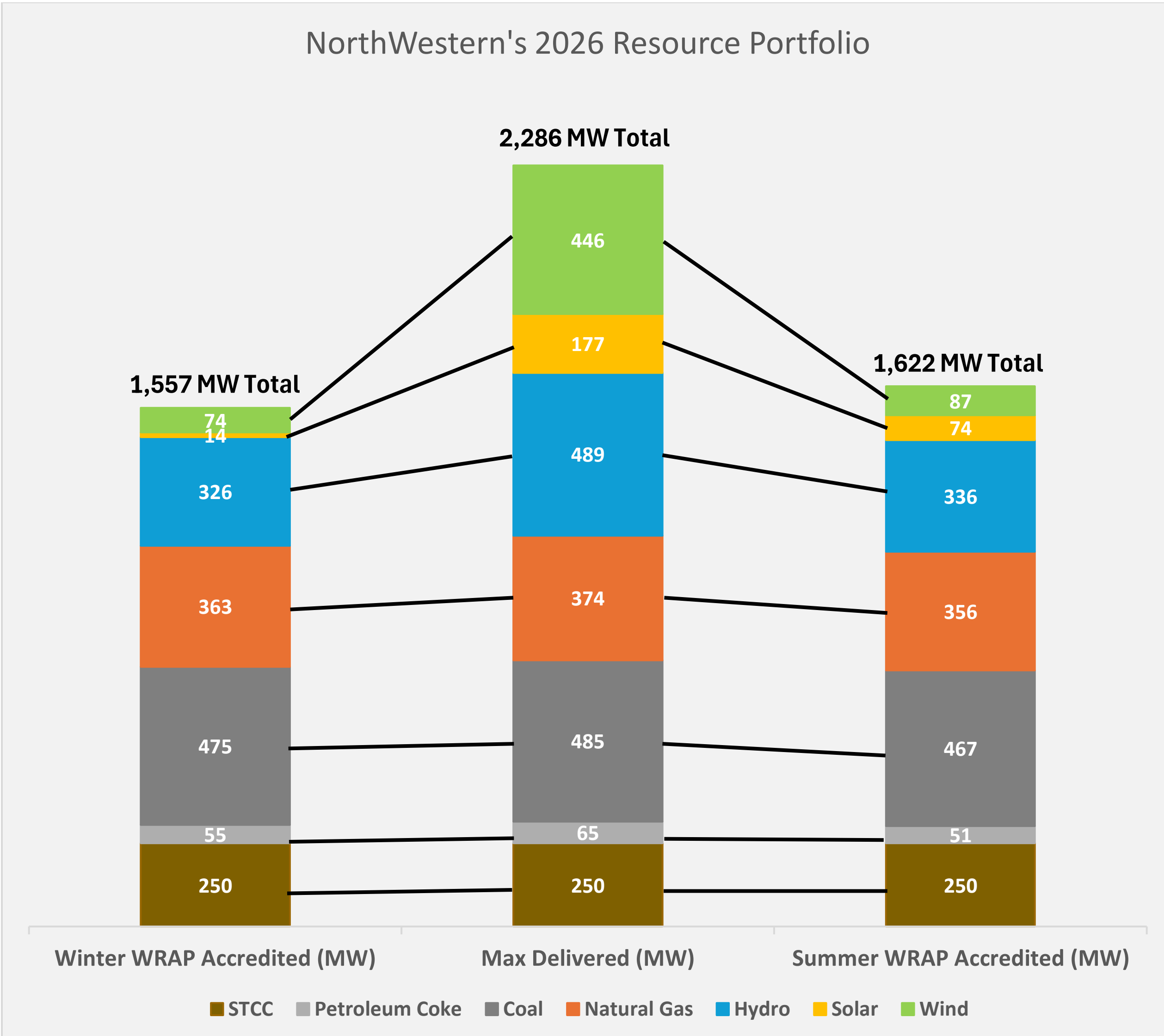


FIGURE 54: TOTAL CAPACITY OF NORTHWESTERN'S RESOURCE PORTFOLIO IN TERMS OF MAXIMUM DELIVERED AND ACCREDITED CAPACITY.

Table 45 lists the effective forced outage rates (EFOR) that were modeled for the existing thermal resources and STCC. The EFORs for STCC were modeled as zero because the capacity contracts do not represent single resources, necessarily; rather, they represent a fleet of resources that result in the contracted capacity, which effectively makes the EFOR zero. EFORs are not modeled for hydro, wind, or solar resources as PowerSIMM uses the historical output to determine the simulated production.

Resource	EFOR (%)
Basin Creek	3.22
DGGS	4.98
YCGS	3.22
Colstrip	[redacted]
CELP	4.36
YELP	0.92
Powerex	0
Heartland	0

TABLE 45: EFORS OF NORTHWESTERN'S EXISTING THERMAL AND STCC RESOURCES.

7.2.2 Candidate Resources

Accredited capacities for candidate resources were assumed using NorthWestern's existing portfolio, if available. The accredited capacity of any CT facility was derived from DGGS, and the accredited capacity of any RICE facility was derived from a weighted average of Basin Creek and YCGS. The accredited capacity of wind and solar facilities were derived from the weighted average of similar technology in NorthWestern's portfolio. The accredited capacity of four-hour BESS was derived as the minimum of accreditation of the winter and summer season as determined by WRAP. The accredited capacities of pumped hydro, eight-hour and 100-hour BESS were assumed to be 100% for both summer and winter seasons assuming they contain enough stored energy to deliver during a peak event. The accredited capacity of SMR was estimated as the minimum of CT, RICE, and Colstrip for each season. This approach is reasonable as an SMR is a dispatchable resource similar to the existing thermal resources. Finally, the hybrid wind and hybrid solar candidate resources were accredited using a standalone LOLP study using NorthWestern's existing resource and load portfolio. As discussed in Section 7.2 above, this accreditation method is unique compared to all other candidate resources, which are accredited according to the regional WRAP study methodologies. The candidate resource capacity accreditations are described below in Table 46. While NorthWestern is using static QCCs in this IRP, saturation curves, or declining accredited capacity curves, may be applied to VERs and energy storage in the future to better reflect the diminishing returns of incremental resources.[67]

Candidate Resource	Summer Accredited Capacity (MW)	Summer Accreditation (%)	Winter Accredited Capacity (MW)	Winter Accreditation (%)
RICE 100 MW	96.1	96.1	99.2	99.2
Aero 100 MW	98.5	98.5	98.5	98.5
Dual Fuel Aero 50 MW	49.3	98.5	49.3	98.5
Frame CT 200 MW	197.0	98.5	197.0	98.5
CCCT 150 MW	147.8	98.5	147.8	98.5
CCCT 320 MW	315.2	98.5	315.2	98.5
Nuclear SMR 320 MW	307.5	96.1	315.2	98.5
Solar 300 MW	125.7	41.9	24.3	8.1
Wind 300 MW	58.5	19.6	73.5	24.5
BESS Li-ion 50 MW, 4h	38.6	77.2	41.1	82.1
BESS Li-ion 100 MW, 4h	77.2	77.2	82.1	82.1
BESS Li-ion 100 MW, 8h	100.0	100	100.0	100
Pumped Hydro 100 MW, 8h	100.0	100	100.0	100
Iron Air 50 MW, 100h	50.0	100	50.0	100
Solar 100 MW, BESS 50 MW 4h	26.1	52.2	13.8	27.5
Solar 100 MW, BESS 100 MW 4h	47.6	47.6	10.6	10.6
Wind 100 MW, BESS 50 MW 4h	5.7	11.4	15.0	29.9
Wind 100 MW, BESS 100 MW 4h	26.3	26.3	50.1	50.2

TABLE 46: CANDIDATE RESOURCE CAPACITY ACCREDITATIONS.

[67] https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf

The annual average accreditation can be calculated as the weighted average of four-month summer accreditation and the five-month winter accreditation. Using the annual average accreditation, Table 35 can be recreated to show the installed overnight cost per accredited capacity, rather than a nameplate capacity basis. Table 47 below shows the installed overnight cost per accredited capacity of all candidate resources. Typically, candidate resources with low annual accreditation have higher installed overnight costs on an accredited capacity basis than candidate resources with higher annual accreditation. Table 47 shows the 200 MW SC CT F Class natural gas resources is the least cost resource per accredited capacity.

Resource	Size (MW)	Storage (h)	Installed Overnight Cost (2025$/$kW_{acc}$)	Rank (1=least cost)	Dispatchability Characteristic
SC CT - F Class	200	NA	$1,845	1	Dispatchable
CCCT - F Class 1x1	320	NA	$1,917	2	Dispatchable
SC RICE	100	NA	$2,071	3	Dispatchable
SC CT - Aero	100	NA	$2,117	4	Dispatchable
CCCT - Industrial 2x1	150	NA	$2,395	5	Dispatchable
SC CT - Dual Fuel Aero	50	NA	$2,415	6	Dispatchable
BESS - Li-Ion	100	4	$2,591	7	Dispatchable
BESS - Li-Ion	50	4	$2,683	8	Dispatchable
SC Dual Fuel RICE	50	NA	$2,788	9	Dispatchable
LDES - Iron-Air	50	100	$3,090	10	Dispatchable
BESS - Li-Ion	100	8	$3,649	11	Dispatchable
PHES - Closed Loop	100	8	$4,800	12	Dispatchable
Solar PV	300	NA	$7,491	13	Variable
Hybrid - Solar PV + BESS	50	4	$7,693	14	Hybrid
Wind	300	NA	$8,382	15	Variable
Hybrid - Wind + BESS	100	4	$10,405	16	Hybrid
Nuclear - SMR	320	NA	$11,305	17	Dispatchable
Hybrid - Wind + BESS	50	4	$14,508	18	Hybrid
Hybrid - Solar PV + BESS	100	4	$14,643	19	Hybrid

TABLE 47: CANDIDATE RESOURCE CAPITAL AND O&M COSTS.

7.3 Capacity Forecast

Using the accreditation and planning reserve margin methodology in section 7.2, NorthWestern's summer and winter capacity forecasts are shown below in Figure 55 and Figure 56, respectively. With the acquisition of the Avista 222 MW share of Colstrip, NorthWestern is capacity long through the summer of 2027. Starting in the winter season of 2027-2028, NorthWestern shows a need for capacity driven by a retirement of the 100 MW Powerex capacity contract. A summer capacity need starts in 2032 after the 100 MW Heartland contract expires. Because the winter season spans November and December of a particular year and the January, February, and March of the following year, Figure 56 shows NorthWestern's winter capacity position being significantly short in 2042 due to the retirement of Colstrip on December 31, 2042.

As shown in Figure 55 and Figure 56 below, NorthWestern uses a short-term load forecast through 2027 and a long-term forecast beginning in 2028. Years 2026 and 2027 use the WRAP load forecast methodology of the seasonal P50 peak load[68] to comply with the FS requirement. From 2028 through 2045, NorthWestern uses an internally developed long-term load forecast. This forecast is explained in Section 4.1.3. The WRAP FS program focuses on the next operating season while NorthWestern's long-term load forecast is a better reflection of load growth for medium- and long-term capacity planning. The two different load forecast methodologies, the WRAP load forecast methodology for 2026 and 2027 and NorthWestern's internal long-term load forecast for 2028 through 2045, explains the load forecast step change from 2027 to 2028. NorthWestern has not submitted a modification to WRAP related to the P50 Peak Load Forecast methodology. The source data for the seasonal capacity forecasts and the associated load forecasts is provided in Appendix H.

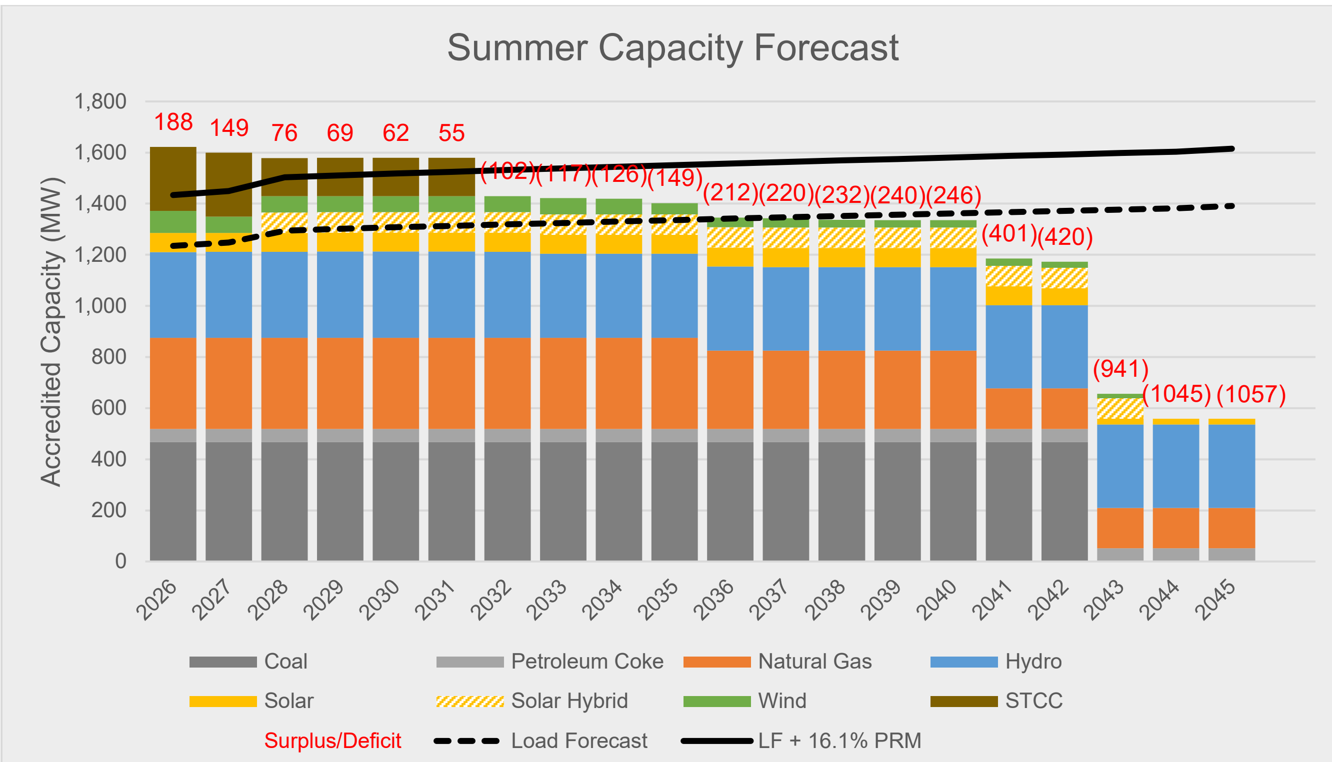


FIGURE 55: NORTHWESTERN'S SUMMER CAPACITY FORECAST.

68 https://www.westernpowerpool.org/resources/versioned/bpm-103-forward-showing-capacity-requirements

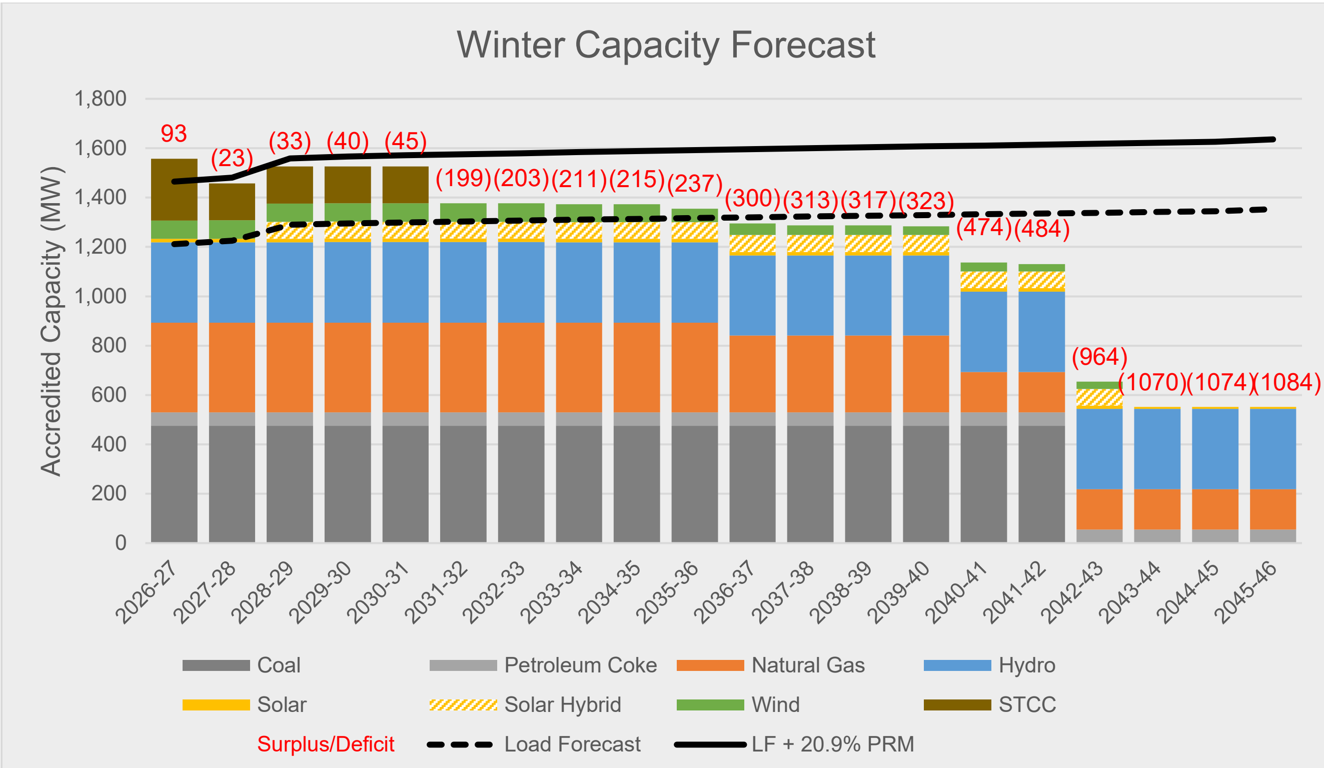


FIGURE 56: NORTHWESTERN'S WINTER CAPACITY FORECAST.

The data that makes up Figure 55 and Figure 56 can be used to show seasonal capacity retirements & PPA expirations by fuel type. Figure 57 and Figure 58 show the summer and winter capacity retirements & PPA expirations, respectively. The largest reductions to the seasonal capacity forecasts in the planning horizon are caused by either the retirements or the PPA expirations of dispatchable fuel types including the STCC (brown), natural gas (orange), coal (grey), and Trident's solar-hybrid project. While there are retirements and PPA expirations from solar, wind, and hydro resources, their impacts to the seasonal capacity forecasts are relatively small due to their lower capacity accreditations.

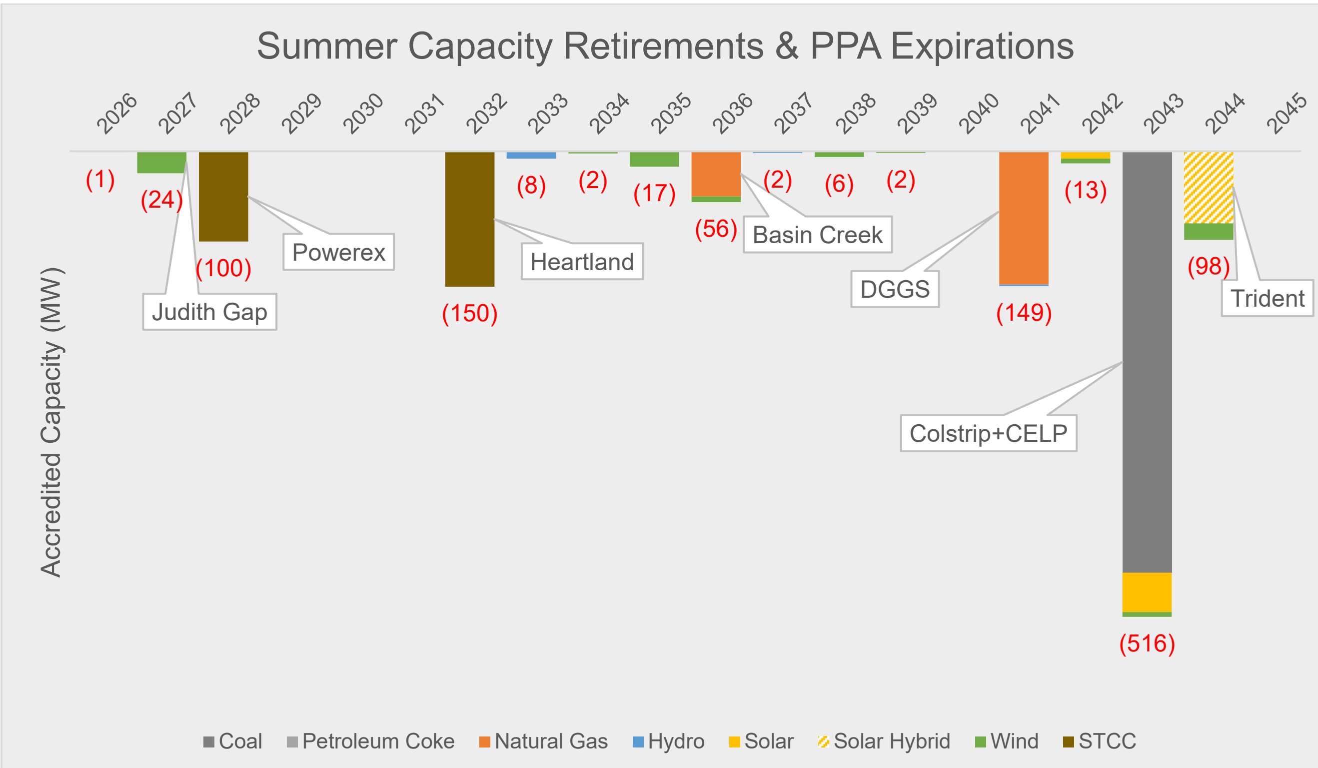


FIGURE 57: SUMMER CAPACITY RETIREMENTS.

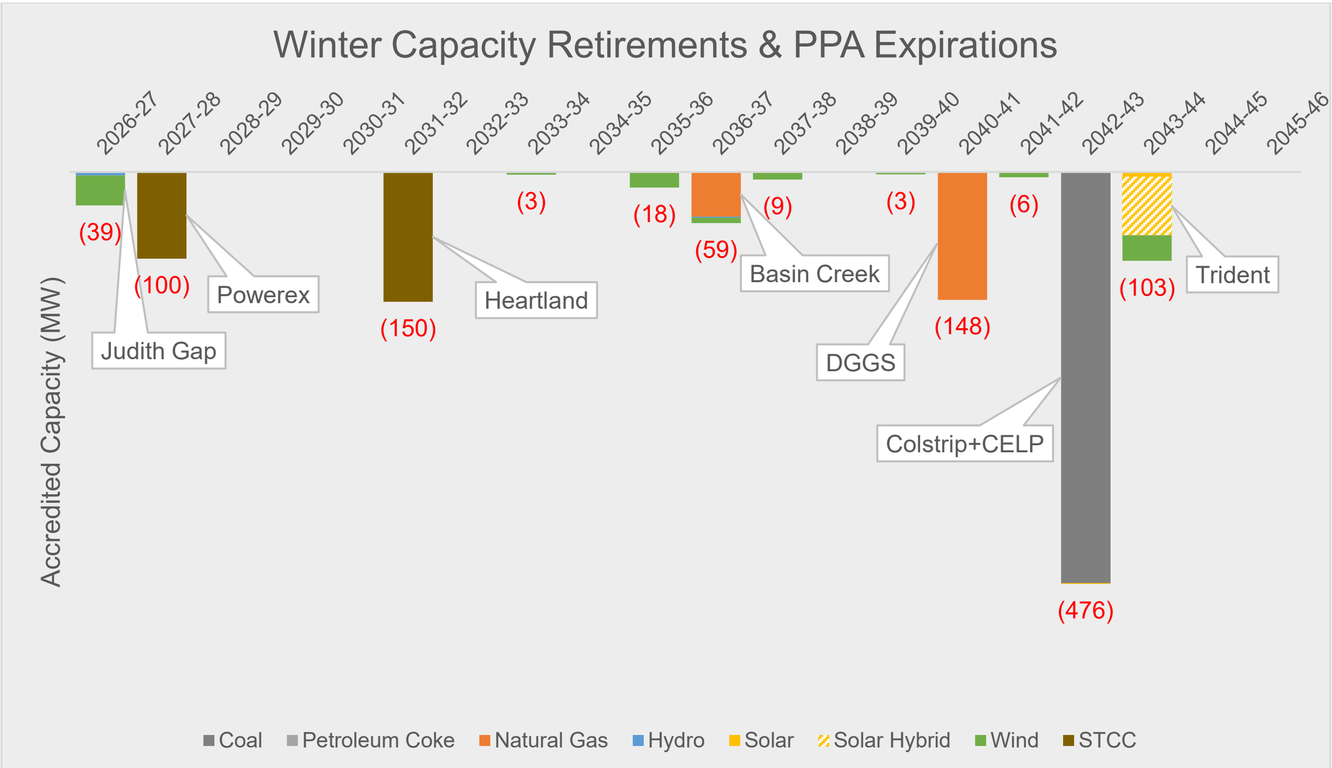


FIGURE 58: WINTER CAPACITY RETIREMENTS.

Figure 55 and Figure 56 above can be compared with NorthWestern's 2023 IRP summer and winter capacity forecasts below in Figure 59 and Figure 60. The major resource differences in the 2023 IRP and 2026 IRP forecasts are the Trident Solar Hybrid PPA execution and the CELP and YELP PPA renewals. In addition, the 2023 IRP load forecast was lower because it used the WRAP load forecast methodology of the seasonal P50 peak load throughout the planning period rather than NorthWestern's internal load forecast for the medium- and long-term planning years.

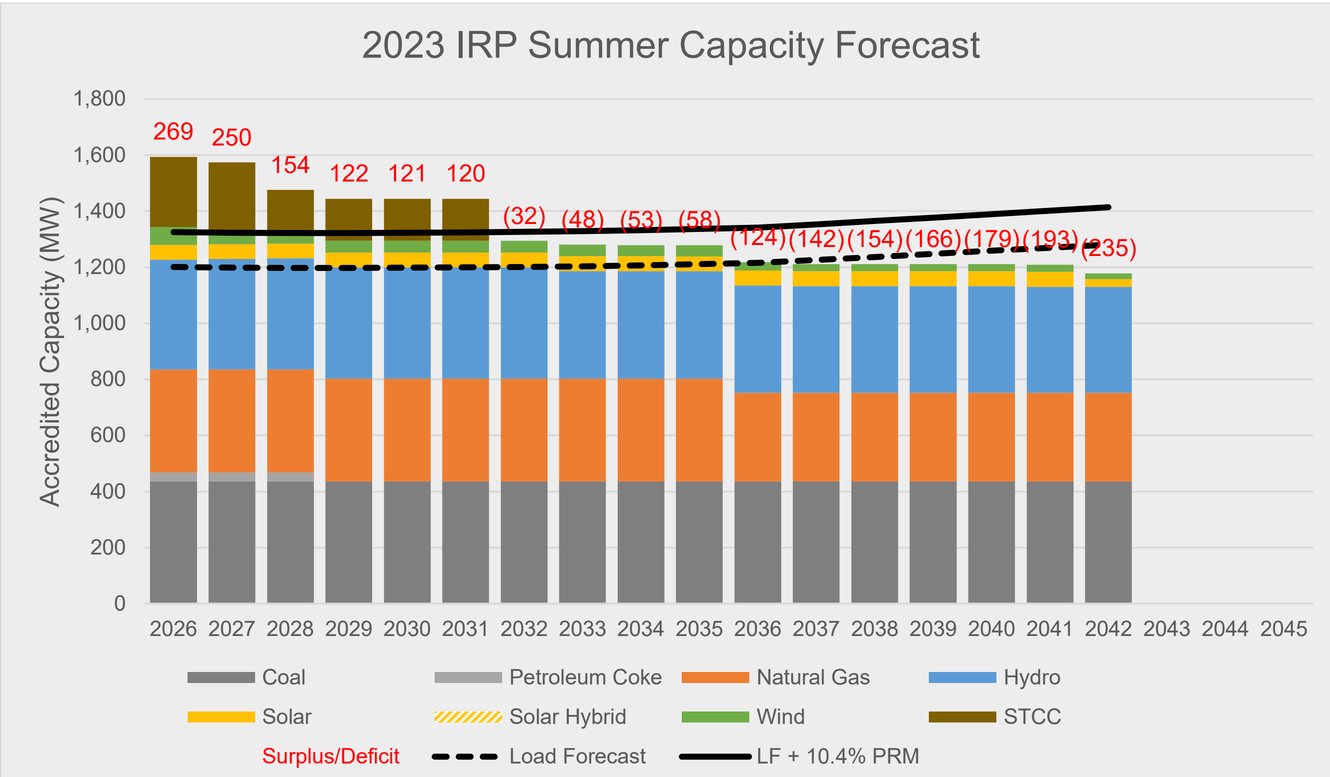


FIGURE 59: NORTHWESTERN'S 2023 IRP SUMMER CAPACITY FORECAST.

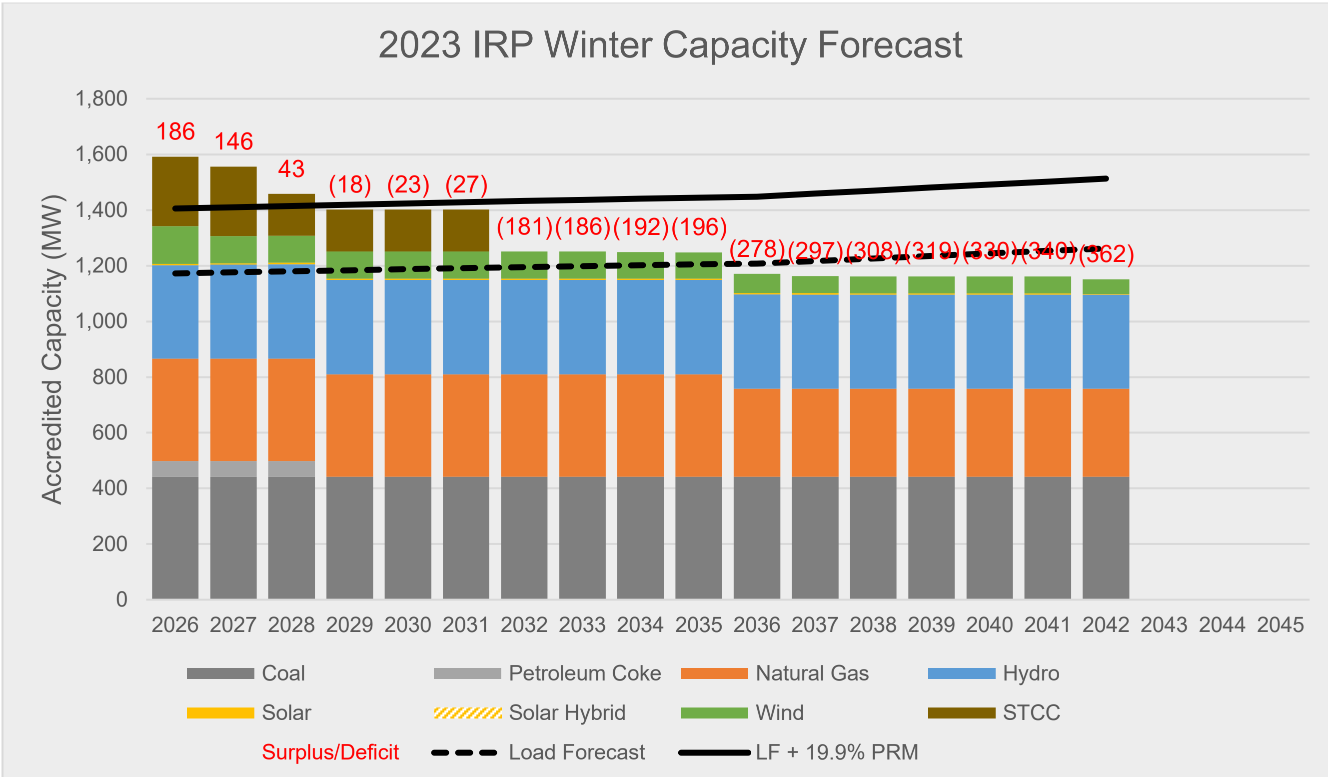


FIGURE 60: NORTHWESTERN'S 2023 IRP WINTER CAPACITY FORECAST.

7.4 Commodity Price Forecasts

7.4.1 Coal Prices

NorthWestern obtains coal supply for Colstrip pursuant to a contract with Westmoreland Rosebud Mining, LLC (Westmoreland), the owner of the Rosebud Coal Mine. [redacted]

[redacted]

FIGURE 61: ESTIMATED COLSTRIP FUEL COST.

7.4.2 Natural Gas Prices

NorthWestern purchases natural gas supply from both the AECO hub and the CIG hub, and the supply is delivered via pipeline as shown in Figure 43. Both DGGS and Basin Creek consume natural gas fuel from AECO on a non-firm basis while YCGS consumes natural gas fuel from CIG on a firm basis. [redacted]

Figure 62 below shows the monthly average AECO, CIG, and Malin natural gas spot price from 2022 through 2024. The relatively high prices starting in early 2022 were a result of the market reaction to the Russian invasion of Ukraine paired with low storage inventories. The significant spike for Malin in December 2022, and AECO and CIG to a lesser extent, was caused by high demand during Winter Storm Elliot.

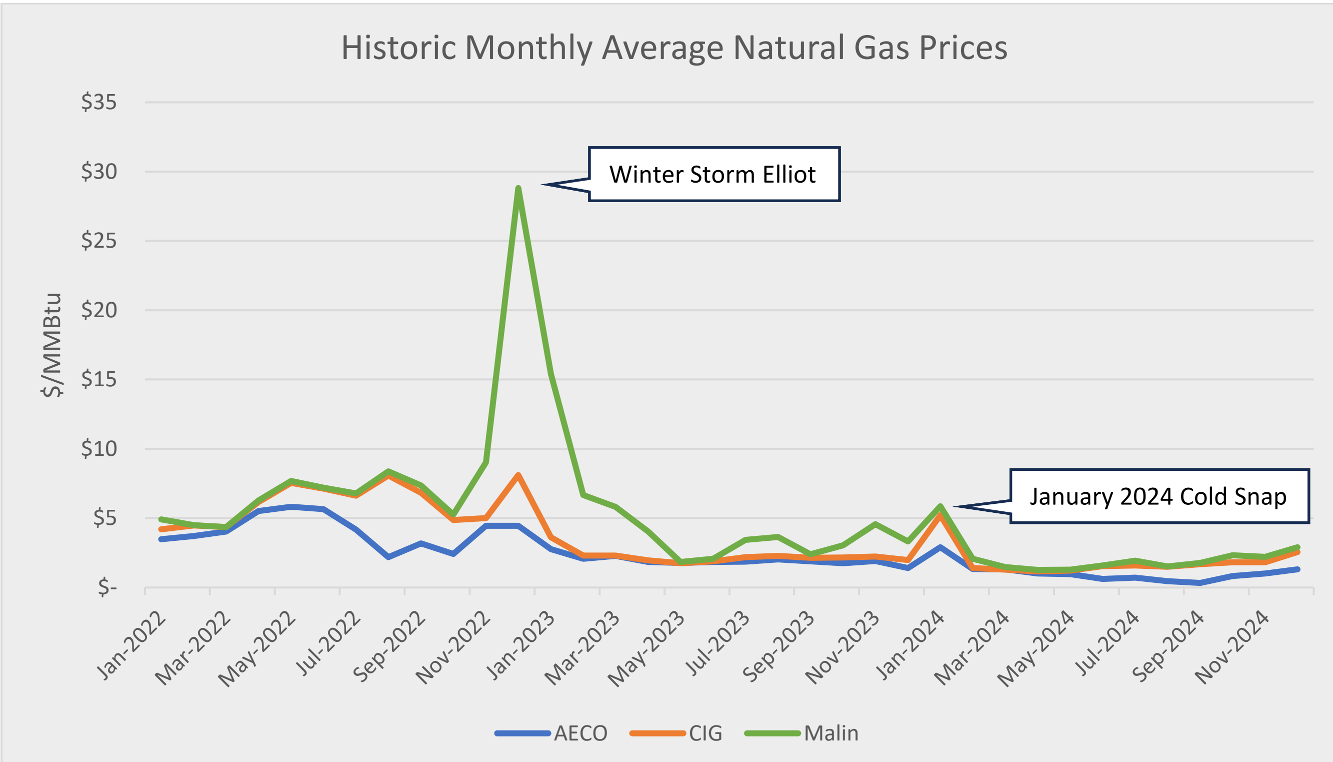


FIGURE 62: HISTORICAL MONTHLY AVERAGE NATURAL GAS PRICES AT AECO AND CIG.

The natural gas price forecasts start with ICE futures prices for AECO, CIG, and Malin hub for the next two years. The price is then escalated based on the 2025 EIA Henry Hub Price escalation. This approach has the benefit of simplicity and ties back to expected forecasts provided by the EIA. At the time of the forecast, forward prices for CIG were higher than AECO prices as shown below in Figure 63.

[redacted]

FIGURE 63: FORECASTED MONTHLY NATURAL GAS PRICES FOR AECO, CIG, AND MALIN.

7.4.3 Power Prices

NorthWestern actively buys and sells energy on a DA basis and an hourly basis at the Mid-C power trading hub. A Mid-C power price forecast is used as an input in the PowerSIMM ARS and PCM models. Based on the historical relationship between Mid-C prices and NorthWestern's WEIM prices, PowerSIMM will simulate NorthWestern's Default Generation Aggregation Point (DGAP) and External Load Aggregation Point (ELAP) prices individually in which transmission imports and exports are bought and sold, respectively. Figure 64 shows the monthly average Powerdex, DGAP, and ELAP power prices from 2022 through 2024. Powerdex is a Mid-C index power price. As shown, NorthWestern energy imbalance market (EIM) DGAP and ELAP prices track closely with the Powerdex Mid-C price.

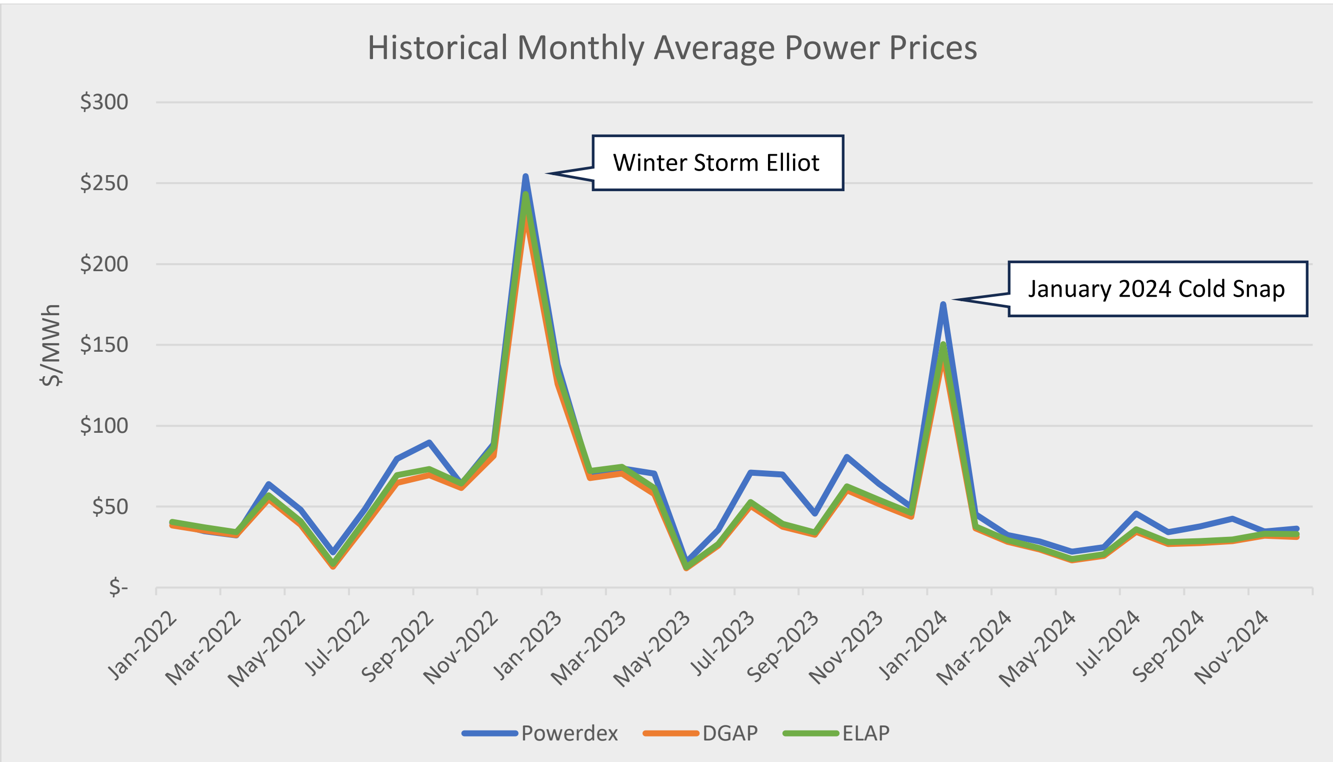


FIGURE 64: MONTHLY AVERAGE POWERDEX, DGAP, AND ELAP POWER PRICES.

Power prices are influenced by a range of factors that operate on different timescales. For example, the demand for power follows based on user demand and seasonal patterns driven largely by the weather. Demand can also exhibit long-term trends based on population growth, economic trends, or improvements in energy efficiency. Like the demand for electricity, renewable generation is also subject to daily and seasonal variations which must be considered when forecasting prices. The primary inputs into the power price forecast include:

- Forward prices for power. NorthWestern's power price forecast starts with eight years of futures prices for power at the Mid-C trading hub. The futures prices were pulled on July 17, 2025, for trading periods up to December 2033. Power is priced in blocks of time for light-load hours (nighttime and Sundays) and heavy-load hours (weekdays and Saturdays).
- AECO natural gas price forecast.

- Planned projects and announced retirements. Data taken from resource plans in the region and the EIA provide information on the near-term supply for the region.
- State and federal policies affecting generation planning.

The forward curves for power are combined with a long-term forecast of Mid-C monthly power prices for heavy load and light load hours and are shown in Figure 65. The power price forecast does not include data center demand.

[redacted]

FIGURE 65: MID-C POWER PRICE FORECAST.

A key aspect of future power markets is that the influx of renewable energy is expected to increase the frequency of periods in which supply exceeds demand and power prices become negative. The pattern of renewable energy putting significant downward pressure on average prices has been seen in California and SPP as the rapid growth of solar and wind energy, respectively, has saturated the market with energy. CAISO's net peak (load minus renewable generation) has been pushed into the evening hours after the sun sets. This phenomenon is not as apparent in the Mid-C market, though the Mid-C and California markets are influenced by each other. The combination of the reduction in average prices with the increase in price volatility represents a shift in the underlying fundamentals of power markets. This shift is driven by the replacement of dispatchable resources with intermittent resources.

PowerSIMM's natural gas and power price simulations follow a forecast and do not adjust with supply and demand imbalances.

7.5 Base Case, Scenarios, and Sensitivities

The Base Case, also referred to as Scenario A, includes the following assumptions:

- The portfolio resources are described in Chapter 5 and how those resources contribute to the capacity forecast is described in Section 7.3, which includes the acquisition of the Avista 222 MW share of Colstrip on January 1, 2026.
- Colstrip continues operating through December 31, 2042.
- The capacity expansion modeling does not allow any new fossil-fueled generation after 2035 in accordance with NorthWestern's Net Zero goal.
- The Base Case includes QFs with an executed PPA (Trident) or final Commission order (YELP) as of June 1, 2025, which was the modeling cutoff date. NorthWestern cannot accurately predict which QFs will ultimately proceed to development.

NorthWestern modeled four alternate scenarios from the Base Case in which the Colstrip operation is modified according to Table 48 below. NorthWestern focused on the future of Colstrip due to its importance in the NorthWestern supply portfolio. In the Colstrip early retirement scenarios, undepreciated capital costs are assumed to continue depreciating through 2042. These scenarios represent possible future portfolios.

Case	Description
A-BaseCase	Base Case – Colstrip retires December 31, 2042.
B-CSretMATS	Colstrip retires on June 30, 2029, due to MATS.
C-CScompMATS	Colstrip complies with MATS using baghouse on July 1, 2030. Colstrip retires December 31, 2042.
D-CSretGHG	Colstrip retires December 31, 2031, due to GHG.
E-CSret2035	Colstrip retires December 31, 2035.

TABLE 48: SCENARIOS MODELED IN THE IRP.

In addition, NorthWestern modeled variations to the Base Case assumptions, or sensitivities, to understand how the modeling results may change due to a change of input assumptions. The sensitivities modeled in the IRP are listed in Table 49 below. The Sensitivity Category in Table 49 is used to group the results in Section 7.7 and Section 7.8.

The Commodity Sensitivities were evaluated to determine how a change in power prices or natural gas prices change the modeling results; the Data Center Sensitivities were evaluated to determine how increased demand from large loads, such as data center loads, change the modeling results; the Resource Sensitivities were evaluated to determine how a change in either the existing resource portfolio or the candidate resource options change the modeling results; and the Other Sensitivities were evaluated to determine how the NPC changes the modeling results, and, separately, how increased DSM and NEM change the modeling results.

Sensitivity Category	Case	Description
Commodity	F-Power50	Power costs reduced by 50%
	G-Power150	Power costs increased by 50%
	H-NatGas50	Natural gas prices reduced by 50%
	I-NatGas150	Natural gas prices increased by 50%
Data Center	J-DC150	• Puget's 370 MW share of Colstrip is added to the portfolio • 75 MW of data center (DC) load starting on 1/1/2026 • plus 75 MW starting on 1/1/2027, totaling 150 MW
	K-DC650	• Puget's 370 MW share of Colstrip is added to the portfolio • 75 MW of DC load starting on 1/1/2026 • plus 175 MW starting on 1/1/2027, totaling 250 MW • plus 100 MW starting on 1/1/2028, totaling 350 MW • plus 100 MW starting on 1/1/2029, totaling 450 MW • plus 200 MW starting on 1/1/2030, totaling 650 MW
	L-DC1160	• Puget's 370 MW share of Colstrip is added to the portfolio • 80 MW of DC load starting on 1/1/2026 • plus 185 MW starting on 1/1/2027, totaling 265 MW • plus 262 MW starting on 1/1/2028, totaling 527 MW • plus 266 MW starting on 1/1/2029, totaling 793 MW • plus 367 MW starting on 1/1/2030, totaling 1160 MW
Resource	M-NoCO2Lim	Carbon emitting resources are allowed to be added to the portfolio throughout the planning horizon.
	N-CO2Free	Only allow carbon free candidate resources to be selected in ARS.
	O-wPseCS	NorthWestern acquires Puget Sound Energy's 370 MW share of Colstrip for retail customers.
	P-NoAvaCS	NorthWestern does not acquire Avista's 222 MW shares of Colstrip for retail customers.
Other	Q-AddNPC300	Add 150 MW of SPP access and 150 MW of MISO access via NPC starting on 1/1/2032.
	R-IncDsmNem	Increase the amount of DSM and NEM in the forecast. The costs associated with increased NEM participation, including potential system and cost-shift impacts, and DSM programmatic costs are not reflected in this sensitivity.

TABLE 49: SENSITIVITIES MODELED IN THE IRP.

7.5.1 Puget 370 MW Share of Colstrip

With adequate capacity in the portfolio in 2026, the 370 MW Puget share of Colstrip is not included in NorthWestern's portfolio at this time, and will be owned by a separate subsidiary, NorthWestern Colstrip 370Pu LLC, not NorthWestern. While it was not included in the Base portfolio, NorthWestern did evaluate adding the 370 MW Puget share to serve retail customers in Sensitivity O as well as the Data Center sensitivities J, K, and L.

NorthWestern has entered into letters of intent with data centers that contemplate increasing load ranging from 150 MW to more than 1,000 MW. These customers require firm capacity and long-term supply commitments. It will be challenging for NorthWestern to align near-term resource additions with the rapid speed-to-market requirements associated with large load additions such as data centers. Therefore, the Data Center Sensitivities assume a rapid increase in demand from 2026-2030 and that NorthWestern acquires the 370 MW Puget share of Colstrip. The Puget share is capable of providing a source of accredited generation to serve these large loads.

The Puget 370 MW share has firm transmission rights from Colstrip to Broadview, i.e. one of NorthWestern's retail load sinks, from January 2026 through December 2029. Starting in 2030, the Puget 370 MW share will continue to have firm transmission rights until one of the following conditions occurs:

1. The date on which Colstrip Units 3 & 4 cease commercial operation.
2. The date on which the NPC starts providing transmission service.

Starting in 2030, the firm transmission rights can be reduced by up to 190 MW if Puget requires transmission from Colstrip to Broadview.

7.6 PowerSIMM Framework

PowerSIMM is a software program designed to simulate the performance of electric power systems with high spatial and temporal granularity. It supports decision-making from the near-term bidding strategies and risk management to long-term resource planning and generation assets investment. PowerSIMM offers capacity expansion, RA, and PCM capabilities.

Stochastic Simulation

PowerSIMM uses a stochastic approach that incorporates variability and uncertainty into its simulations. Weather is the primary driver of simulations which span a wide range of possible future conditions to ensure thorough coverage in the model. Configuration of renewable resources and load requires hourly historical data and expected monthly forecast generation or demand. Historical data from 2015 through 2024 is used for NorthWestern's model. PowerSIMM captures the correlations observed among the historical weather patterns, hourly and daily load shapes, renewable generation, fuel and power prices. Load and renewable simulations are scaled to forecast values. Figure 66 describes how PowerSIMM uses different data sources to derive the Portfolio Summarization, i.e. simulation results.

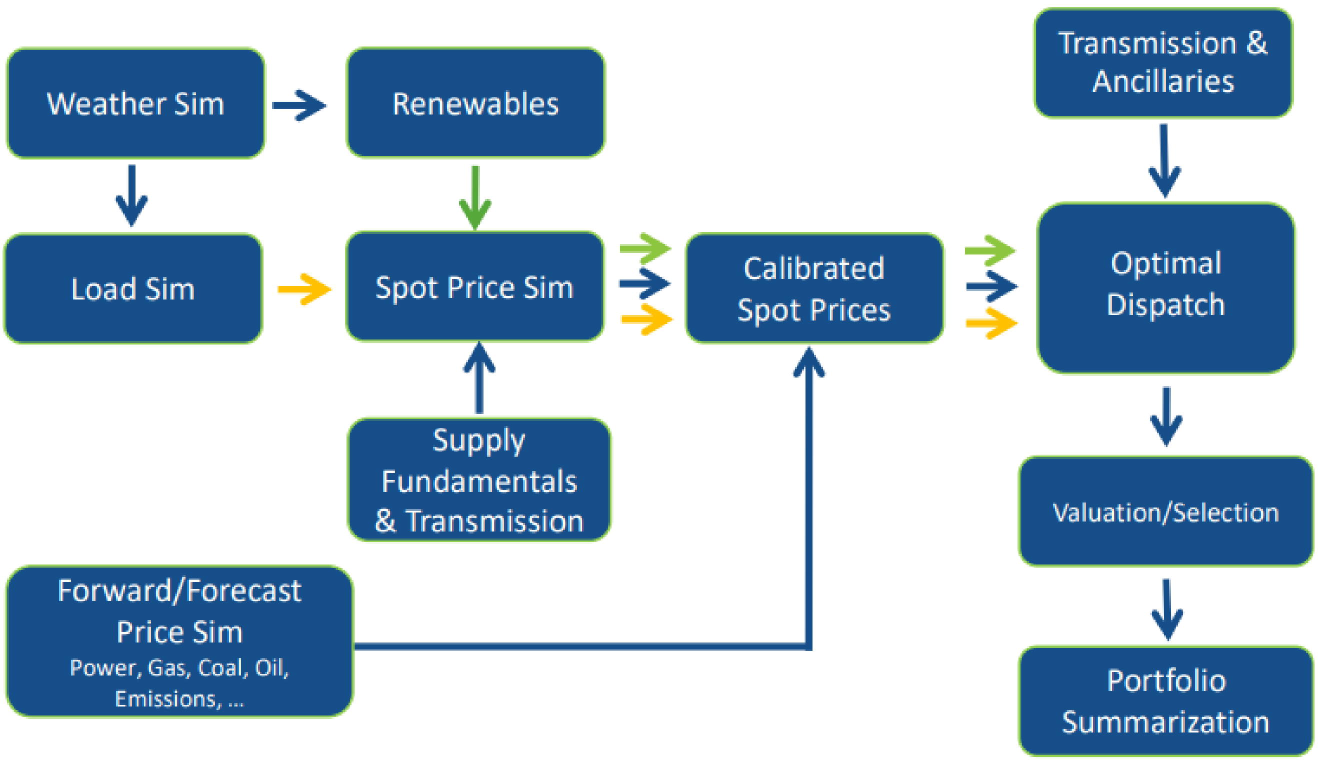


FIGURE 66: POWERSIMM MODELING FRAMEWORK.

Weather Modeling

PowerSIMM starts by simulating weather. It sources historical weather data for all U.S. locations from the National Climate Data Center (NCDC). Users have the ability to create weather zones by selecting more than one weather station and allocate weather zones to load and renewables. Using time series data unique to each weather station, the model projects future weather patterns based on historical trends and maintains the relationship with the neighboring weather stations.

Load & Renewable Generation Modeling

Load is driven from simulated weather. Load has significant bearing on the electricity prices. Therefore, accurate load modeling is essential for price simulations. The load simulations are based on the calendar-based load patterns, including hourly and daily shapes, weather-related influences, and temporal autocorrelation, reflecting the persistence load behavior over time. Weather variables influence load differently depending on the hour of day and day of the week, and seasonal variations. To accurately simulate load, the model integrates these components and their interactions.

A similar simulation approach is used for determining the renewable generation. Renewable simulations are also driven by weather, hourly and daily generation shapes, and temporal autocorrelation in renewable generation. The model integrates these components and interactions to produce accurate renewable simulations.

Market Price Modeling

PowerSIMM also explicitly includes market fundamentals such as forward prices, price volatility and shapes within a stochastic framework that reflects the interdependencies between weather, load, renewables, and prices. The model simulates multiple strips of forward curves paths simultaneously using the historical observations. It simulates each forward contract's price based on its own behavior and in relation to other commodities. The average of forward simulations is scaled to the input forecasts indicated by the user. Spot price simulations are then derived based on the weather, load, renewable and forward price simulations. The model captures the uncertainty in market prices across trading hubs while staying consistent with the forward price simulations. The model also enforces spot price volatility, price shapes, and minimum and maximum price limits as indicated by the user for scaling and enforcing fundamentals that may not be observed in historical data. The model also simulates nodal prices based on their relationship with hub prices.

Dispatch Optimization

These simulations roll into the dispatch module where PowerSIMM simulates dispatch of batteries and thermal assets by optimizing these resources to serve load at the least cost, while accounting for transmission limits. Ancillary services such as regulation up, down, spinning, and non-spinning reserves are co-optimized with the supply resources to fulfill the ancillary requirements and serve load.

7.6.1 Automatic Resource Selection & Constraints

Automatic Resource Selection (ARS) is PowerSIMM's capacity expansion module. ARS provides the least-cost resource procurements that satisfy the constraints defined in the model. The modeling process begins with defining the planning objectives, assumptions, and inputs to the model. Primary inputs to the ARS include the candidate resource options, their capacity contribution to the PRM requirements, resource costs, build limits, and model constraints such as PRM requirements and energy needs. The ARS model evaluates the performance of existing and candidate resources across a range of future operating conditions to assess their revenues, costs and generation. The model determines the optimal timing and quantity of the new resource selections, while ensuring the constraints are satisfied at the lowest cost. PowerSIMM's solver optimizes the selections at the least cost. The solution tolerance is 0.01%.

The constraints in the ARS process limit physical risks of not meeting load. NorthWestern employed the following constraints:

- PRM Constraint – The resource portfolio must meet the seasonal peak load forecast plus a seasonal PRM. The winter PRM is 20.9% and the summer PRM is 16.1%. The winter PRM was calculated by WRAP for the 2026-2027 Winter FS and the summer PRM was calculated by WRAP for the 2025 Summer FS; these PRMs were the most recent values available at the time of modeling.

- Initial Resource Build Constraint – Candidate resources are not immediately available in the ARS process to be selected to exhibit real-life time lags from resource inception to commercial operation. Examples of time lags could include RFPs, permitting, or construction. The first year of availability for each candidate resource is January 1, 2030.
- Resource Overbuild Constraint – ARS may build resources early in the planning horizon to generate revenue for the portfolio even though the existing portfolio is capacity sufficient. To prevent overbuilding, an overbuild penalty (soft constraint) was implemented to discourage the model from overbuilding resources early in the planning period. The discussion in Section 7.7.1 shows different ARS results with and without the overbuild constraint.

If a portfolio is capacity deficit, ARS will choose the least cost candidate resource to mitigate the deficit that also satisfies the planning constraints by evaluating the candidate resource's likely revenues and total costs. The model selects the resources such that the overall portfolio costs are minimized while ensuring all the constraints, including capacity requirements, energy requirements, the individual resource build limits, and overbuild constraints, are satisfied.

The model must include economic assumptions such as the WACC, expected inflation rate, and resource costs, including capital costs, book life, and tax depreciation life, and any other rate-based contributions to the model. The model first adjusts the resource's capital costs based on the economic assumptions and discounts it back to the beginning of the study.

7.6.2 Production Cost Modeling

All portfolios are evaluated in PCM to gain detailed insights of system operations over the planning period. Key inputs to the PCM include simulated system conditions (such as load, market prices, and renewable generation) and operating parameters (such as heat rates, ramp times, start-up times, and planned maintenance outages for thermal assets, and RTE, leakage rates, and duration for batteries). Planned maintenance for Colstrip is included in the model because it occurs on a periodic basis. Planned maintenance for DGGS and YCGS are not included in the model as those depend on the number of unit run-hours. However, when planned maintenance does occur, NorthWestern plans for the outages of those units during the shoulder seasons. The model returns a range of detailed results, including generation costs, such as fuel costs, startup costs, O&M costs, fuel consumption, battery charge and discharge states, individual generator production volumes, carbon emissions, transmission imports (i.e. market purchases) and exports (i.e. market sales), and other key performance characteristics.

Fixed costs for NorthWestern's rate-based assets are calculated in a partial RR separate from the PCM simulation. However, the partial RRs are incorporated into the overall portfolio costs. This incorporation is shown in the figures below in Section 7.8.

The PCM analysis limits the amount of transmission export and import capacity available for use in the portfolio. The determination of transmission capacity limits is challenging because the quantity changes significantly based on many different factors including short-term and long-term use of the transmission system, planned maintenance outages, transmission redirects and wheeling of energy, seasonal limitations, etc. An estimation of transmission limits used in the PCM studies is shown in Table 50 below. Table 50 represents the yearly firm ATC on all NorthWestern's transmission paths as of April 29, 2025, when the query was made. The values in Table 50 do not include pending transmission service requests that may be under study. While NorthWestern does not own the firm transmission rights in Table 50, the magnitude and trend represent a reasonable estimate of transmission limits for purposes of the PCM studies. Historically, there are many hours in which NorthWestern has imported more or less than the total limits provided in Table 50. NorthWestern has historically not been a significant exporter due to its relatively small generation portfolio. However, as generation builds continue, the magnitude and frequency of power exports could increase.

	Path 8 BPAT		**Path 8 AVAT**		**Path 18 BRDY**		**Path 18 Jeff**		**Path 80 YTP/ Crossover**		**Path 83 MATL**		**TOTAL**	
	Imp	**Exp**	**Imp**	**Exp**	**Imp**	**Exp**	**Imp**	**Exp**	**Imp**	**Exp**	**Imp**	**Exp**	**Imp**	**Exp**
2026	22	0	109	0	0	0	47	0	0	530	0	0	**178**	**530**
2027	22	0	109	0	0	0	47	0	0	580	0	0	**178**	**580**
2028	22	0	159	0	0	0	47	30	0	580	0	0	**228**	**610**
2029	20	0	159	0	0	0	47	30	0	580	0	0	**226**	**610**
2030	20	0	159	0	0	0	47	30	0	580	0	0	**226**	**610**
2031	20	0	159	0	0	0	47	30	0	580	80	0	**306**	**610**
2032	20	0	159	0	0	0	47	80	0	580	80	0	**306**	**660**
2033	20	0	159	0	0	0	47	80	0	580	80	0	**306**	**660**
2034	20	0	159	0	0	0	47	80	0	580	80	0	**306**	**660**

TABLE 50: TRANSMISSION LIMITS ASSUMED FOR THE PCM STUDIES.

7.6.2.1 Ancillary Services

The PCM also considers resources reserved to meet ancillary reserve requirements. NorthWestern models Schedule 3, regulation and frequency response, and Schedules 5 and 6, operating reserves, of NorthWestern's OATT. Regulation and frequency response service, or Schedule 3, is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz). Regulation and frequency response service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load.[69] NorthWestern models 10 MW of regulation up and 10 MW of regulation down in PowerSIMM, which results in 20 MW of regulation-eligible units to be reserved in all hours. The amount of modeled regulation is consistent with real-time operations. The INC component of Schedule 3 is not reserved on eligible resources in PowerSIMM because the megawatts required for INC in real-time operations are economically dispatched through the WEIM.

Spinning reserve service, or Schedule 5, is needed to serve load immediately in the event of a system contingency. Spinning reserve service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service.[70] Supplemental reserve service, or Schedule 6, is also needed to serve load in the event of a system

[69] https://www.oasis.oati.com/woa/docs/NWMT/NWMTdocs/Schedule_3_-_Regulation_and_Frequency_Response_Service.pdf
[70] https://www.oasis.oati.com/woa/docs/NWMT/NWMTdocs/Schedule_5_-_Operating_Reserve_-_Spinning.pdf

contingency. However, it is not available immediately to serve load but rather within a short period of time. Supplemental reserve service may be provided by generating units that are on-line but unloaded, by quick-start generation, or by interruptible load or other non-generation resources capable of providing this service.[71] Schedules 5 and 6 are dynamically calculated by PowerSIMM as 3% of total generation and 3% of total load where 50% must be supplied by online resources that are loaded at less-than-maximum output.

7.6.2.2 Sub-Hourly Credits

The sub-hourly credits represent the additional revenue earned by the dispatchable resources from participating in an intra-hour market, such as the CAISO WEIM. Fast ramping resources like RICE, CTs, and batteries can take advantage of price fluctuations to earn extra revenue in the real-time market.

Methodology

In the modeling, the assets are dispatched to the hourly DA prices. This approach is referred to as hourly analysis. To quantify the additional revenue potential in the intra-hour market, a real-time analysis is conducted at the DGAP_NWMT node.

PowerSIMM can simulate future real-time (5-minute) prices based on the observed real-time historical data patterns. The model optimizes the asset operation by dispatching them to the real-time prices, allowing the fast-ramping resources to capitalize on the price fluctuations. This method is called sub-hourly modeling.

[71] https://www.oasis.oati.com/woa/docs/NWMT/NWMTdocs/Schedule_6_-_Operating_Reserve_-_Supplemental.pdf

Net Revenues from the sub-hourly model and hourly model are compared to estimate the additional revenue earned by the assets. This additional revenue earned by the assets is referred to as sub-hourly credit and can be expressed as the revenue earned per kW of capacity. Figure 67 below shows the additional revenue earned by eligible assets through participating in the real-time market.

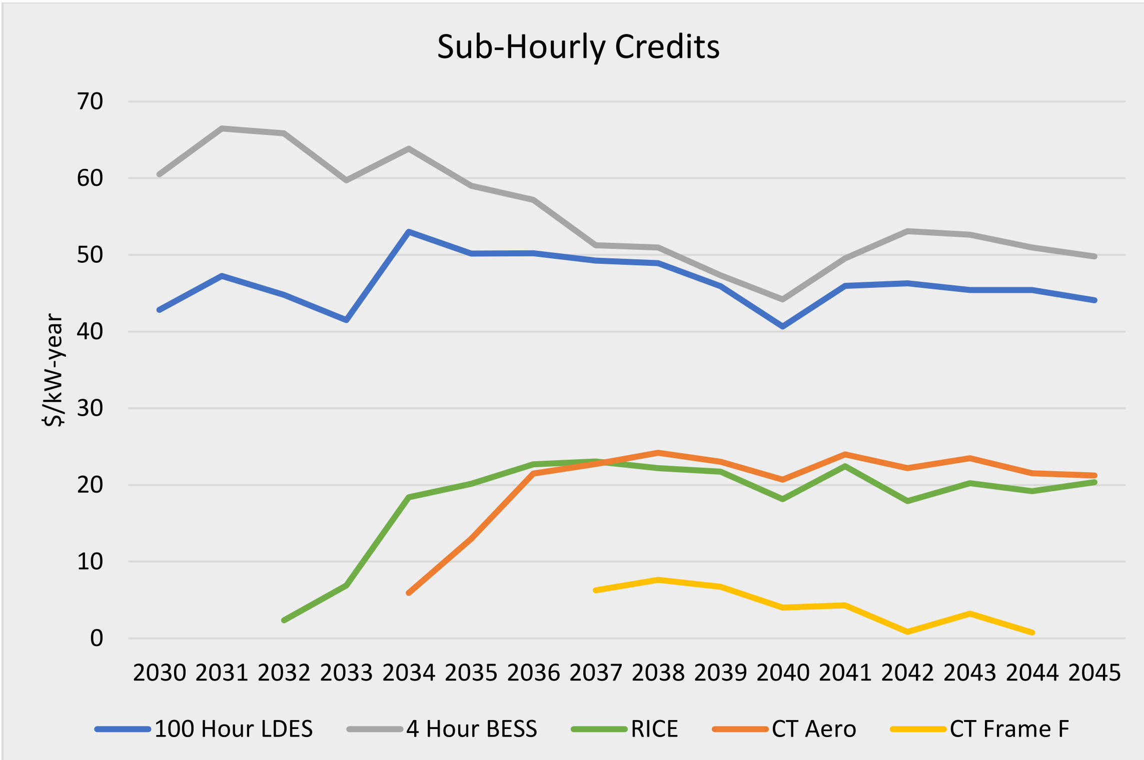


FIGURE 67: SUB-HOURLY CREDITS FOR CANDIDATE RESOURCES.

Sub-hourly credits could be included as a reduction to the total candidate resource cost in the ARS module. However, sub-hourly credits were not included in the IRP's ARS analysis due to the timing in which the sub-hourly analysis was completed. Additionally, the model allows limited 4-hour duration storage to avoid creating new peak events during charging periods, as well as limited LDES until further analysis can be completed. The ARS module selects the maximum threshold of 4-hour storage resources and usually the maximum LDES resources in the majority of portfolio outcomes; therefore, including sub-hourly credits is likely to have limited impact on the final portfolio selection for battery storage. However, it may influence the selection of natural gas generation such as a CT Aero, Rice, or CT Frame rather than a CCCT.

7.6.3 Process to Obtain Data for Alternative Modeling

NorthWestern will provide modeling inputs electronically to stakeholders to conduct alternative modeling upon request, subject to applicable protective orders. Stakeholders may request modeling inputs by contacting NorthWestern's Supply Planning group at IRP@NorthWestern.com. The input categories are listed in Table 51 below.

ARS and PCM Inputs
Ancillary Services
Battery Assets
Forward Curve Constraints
Forward Curves
Forward Curve Volume Constraints
Generation Assets
Hydro Assets
Load Assets
Renewable Assets
Transmission Lines

TABLE 51: INPUTS TO THE POWERSIMM MODEL.

7.7 ARS Results

The following sections describe the ARS results for the scenarios and sensitivities defined in Section 7.5. Supporting files for the ARS results are included as attachments in Appendix H.

7.7.1 ARS Results: Scenario A – Base Case

Scenario A represents the Base Case portfolio in which the resources described in Chapter 5 operate through their expected depreciable life or contract expiration date. Figures 46 through 49 show the Base Case ARS results and associated winter capacity forecast, both with and without the overbuild constraint applied.

Without the overbuild constraint, the model selects 370 MW of nameplate capacity in 2030. When the overbuild constraint is applied, the selected nameplate capacity in 2030 is reduced to 150 MW. Both simulations meet the minimum amount of required capacity. However, in the absence of the overbuild constraint, the model selects a substantially larger amount of capacity in the 2030-31 winter season in excess of the load plus PRM target because the additional revenue offsets the additional fixed costs. However, this selection may not reflect the reality of a regulated utility acquiring resources and seeking cost recovery because large and/or early resource builds may be burdensome to customers depending on the timing and resource size. Without the overbuild constraint, there is approximately 420 MW of surplus accredited capacity in the 2030 summer season and approximately 313 MW of surplus accredited capacity in the 2030-2031 winter season.

To address this issue, an overbuild penalty is applied when resource selections exceed a 150 MW threshold. After applying the overbuild penalty, the amount of surplus capacity in the 2030-31 winter season in excess of the load plus PRM target is reduced, as shown in Figure 71. With the overbuild constraint in place, surplus accredited capacity is reduced to approximately 104 MW in the 2030 summer season and 80 MW in the 2030-2031 winter season.

NorthWestern chose a 150 MW threshold to discourage significant overbuilding while still allowing larger candidate resources to be selected without penalty or with a lower penalty. Establishing an appropriate threshold for the overbuild penalty requires balancing flexibility and practicality. For example, a threshold of 5 MW is impractical because it is unlikely that ARS can select resources without incurring some level of overbuild penalty. Conversely, a 500 MW threshold is too large as multiple resources could be selected, without penalty, to satisfy the capacity need. The 150 MW overbuild threshold is reasonable as it is approximately half of the largest candidate resource and allows for some flexibility in ARS to select optimal resources. This same overbuild constraint and penalty structure was applied consistently across all scenarios and sensitivities.

The difference in candidate resource selections between the Base Case without the overbuild constraint and the Base Case with the overbuild constraint is related to the limitations on BESS. As discussed in Section 7.1.4, 4-hour BESS are limited to 250 MW and LDES are limited to 150 MW. When the overbuild constraint is implemented, the model selects 100 MW of BESS in 2030, as shown in Figure 70. Because this 100 MW of BESS is no longer available to help replace the lost capacity in January 2043 due to the Colstrip retirement, as shown in Figure 68, the model must select other candidate resources to meet the capacity need. Among the candidate resources available in January 2043, ARS selects SMRs, reflecting their high-capacity accreditation and greater market sales revenues.

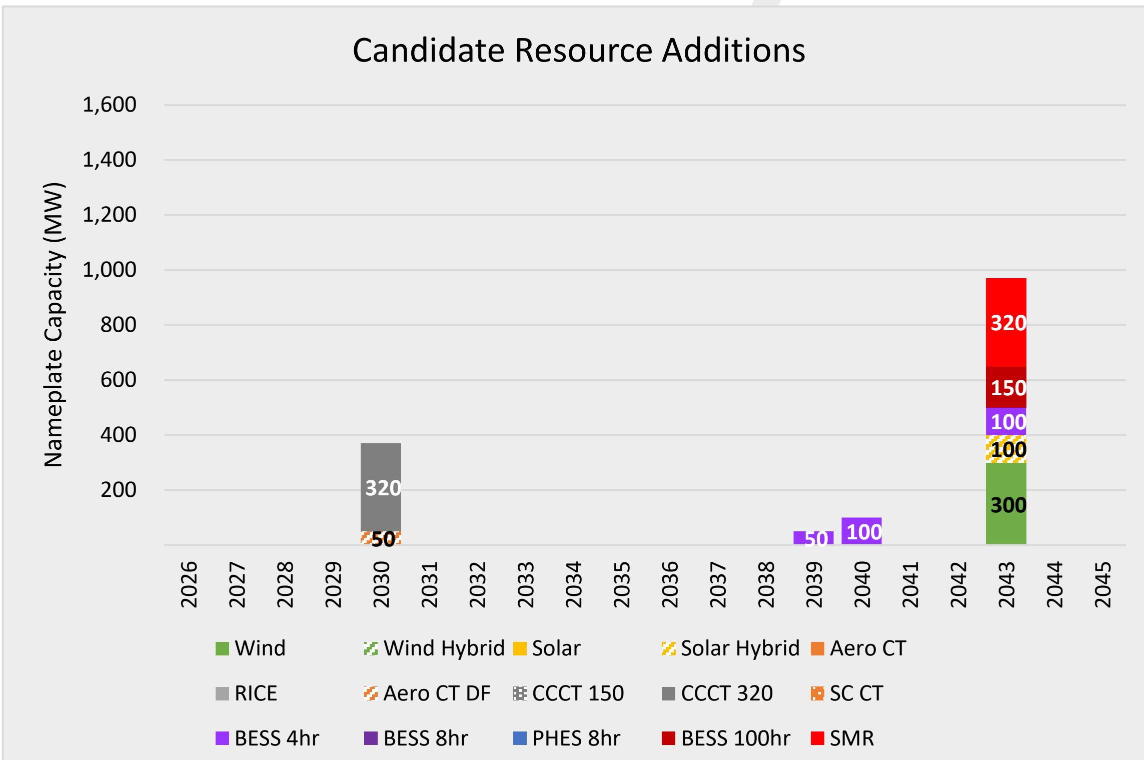


FIGURE 68: ARS RESULTS FOR SCENARIO A – BASE CASE WITH NO OVERBUILD CONSTRAINT.

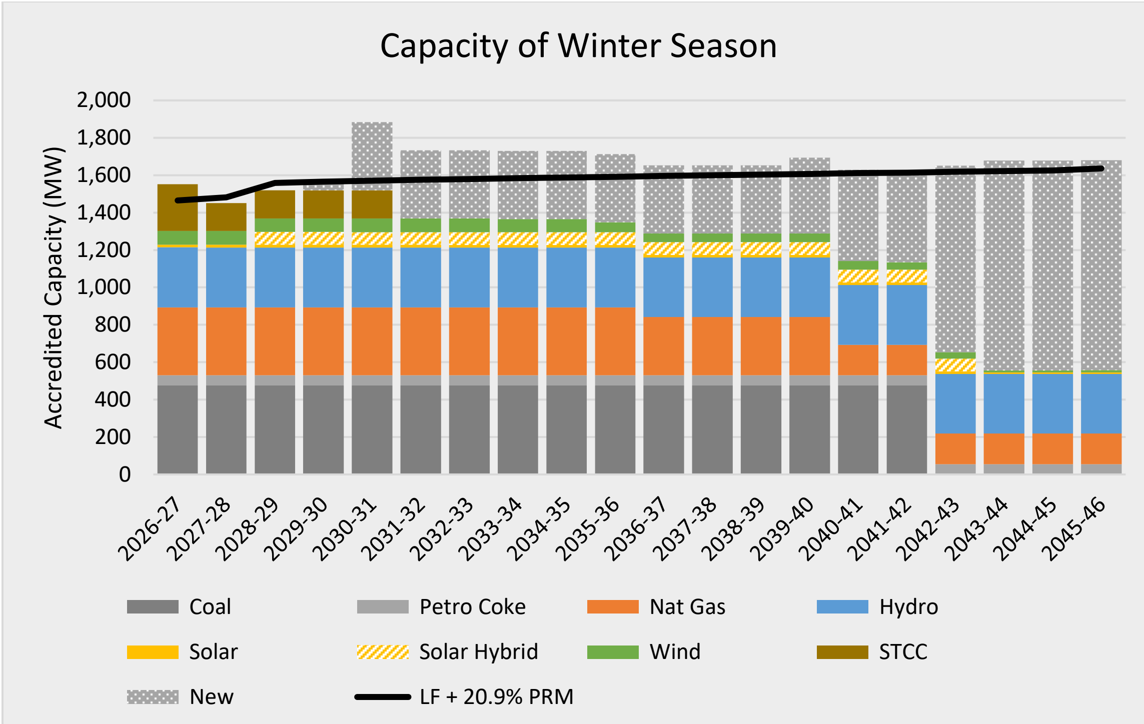


FIGURE 69: WINTER CAPACITY FORECAST WITH NO OVERBUILD CONSTRAINT.

Figure 70 presents the ARS results for Scenario A, Base Case, showing resource selections beginning in 2030 to meet a winter capacity shortfall. Additional capacity is selected in 2032 after the expiration of the 150 MW Heartland contract. Small amounts of short-BESS and LDES are selected from 2039 through 2041 to meet load growth and replace retiring contracts and owned resources, including the DGGS retirement in December 2040. The major resource additions occur in January 2043 when two, 320 MW SMRs and an additional 50 MW of LDES are selected to replace Colstrip.

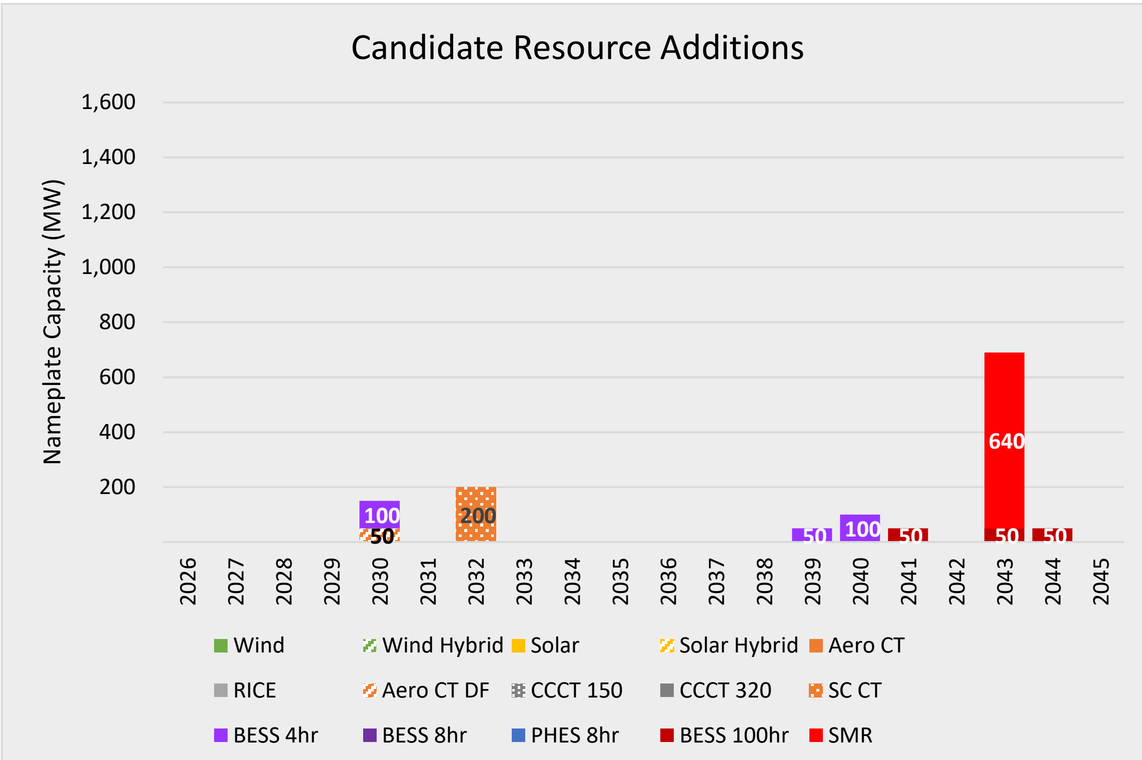


FIGURE 70: ARS RESULTS FOR SCENARIO A – BASE CASE WITH AN OVERBUILD CONSTRAINT.

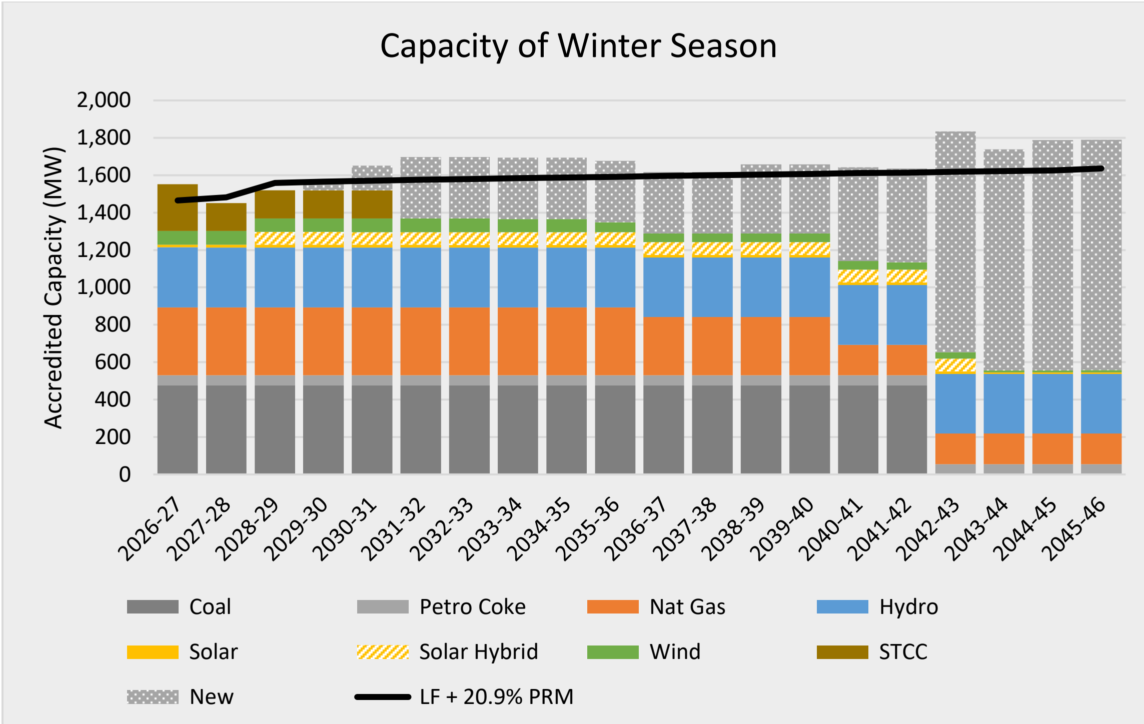


FIGURE 71: WINTER CAPACITY FORECAST WITH AN OVERBUILD CONSTRAINT.

7.7.1.1 Evaluation of Scenario A without Energy Storage Limits

An ARS simulation was conducted for Scenario A without energy storage limits (while retaining the overbuild constraint), and the results are shown in Figure 72 below. Figure 72 shows that 1,150 MW of four-hour duration BESS is selected to meet the load plus PRM across the planning period. Without the use of declining accredited capacity curves, the model assumes the next unit of BESS has the same accredited capacity as the previous unit of BESS. This is not a reasonable outcome, as the capacity accreditation of multiple units of BESS would likely decline to the point where BESS is no longer the least cost capacity resource. As discussed in Section 7.2.27.2.2, NorthWestern may apply declining accredited capacity curves to VERs and energy storage in the future. Therefore, the 250 MW limit for four-hour duration BESS discussed in Section 7.1.4 is reasonable for this IRP.

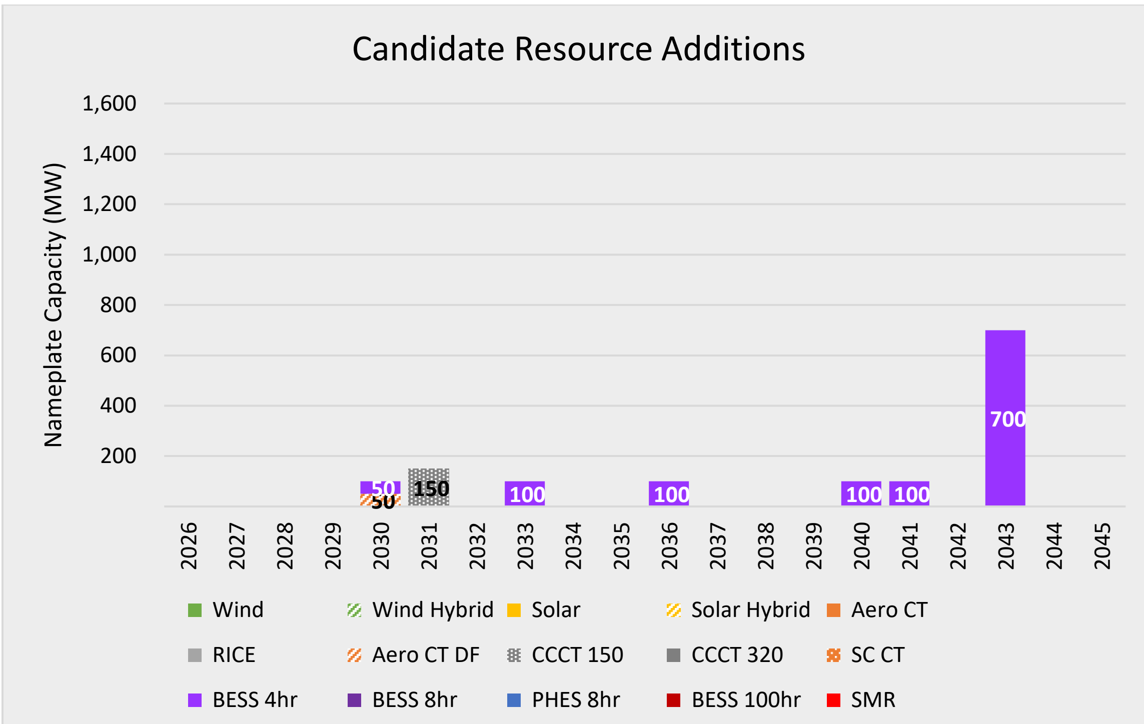


FIGURE 72: ARS RESULTS FOR SCENARIO A – BASE CASE WITHOUT ENERGY STORAGE LIMITS.

An ARS simulation was also conducted for Scenario A without the LDES limit, while retaining the 250 MW limit for four-hour duration BESS (and including the overbuild constraint), and the results are shown in Figure 73 below. Figure 73 shows that 800 MW of LDES is selected to meet the load plus PRM across the planning period. Again, without the use of declining accredited capacity curves, there is uncertainty as to whether LDES would remain the least cost capacity resource up to 800 MW. Therefore, the 150 MW limit for LDES discussed in Section 7.1.4 is reasonable for this IRP.

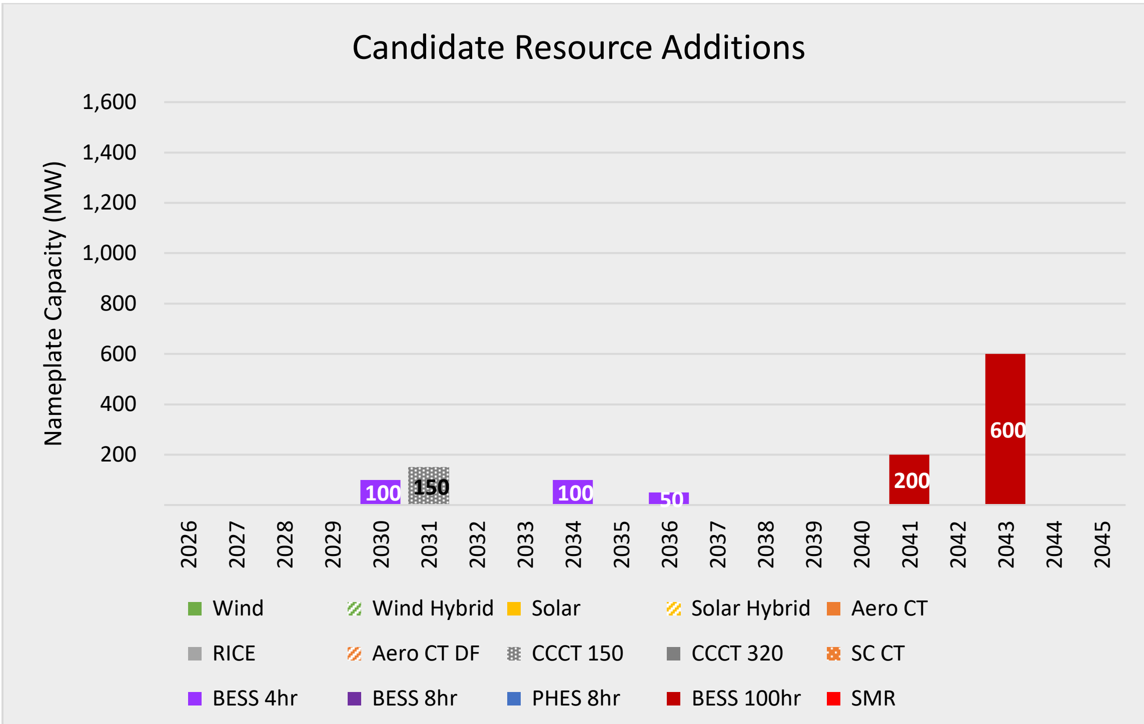


FIGURE 73: ARS RESULTS FOR SCENARIO A – BASE CASE WITHOUT LONG-DURATION ENERGY STORAGE LIMITS.

7.7.1.2 Least Cost Capacity Resource Ranking using Different Electrical Network Upgrade Costs

As discussed in Section 7.6.1, ARS selects the least cost candidate resource to mitigate a capacity deficit that also satisfies the planning constraints by evaluating the candidate resource's likely revenues and total costs, which include electrical network upgrade (ENU) costs. The ENU cost assumptions are discussed in Section 7.1.6.2. To assess the impact of ENU costs on the least cost ranking of candidate resources, NorthWestern reduced the ENU costs by a factor of one tenth (0.1) and increased the ENU costs by a factor of ten (10) as compared to the Base ENU costs. Then, the 2030 net cost of each candidate resource per accredited capacity was ranked under each ENU scenario, i.e. 0.1*Base ENU, Base ENU, and 10*Base ENU. The results of these calculations are shown in Table 52 below.

Table 52 provides insight into the ARS selection of the least cost candidate resources. Under the *Base Elec Network Upgrade Cost* column, the 50 MW dual-fueled Aero and the 320 MW CCCT units are the first and second least cost ranked candidate resources. Figure 68 above shows that these two candidate resources were selected in 2030 as the least cost capacity resources, absent the overbuild constraint. As discussed in Section 7.1.1, ARS was only allowed to select one dual-fueled candidate resource. Figure 70 above shows that the 50 MW dual-fueled Aero and the 100 MW BESS units are selected when the overbuild constraint is applied. The selection of the 100 MW BESS instead of the lower cost ranked 320 MW CCCT, the 200 MW SC CT, and the 150 MW CCCT is a result of those natural gas-fueled candidate resources incurring an overbuild penalty that makes the 100 MW BESS the least cost candidate resource to fill the capacity deficit.

Table 52 shows that natural gas-fueled resources and BESS are consistently ranked as lower cost than wind, solar, and hybrid projects in 2030 across the range of ENU cost scenarios.

2030 Least Cost Rank	0.1*Base Elec Network Upgrade Costs		Base Elec Network Upgrade Costs		10*Base Elec Network Upgrade Costs	
	Resource	Net Cost (2030$/MWacc)	Resource	Net Cost (2030$/MWacc)	Resource	Net Cost (2030$/MWacc)
1	CCCT F Class 1x1 320 MW	$ 1,280,941	SC CT Dual Fuel Aero 50 MW	$ 2,553,605	SC CT Dual Fuel Aero 50 MW	$ 2,553,605
2	SC CT F Class 200 MW	$ 2,123,547	CCCT F Class 1x1 320 MW	$ 3,204,589	CCCT F Class 1x1 320 MW	$ 22,441,068
3	CCCT Industrial 2x1 150 MW	$ 2,172,397	SC CT F Class 200 MW	$ 4,072,406	SC CT F Class 200 MW	$ 23,560,993
4	SC CT Dual Fuel Aero 50 MW	$ 2,553,605	CCCT Industrial 2x1 150 MW	$ 4,143,666	CCCT Industrial 2x1 150 MW	$ 23,856,349
5	BESS Li-Ion 100 MW 4 h	$ 2,566,017	BESS Li-Ion 100 MW 4 h	$ 5,050,740	SC CT Aero 100 MW	$ 25,229,214
6	BESS Li-Ion 50 MW 4 h	$ 2,659,745	SC CT Aero 100 MW	$ 5,068,339	BESS Iron-Air 50 MW 100 h	$ 26,426,208
7	SC CT Aero 100 MW	$ 3,052,252	BESS Iron-Air 50 MW 100 h	$ 5,243,340	SC RICE 100 MW	$ 26,652,383
8	BESS Iron-Air 50 MW 100 h	$ 3,125,053	BESS Li-Ion 50 MW 4 h	$ 5,310,181	BESS Li-Ion 100 MW 4 h	$ 29,897,974
9	SC RICE 100 MW	$ 4,321,764	SC RICE 100 MW	$ 6,351,820	BESS Li-Ion 50 MW 4 h	$ 31,814,534
10	Wind 300 MW	$ 4,783,231	Hy Wind+BESS 100 MW 4h	$ 12,952,551	Hy Wind+BESS 100 MW 4h	$ 63,128,338
11	Solar 300 MW	$ 5,409,102	Wind 300 MW	$ 13,283,964	Hy Solar PV+BESS 50 MW 4h	$ 72,669,999
12	Hy Wind+BESS 100 MW 4h	$ 7,934,972	Solar 300 MW	$ 13,615,720	Hy Solar PV+BESS 100 MW 4h	$ 92,624,255
13	Hy Solar PV+BESS 100 MW 4h	$ 11,852,370	Hy Solar PV+BESS 50 MW 4h	$ 17,617,786	Solar 300 MW	$ 95,681,897
14	Hy Solar PV+BESS 50 MW 4h	$ 12,112,565	Hy Solar PV+BESS 100 MW 4h	$ 19,195,268	Wind 300 MW	$ 98,291,288
15	Hy Wind+BESS 50 MW 4h	$ 24,076,117	Hy Wind+BESS 50 MW 4h	$ 33,847,814	Hy Wind+BESS 50 MW 4h	$ 131,564,787

TABLE 52: RANKING OF CANDIDATE RESOURCE 2030 NET COSTS.

Table 53 shows the 2043 least cost ranking of candidate resources. This table is provided to help understand the Scenario A selection of two 320 MW nuclear SMRs in 2043 to replace Colstrip after retiring, as shown in Figure 70. Natural gas-fueled candidate resources are not allowed to be selected to replace Colstrip in accordance with NorthWestern's Net Zero Goal, as discussed in Section 7.1.1. BESS and LDES resources are selected to their maximum limits in other years of the planning horizon. As a result, the remaining candidate resources available to replace Colstrip in 2043 are nuclear SMRs, solar, wind, and hybrids. As shown in Table 53, nuclear SMRs are the least cost candidate resource under the Base ENU cost scenario.

The 0.1*Base ENU cost scenario in Table 53 shows that standalone solar and wind are lower cost than nuclear SMRs in 2043. It's possible that standalone wind would be selected to replace Colstrip in 2043 using 0.1*Base ENU costs. It is unlikely that standalone solar would be selected given its low winter accreditation, as described in Table 46.

2043 Least Cost Rank	0.1*Base IRP Elec Network Upgrade Costs		Base IRP Elec Network Upgrade Costs		10*Base IRP Elec Network Upgrade Costs	
	Resource	Net Cost (2043$/$MW_{acc}$)	Resource	Net Cost (2043$/$MW_{acc}$)	Resource	Net Cost (2043$/$MW_{acc}$)
1	BESS Li-Ion 100 MW 4 h	$ 3,686,504	SC CT Dual Fuel Aero 50 MW	$ 4,548,287	SC CT Dual Fuel Aero 50 MW	$ 4,548,287
2	BESS Iron-Air 50 MW 100 h	$ 3,694,248	BESS Iron-Air 50 MW 100 h	$ 6,614,330	CCCT F Class 1x1 320 MW	$ 33,642,771
3	BESS Li-Ion 50 MW 4 h	$ 3,804,970	BESS Li-Ion 100 MW 4 h	$ 7,111,723	SC CT F Class 200 MW	$ 34,180,218
4	CCCT F Class 1x1 320 MW	$ 4,473,302	CCCT F Class 1x1 320 MW	$ 7,125,072	CCCT Industrial 2x1 150 MW	$ 35,396,279
5	SC CT Dual Fuel Aero 50 MW	$ 4,548,287	SC CT F Class 200 MW	$ 7,314,986	BESS Iron-Air 50 MW 100 h	$ 35,815,148
6	SC CT F Class 200 MW	$ 4,628,462	BESS Li-Ion 50 MW 4 h	$ 7,458,625	SC CT Aero 100 MW	$ 35,924,649
7	SC CT Aero 100 MW	$ 5,353,462	SC CT Aero 100 MW	$ 8,132,661	SC RICE 100 MW	$ 36,329,954
8	CCCT Industrial 2x1 150 MW	$ 5,504,713	CCCT Industrial 2x1 150 MW	$ 8,222,128	BESS Li-Ion 100 MW 4 h	$ 41,363,909
9	SC RICE 100 MW	$ 5,546,949	SC RICE 100 MW	$ 8,345,404	BESS Li-Ion 50 MW 4 h	$ 43,995,169
10	Solar 300 MW	$ 8,723,515	SMR 320 MW	$ 17,706,029	SMR 320 MW	$ 44,514,035
11	Wind 300 MW	$ 14,350,191	Solar 300 MW	$ 20,036,428	Hy Wind+BESS 100 MW 4h	$ 92,754,390
12	SMR 320 MW	$ 15,025,229	Hy Wind+BESS 100 MW 4h	$ 23,586,513	Hy Solar PV+BESS 50 MW 4h	$ 102,295,818
13	Hy Wind+BESS 100 MW 4h	$ 16,669,725	Wind 300 MW	$ 26,068,545	Hy Solar PV+BESS 100 MW 4h	$ 130,451,488
14	Hy Solar PV+BESS 50 MW 4h	$ 18,816,726	Hy Solar PV+BESS 50 MW 4h	$ 26,405,734	Solar 300 MW	$ 133,165,560
15	Hy Solar PV+BESS 100 MW 4h	$ 19,106,551	Hy Solar PV+BESS 100 MW 4h	$ 29,228,818	Wind 300 MW	$ 143,252,080
16	Hy Wind+BESS 50 MW 4h	$ 47,648,222	Hy Wind+BESS 50 MW 4h	$ 61,118,614	Hy Wind+BESS 50 MW 4h	$ 195,822,541

TABLE 53: RANKING OF CANDIDATE RESOURCE 2043 NET COSTS.

7.7.2 ARS Results: Scenario B – Colstrip Retires to Comply with MATS

Scenario B represents an early Colstrip retirement on June 30, 2029, due to compliance with the MATS rules discussed in Section 8.1.1. Figure 74 shows the ARS results for Scenario B. New capacity is selected in 2030 to mitigate the retirement of Colstrip due to MATS. Smaller resource additions including short BESS and LDES are selected later in the planning period starting in 2039 due to load growth and subsequent contract and owned resource retirements.

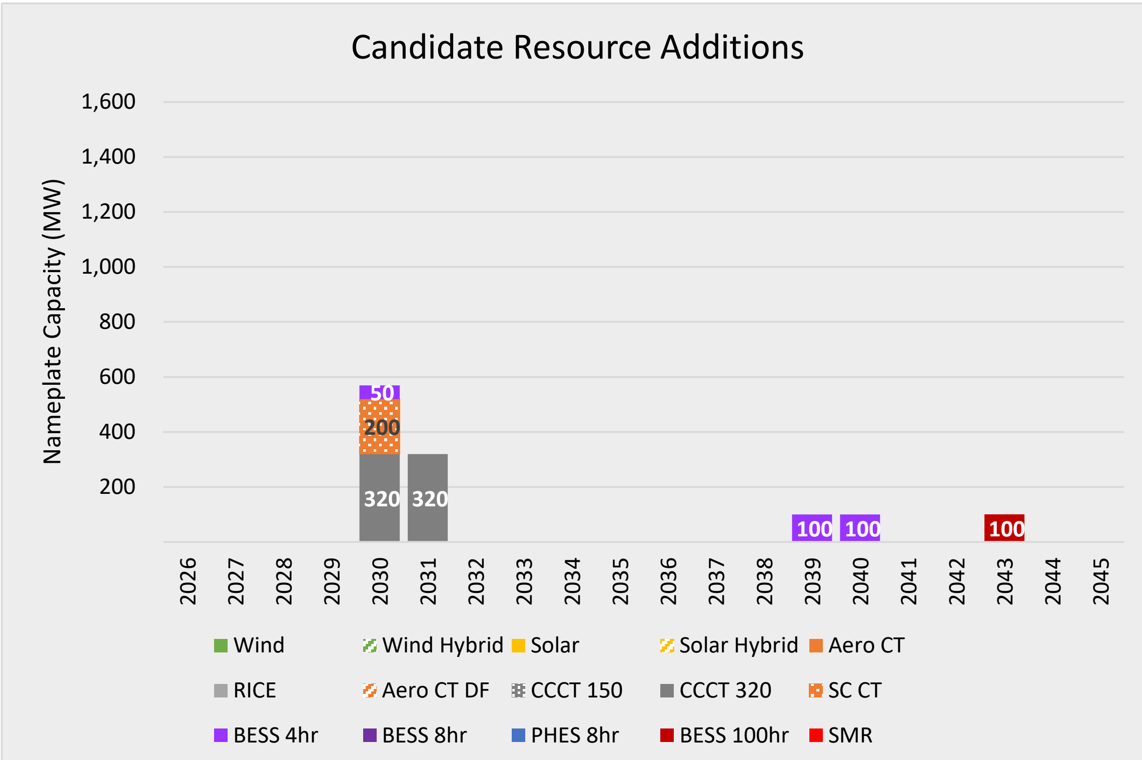


FIGURE 74: ARS RESULTS FOR SCENARIO B.

7.7.3 ARS Results: Scenario C – Colstrip Complies with MATS via Baghouse

Scenario C represents added baghouse infrastructure at Colstrip to comply with the MATS rules discussed in Section 8.1.1. NorthWestern does not have information on how the baghouse might impact operational efficiency or generation output. Therefore, there is no ARS modeling change for Scenario C. The ARS results are the same as Scenario A. The additional costs of the baghouse are accounted for in the PCM results of Scenario C described in Section 7.8.2 below.

7.7.4 ARS Results: Scenario D – Colstrip Retires to Comply with GHG

Scenario D represents an early Colstrip retirement on December 31, 2031, due to compliance with the GHG rules discussed in Section 8.1.2. Figure 75 shows the ARS results for Scenario D. The ARS results for Scenario D show resource selections in 2030 to meet a winter capacity shortfall. Two large 320 MW CCCT resources are selected at the start of 2032 to mitigate the retirement of Colstrip due to GHG. Smaller resource selections are made later in the planning period starting in 2036 due to load growth and contract and owned resource retirements. A 300 MW wind resource and two 50 MW hybrid solar projects are selected in November 2043. While the 400 MW combined nameplate capacity of these resources is large, the resulting accredited capacity is significantly less. One contributing factor of the standalone wind resource being selected over the standalone solar resource is due to the relatively seasonally balanced accreditation of wind as compared to the seasonally lopsided accreditation of solar as described in Table 46 above.

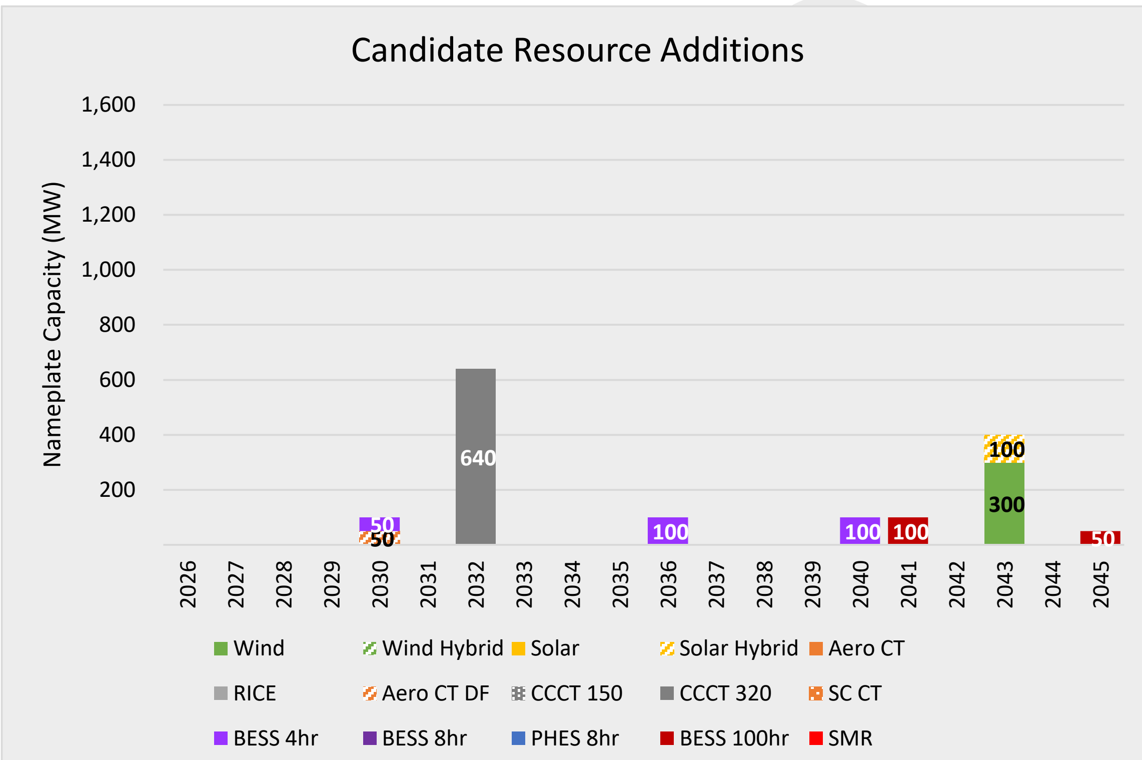


FIGURE 75: ARS RESULTS FOR SCENARIO D.

7.7.5 ARS Results: Scenario E – Colstrip Retires in 2035

Scenario E represents an early Colstrip retirement on December 31, 2035. This retirement date is not reflective of any environmental compliance obligations. Instead, it shows how the portfolio might change due to a Colstrip retirement later in the planning period as compared to Scenario B or Scenario D. Figure 76 shows ARS results for Scenario E. Similar to the scenarios above, the results for Scenario E show resource selections in 2030 to meet a winter capacity shortfall, and an additional selection in 2032 to mitigate the expiration of the 150 MW Heartland contract. A large 320 MW CCCT is selected in November 2035 as well as both short BESS and LDES in January 2036 to mitigate the Colstrip retirement. A 320 MW SMR and 50 MW of LDES are selected later in the planning period starting in 2041 and 2043, respectively, due to load growth and contract and owned resource retirements.

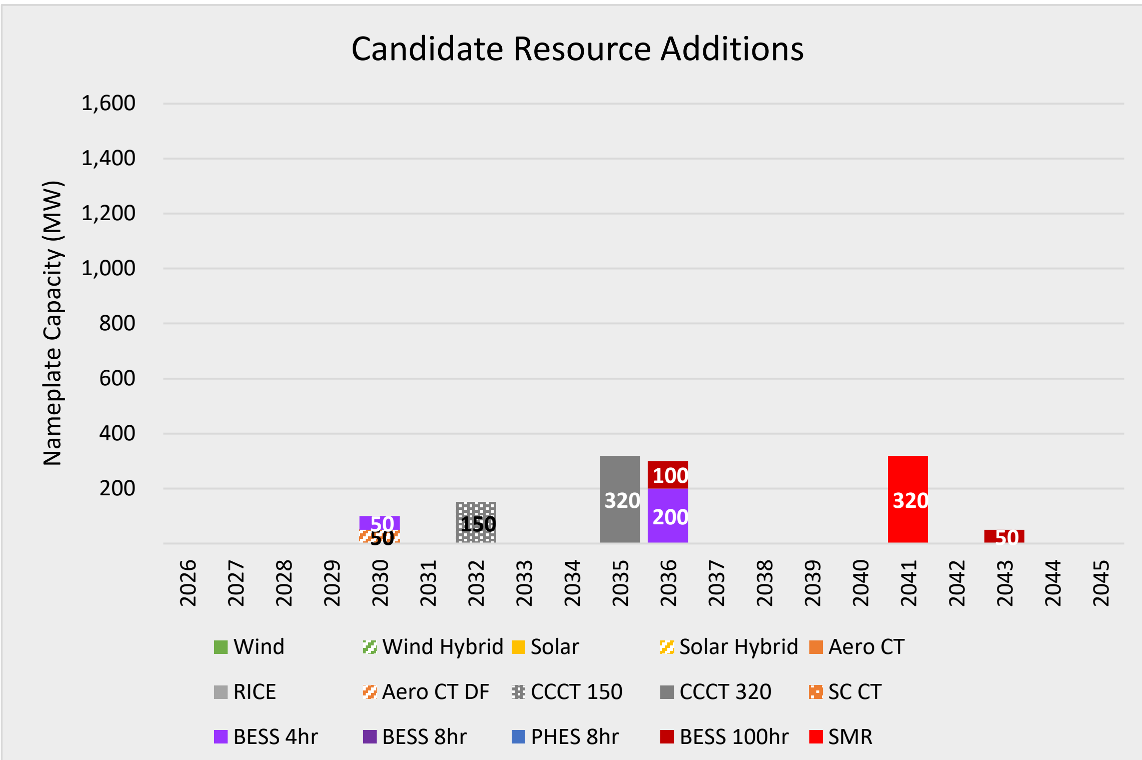


FIGURE 76 : ARS RESULTS FOR SCENARIO E.

7.7.6 ARS Results: Sensitivity F – Power Price Forecast Reduced by 50%

Sensitivity F represents a 50% reduction in the Mid-C power price forecast. More information about the base power price forecast is discussed in Section 7.4.3 above. Figure 77 shows the ARS results for Sensitivity F. While the results of Sensitivity F show slightly less natural gas fuel capacity is selected, the results are very similar to Scenario A. The major resource selections are the two, 320 MW SMRs in January 2043 to mitigate the Colstrip retirement. More information about the change in portfolio costs due to the change in power prices is described in Section 7.8.3, which provides the PCM results for the commodity sensitivities.

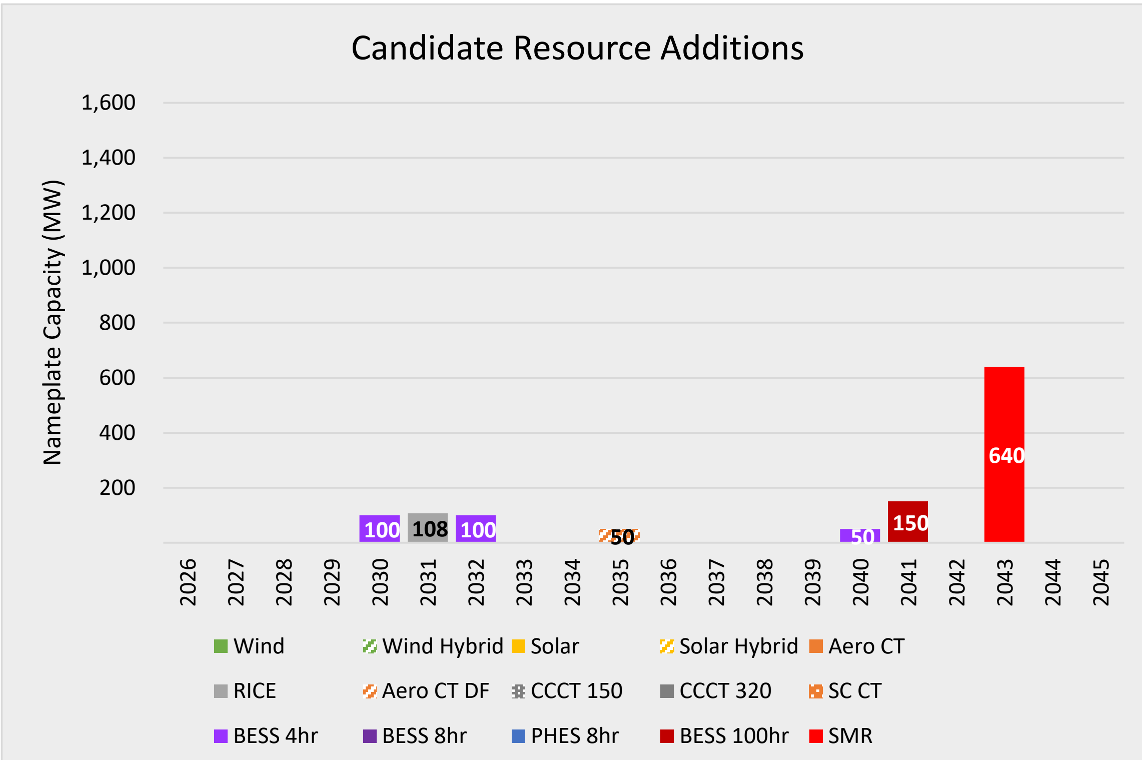


FIGURE 77: ARS RESULTS FOR SENSITIVITY F.

7.7.7 ARS Results: Sensitivity G – Power Price Forecast Increased by 50%

Sensitivity G represents a 50% increase in the Mid-C power price forecast. More information about the base power price forecast is discussed in Section 7.4.3 above. Figure 78 shows the ARS results for Sensitivity G. Again, the results of Sensitivity G are very similar to Scenario A. The major resource selections are the two, 320 MW SMRs in January 2043 to mitigate the Colstrip retirement. More information about the change in portfolio costs due to the change in power prices is described in Section 7.8.3 describing the PCM results for the commodity sensitivities.

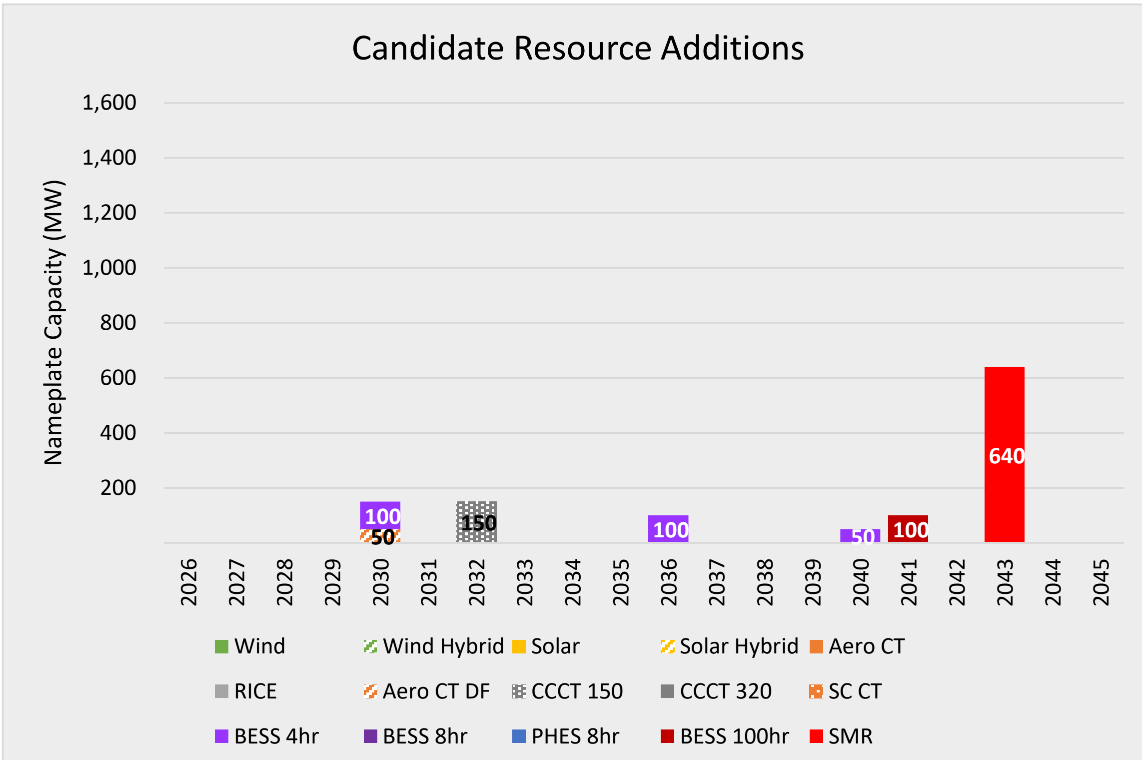


FIGURE 78: ARS RESULTS FOR SENSITIVITY G.

7.7.8 ARS Results: Sensitivity H – Natural Gas Price Forecast Reduced by 50%

Sensitivity H represents a 50% reduction in the natural gas price forecasts. More information about the base natural gas price forecast is discussed in Section 7.4.2. Figure 79 shows the ARS results for Sensitivity H. Again, the results of Sensitivity H are very similar to Scenario A. The major resource selections are the two, 320 MW SMRs in January 2043 to mitigate the Colstrip retirement. More information about the change in portfolio costs due to the change in natural gas prices is described in Section 7.8.3 describing the PCM results for the commodity sensitivities.

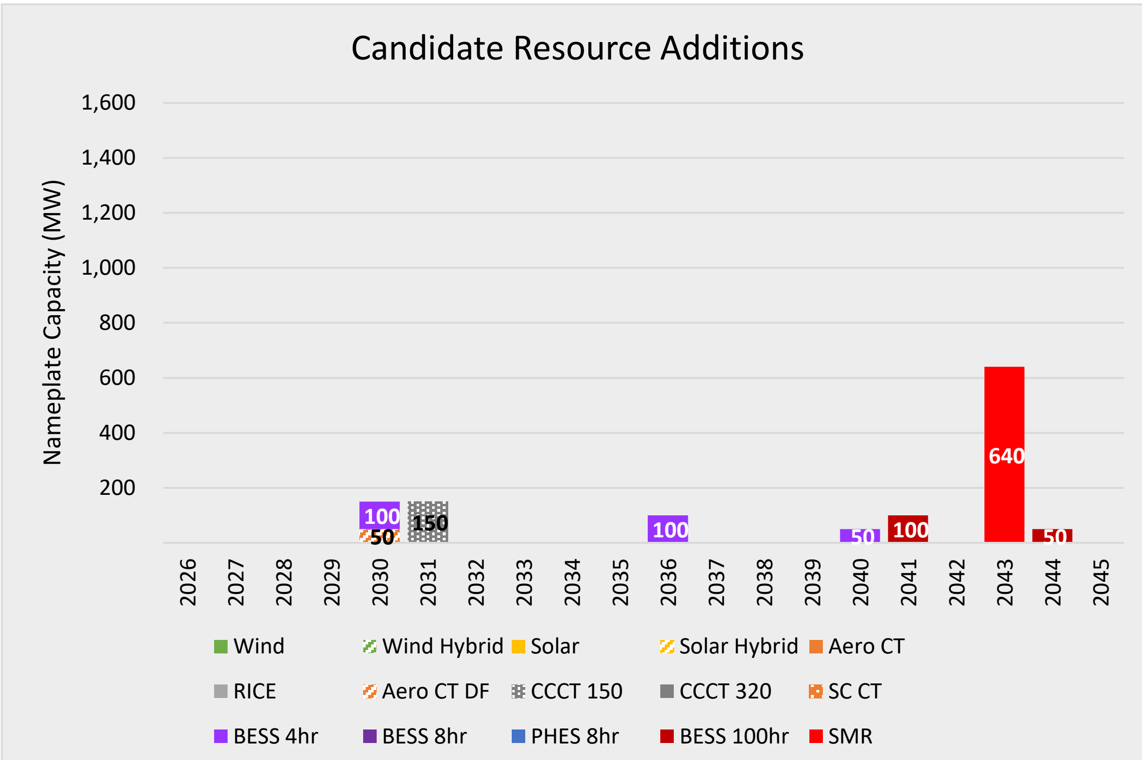


FIGURE 79: ARS RESULTS FOR SENSITIVITY H.

7.7.9 ARS Results: Sensitivity I – Natural Gas Price Forecast Increased by 50%

Sensitivity I represents a 50% increase in the natural gas price forecasts. More information about the base natural gas price forecast is discussed in Section 7.4.2 above. Figure 80 shows the ARS results for Sensitivity I. Again, the results of Sensitivity I are very similar to Scenario A. The major resource selections are the two, 320 MW SMRs in January 2043 to mitigate the Colstrip retirement. More information about the change in portfolio costs due to the change in natural gas prices is described in Section 7.8.3 describing the PCM results for the commodity sensitivities.

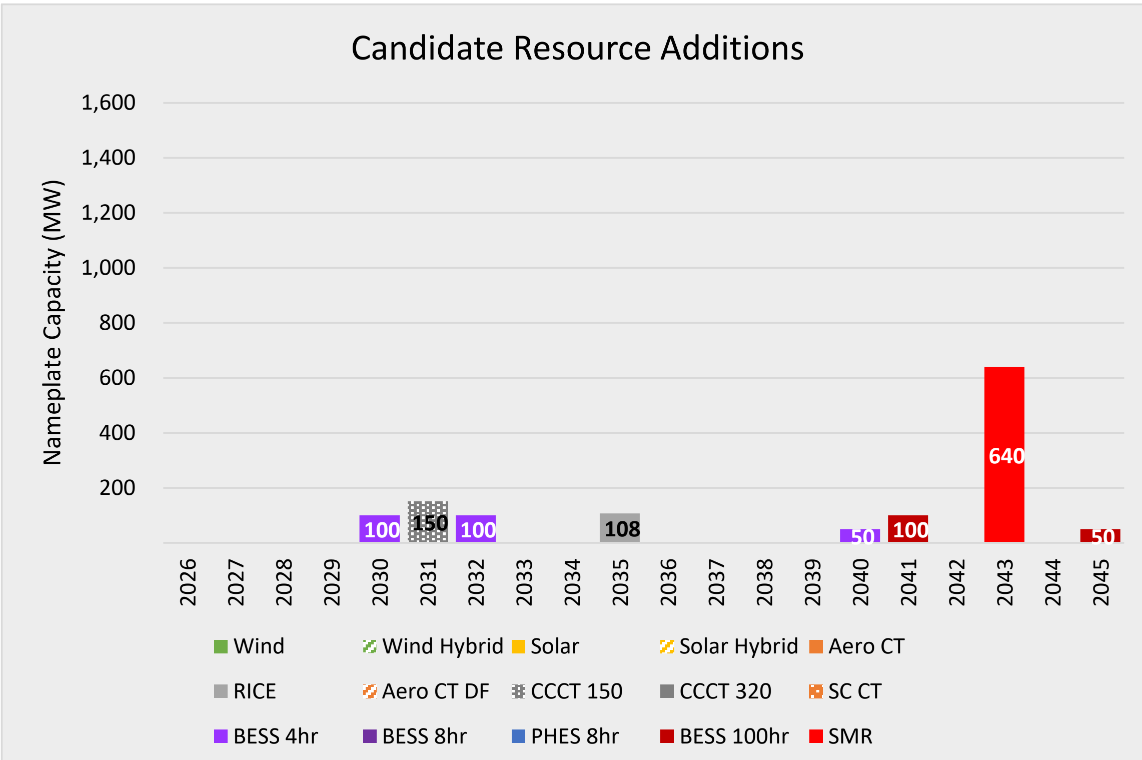


FIGURE 80: ARS RESULTS FOR SENSITIVITY I.

7.7.10 ARS Results: Sensitivity J – Add 150 MW of Data Center Load

Sensitivity J represents a 150 MW total increase in NorthWestern's retail load obligation due to data center additions. The timeline in which data center load is added to the portfolio is described in Section 7.5 above. Sensitivity J also includes the 370 MW Puget share of Colstrip in the portfolio to serve retail load. The additional Colstrip share is included in the data center sensitivities to help meet the additional capacity requirement. Figure 81 shows the ARS results for Sensitivity J. The addition of the Puget share to the resource portfolio allows for surplus capacity even with the additional 150 MW of data center load. There are relatively small resource additions throughout the planning period until the Colstrip retirement. The major resource selections are the three, 320 MW SMRs in January 2043 to mitigate the Colstrip retirement. While the total generation does increase from Scenario A, there are also more customers and total energy consumption in which the additional costs will be shared. More information about the change in portfolio costs due to the additional data center load and additional shares of Colstrip are described in Section 7.8.4 describing the PCM results for the data center sensitivities.

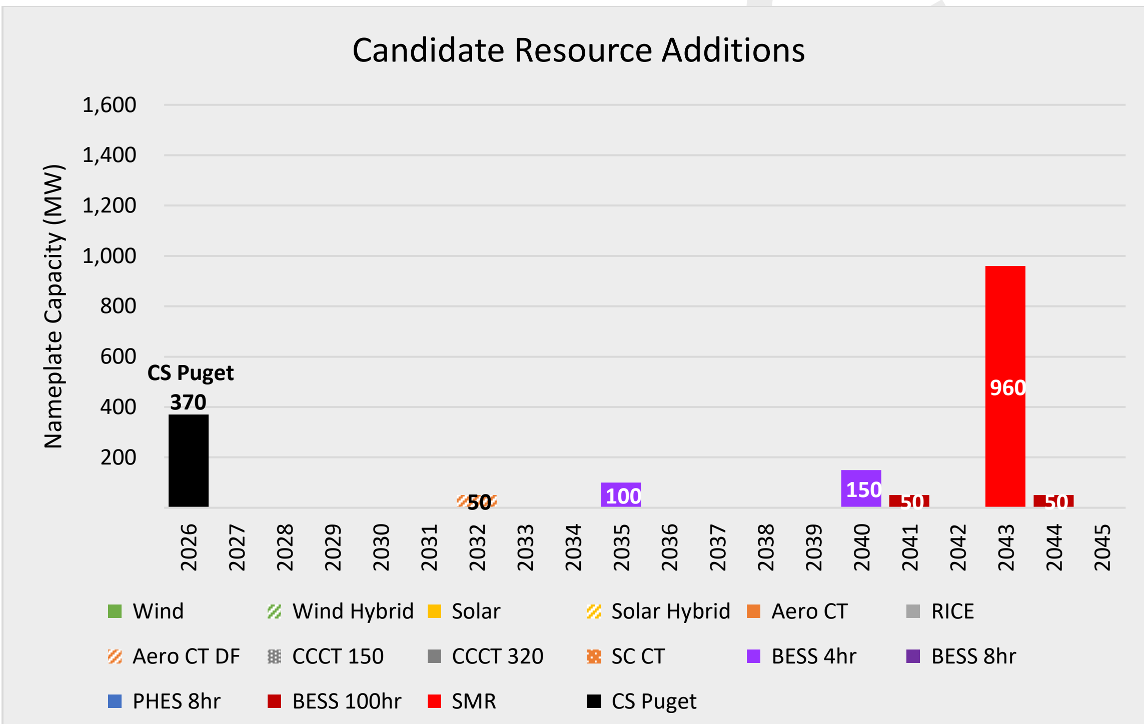


FIGURE 81: ARS RESULTS FOR SENSITIVITY J.

7.7.11 ARS Results: Sensitivity K – Add 650 MW of Data Center Load

Sensitivity K represents a 650 MW total increase in NorthWestern's retail load obligation due to data center additions. The timeline in which data center load is added to the portfolio is described in Section 7.5 above. Sensitivity K also includes the 370 MW Puget share of Colstrip in the portfolio to serve retail load. The additional Colstrip share is included in the data center sensitivities to help meet the additional capacity requirement. Figure 82 shows the ARS results for Sensitivity K. The large data center load addition exceeds the additional Colstrip capacity from Puget. Therefore, a large number of resources are selected immediately in January 2030 to meet the capacity need. The next major resource selections are the three, 320 MW SMRs, and two, 50 MW LDES in January 2043 to mitigate the Colstrip retirement. Additional wind and LDES resources are selected in November 2045. While the total generation does increase from Scenario A, there are also more customers and total energy consumption in which the additional costs will be shared. More information about the change in portfolio costs due to the additional data center load and additional shares of Colstrip are described in Section 7.8.4 describing the PCM results for the data center sensitivities.

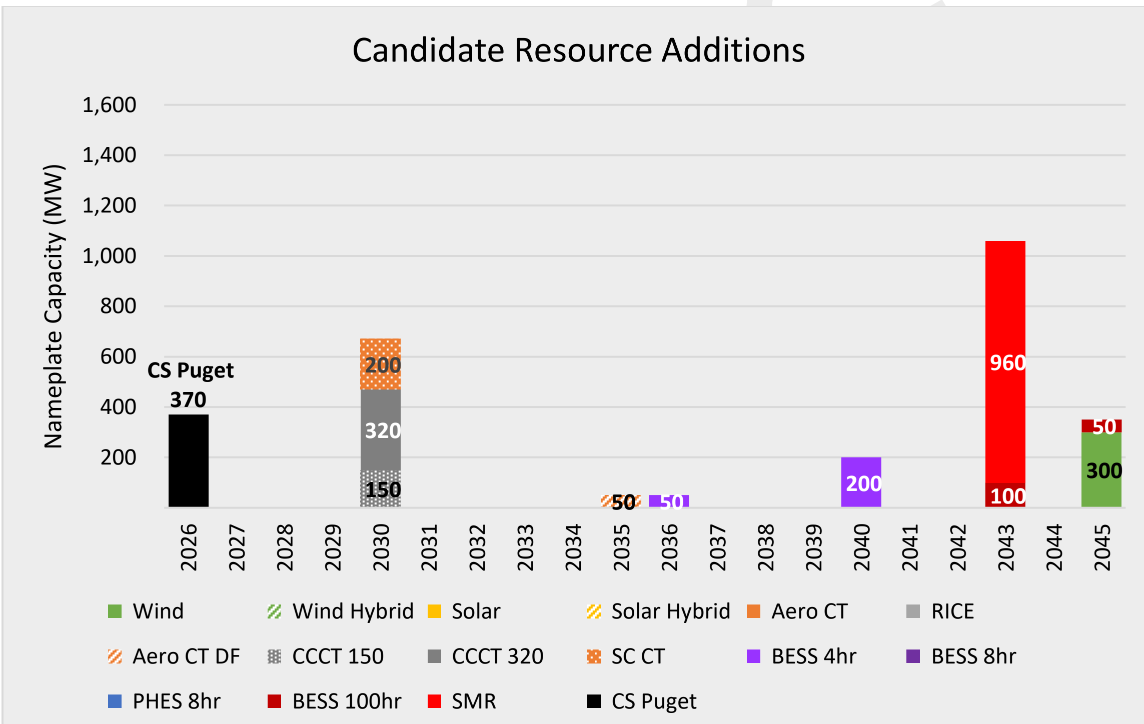


FIGURE 82: ARS RESULTS FOR SENSITIVITY K.

7.7.12 ARS Results: Sensitivity L – Add 1,160 MW of Data Center Load

Sensitivity L represents a 1,160 MW total increase in NorthWestern's retail load obligation due to data center additions. The timeline in which data center load is added to the portfolio is described in Section 7.5 above. Sensitivity L also includes the 370 MW Puget share of Colstrip in the portfolio to serve retail load. The additional Colstrip share is included in the data center sensitivities to help meet the additional capacity requirement. Figure 83 shows the ARS results for Sensitivity L. The large data center load addition exceeds the additional Colstrip capacity from Puget. Therefore, a large number of resources are selected immediately in January 2030 to meet the capacity need. The next major resource selections are the three, 320 MW SMRs, and two, 50 MW LDES, in January 2043 to mitigate the Colstrip retirement. Additional hybrid solar resources are selected in November 2044. While the total generation does increase from Scenario A, there are also more customers and total energy consumption in which the additional costs will be shared. More information about the change in portfolio costs due to the additional data center load and additional shares of Colstrip are described in Section 7.8.4 describing the PCM results for the data center sensitivities.

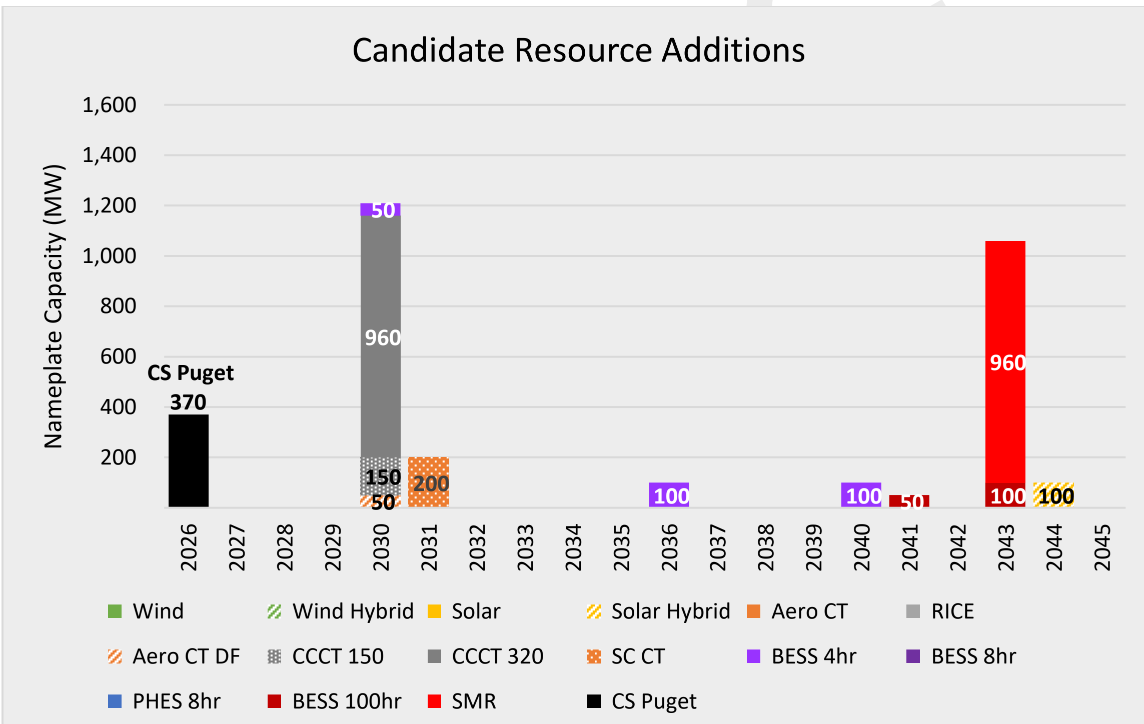


FIGURE 83: ARS RESULTS FOR SENSITIVITY L.

7.7.13 ARS Results: Sensitivity M – No Limitation on Carbon Emitting Resources

Sensitivity M allows carbon emitting resources to be selected throughout the planning period to comply with the Commission's comments from the 2023 Montana IRP. Figure 84 shows the ARS results for Sensitivity M. Similar to Scenario A, Base Case, the near-term results for Scenario M show resource selections in 2030 to meet a winter capacity shortfall, and additional short-duration BESS selections in 2032 to mitigate the expiration of the 150 MW Heartland contract. Later in the planning period, ARS views both the small 150 MW and large 320 MW CCCT units as optimal resources to meet load growth as well as to mitigate the Colstrip retirement, as well as 50 MW of LDES. This result is different in the post-2035 period from Scenario A because carbon emitting resources, i.e. natural gas-fueled resources, are allowed to be selected to meet capacity needs. More information about the change in portfolio costs due to the different resource options is described in Section 7.8.5 describing the PCM results for the resource sensitivities.

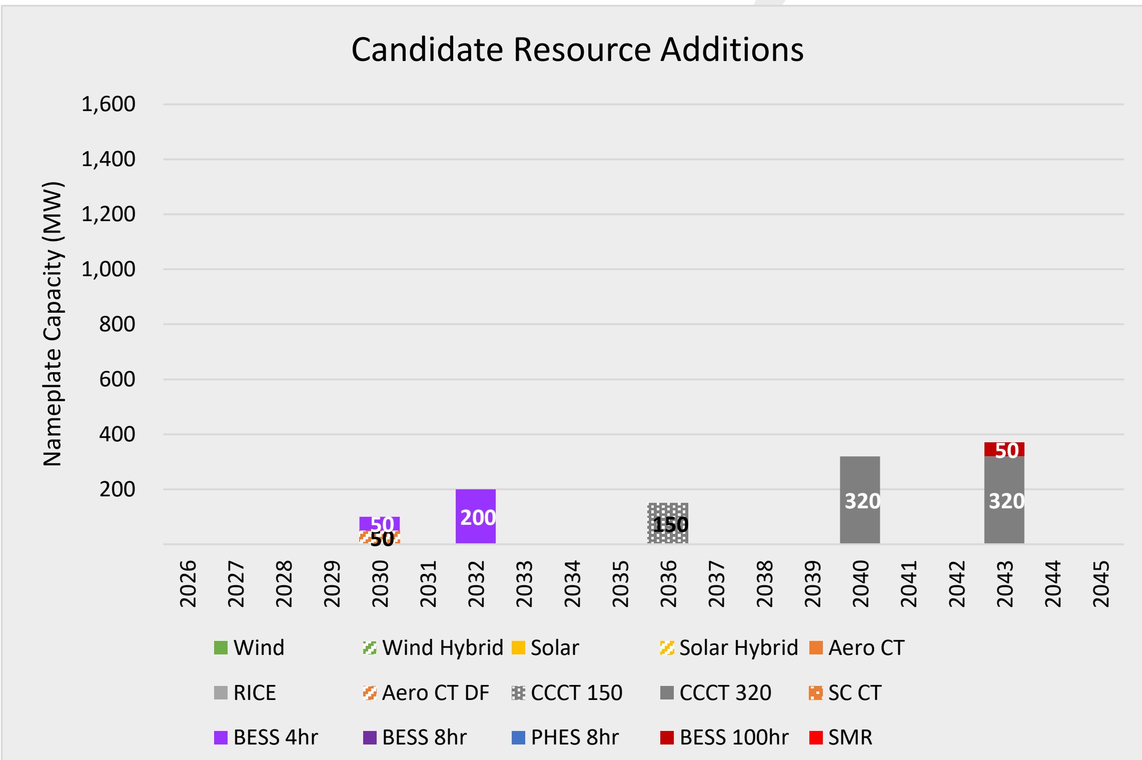


FIGURE 84: ARS RESULTS FOR SENSITIVITY M.

7.7.14 ARS Results: Sensitivity N – Carbon Free Candidate Resources Only

Sensitivity N allows only carbon free candidate resources to be selected to fill capacity needs throughout the planning horizon. Figure 85 shows the ARS results for Sensitivity N. Capacity needs are met with both short BESS and LDES resources early in the planning period. Wind and SMR resources are selected to meet load growth and resource retirements later in the planning period. More information about the change in portfolio costs due to the different resource options is described in Section 7.8.5 describing the PCM results for the resource sensitivities.

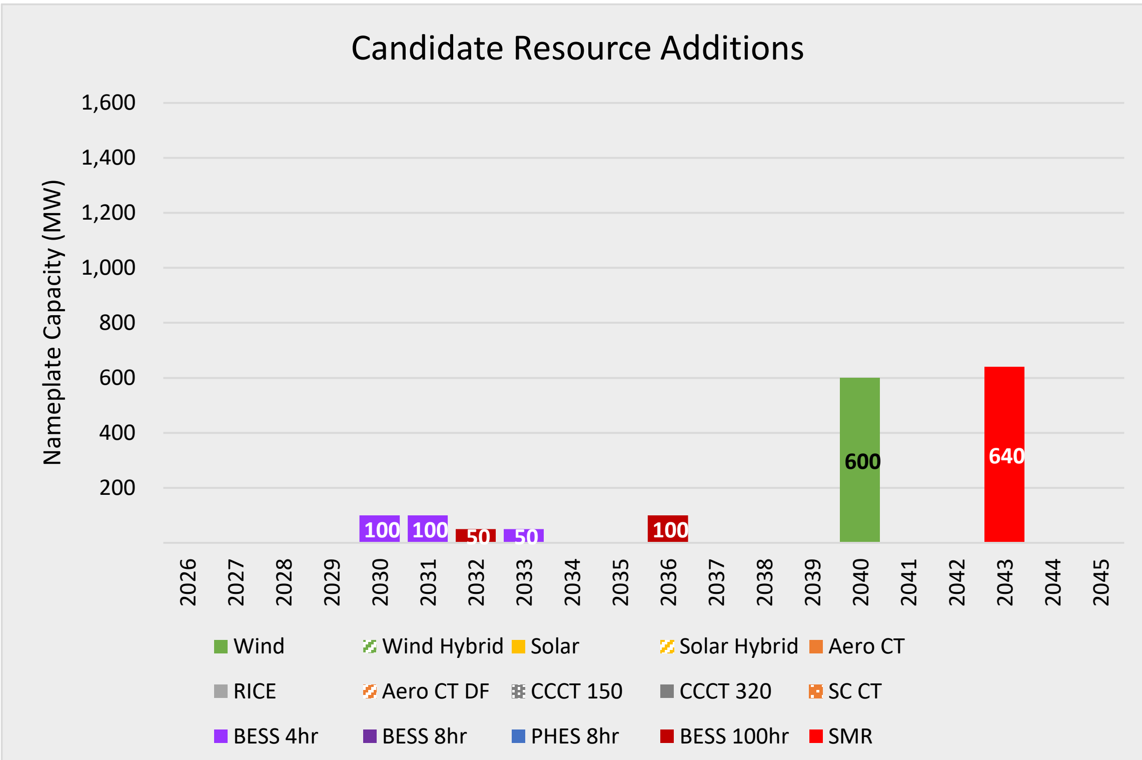


FIGURE 85: ARS RESULTS FOR SENSITIVITY N.

7.7.15 ARS Results: Sensitivity O – PSE Colstrip Share is used for Retail Load

Sensitivity O evaluates the portfolio assuming the 370 MW Puget share of Colstrip is included in the resource portfolio to serve retail load. Figure 86 shows the ARS results for Sensitivity O. With the additional 370 MW of Colstrip from Puget, new capacity is not needed until December 2040. When Colstrip retires at the end of 2042, the large capacity deficit is filled at the start of 2043. More information about the change in portfolio costs due to the different resource options is described in Section 7.8.5 describing the PCM results for the resource sensitivities.

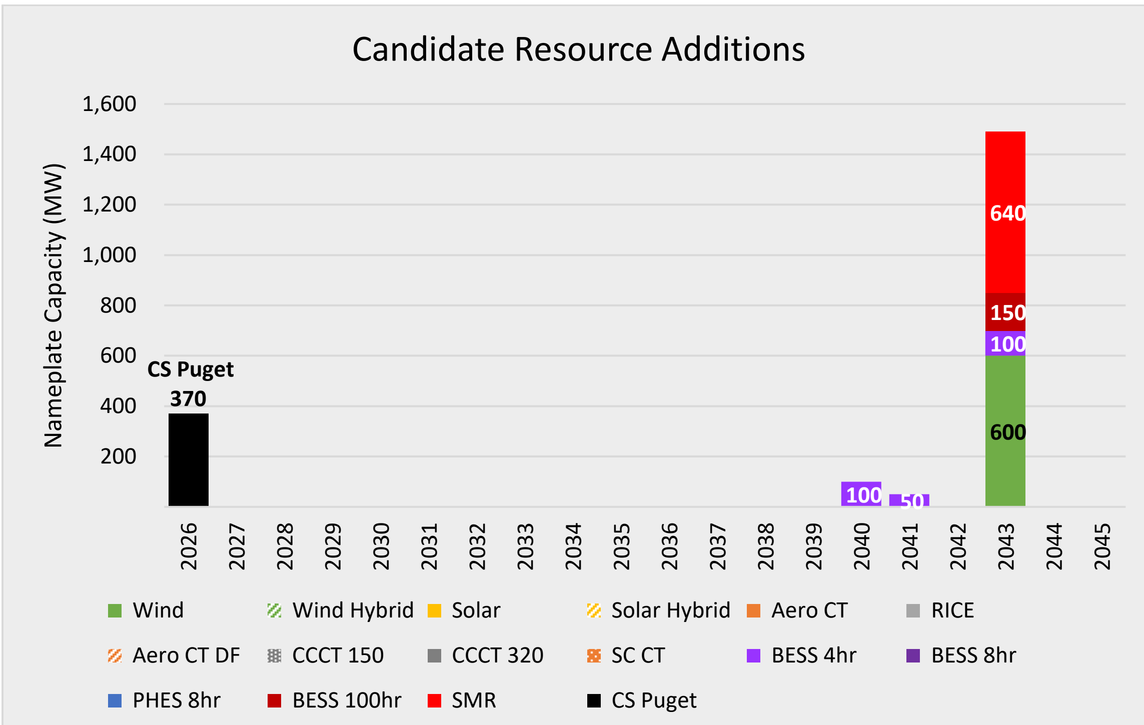


FIGURE 86: ARS RESULTS FOR SENSITIVITY O.

7.7.16 ARS Results: Sensitivity P – Avista's Colstrip Shares are not Acquired

Sensitivity P evaluates the portfolio assuming Avista's 222 MW of Colstrip are not acquired. Figure 87 shows the ARS results for Sensitivity P. Without the additional 222 MW of Colstrip from Avista, more capacity is needed earlier in the planning horizon. ARS selects 350 MW of nameplate capacity in January 2030 as well as an additional 320 MW in January 2032. The Colstrip retirement in 2042 is less significant compared to other sensitivities because there are only 222 MW of total nameplate capacity of Colstrip in the portfolio so the resource selections in 2043 are less than other sensitivities. More information about the change in portfolio costs due to the different resource options is described in Section 7.8.5 below, which details the PCM results for the resource sensitivities.

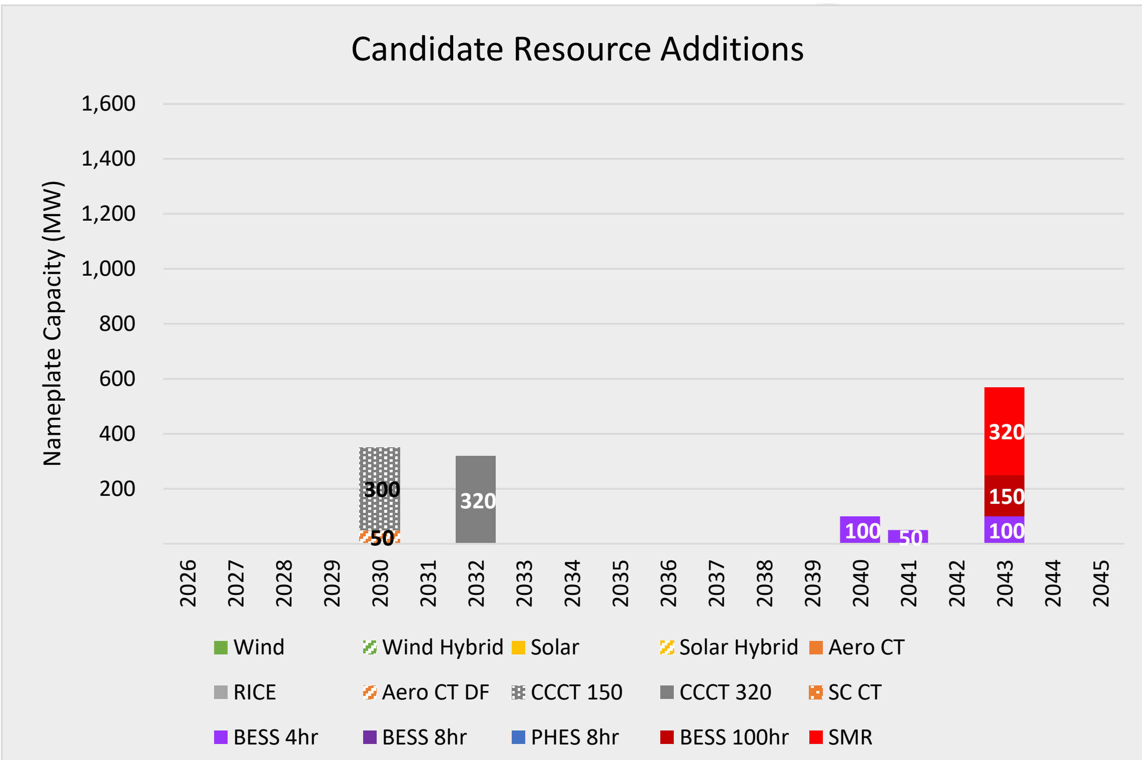


FIGURE 87: ARS RESULTS FOR SENSITIVITY P.

7.7.17 ARS Results: Sensitivity Q – Add 300 MW of NPC Capacity

Sensitivity Q evaluates the potential benefits of NorthWestern's 300 MW share of the NPC. However, the ARS results do not change with changes in transmission capacity or new market access because ARS assumes that all candidate resource revenue is delivered to the main market, i.e. Mid-C. Therefore, the ARS results for Scenario Q are the same as Scenario A. More information about the NPC can be found in Section 6.5, and more information about the change in portfolio costs due to the increased transmission capacity from NPC is described in Section 7.8.6 describing the PCM results for the "other" sensitivities.

7.7.18 ARS Results: Sensitivity R – Increase DSM and NEM Forecasts

Sensitivity R evaluates any changes to the portfolio due to a doubling of the DSM acquisition goal and an increased NEM forecast. Figure 88 shows the comparison of the seasonal peak load forecasts between Scenario A and Sensitivity R. Given the modified load forecast for Sensitivity R, Figure 89 shows the ARS results. The results for Sensitivity R show a small reduction in resource selections compared to Scenario A with the major resource selections occurring in January 2043 to mitigate the Colstrip retirement. More information about the change in portfolio costs due to the reduced load from increased DSM and NEM is described in Section 7.8.6 describing the PCM results for the "other" sensitivities.

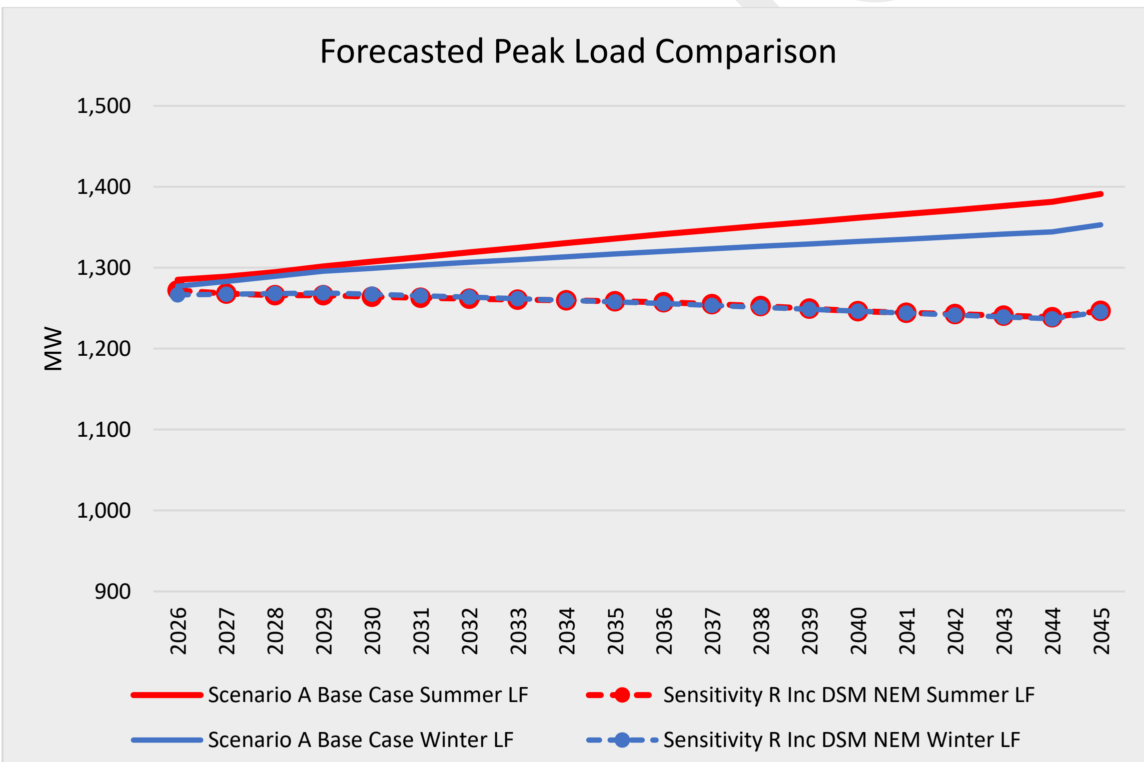


FIGURE 88: COMPARISON OF THE SEASONAL PEAK LOAD FORECAST FOR SCENARIO A BASE CASE AND SENSITIVITY R INCREASE DSM AND NEM FORECASTS.

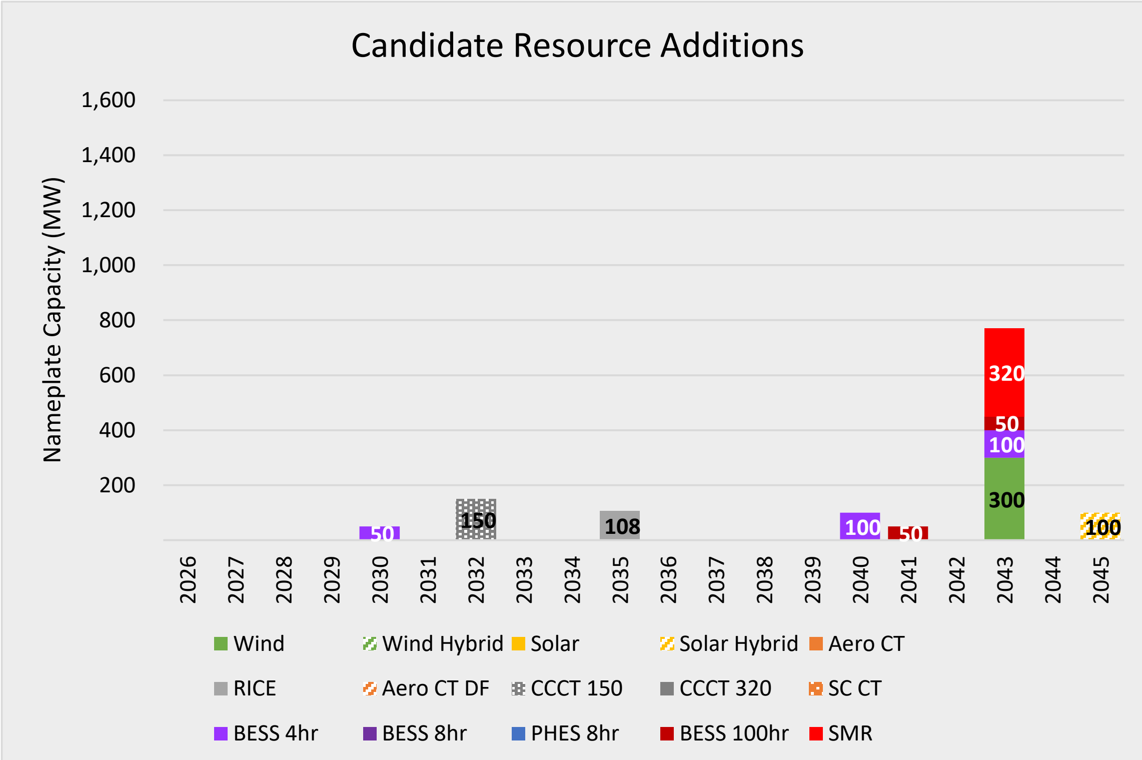


FIGURE 89: ARS RESULTS FOR SENSITIVITY R.

7.7.19 ARS Summary of Base Case and Main Scenarios

Figure 90 shows a summary of the resource mix chosen across different scenarios including Scenario A, Base Case, and Scenarios B through E. The results of Scenario C, Colstrip Complies with MATS via Baghouse, are not shown here because it is assumed that the ARS results do not change from Scenario A, as described in Section 7.7.3 above. The ARS results for scenarios B, D, and E show that more natural gas-fueled resources are selected as compared to Scenario A due to the large capacity needs occurring before the Net Zero constraint occurs starting in 2036. While there are differences in total generation across the main scenarios, they are not significant given the 20-year planning period. It is important to remember that the time in which each resource is added to the portfolio does impact the overall portfolio cost. More information about the total portfolio costs for each of the main scenarios is described in Section 7.8.2.

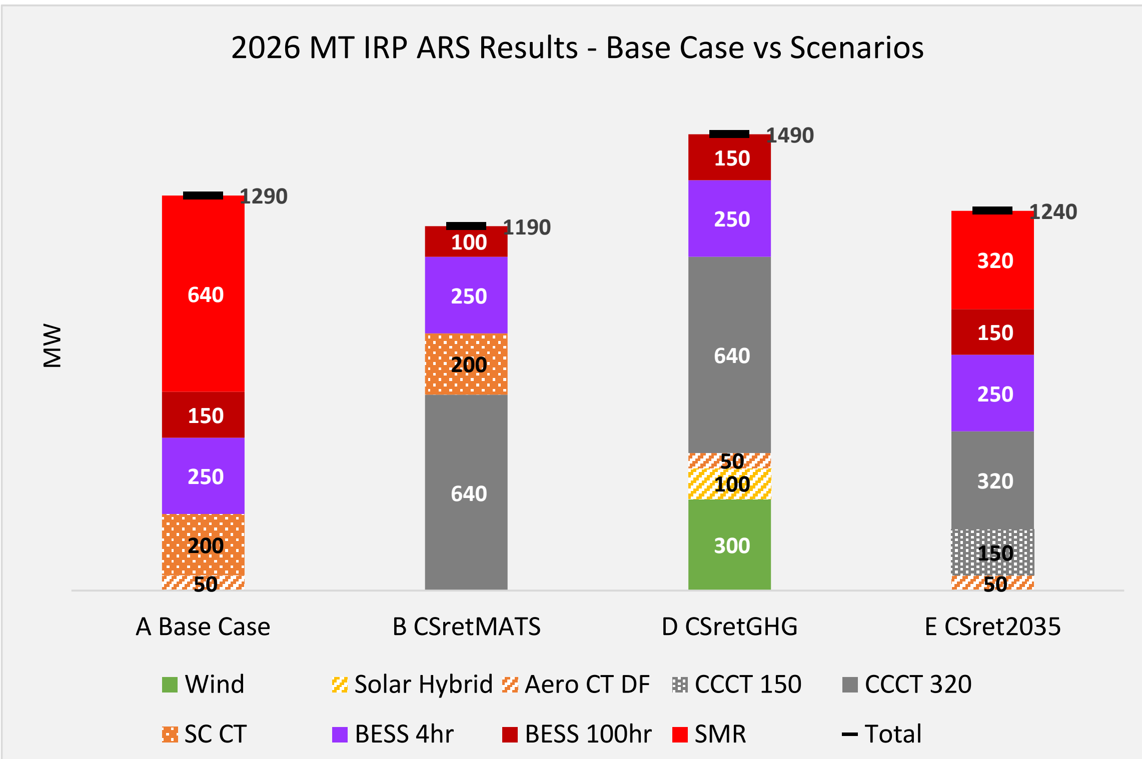


FIGURE 90: ARS SUMMARY OF THE BASE CASE AND THE MAIN SCENARIOS.

7.7.20 ARS Summary of Commodity Sensitivities

Figure 91 shows a summary of the resource mix chosen across Scenario A, Base Case, and the sensitivities that modeled different commodity prices. Sensitivities F and G modeled a 50% decrease and a 50% increase in power prices, respectively, and Sensitivities H and I modeled a 50% decrease and a 50% increase in natural gas prices, respectively. The ARS results of sensitivities F, G, H, and I show very minor changes in resource selections compared to Scenario A. The differences in generation dispatch due to change in power or natural gas prices are evident in the PCM studies. More information about the total portfolio costs for each of the commodity sensitivities is described in Section 7.8.3.

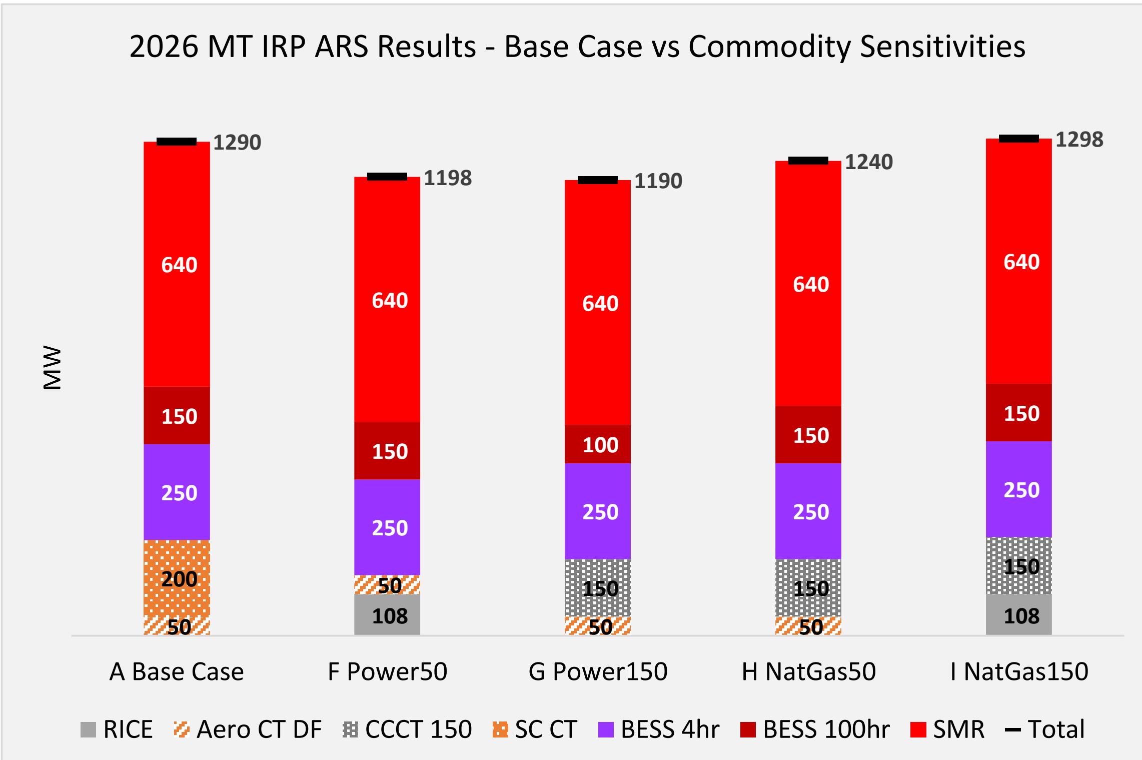


FIGURE 91: ARS SUMMARY OF THE BASE CASE AND THE COMMODITY SENSITIVITIES.

7.7.21 ARS Summary of Data Center Sensitivities

Figure 92 shows a summary of the resource mix chosen across the Base Case and the sensitivities that modeled different levels of data center additions. Sensitivities J, K, and L modeled an additional 150 MW, 650 MW, and 1160 MW of data center load, respectively. The timeline in which data center load is added to each portfolio is described in Section 7.5 above. For each of these sensitivities, it was also assumed that the 370 MW Puget share of Colstrip was also included in the portfolio to serve retail load. The ARS results of sensitivity J does not vary significantly from Scenario A. However, sensitivities K and L show large additions of generation to meet the increased data center demand. While the total generation does increase from Scenario A, there are also more customers and total energy consumption in which the additional costs will be shared. More information about the total portfolio costs for each of the data center sensitivities is described in Section 7.8.4.

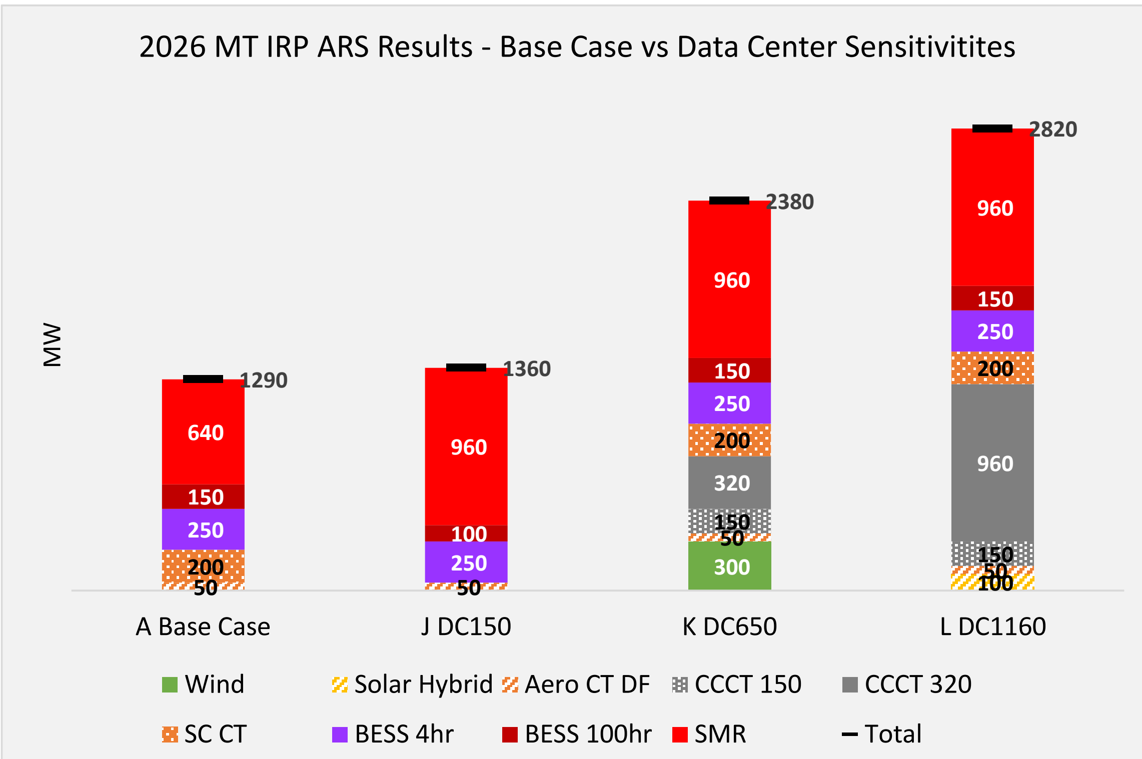


FIGURE 92: ARS SUMMARY OF THE BASE CASE AND THE DATA CENTER SENSITIVITIES.

7.7.22 ARS Summary of Resource Sensitivities

Figure 93 shows a summary of the resource mix chosen across the Base Case and the sensitivities that modeled different amounts of Colstrip as well as different candidate resource options. Sensitivity M allowed carbon emitting resources to be selected throughout the planning horizon while Sensitivity N allowed no carbon emitting resources to be selected throughout the planning horizon. Sensitivity O shows how the portfolio changes with the addition of the 370 MW Puget share of Colstrip while Sensitivity P shows how the portfolio changes without any Colstrip acquisition from either Avista or Puget. The results show that Sensitivity M requires the least amount of generation additions. Interestingly, Sensitivity N and Sensitivity O result in the same total resource mix. Sensitivity P does not show a significant difference in the magnitude of total resources. However, the timing of the resource additions to the portfolio does impact the overall portfolio cost. More information about the total portfolio costs for each of the resource sensitivities is described in Section 7.8.5.

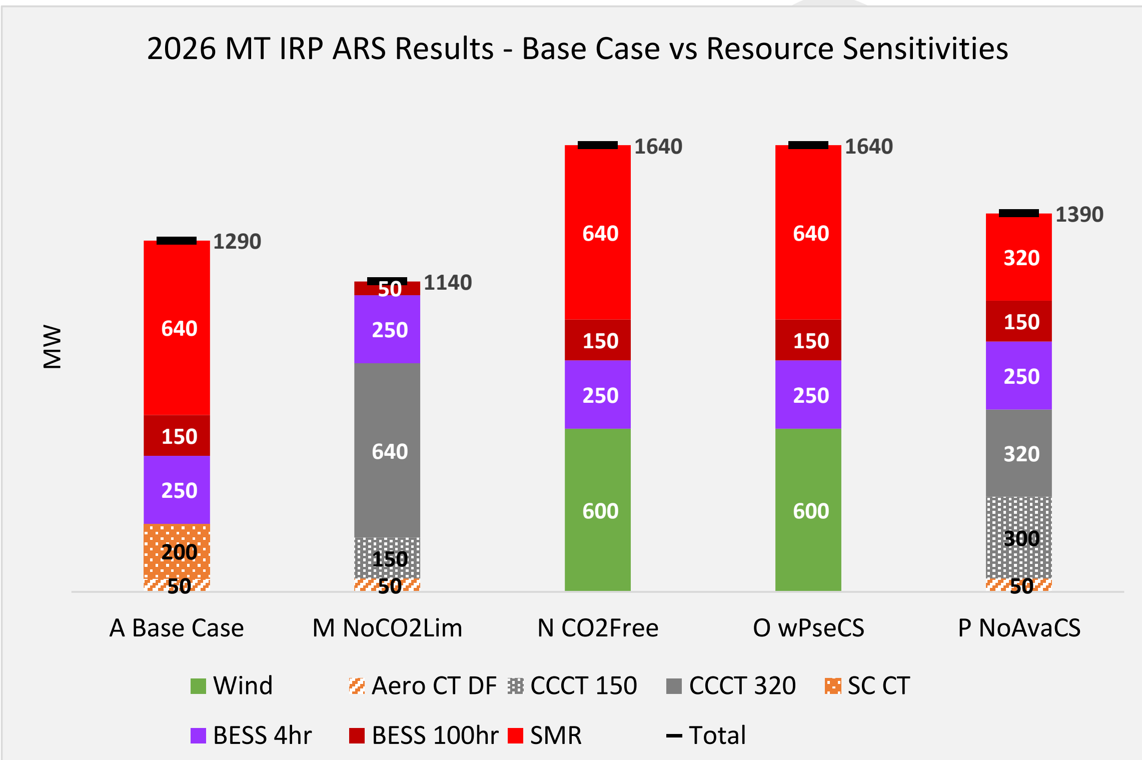


FIGURE 93: ARS SUMMARY OF THE BASE CASE AND THE RESOURCE SENSITIVITIES.

7.7.23 ARS Summary of Other Sensitivities

Figure 94 shows a summary of the resource mix chosen across the Base Case and Sensitivity R which consisted of increased DSM and NEM acquisitions. The ARS results of Sensitivity R show that the total resource additions do not vary significantly from Scenario A. Again, the timing of the resource additions to the portfolio does impact the overall portfolio cost. More information about the total portfolio costs for each of the other sensitivities is described in Section 7.8.6. Sensitivity Q, the addition of 300 MW of new transmission capacity from the NPC, is also included in the "other" sensitivity category, but, as explained above in Section 7.7.17, the ARS results do not change with changes in transmission capacity or new market access. Therefore, the ARS results for Sensitivity Q are the same as Scenario A.

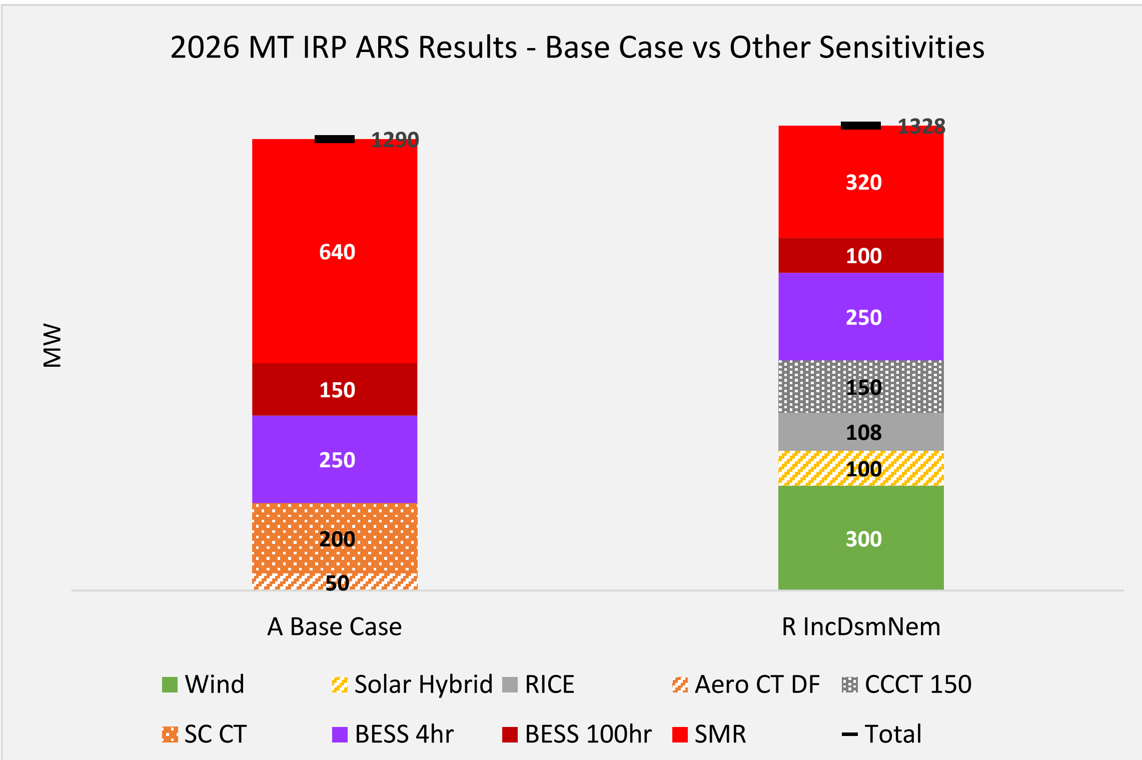


FIGURE 94: ARS SUMMARY OF THE BASE CASE AND THE OTHER SENSITIVITIES.

7.8 PCM Results

The following sections describe the PCM results for the scenarios and sensitivities defined in Section 7.5. The total portfolio costs are broken down into sub-categories that include transmission export revenues, portfolio production costs, transmission import costs, existing resource partial RR, and candidate resource partial RR. All costs represent a 20-year NPV from 2026 to 2045 using a 6.72% discount rate. The discount rate is the WACC approved in NorthWestern's 2022 electric rate case (Docket 2022.07.078). Each portfolio cost is also compared on a percentage basis to the Base Case.

Transmission export costs represent market sales when the portfolio can sell excess energy to the market above variable costs; these costs are captured as a negative cost, or credit, that offsets the total cost. Portfolio production costs include fuel costs, fuel delivery costs, startup costs, fixed and variable O&M, and PPA costs. Transmission import costs represent market purchases when the portfolio is short of energy or when energy can be purchased from the market cheaper than the portfolio's resources can be dispatched. These variables are derived from the PowerSIMM PCM study.

The existing resource partial RR costs are made up of NorthWestern's currently owned resources described in Table 16 including Colstrip, DGGS, YCGS, the hydro fleet, Spion Kop and Two Dot Wind. The existing resource partial RR calculations have been simplified such that no additional capital investments are assumed for these assets over the study period. Operating expenses escalate every year by an assumed 2.5% inflation rate. For both existing and candidate resources, the annual stream of partial RR from 2026 through 2045 assumes that NorthWestern establishes a new partial RR each year using a consistent rate of return. This methodology differs from a traditional rate case, in which the RR typically reflects incremental capital additions from the previous case and is not reset on an annual basis. The partial Colstrip RR, however, includes the projected increases in O&M expenses associated with NorthWestern's increased ownership share of Colstrip, as applicable under each modeled scenario or sensitivity. Finally, for simplification, no Tax Cuts and Jobs Act excess deferred income tax impacts were computed with respect to the existing resource partial RR calculations. The partial RR for candidate resources are included in the ARS module as well as the PCM results for each scenario or sensitivity.

The PCM results also include separate figures that describe the remaining book value of candidate resources in 2046 discounted back to 2026. These figures are an additional measure to help the reader understand capital costs that were not included in the 20-year NPV analysis. In addition to the capital costs that are not captured in the total NPV portfolio costs, there are other costs, such as fuel, O&M, or additional market sales or purchases, that NorthWestern does not attempt to include.

Supporting files for the PCM results are included as attachments in Appendix H.

7.8.1 PCM Results: Scenario A – Base Case

As described above, Scenario A represents the Base Case portfolio in which the resources described in Chapter 5 operate through their expected depreciable life or contract expiration date. All candidate resources selected to meet the projected capacity forecast of the Base Case are described in ARS Results, Section 7.7.1. The simulated energy production of the entire resource portfolio, including owned and contracted resources as well as the selected candidate resources, is shown in Figure 95 below. The results show that the portfolio generates enough energy to meet the energy forecast plus additional market sales.

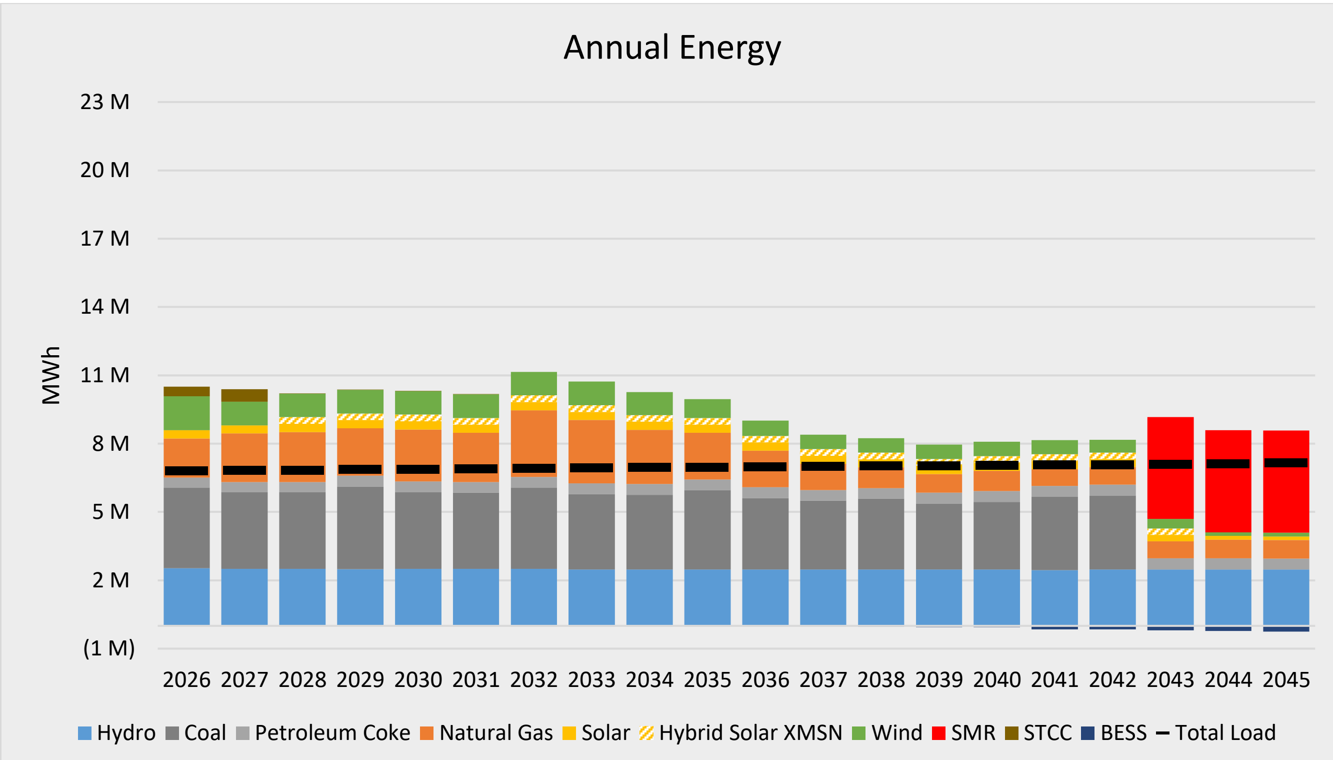


FIGURE 95: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO A – BASE CASE.

The capacity factors of resources in the existing portfolio are described in Figure 96. The results show that, in the near term, DGGS and YCGS have very high-capacity factors while Basin Creek generates at its maximum output allowed by its air permit. These high-capacity factors in the near term are a result of high projected revenues between power prices and the resources' variable costs, including relatively low natural gas prices.

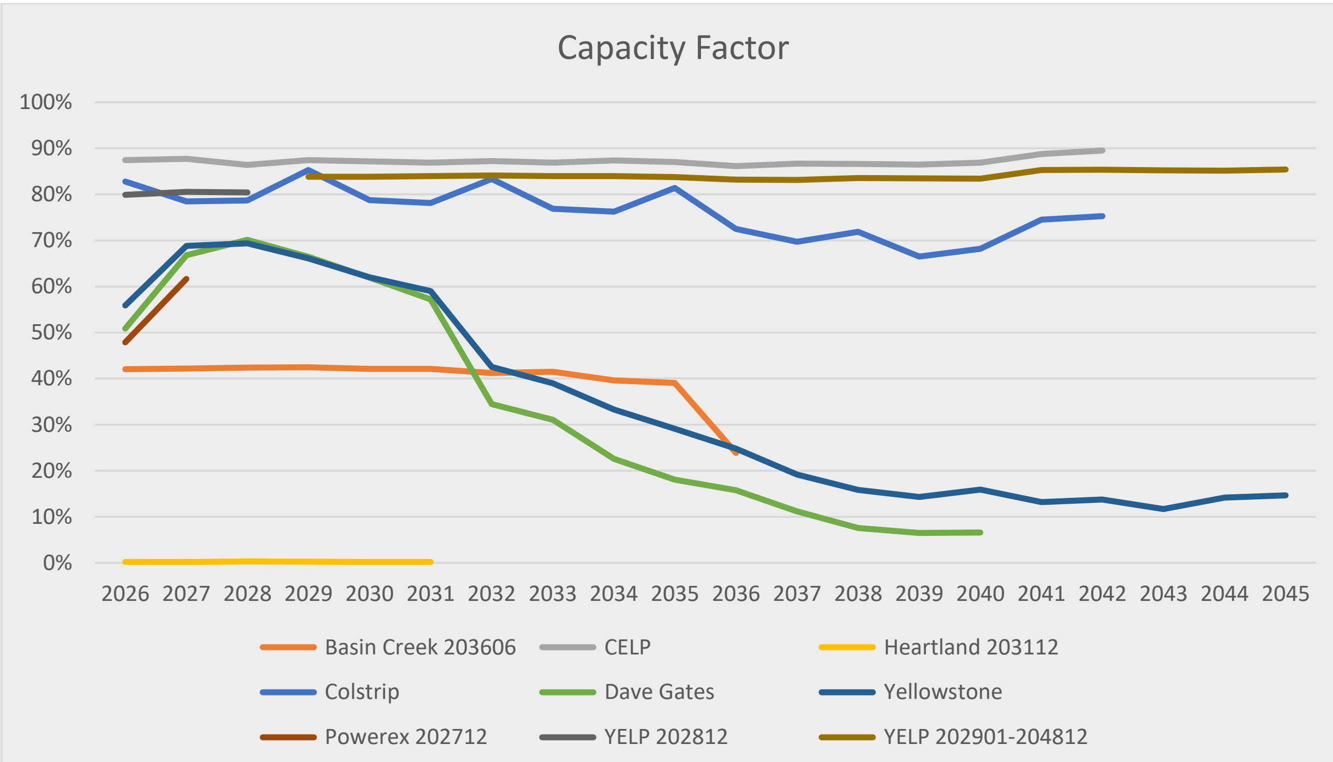


FIGURE 96: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO A – BASE CASE.

The simulated emissions are shown in Figure 97 in which Colstrip makes up more than half of emissions through 2042.

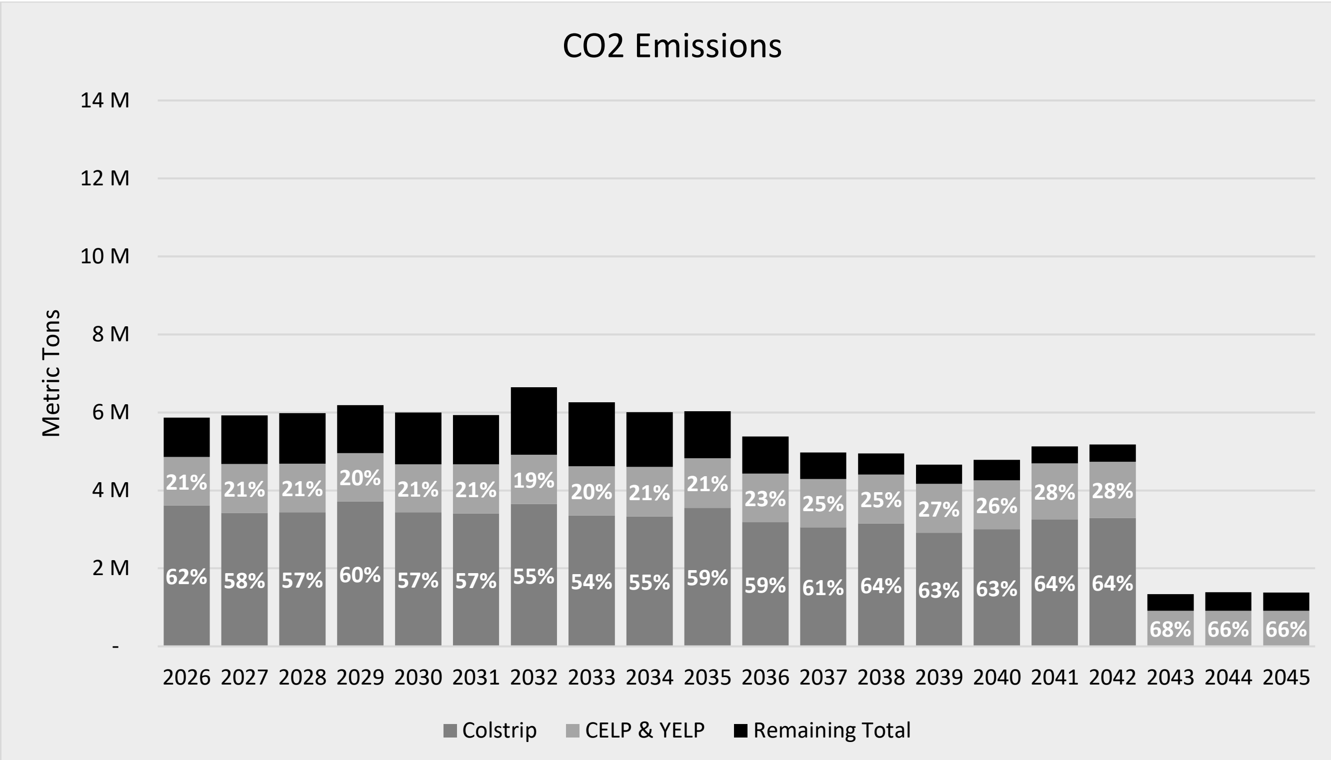


FIGURE 97: EMISSIONS FOR PCM RESULTS OF SCENARIO A – BASE CASE.

Figure 98, Figure 99, and Figure 100 show the simulated transmission volumes, both import and export, the average transmission usage, and the revenues associated with those transmission volumes. The shape of the transmission volumes, and associated revenues, track closely with the Mid-C power price forecast shown in Figure 65. The relatively high transmission exports indicate that the Base Case portfolio can take advantage of the high-power prices to offset costs for retail customers. The relatively low transmission imports are expected as the portfolio is both capacity and energy sufficient, as opposed to a short portfolio that is continually procuring energy and/or capacity from the market.

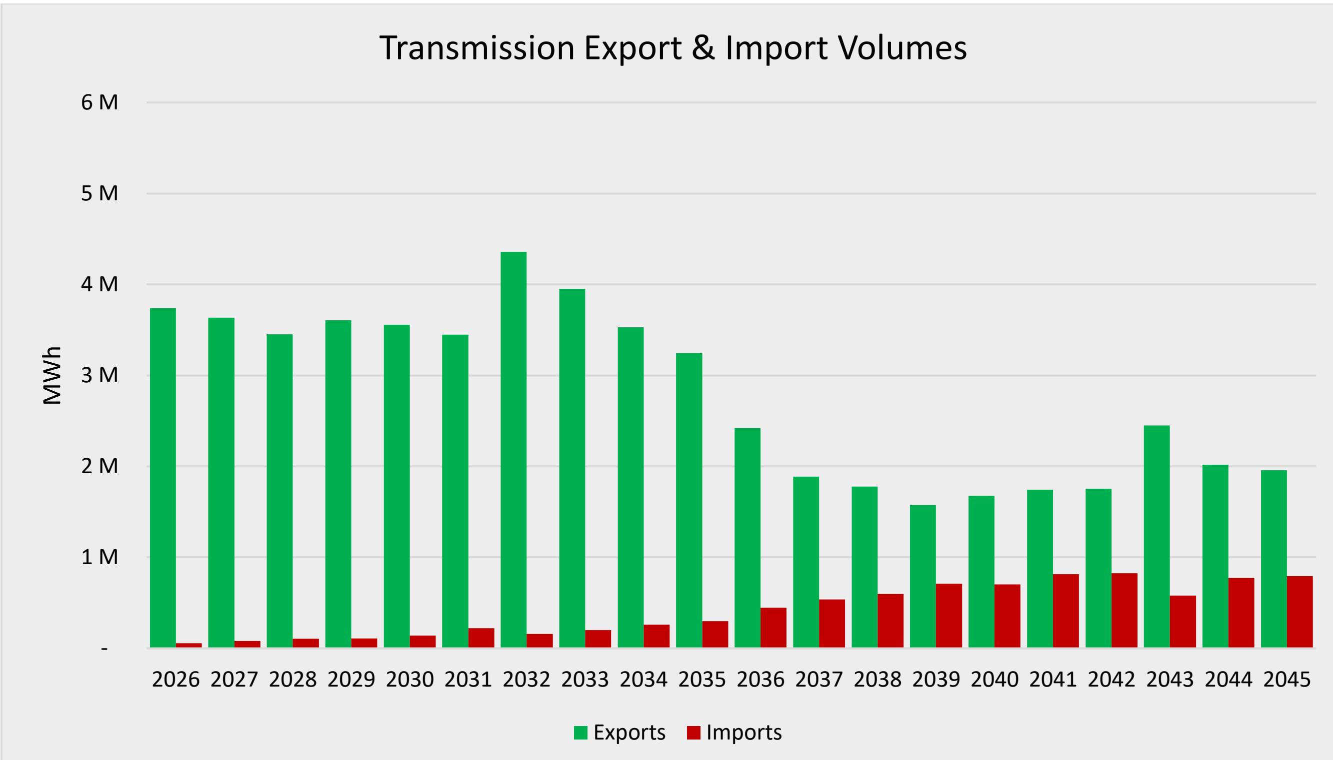


FIGURE 98: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO A – BASE CASE.

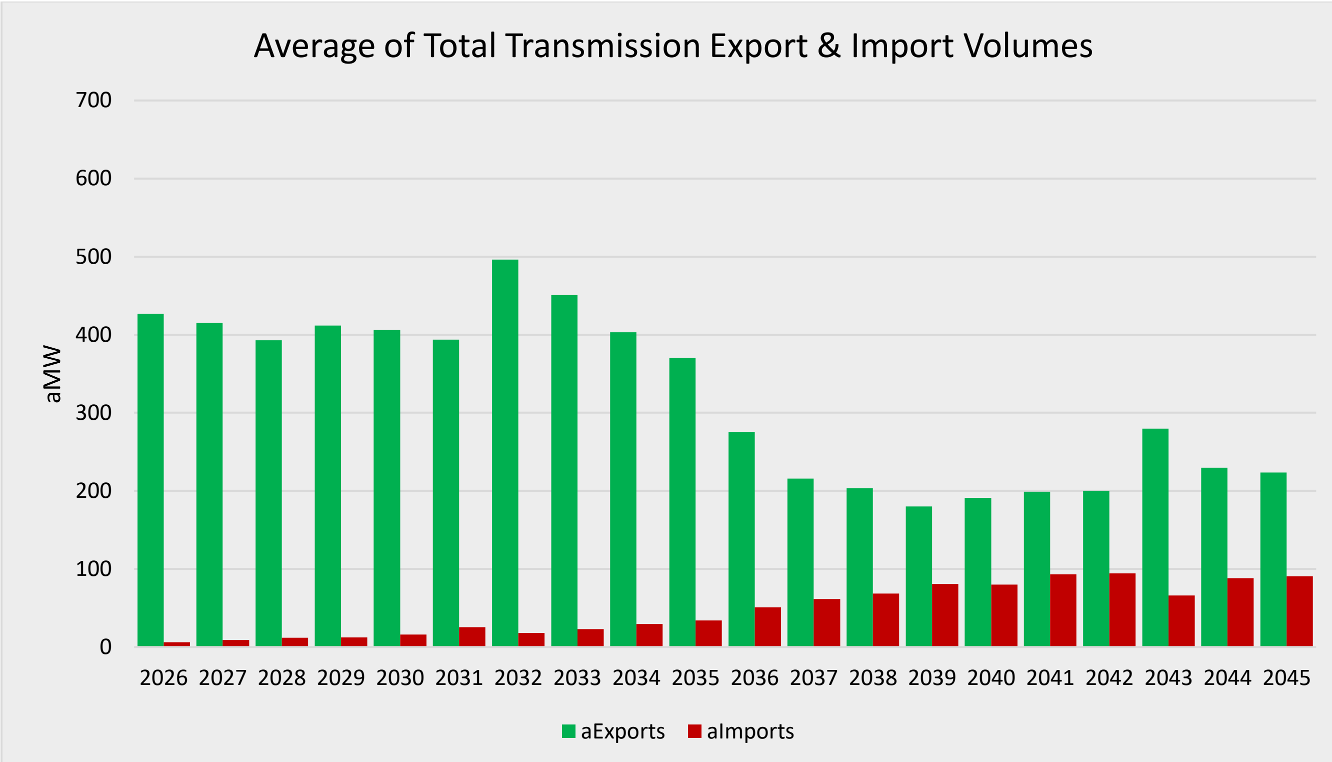


FIGURE 99: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO A – BASE CASE.

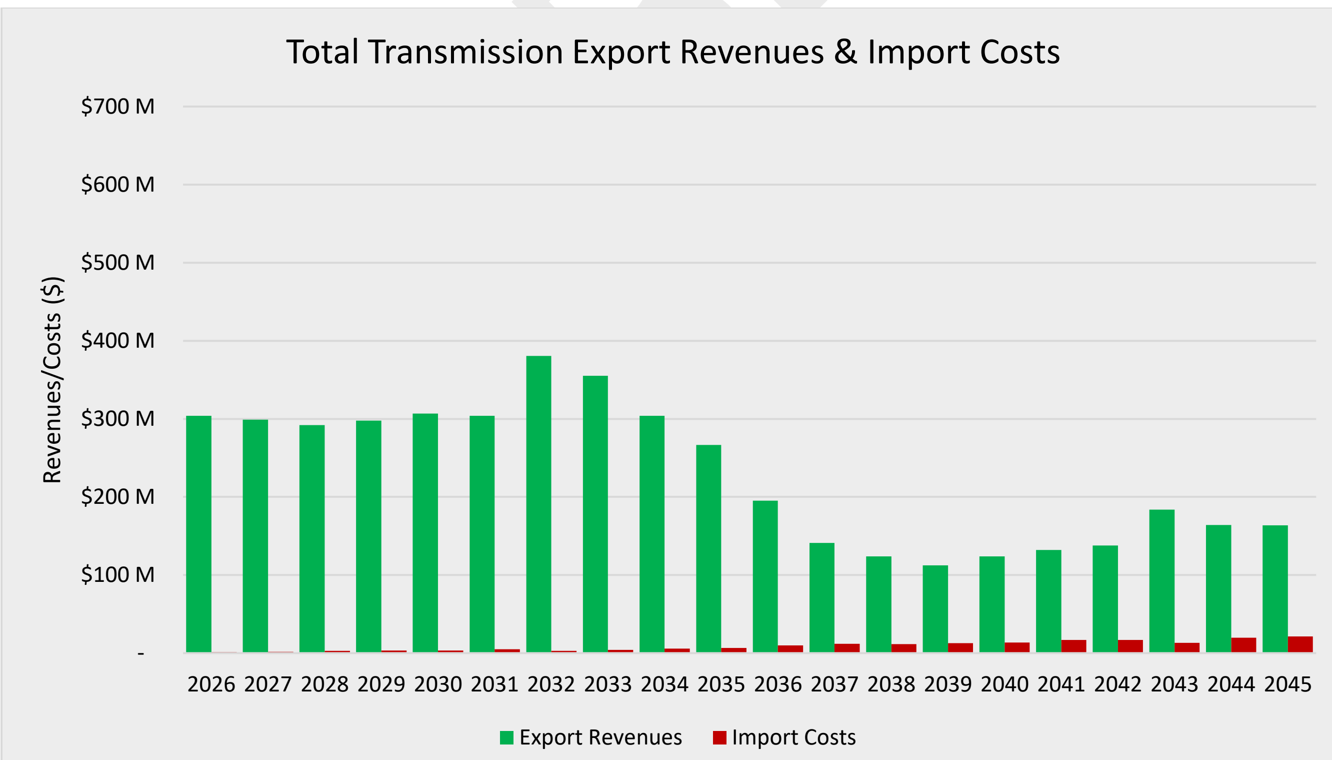


FIGURE 100: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO A – BASE CASE.

Finally, Figure 101 shows the 20-year NPV of the total Base Case portfolio cost as the sum of revenues from transmission exports, or market sales, existing resource partial RR, candidate resource partial RR, the production costs, and transmission import costs, or market purchases. The Base Case portfolio results in a 20-year NPV of $5.672 billion.

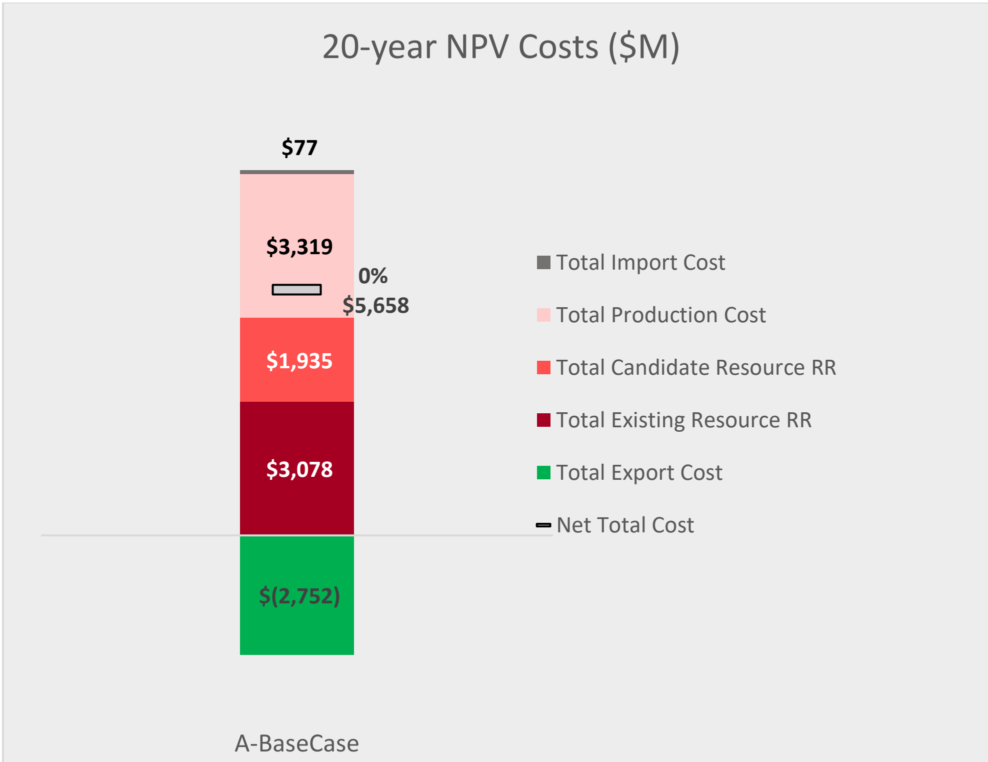


FIGURE 101: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO A – BASE CASE.

Table 54, Table 55, Table 56, Table 57, Table 58, and Table 59 show the Base Case projected resource variable or PPA costs for owned thermal, contracted thermal, contracted hydro, contracted solar, contracted wind, and contracted STCC, respectively. NorthWestern's owned hydro and wind resources do not have variable costs.

Resource	2026	2031	2036	2041
	$/MWh			
Colstrip	[redacted]	[redacted]	[redacted]	[redacted]
YCGS	$40.20	$48.87	$61.42	$65.86
DGGS	$49.06	$58.28	$77.15	retired

TABLE 54: BASE CASE PROJECTED VARIABLE COSTS FOR OWNED THERMAL RESOURCES.

Resource	2026	2031	2036	2041
	$/MWh			
CELP	$114.48	$115.68	$100.80	$91.05
YELP Historic PPA	$129.77	expired	expired	expired
YELP PPA Renewal 2029-01	#N/A	$121.17	$106.05	$96.78
Basin Creek[72]	$62.90	$67.01	$105.32	expired

TABLE 55: BASE CASE PROJECTED CONTRACT COSTS FOR CONTRACTED THERMAL RESOURCES.

[72] The Basin Creek PPA expires June 30, 2036, so the average PPA cost is evaluated over 6 months rather than a full year of production.

Resource	2026	2031	2036	2041
	$/MWh			
Boulder Hydro	$61.10	expired	expired	expired
Broadwater	$63.35	expired	expired	expired
Flint Creek	$72.24	$72.95	$72.99	expired
Hanover Hydro	$62.40	$62.40	expired	expired
Lower South Fork	$72.24	$72.95	$72.99	expired
Pony Generating Station	$41.96	expired	expired	expired
Ross Creek Hydro	$32.34	$32.34	expired	expired
South Dry Creek Hydrodynamics	$43.28	$43.28	$43.36	$13.39
Strawberry Creek Hydrodynamics	$50.58	expired	expired	expired
Wisconsin Creek	$50.58	expired	expired	expired
Turnbull	$73.25	$73.75	expired	expired

TABLE 56: BASE CASE PROJECTED CONTRACT COSTS FOR CONTRACTED HYDRO RESOURCES.

Resource	2026	2031	2036	2041
	$/MWh			
Apex Solar	$43.38	$43.38	$43.38	$43.38
Black Eagle Solar	$67.67	$67.67	$67.67	$67.67
Great Divide Solar	$67.93	$67.93	$67.93	$67.93
Green Meadow Solar	$68.14	$68.14	$68.14	$68.14
Magpie Solar	$67.51	$67.51	$67.51	$67.51
MT Sun	$43.59	$43.59	$43.59	$43.59
River Bend Solar	$67.50	$67.50	$67.50	$67.50
South Mills Solar	$67.67	$67.67	$67.67	$67.67

TABLE 57: BASE CASE PROJECTED CONTRACT COSTS FOR CONTRACTED SOLAR RESOURCES.

Resource	2026	2031	2036	2041
	$/MWh			
Big Timber	$45.49	$45.49	$45.49	$45.49
Broadview East	$54.39	$54.39	$54.39	$54.39
DA Wind Investors	$54.39	$54.39	$54.39	$54.39
Fairfield	$62.92	$62.92	expired	expired
Gordon Butte	$69.21	$69.21	$69.21	expired
Greenfield	$53.99	$53.99	$53.99	$53.99
Musselshell Wind	$69.21	$69.21	$69.21	expired
Musselshell Wind 2	$69.21	$69.21	$69.21	expired
Oversight Resources	$54.39	$54.39	$54.39	$54.39
South Peak	$22.46	$22.46	expired	expired
Stillwater	$37.63	$37.63	$37.63	$37.63
71 Ranch LP	$54.39	$54.39	$54.39	$54.39
Judith Gap	[redacted]	expired	expired	expired

TABLE 58: BASE CASE PROJECTED CONTRACT COSTS FOR CONTRACTED WIND RESOURCES.

Resource	2026	2031	2036	2041
	$/MWh			
Powerex	[redacted]	expired	expired	expired
Heartland[73]	[redacted]	[redacted]	expired	expired

TABLE 59: BASE CASE PROJECTED CONTRACT COSTS FOR STCC.

73 The Heartland STCC is a capacity contract that is dispatched infrequently. Heartland was limited in production based on historical dispatch, so this causes the projected average cost to be high.

7.8.2 PCM Summary: Base Case & Main Scenarios

The following section compares Scenario A, Base Case, to the main scenarios in which early retirement dates of Colstrip are evaluated. Figure 102 shows the total energy production of resources in the Base Case and resources in the main scenarios relative to the forecasted total load consumption. There is little change in energy production across scenarios, even with different resources added to the portfolio to mitigate the Colstrip retirement at different times in the planning horizon.

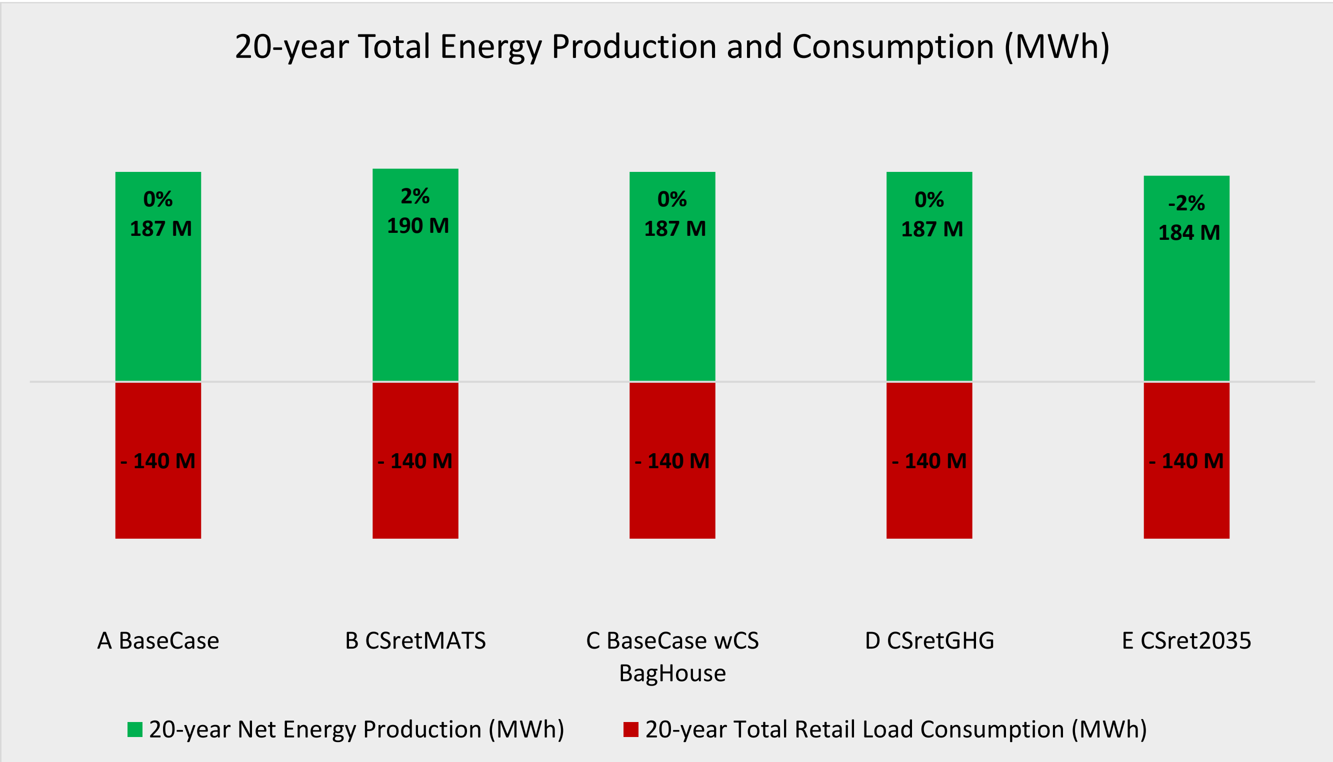


FIGURE 102: THE TOTAL ENERGY PRODUCTION OF THE BASE CASE AND THE MAIN SCENARIOS RELATIVE TO THE FORECASTED LOAD.

Figure 103 shows the simulated CO2 emissions in the Base Case and the main scenarios. Scenario B results in the least amount of CO2 emissions at 71 million metric tons over the planning horizon due to Colstrip retiring because of MATS compliance.

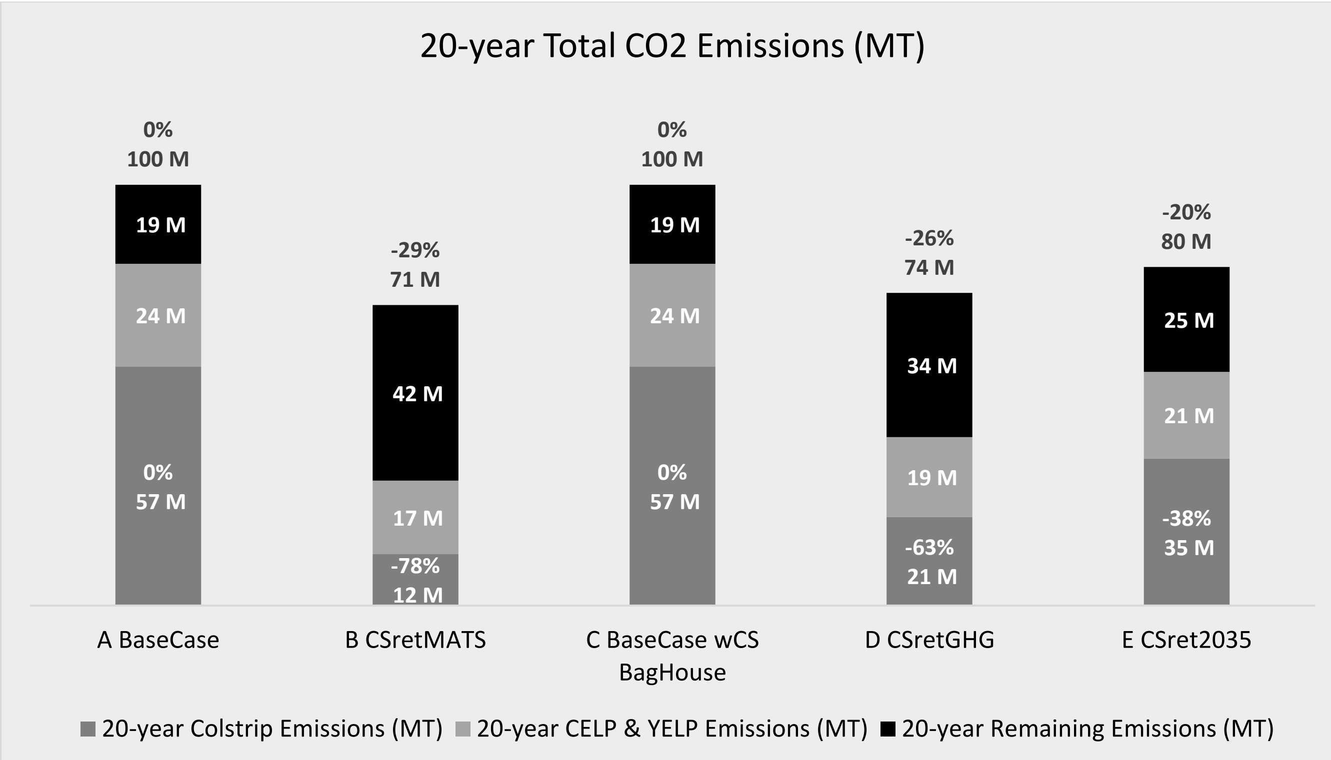


FIGURE 103: CO2 EMISSIONS FROM THE BASE CASE AND THE MAIN SCENARIOS.

Figure 104 shows the net transmission exports and imports in the Base Case and the main scenarios. The results show relatively little differences in transmission volumes as compared to the Base Case.

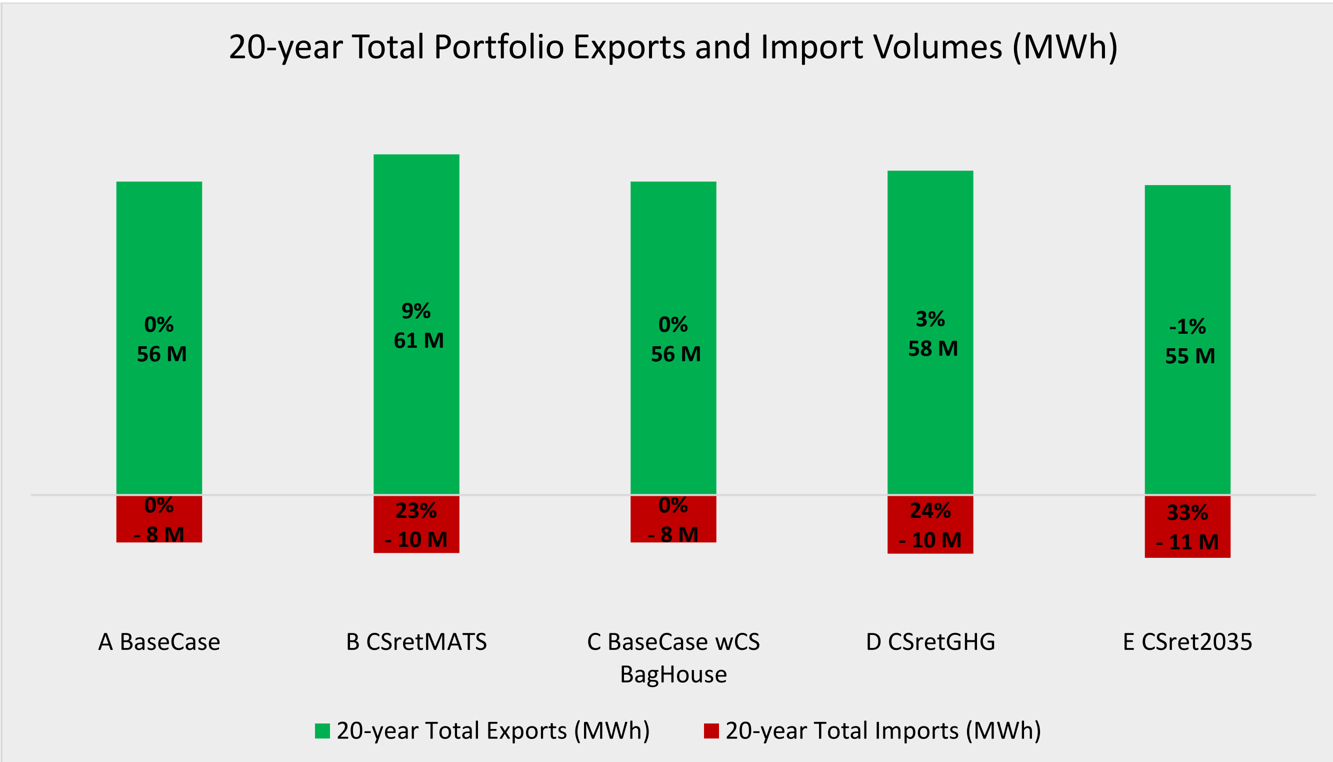


FIGURE 104: TRANSMISSION IMPORTS AND EXPORTS FROM THE BASE CASE AND THE MAIN SCENARIOS.

Figure 105 shows the 20-year NPV of the Base Case and the main scenarios. The results show that any early retirement in Colstrip results in a higher total portfolio cost as compared to the Base Case. As stated in Section 7.5, the undepreciated capital costs of Colstrip in the early retirement scenarios are collected through 2042; NorthWestern did not assume any alternate recovery method such as accelerated depreciation. However, Colstrip fixed O&M is not collected after retirement.

Note that Scenario C in Figure 105 includes additional costs for the Colstrip baghouse. In 2024, Burns & McDonnell estimated the cost of the reheat fabric filter as $409 to $664 million. NorthWestern used the high end of the range for analysis and assumed NorthWestern's share of the baghouse costs were 55% of the total, or $365 million, which includes the Avista and Puget shares. This cost was escalated from 2024 to 2030, the first full year in which the baghouse would be in service, to account for any inflation changes. The 2030 cost was then used as an input for a partial RR to calculate the total cost of the baghouse from 2030 through 2042.

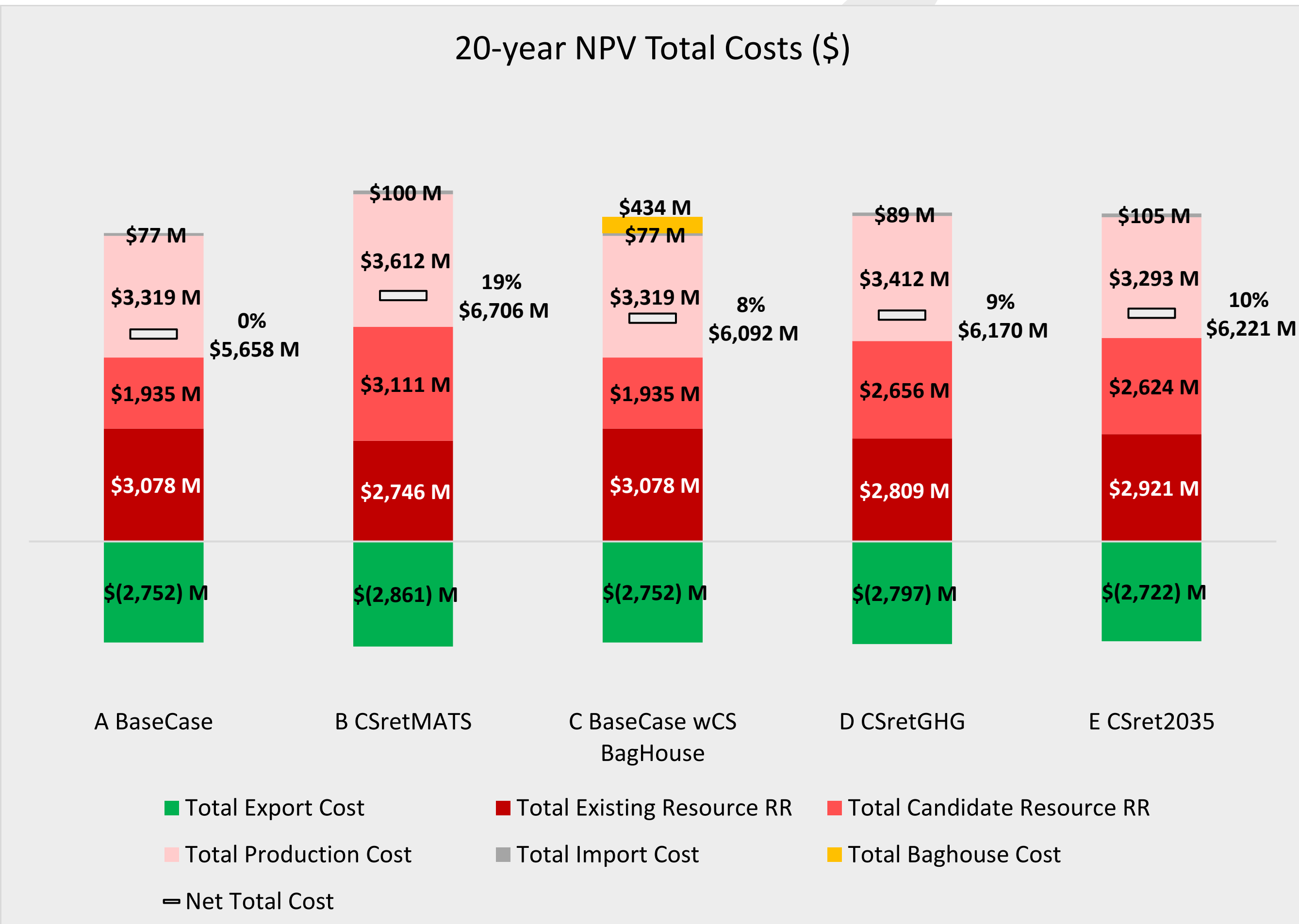


FIGURE 105: PCM RESULTS FOR THE BASE CASE AND THE MAIN SCENARIOS.

Figure 106 shows the remaining book value for the candidate resources in the Base Case and the main scenarios. Scenario B has the least amount of remaining book value for candidate resources because more resources are built earlier in the planning horizon than the Base Case. Graphs and charts for individual scenarios are provided in Appendix E.

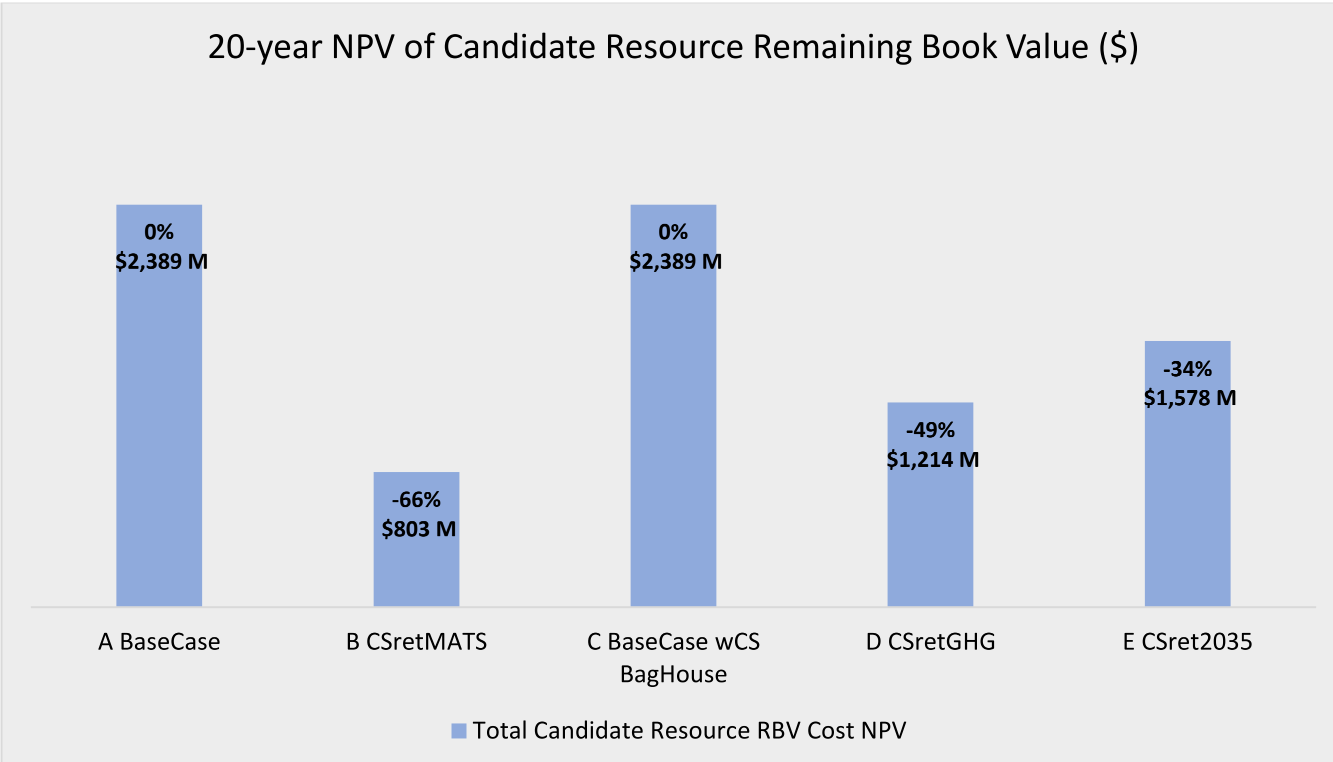


FIGURE 106: REMAINING BOOK VALUE FOR CANDIDATE RESOURCES IN THE BASE CASE AND THE MAIN SCENARIOS.

7.8.3 Base Case & Commodity Sensitivities

The following section compares Scenario A, Base Case, to the commodity sensitivities including Sensitivities F and G that model a 50% reduction and a 50% increase, respectively, in the Mid-C power price forecast, and Sensitivities H and I that model a 50% reduction and a 50% increase, respectively, in the natural gas price forecast. Figure 107 shows the total energy production of resources in the Base Case and resources in the commodity sensitivities relative to the forecasted total load consumption. The results show that an increase in power prices or a reduction in natural gas prices cause an overall increase in energy production due to increased revenues from market sales. Conversely, a reduction in power prices or an increase in natural gas prices cause a decrease in energy production due to reduced revenues from market sales.

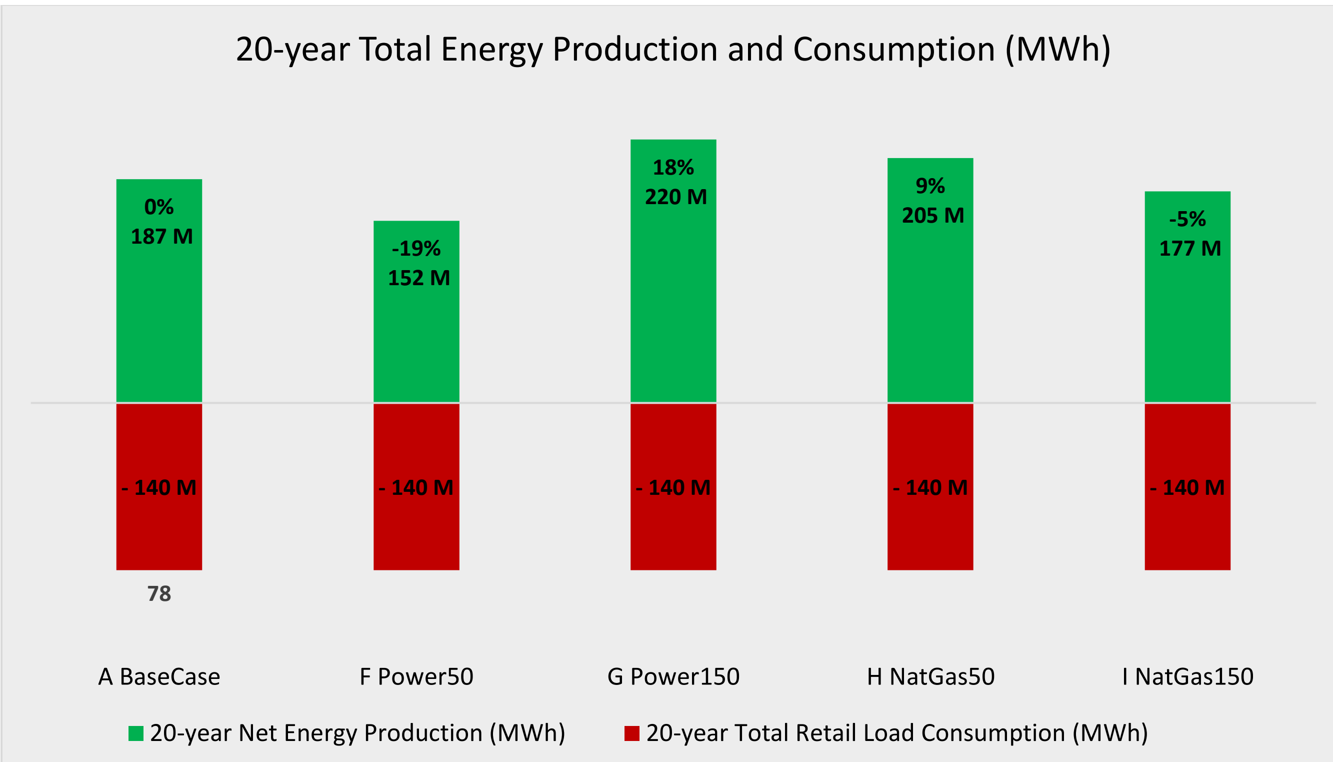


FIGURE 107: THE TOTAL ENERGY PRODUCTION OF THE BASE CASE AND COMMODITY SENSITIVITIES RELATIVE TO THE FORECASTED LOAD.

Figure 108 tracks closely with the simulated energy production where lower power prices result in the least CO2 emissions at 76 million metric tons due to lower generation dispatch, and higher power prices cause the highest CO2 emissions at 114 million metric tons due to higher generation dispatch.

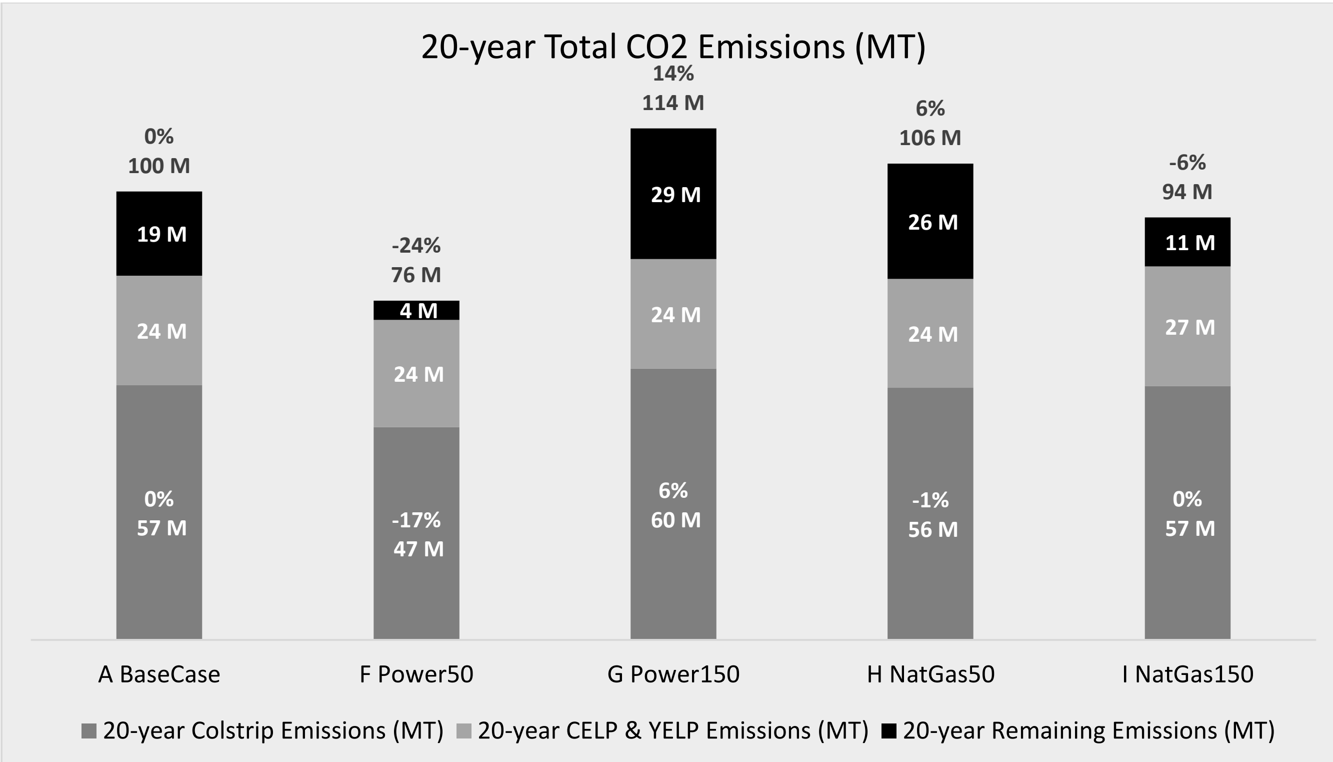


FIGURE 108: CARBON EMISSIONS FROM THE BASE CASE AND COMMODITY SENSITIVITIES.

Figure 109 shows the net transmission exports and imports in the Base Case and commodity sensitivities. High power prices produce the highest volume of exports as well as the lowest volume of imports due to the high generation dispatch. Conversely, low power prices produce the lowest volume of exports and the highest volume of imports.

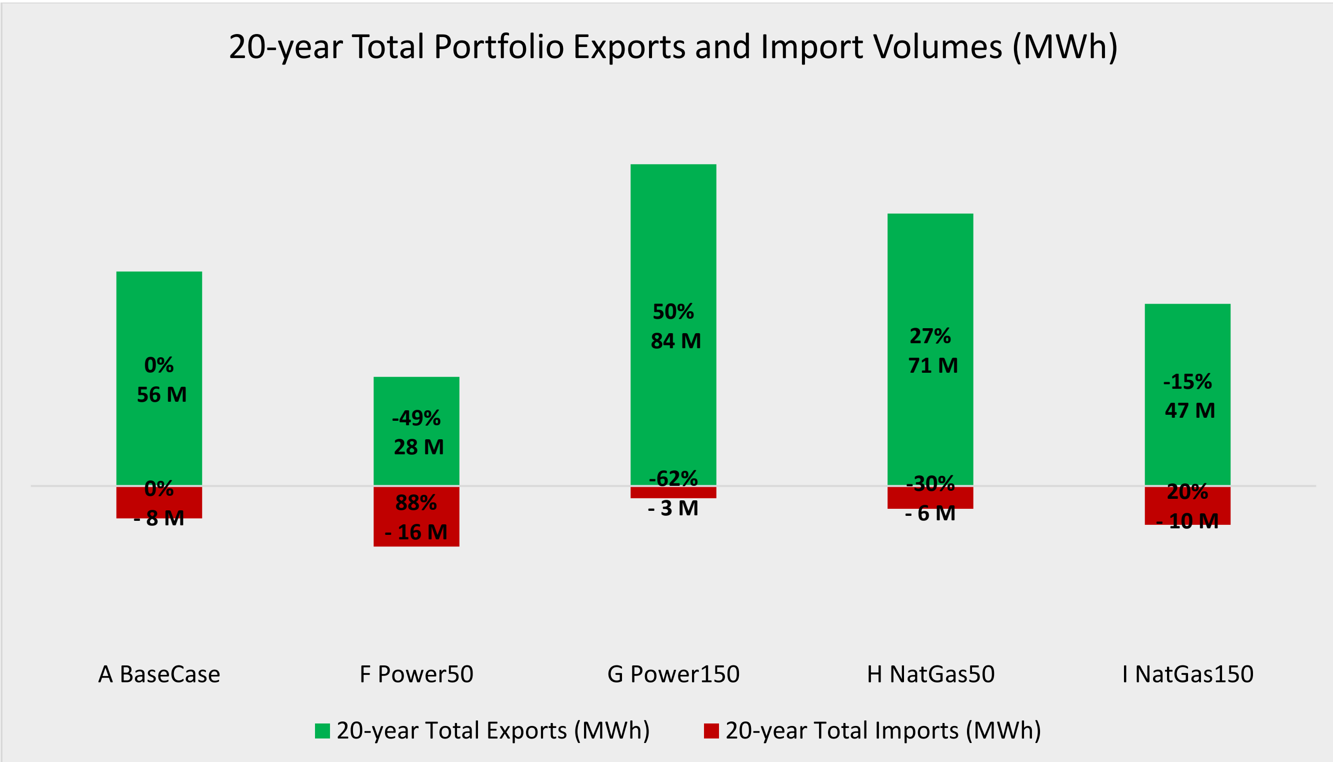


FIGURE 109: TRANSMISSION IMPORTS AND EXPORTS FROM THE BASE CASE AND COMMODITY SENSITIVITIES.

Figure 110 shows the 20-year NPV of the Base Case and the commodity sensitivities. The results show that higher power prices create large offsetting revenues to the total portfolio cost as long as dispatchable resources are able to respond to the high power prices and export to buyers. Lower power prices cause a net increase in total portfolio costs because the portfolio cannot generate as much offsetting revenues.

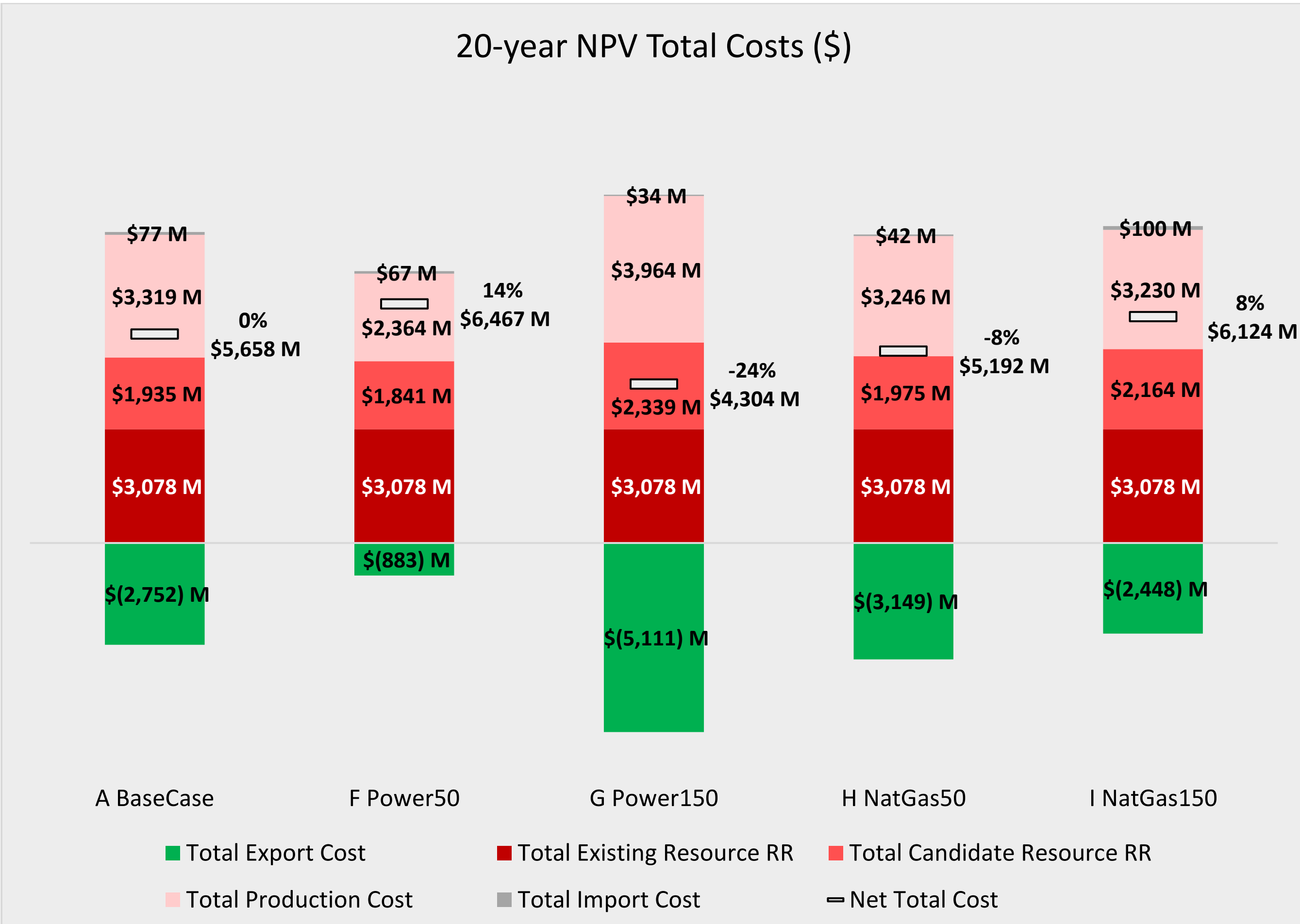


FIGURE 110: PCM RESULTS FOR THE BASE CASE AND COMMODITY SENSITIVITIES.

Figure 111 shows the remaining book value for the candidate resources in the Base Case and the commodity sensitivities. The Base Case and each commodity sensitivity had relatively equal remaining book values because the resources selected in the ARS module are nearly the same technologies and the same selection years. Graphs and charts for individual sensitivities are provided in Appendix E.

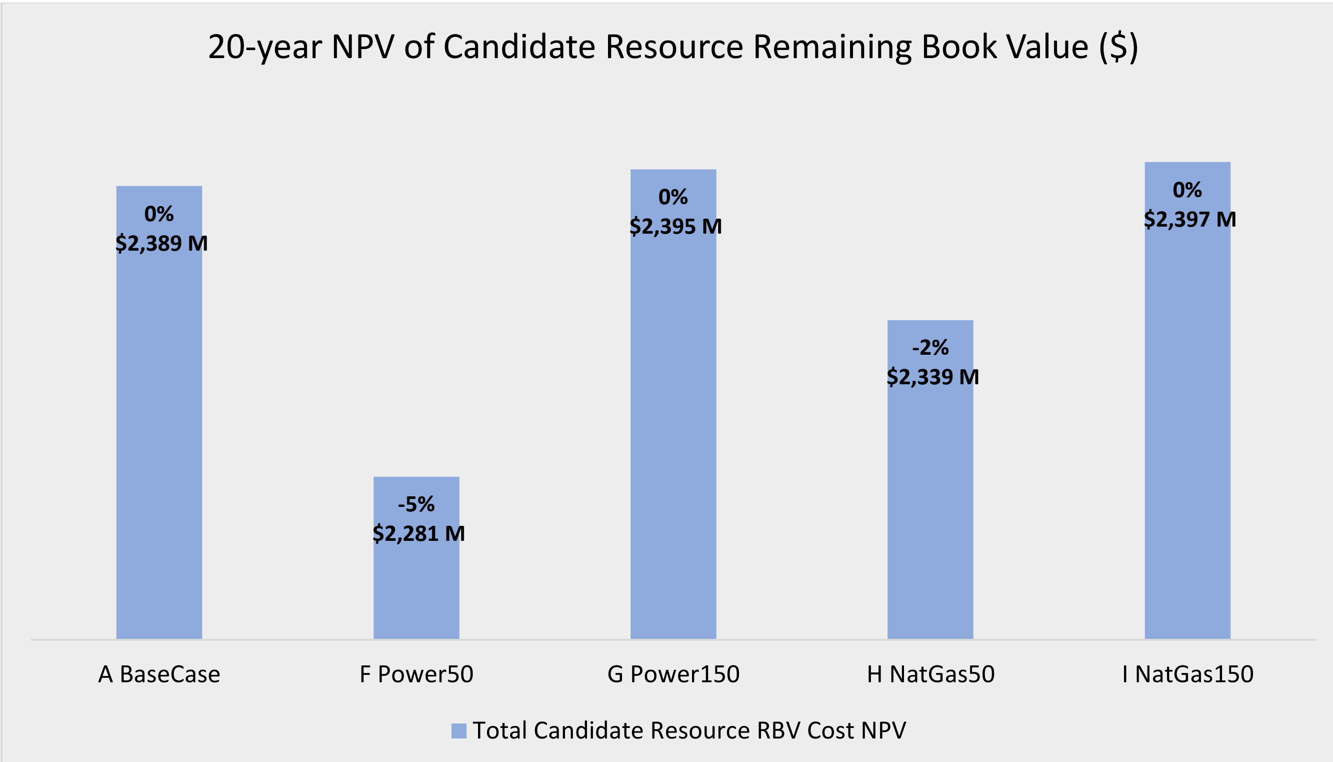


FIGURE 111: REMAINING BOOK VALUE FOR CANDIDATE RESOURCES IN THE BASE CASE AND COMMODITY SENSITIVITIES.

7.8.4 Base Case & Data Center Sensitivities

The following section compares Scenario A, Base Case, to the data center sensitivities including Sensitivities J, K, and L that model an additional 150 MW, 650 MW, and 1,160 MW of data center load, respectively. The additional data center load was modeled at an 85% load factor. Each sensitivity assumes that NorthWestern acquires the 370 MW Colstrip shares from Puget. Figure 112 shows the total energy production of resources in the Base Case and resources in the data center sensitivities relative to the forecasted total load consumption. The total load consumption in Sensitivity J, K, and L increase by 18%, 72%, and 126%, respectively, relative to the base case. As more data center load is added, additional generation is added in the ARS module to meet the capacity need. The results show that the resources generate more energy to both serve the additional load as well as for market sales.

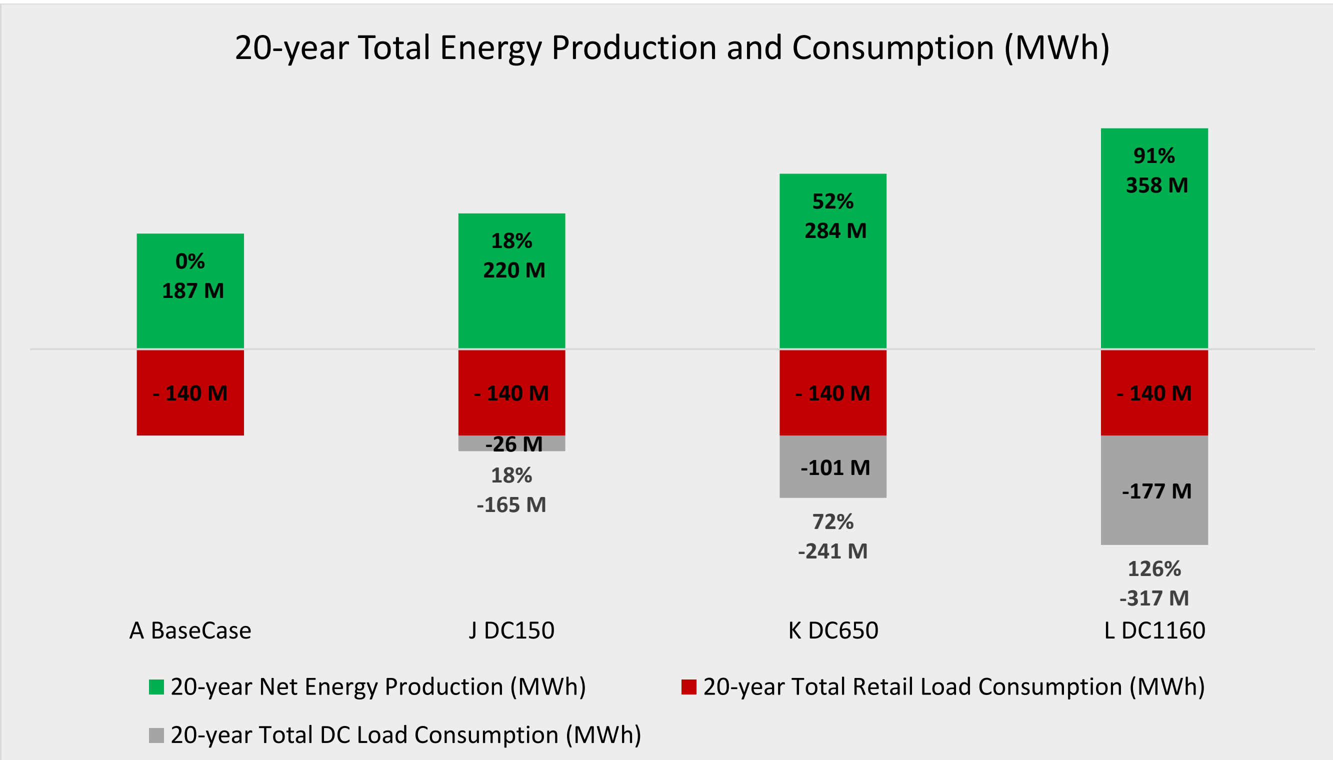


FIGURE 112: THE TOTAL ENERGY PRODUCTION OF THE BASE CASE AND THE DATA CENTER SENSITIVITIES RELATIVE TO THE FORECASTED LOAD.

Figure 113 shows the simulated CO2 emissions in the Base Case and the data center sensitivities. The simulated CO2 emissions track closely with the simulated energy production where increased generation drives an increase in CO2 emissions. The simulation shows that Sensitivity L generates 196 million metric tons of CO2, or 96% more than the Base Case.

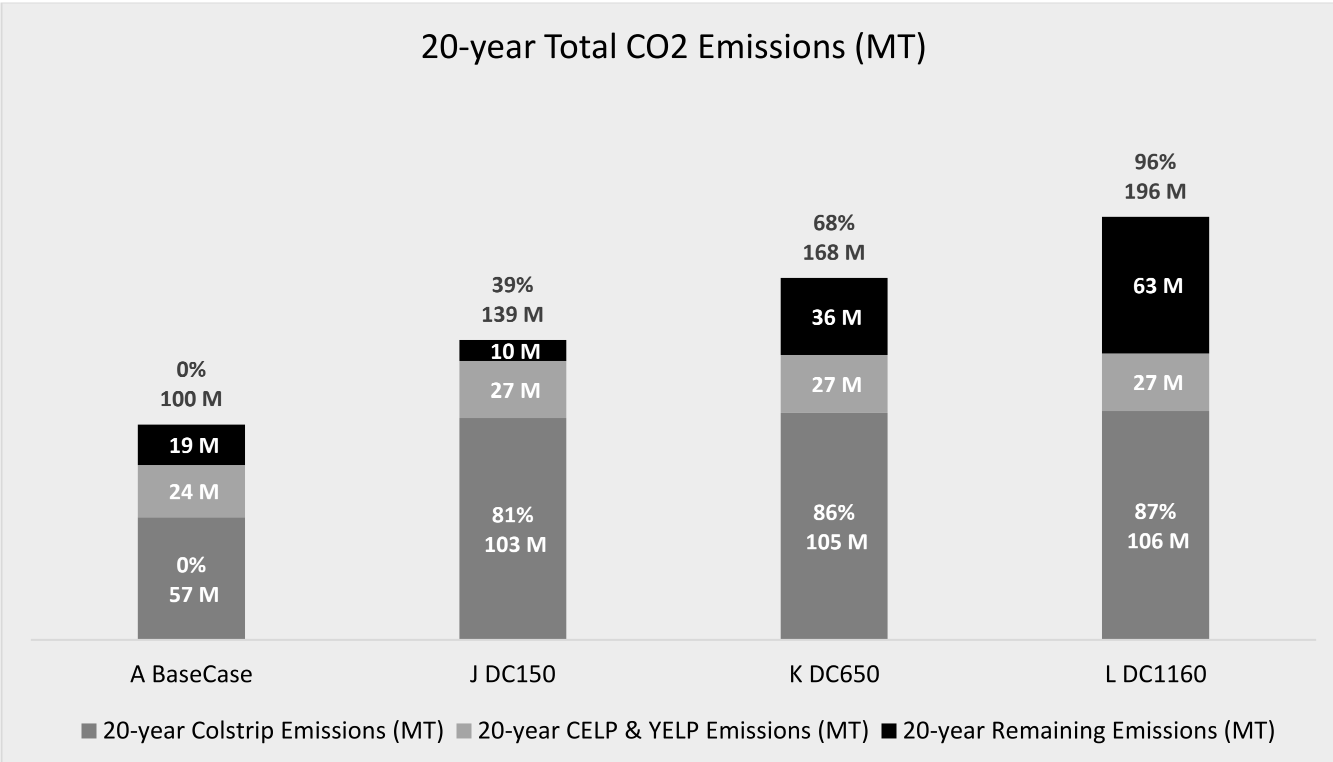


FIGURE 113: CARBON EMISSIONS FROM THE BASE CASE AND THE DATA CENTER SENSITIVITIES.

Figure 114 shows the net transmission exports and imports in the Base Case and data center sensitivities. Sensitivity J shows an increase in market sales and a decrease in market purchases caused by including the 370 MW Puget shares of Colstrip exceeding the additional 150 MW of data center demand. Sensitivities K and L show a relatively equal volume of transmission exports while the transmission imports increase relative to the Base Case with increased data center load.

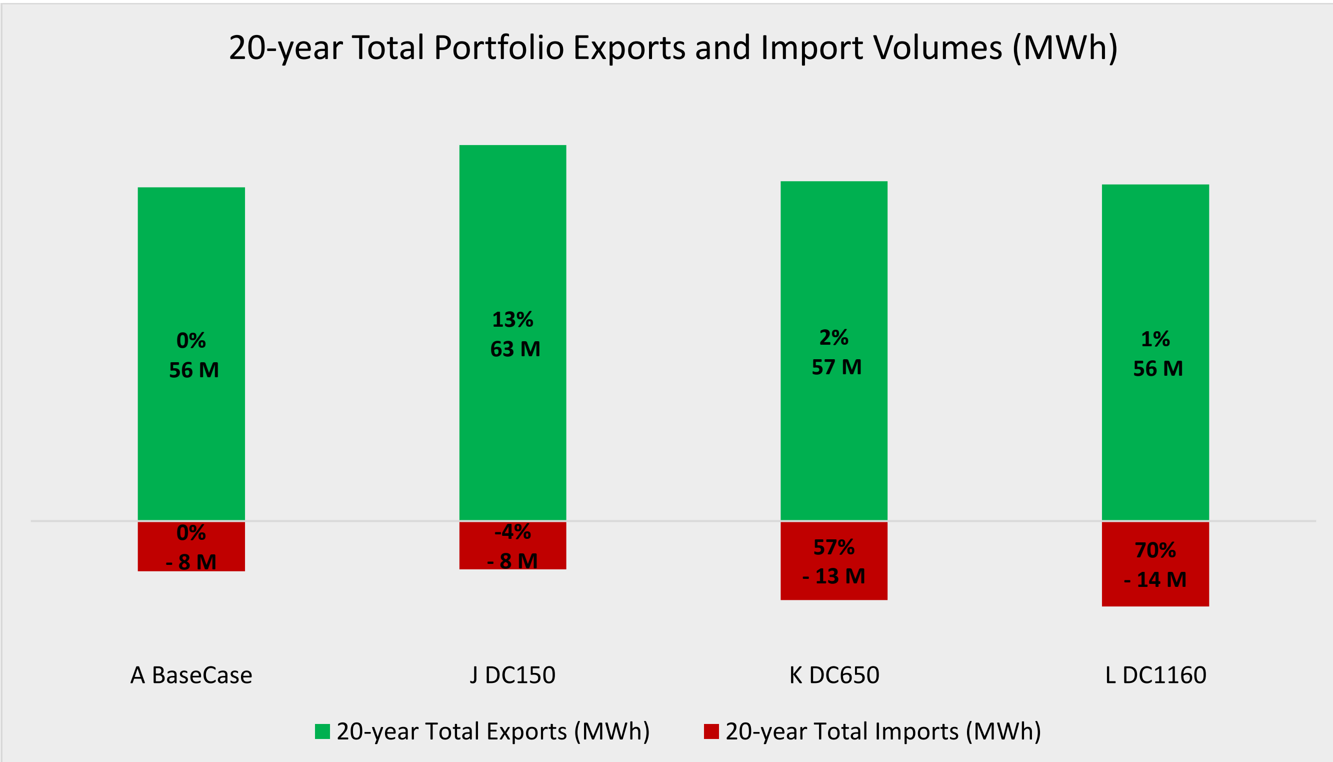


FIGURE 114: TRANSMISSION IMPORTS AND EXPORTS FROM THE BASE CASE AND THE DATA CENTER SENSITIVITIES.

Figure 115 shows the 20-year NPV of the Base Case and the data center sensitivities. The results show that the total portfolio costs increase with additional data center load due to the additional resources, and their associated operating costs, that are needed to meet the increased capacity need. However, Figure 116 shows that when the total portfolio cost is normalized against the total 20-year load consumption, the average cost per megawatt-hour for Sensitivity J shows a 13% decrease, Sensitivity K shows a 2% decrease, and Sensitivity L shows a 4% increase relative to the Base Case. Figure 116 is not meant to be an indication of a future rate design, tariff, customer allocation, etc.; rather, it shows that the increased costs caused by additional load can be tempered by having increased load in which the costs can be shared.

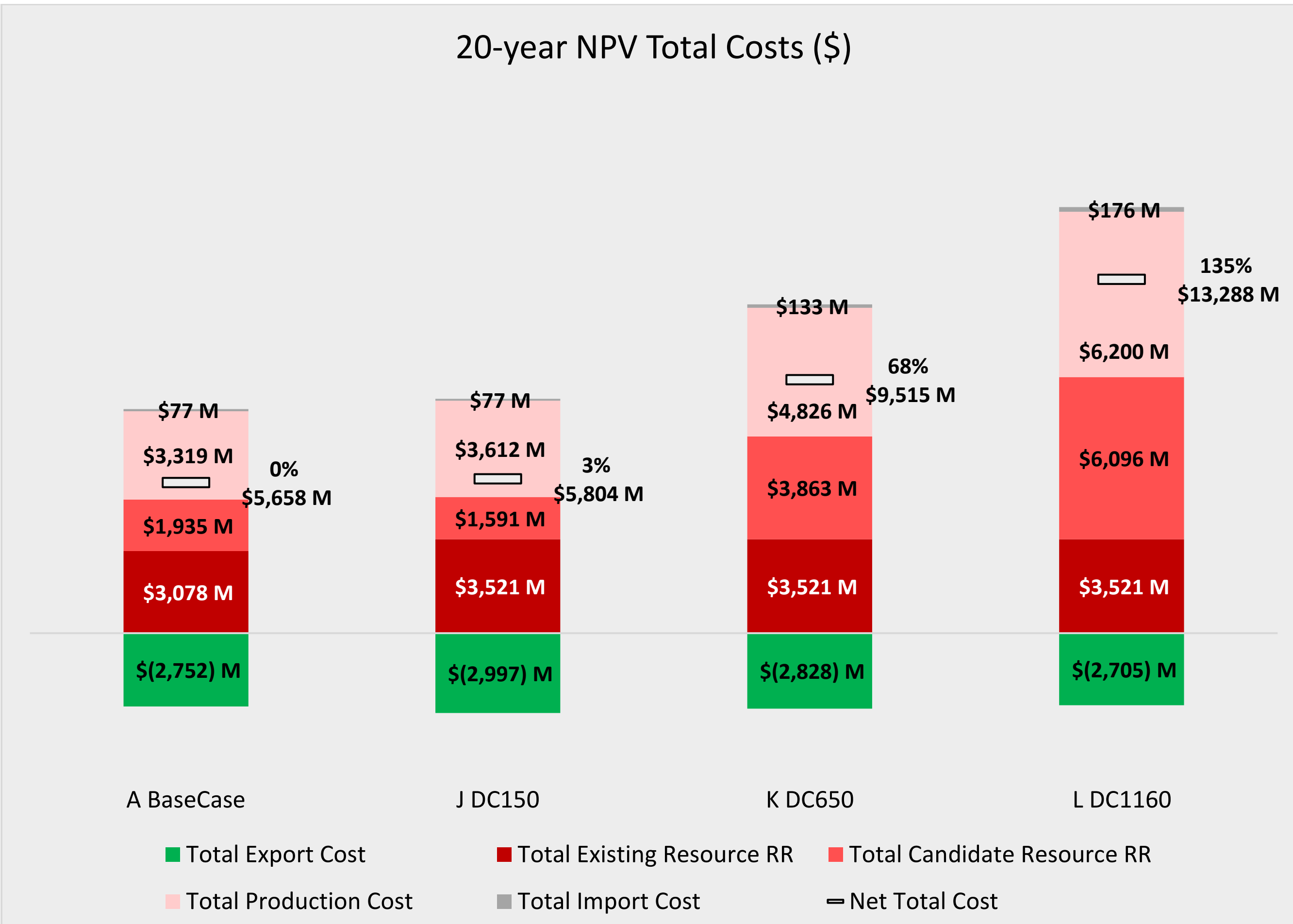


FIGURE 115: PCM RESULTS FOR THE BASE CASE AND DATA CENTER SENSITIVITIES.

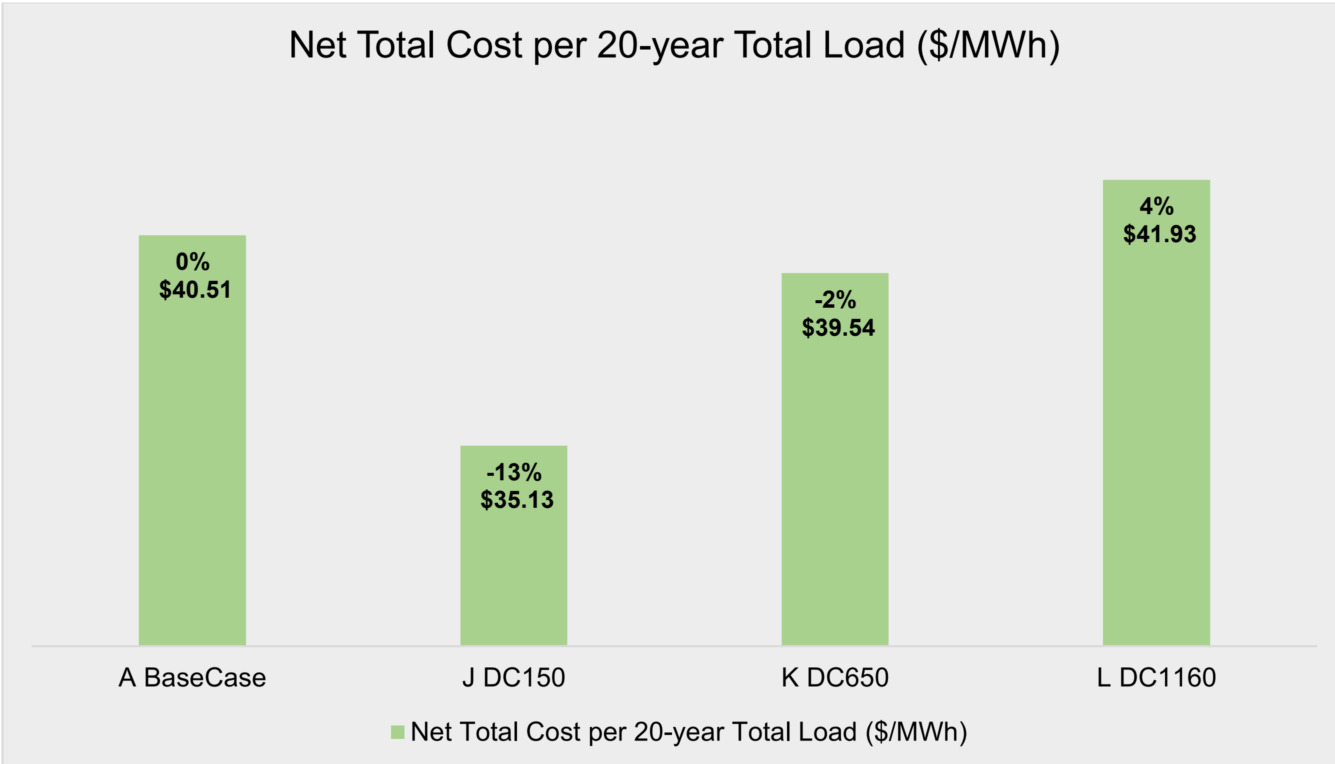


FIGURE 116: PCM RESULTS FOR THE BASE CASE AND DATA CENTER SENSITIVITIES REPRESENTED AS THE 20-YEAR NPV TOTAL COST PER TOTAL 20-YEAR TOTAL LOAD.

Figure 117 shows the remaining book value for the candidate resources in the Base Case and the data center sensitivities. The results show that the remaining book value increases with additional candidate resources selected to meet the additional capacity need. Graphs and charts for individual sensitivities are provided in Appendix E.

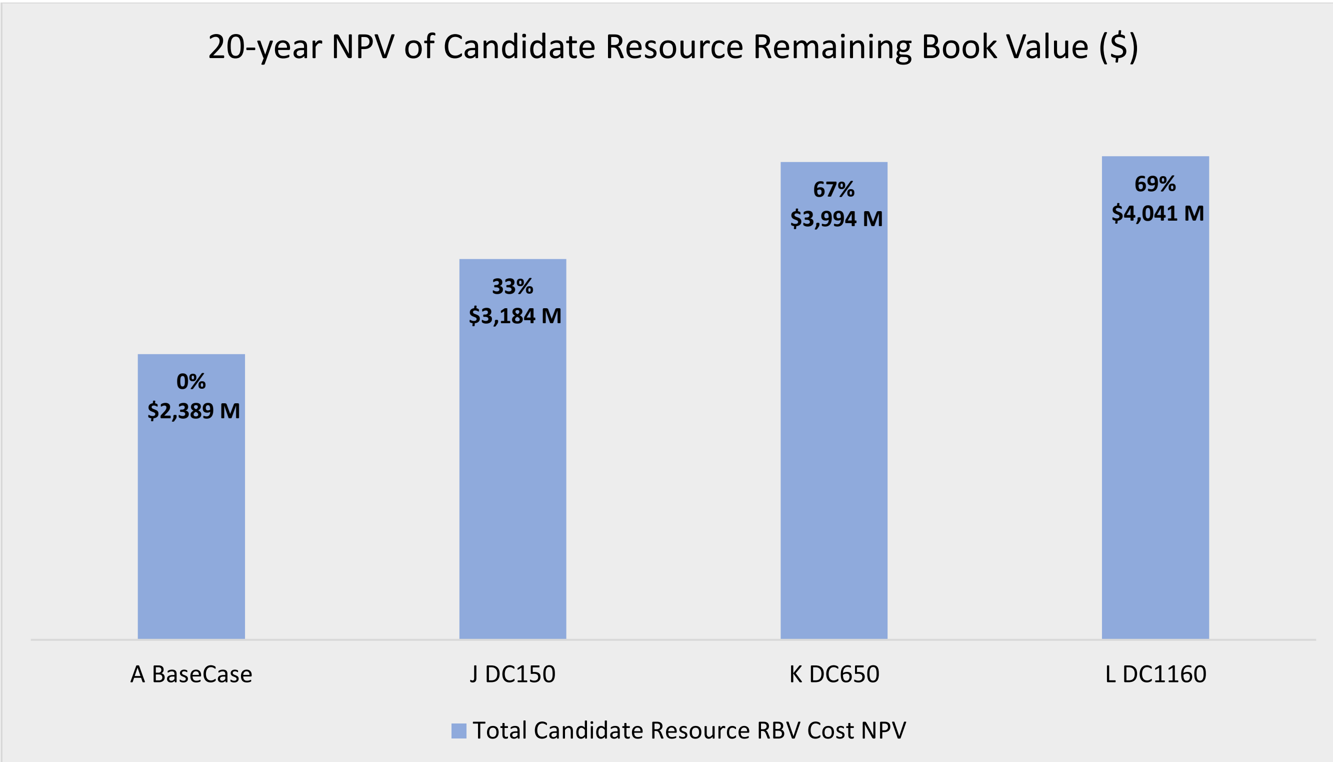


FIGURE 117: REMAINING BOOK VALUE FOR CANDIDATE RESOURCES IN THE BASE CASE AND DATA CENTER SENSITIVITIES.

7.8.5 Base Case & Resource Sensitivities

The following section compares Scenario A, Base Case, to the resource sensitivities including Sensitivity M, No Limitation on Carbon Emitting Resources, Sensitivity N, Carbon Free Candidate Resources Only, Sensitivity O, PSE Colstrip Share is used for Retail Load, and Sensitivity P, Avista's Colstrip Shares are not Acquired. Figure 118 shows the total energy production of resources in the Base Case and the resource sensitivities relative to the forecasted total load consumption. The results show Sensitivities M and N do not cause a significant change in energy production. Sensitivity O shows an increase in generation production due to the additional 370 MW shares of Colstrip from Puget. Sensitivity P also shows a small increase in generation production due to additional CCCT units selected in the ARS module to meet the capacity need.

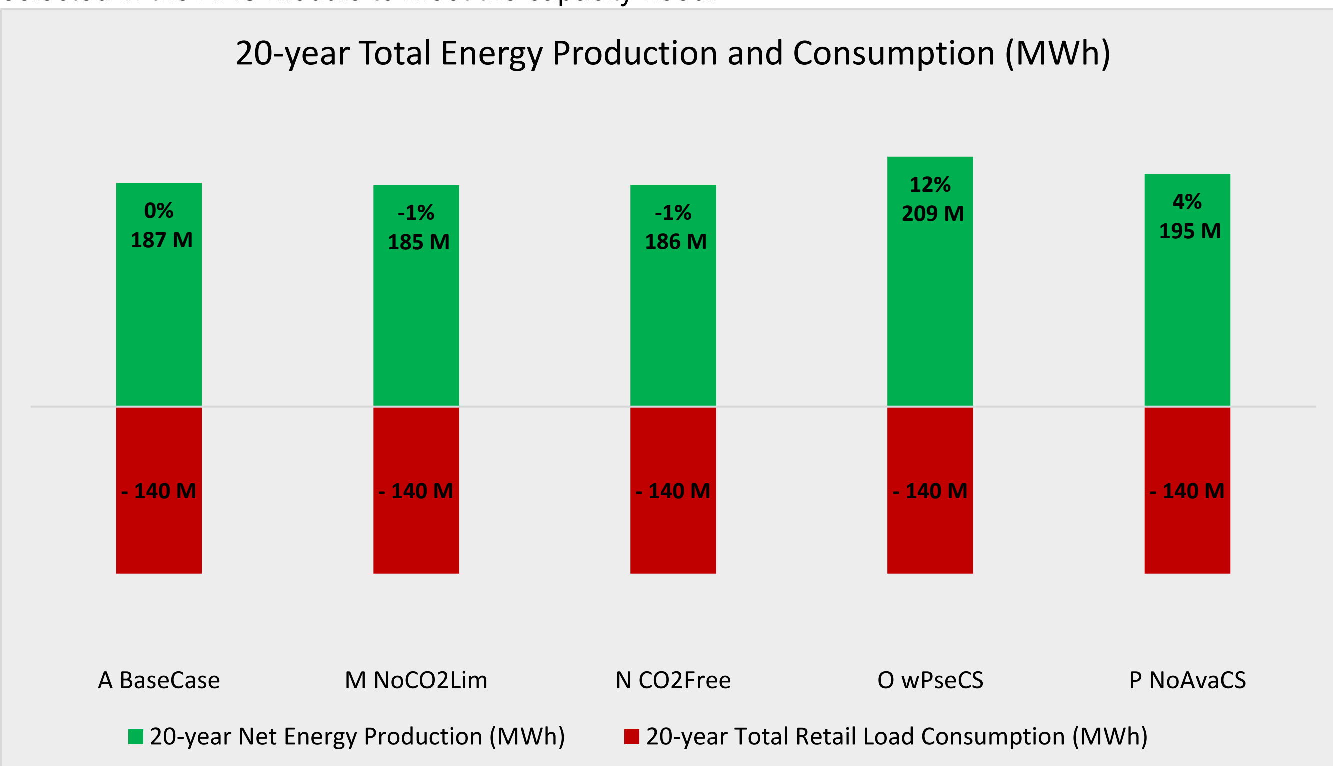


FIGURE 118: THE TOTAL ENERGY PRODUCTION OF THE BASE CASE AND THE RESOURCE SENSITIVITIES RELATIVE TO THE FORECASTED LOAD.

Figure 119 shows the simulated CO2 emissions in the Base Case and the resource sensitivities. Sensitivities M and N show a 4% increase and a 4% decrease in CO2 emissions, respectively. The change in CO2 emissions from Sensitivities M and N relative to the Base Case do not change significantly because the great majority of the emissions are sourced from Colstrip, CELP, and YELP, which act as baseload resources. Sensitivity O shows a 32% increase in CO2 emissions due to the additional 370 MW shares of Colstrip from Puget, and Sensitivity P shows a 14% decrease in CO2 emissions due to the removal of 222 MW share of Colstrip from Avista.

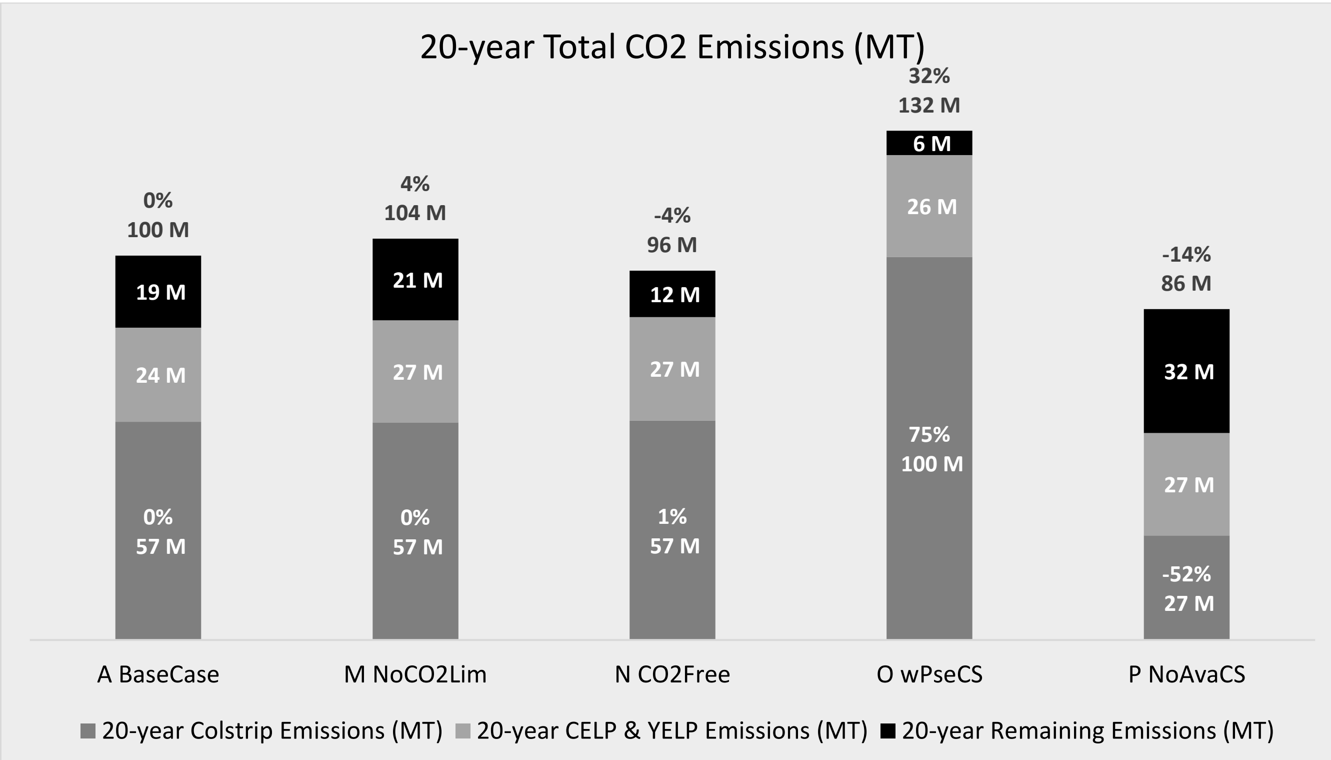


FIGURE 119: CARBON EMISSIONS FROM THE BASE CASE AND THE RESOURCE SENSITIVITIES.

Figure 120 shows the net transmission exports and imports in the Base Case and resource sensitivities. Similar to the energy production, the results show Sensitivities M and N do not cause a significant change in transmission exports or imports. Sensitivity O shows a 32% increase in transmission exports and a 45% reduction in transmission imports due to the additional 370 MW shares of Colstrip from Puget. Sensitivity P shows a 14% increase in transmission exports due to additional CCCT units selected in the ARS module to meet the capacity need.

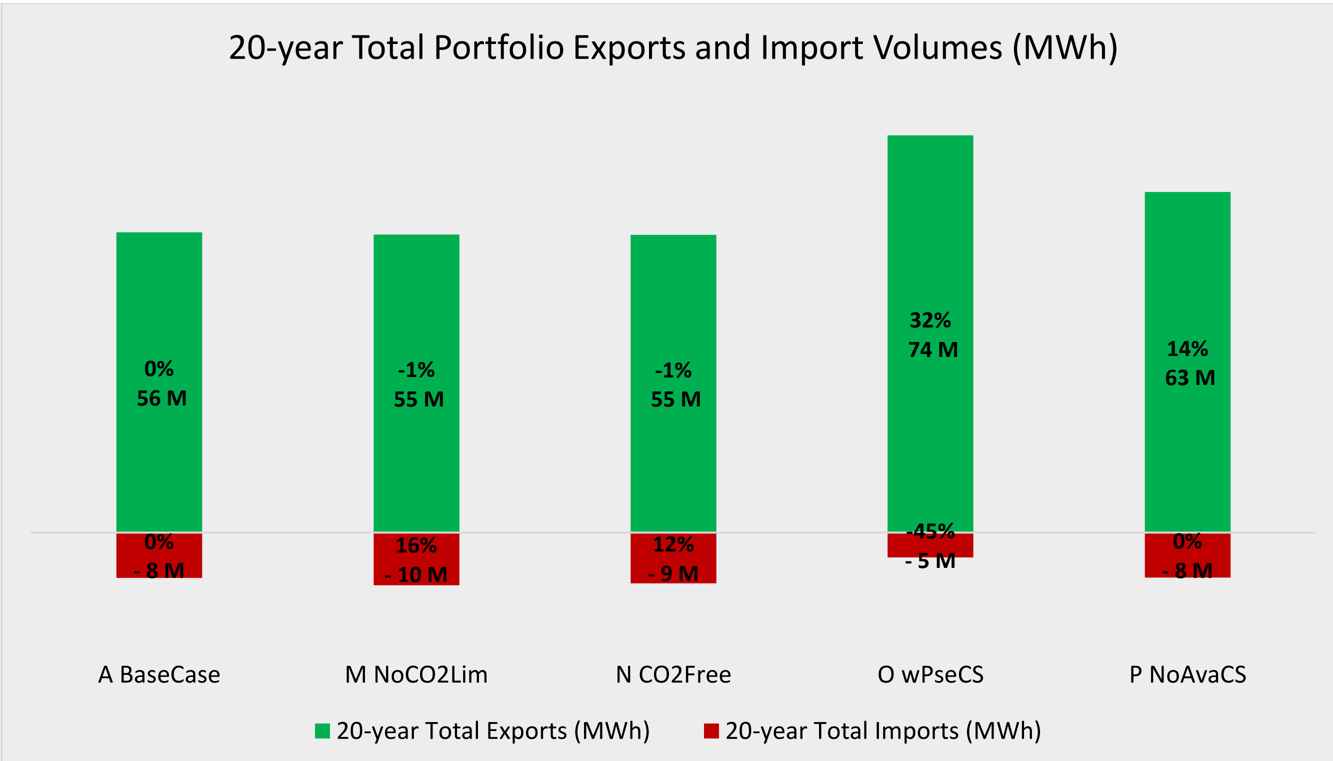


FIGURE 120: TRANSMISSION IMPORTS AND EXPORTS FROM THE BASE CASE AND THE RESOURCE SENSITIVITIES.

Figure 121 shows the 20-year NPV of the Base Case and the resource sensitivities. Sensitivity M shows a 2% decrease and Sensitivity N shows a 5% increase in total costs relative to the Base Case. Sensitivity M has lower RR costs from candidate resources but higher operating costs due to more natural gas fuel. Conversely, Sensitivity N has higher RR costs from candidate resources and lower operating costs due to wind and SMR candidate resources. Sensitivity O shows a 15% decrease in total costs due to lower RR cost from candidate resources, increased market sales, along with higher RR costs for existing resources which includes the additional 370 MW shares of Colstrip from Puget. Sensitivity P shows an 11% increase in total costs due to, primarily, higher RR cost from candidate resources.

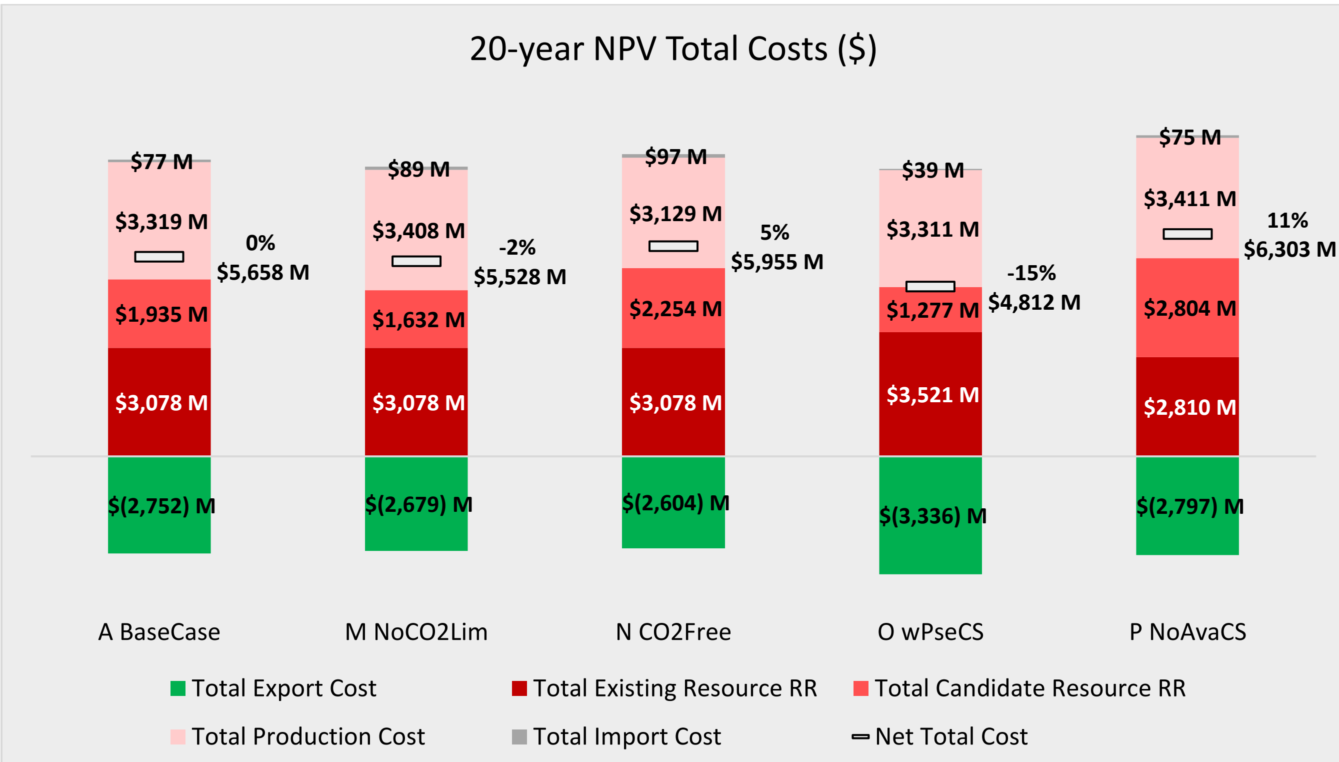


FIGURE 121: PCM RESULTS FOR THE BASE CASE AND THE RESOURCE SENSITIVITIES.

Figure 122 shows the remaining book value for the candidate resources in the Base Case and the resource sensitivities. Sensitivity M has the least amount of remaining book value because there are no SMRs in the portfolio, which have 60-year book lives as compared to natural gas projects that have 32-year book lives. Sensitivity P has a lower remaining book value relative to the Base Case for the same reason, although it does have one SMR in the portfolio. Sensitivity O has the highest remaining book value because the portfolio does include two SMRs and all of the candidate resources are selected late in the planning horizon. Graphs and charts for individual sensitivities are provided in Appendix E.

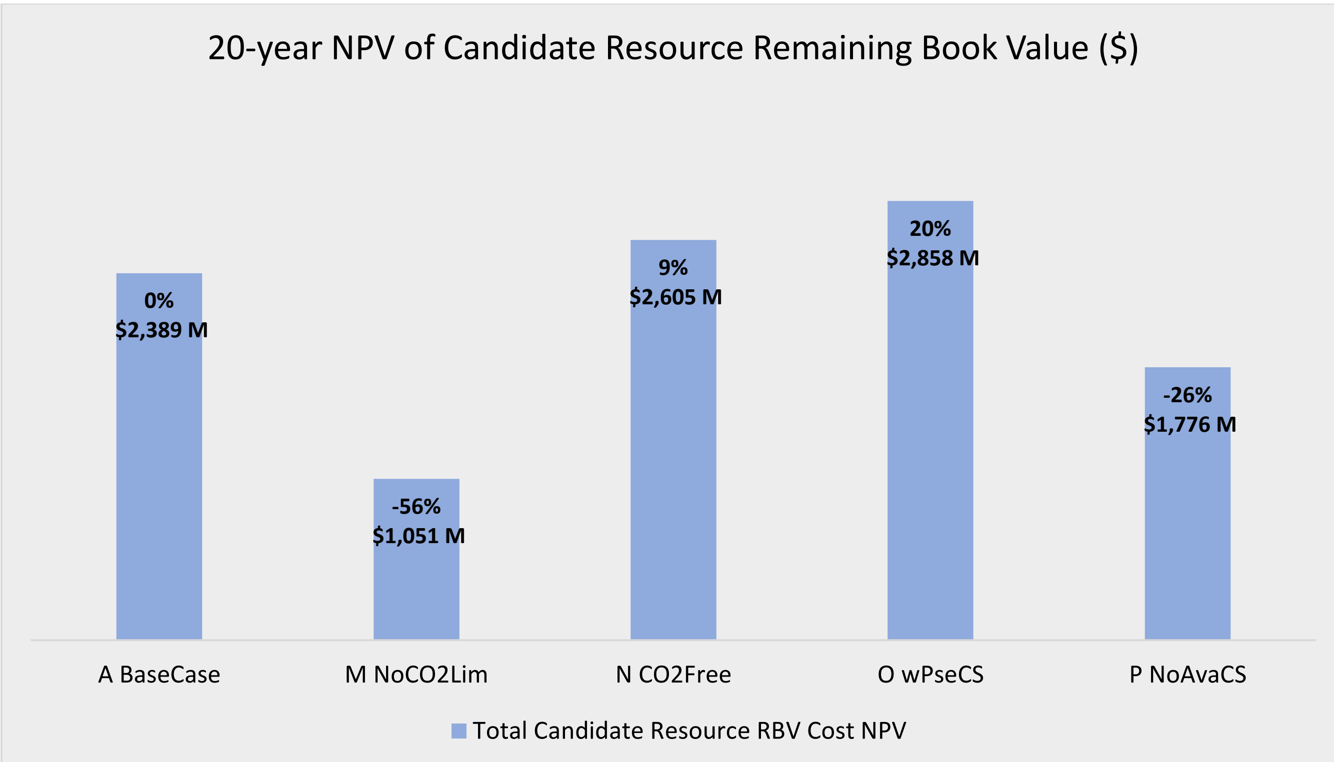


FIGURE 122: REMAINING BOOK VALUE FOR CANDIDATE RESOURCES IN THE BASE CASE AND THE RESOURCE SENSITIVITIES.

7.8.6 Base Case & Other Sensitivities

The following section compares Scenario A, Base Case, to the other sensitivities including Sensitivity Q, Add 300 MW of NPC Capacity, and Sensitivity R, Increase DSM and NEM Forecasts. Figure 123 shows the total energy production of the resources in the Base Case and other sensitivities relative to the forecasted annual energy. The results show that the energy production did not change significantly in either Sensitivity Q or R. The total energy consumption decreased by 6% in Sensitivity R due to increased energy savings from increased DSM and NEM.

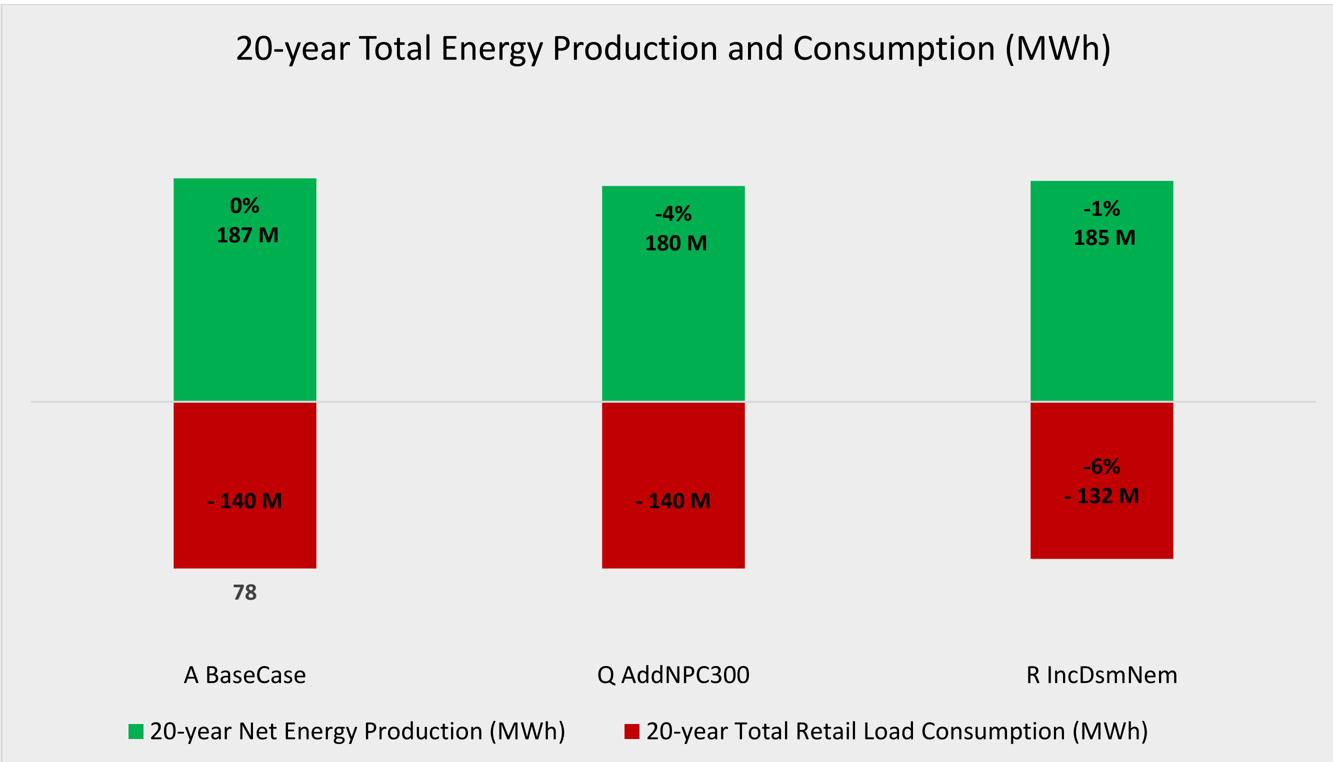


FIGURE 123: THE TOTAL ENERGY PRODUCTION OF THE BASE CASE AND THE OTHER SENSITIVITIES TO THE FORECASTED LOAD.

Figure 124 shows the simulated CO2 emissions in the Base Case and the other sensitivities. The simulated CO2 emissions remain relatively unchanged as compared to the Base Case.

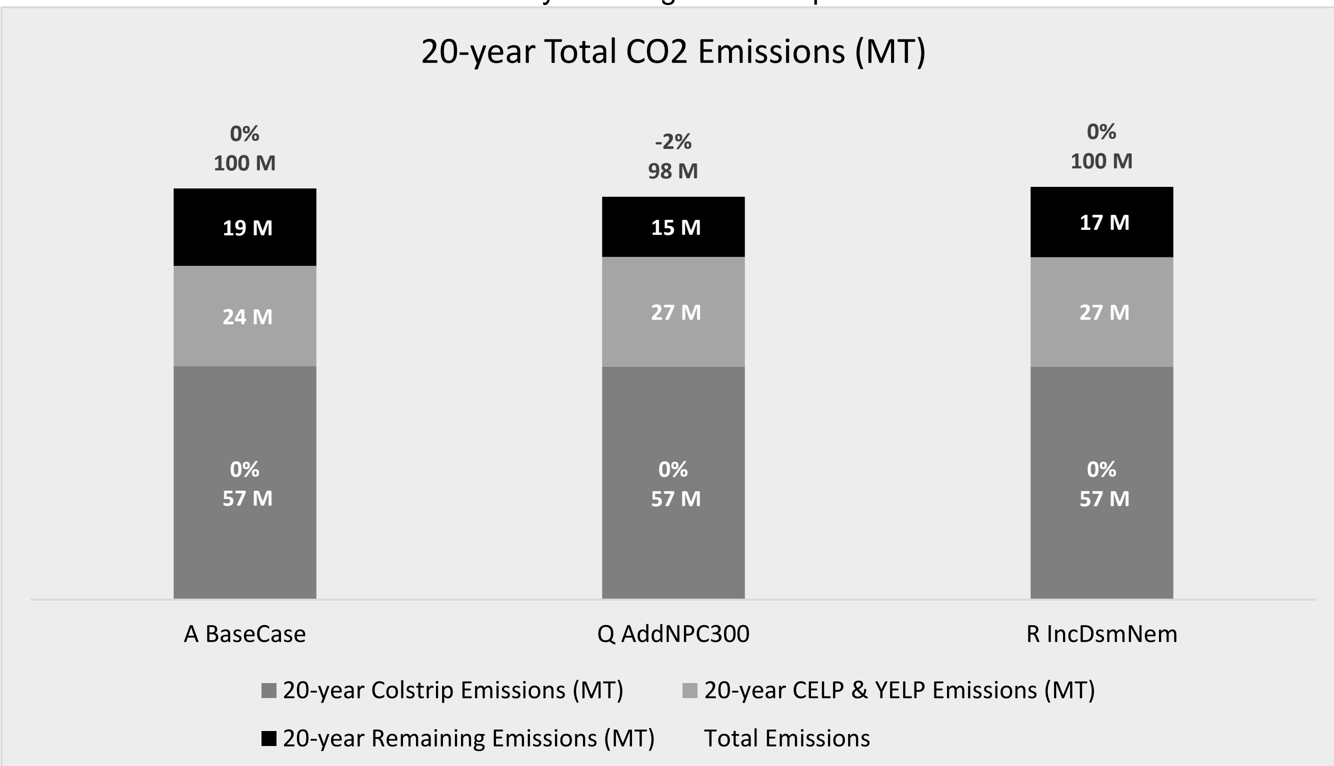


FIGURE 124: CARBON EMISSIONS FROM THE BASE CASE AND THE OTHER SENSITIVITIES.

Figure 125 shows the net transmission exports and imports in the Base Case and other sensitivities. Sensitivity Q shows a 39% increase in transmission exports and a 340% increase in transmission imports. These large increases in transmission activity are a result of new access to the MISO and SPP power markets facilitated by the NPC transmission line. The transmission activity in Sensitivity R remains nearly unchanged as compared to the Base Case.

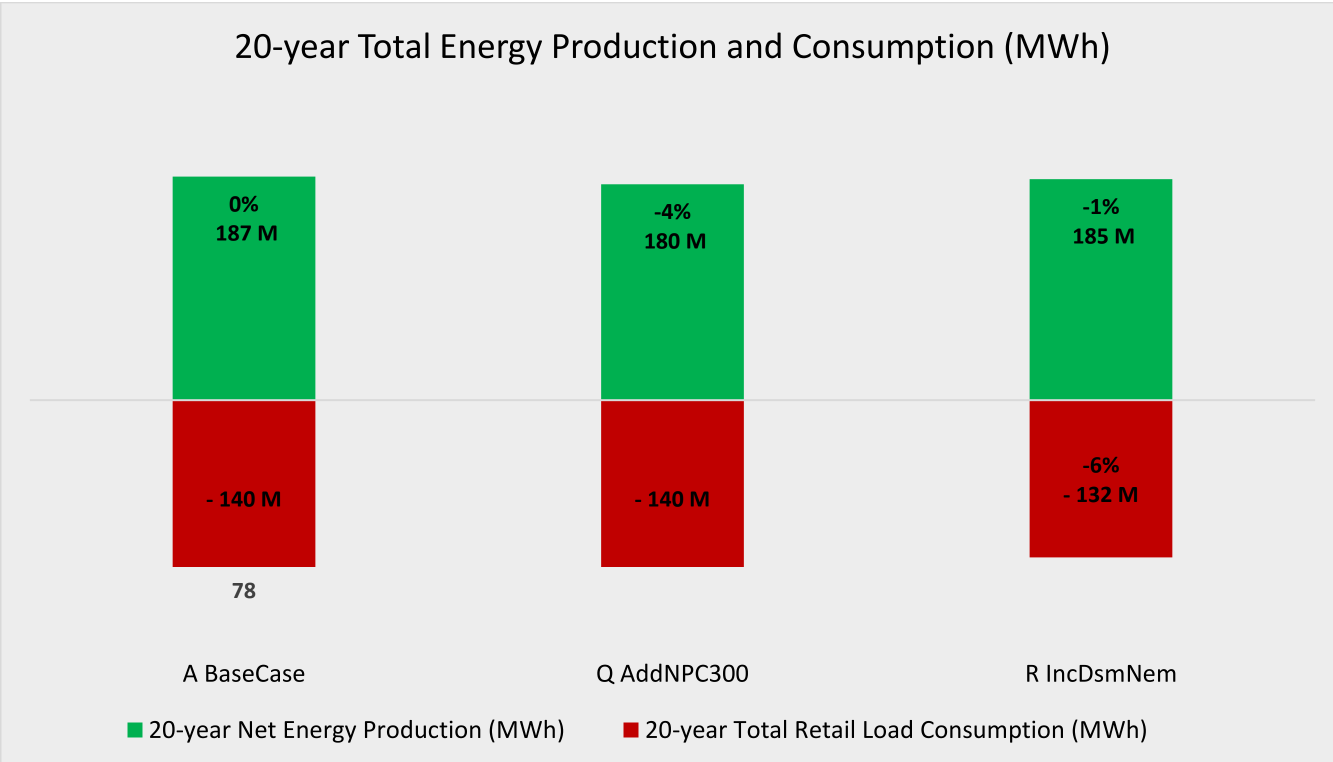


FIGURE 125: TRANSMISSION IMPORTS AND EXPORTS FROM THE BASE CASE AND THE OTHER SENSITIVITIES.

When the NPC is present in the simulation, market sales will be made when the portfolio's generation exceeds load for a particular hour to the market that yields the highest, positive revenue up to the transmission limit. Similarly, market purchases will be made when either the portfolio's generation cannot meet the load in a particular hour, or when the cost of purchasing from the market is lower than marginal cost of the portfolio's dispatchable generation. Market purchases are also limited by the transmission availability. Wheeling, or a market-to-market transfer, can occur in the simulation when there is additional transmission capacity and price differentials between the Mid-C, SPP, or MISO markets. The heavy load and light load power prices assumed for Sensitivity Q are shown in Figure 126 and Figure 127, respectively. Note that while PowerSIMM does not model congestion relief created by new transmission connectivity, it is expected that NPC will create some price convergence between markets. However, the magnitude of the price convergence between markets is unknown.

[redacted]

FIGURE 126: HEAVY LOAD POWER PRICE FORECAST FOR MID-C, MISO, AND SPP.

[redacted]

FIGURE 127: LIGHT LOAD POWER PRICE FORECAST FOR MID-C, MISO, AND SPP.

The wheeling volumes for any given hour averaged between 225 MW and 255 MW, as shown in Figure 128. The net revenues associated with a transmission wheel, i.e. the cost of energy purchased from one market(s) and the revenue of energy sold to another market(s), are included in the Total Import Cost and Toal Export Cost of Figure 132 below. More information on the specific transmission activity by market is discussed below.

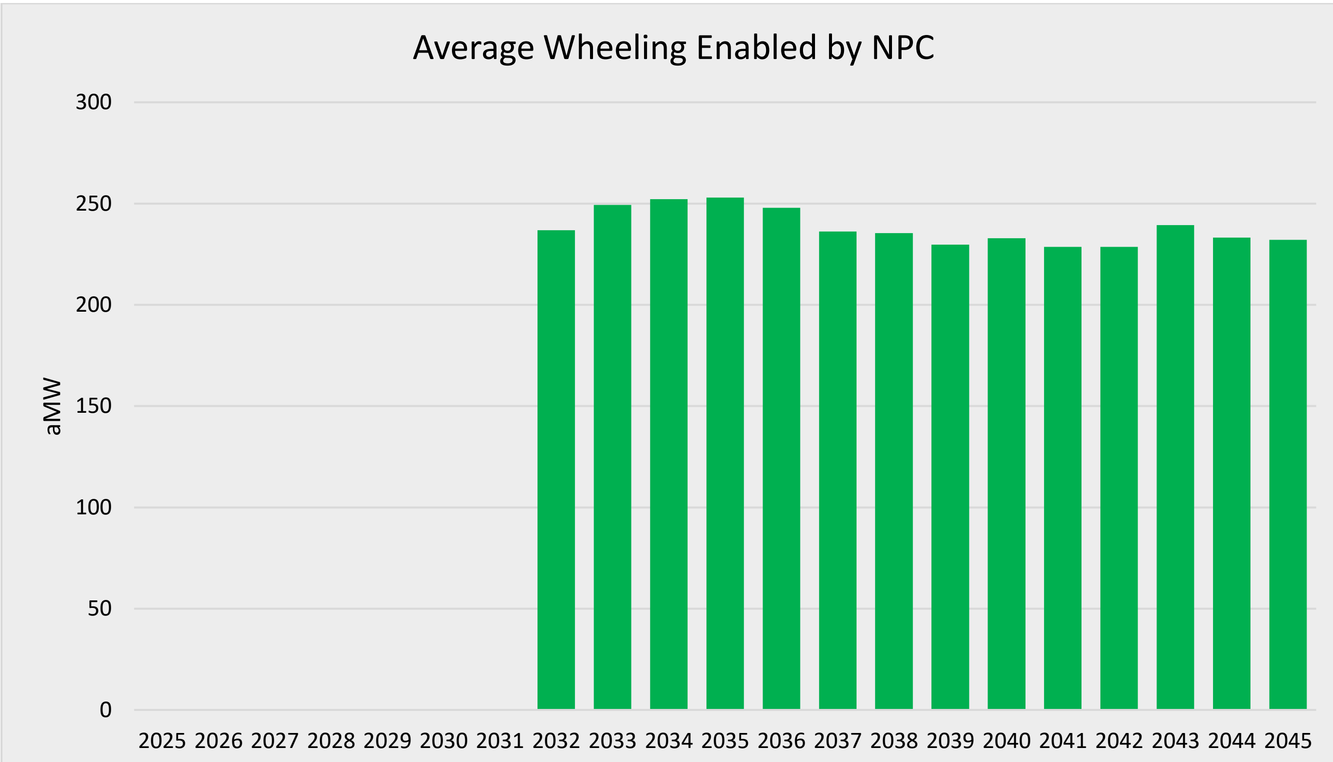


FIGURE 128: SENSITIVITY Q AVERAGE WHEELING VOLUMES ENABLED BY THE NPC.

Figure 129, Figure 130, and Figure 131 show the transmission imports from and exports to WECC, the MISO market, and the SPP market, respectively. The results show that the NPC facilitates more imports from MISO and SPP than WECC due to lower market prices. There are exports to MISO and SPP as well, but the great majority of transmission exports are made to WECC due to higher market prices at Mid-C and the size of the transmission interconnection already established.

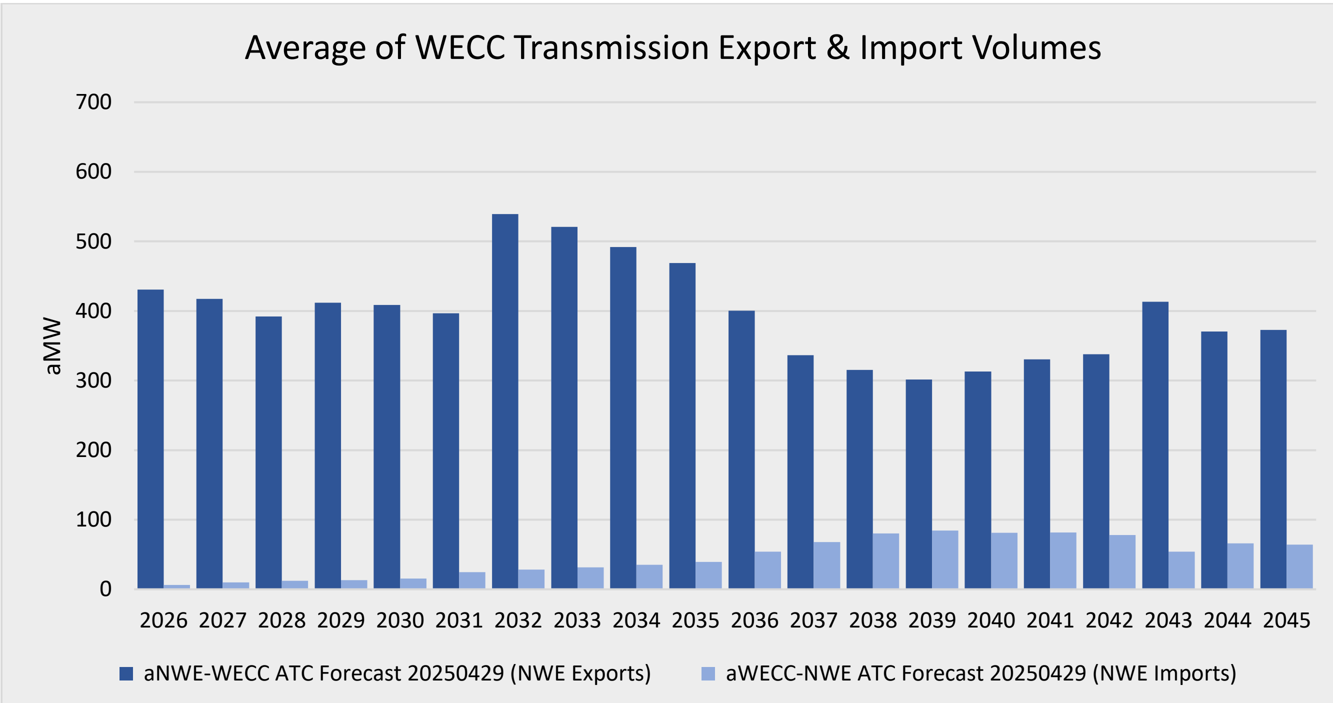


FIGURE 129: SENSITIVITY Q TRANSMISSION IMPORTS AND EXPORTS FROM AND TO THE WECC INTERCONNECTION.

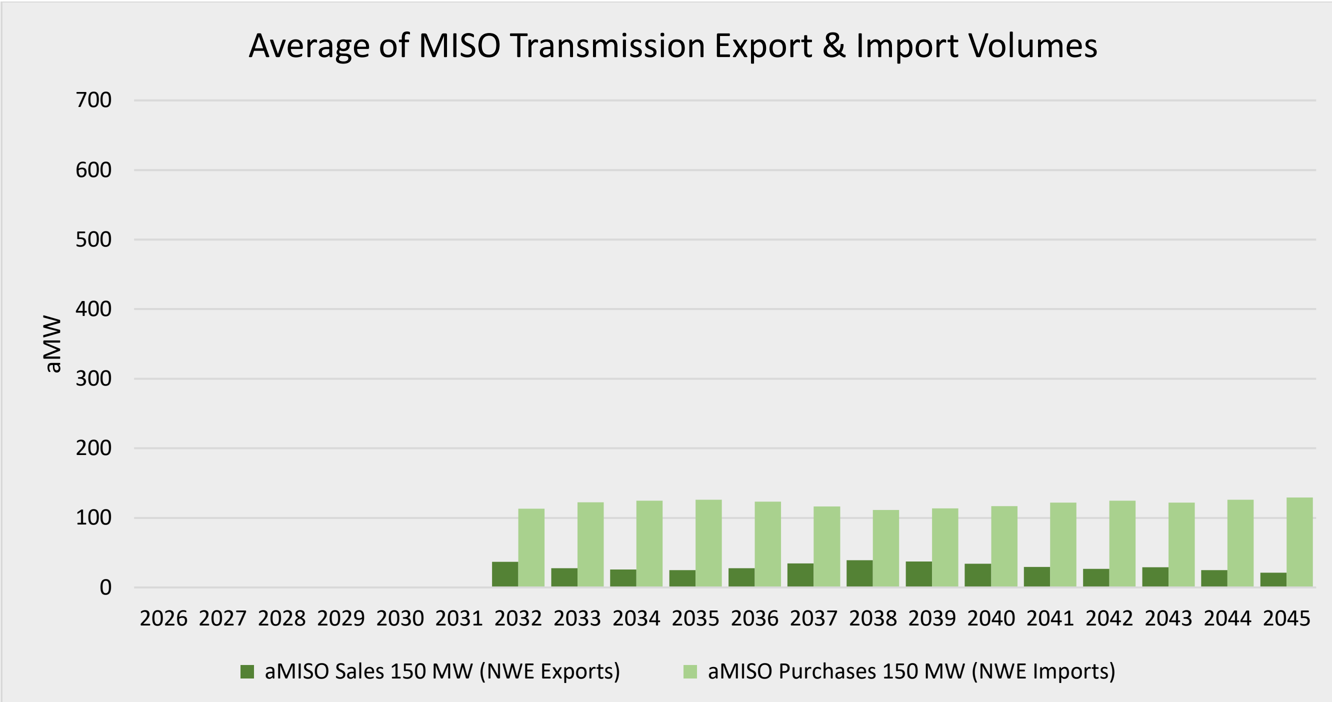


FIGURE 130: SENSITIVITY Q TRANSMISSION IMPORTS AND EXPORTS FROM AND TO THE MISO POWER MARKET.

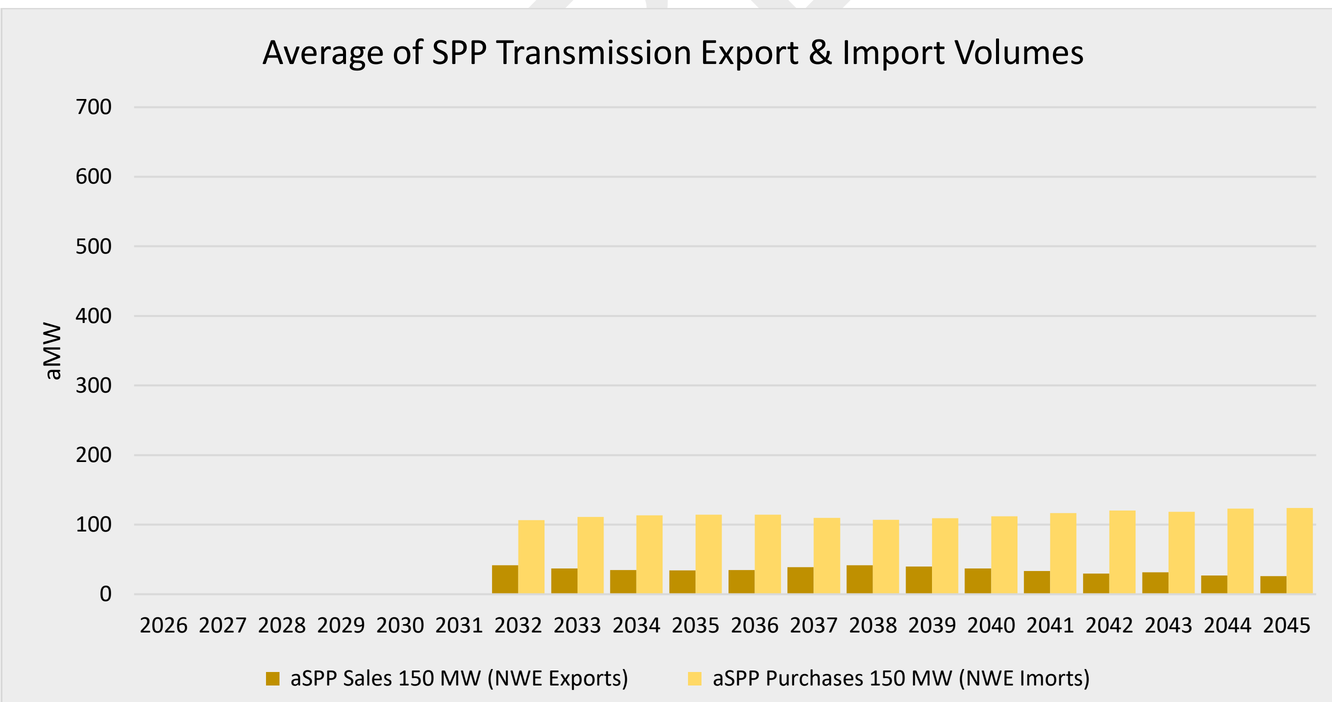


FIGURE 131: SENSITIVITY Q TRANSMISSION IMPORTS AND EXPORTS FROM AND TO THE SPP POWER MARKET.

Figure 132 shows the 20-year NPV of the Base Case and the other sensitivities. Sensitivity Q shows a 2% reduction in total costs due to increased market access from SPP and MISO for lower market purchases and occasion higher market sales as well as market arbitrage via wheeling. Sensitivity R shows a 10% reduction in total costs due to lower RR of candidate resources and lower production costs. However, Sensitivity R does not include cost increases related to additional DSM program facilitation or any potential costs or cost-shifts related to increased NEM.

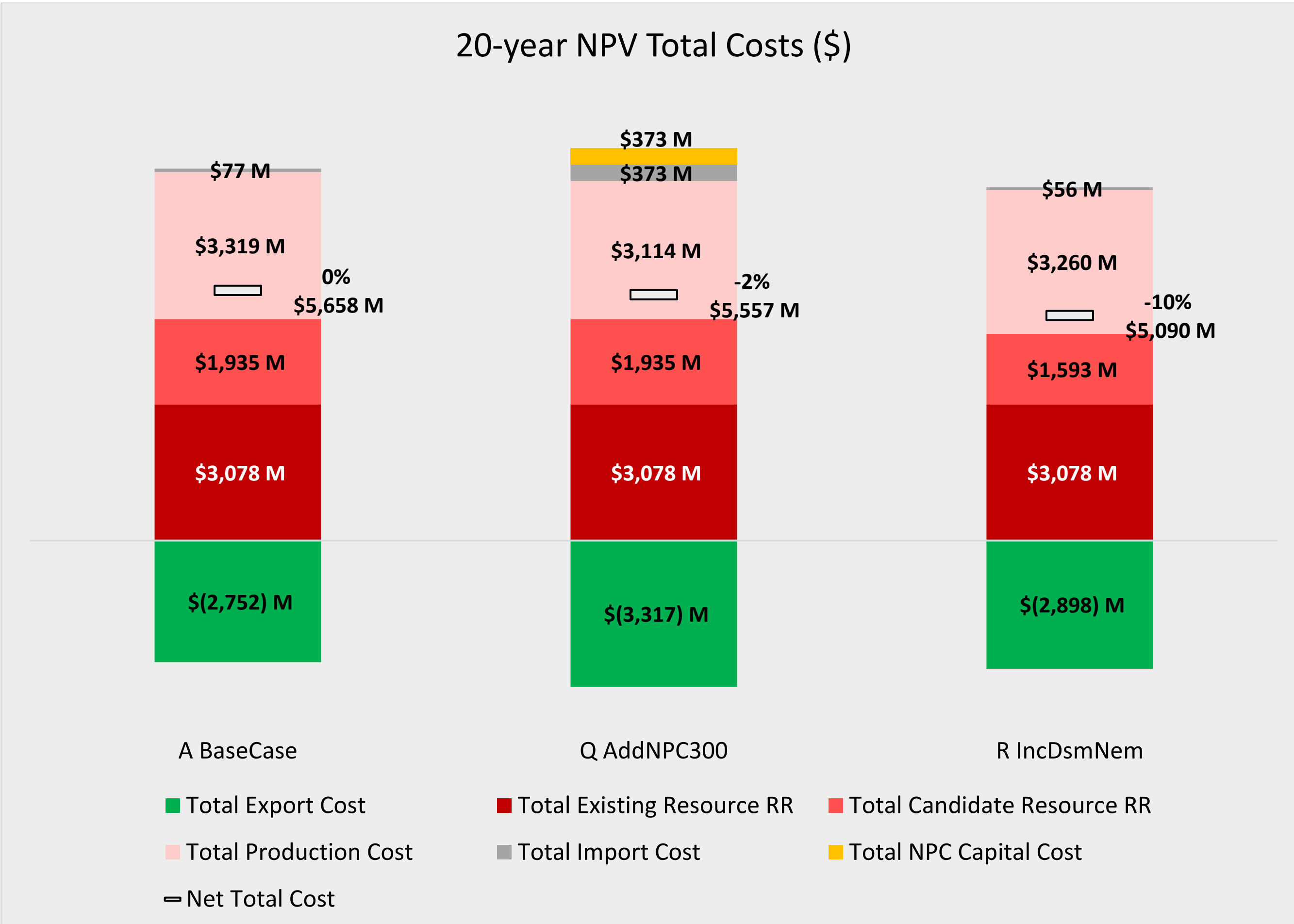


FIGURE 132: PCM RESULTS FOR THE BASE CASE AND THE OTHER SENSITIVITIES.

Figure 133 shows the remaining book value for the candidate resources in the Base Case and the other sensitivities. The remaining book value of sensitivity Q does not change because the ARS results do not change from the Base Case. Sensitivity R shows a 27% reduction in remaining book value due to one less SMR than the Base Case. Graphs and charts for individual sensitivities are provided in Appendix E.

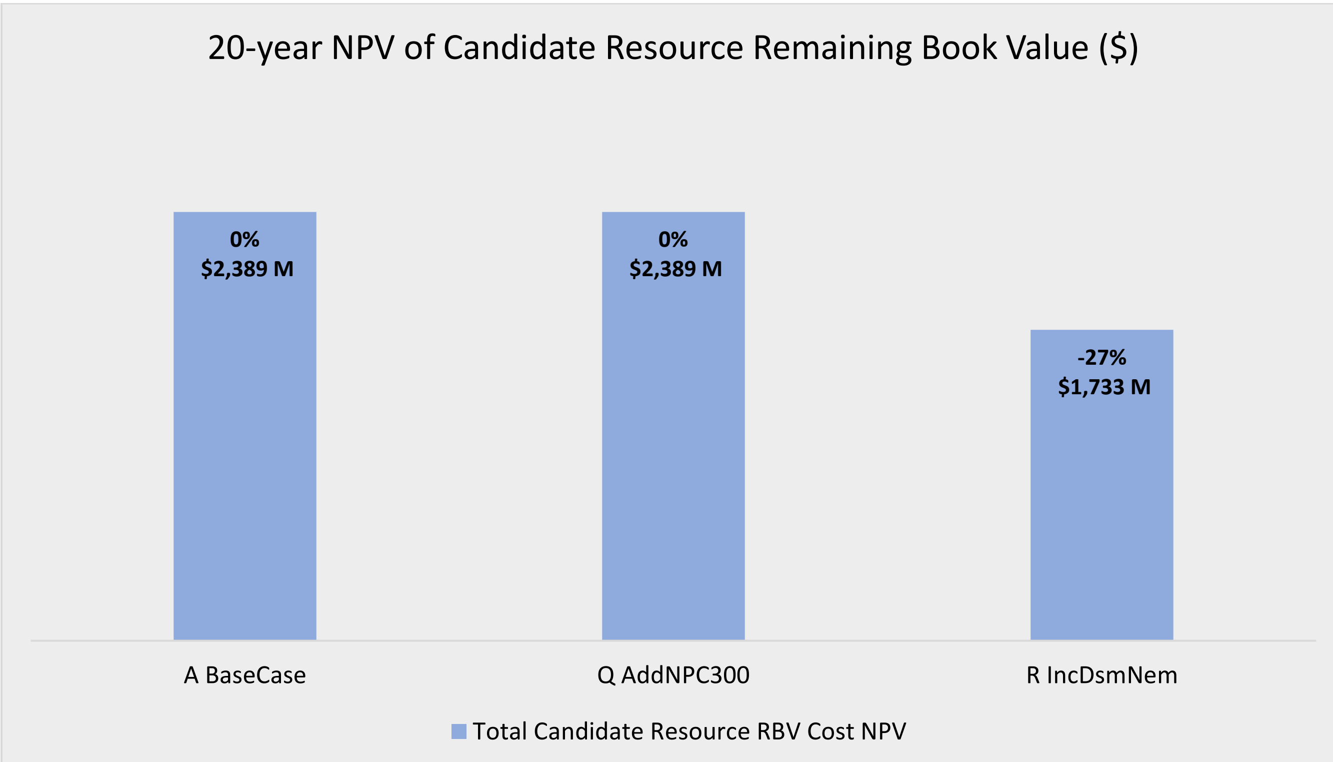


FIGURE 133: REMAINING BOOK VALUE FOR CANDIDATE RESOURCES IN THE BASE CASE AND THE OTHER SENSITIVITIES.

7.9 Summary of Portfolio Assessments

Table 60 below summarizes the results for each scenario and sensitivity from Sections 7.7 for total added nameplate capacity, and Section 7.8 for 20-year NPV cost, 20-year NPV cost per total load consumption, and 20-year carbon intensity of generation.

Category	Case	Total Added Nameplate Capacity (MW)	20-yr NPV Cost ($M)	20-yr NPV Cost per Total Load ($/MWh)	20-yr CO_2 Intensity of Generation (tons/MWh)
Base Case & Main Scenarios	A-BaseCase	1,290	$5,658 M	$40.51	0.53
	B-CSretMATS	1,190	$6,706 M	$48.02	0.37
	C-CScompMATS	1,290	$6,092 M	$43.62	0.53
	D-CSretGHG	1,490	$6,170 M	$44.18	0.40
	E-CSret2035	1,240	$6,221 M	$44.55	0.44
Commodity	F-Power50	1,198	$6,467 M	$46.31	0.51
	G-Power150	1,190	$4,304 M	$30.82	0.52
	H-NatGas50	1,240	$5,192 M	$37.18	0.52
	I-NatGas150	1,298	$6,124 M	$43.85	0.54
Data Center	J-DC150	1,360	$5,804 M	$35.13	0.63
	K-DC650	2,380	$9,515 M	$39.54	0.59
	L-DC1160	2,820	$13,288 M	$41.93	0.55
Resource	M-NoCO2Lim	1,140	$5,528 M	$39.59	0.56
	N-CO2Free	1,640	$5,955 M	$42.64	0.52
	O-wPseCS	1,640	$4,812 M	$34.46	0.63
	P-NoAvaCS	1,390	$6,303 M	$45.13	0.44
Other	Q-AddNPC300	1,290	$5,557 M	$39.79	0.54
	R-IncDsmNem	1,328	$5,090 M	$38.70	0.54

TABLE 60: SUMMARY OF SCENARIO AND SENSITIVITY RESULTS.

8 RISK AND UNCERTAINTY

8.1 Changes to Environmental Regulations

When evaluating the resources that can satisfy NorthWestern's capacity needs, NorthWestern considered risks related to uncertainty and changes in public policy and environmental regulations.

8.1.1 Mercury and Air Toxic Standards

The EPA first issued the MATS rule in 2012 to limit mercury and other hazardous air pollutants from coal- and oil-fired utility steam generating units. In 2024, the EPA adopted more stringent standards for mercury and filterable particulate material (fPM), which is used as a surrogate for hazardous air pollutants. Colstrip Units 3 and 4 meet the mercury standards but do not meet the new fPM standard, which EPA reduced from 0.030 lb/MMBtu to 0.010 lb/MMBtu. Under the 2024 rule, Colstrip Units 3 and 4 had to meet the new fPM standard by July 8, 2027.

NorthWestern included compliance with the 2024 MATS rule as a modeling scenario. Although the EPA repealed the 2024 MATS rule in February 2026 and reverted to the 2012 standard, the 2024 rule represented the most current information available at the time the modeling was conducted. Scenario B, Section 7.7.2, shows the portfolio if Colstrip retires to comply with MATS. The PCM results for the main scenarios described in Section 7.8.2 include the assumed costs of the baghouse infrastructure.

8.1.2 Performance Standards for Greenhouse Gas Emissions

Effective July 8, 2024, EPA adopted regulations for GHG, which are summarized in Table 61. These rules require technologies such as carbon capture and sequestration (CCS), alternate fuels (natural gas or hydrogen), and/or capacity limits to reduce emissions for facilities that plan to operate beyond 2032. However, if plants plan to retire by 2032 the rules do not require additional investments for pollution control. For plants that plan to operate past 2032, the standards begin to affect operations in 2030. Depending upon the planned retirement date of these plants, different standards are required. However, on June 11, 2025, the EPA issued a NOPR containing two proposals. The first, or lead, proposal would exclude the power sector from Clean Air Act regulation for GHG. The second, or "alternative," proposal would eliminate the CCS-based standards and other requirements from the 2024 final rule. On February 27, 2026, the EPA extended the deadline for 2025 GHG emissions reporting from March 31, 2026, to October 30, 2026, with the possibility of cancellation of the GHG reporting obligation entirely. If finalized, the proposal would remove reporting obligations for most large facilities, all fuel and industrial gas suppliers, and CO_2 injection sites. Scenario D, detailed in Section 7.7.4, evaluates Colstrip's retirement in 2032 to comply with GHG. Given the EPA's NOPR, NorthWestern did not model additional restrictions to natural gas-fueled resources.

Final Best System of Emissions Reduction (BSER) and Resulting Performance Standards[1]			
	Through Dec. 31, 2031	Jan. 1, 2032 - Dec. 31, 2038	2039 and beyond
Coal			
111(d) - Existing Steam EGUs[3] (coal-fired)*			
● Retire by 12/31/2031	Excluded from regulation	**Unit retired**	
● Retire 2032-2038	40% natural gas co-firing, presumed 16 percent emissions reduction: beginning 1/1/2030**		**Unit Retired**
● Retire after 1/1/2039	No applicable standard	CCS[4] at 90% cature rate, presumed 88.4 percent emissions reduction **	
111(d) - Existing Steam EGUs[3] (gas-fired)*			
● ≥ 45% Capacity Factor	Routine efficient operations: 1,400 lb CO_2/MWh beginning 1/1/2030		
● < 45% Capacity Factor	Routine efficient operations: 1,600 lb CO_2/MWh beginning 1/1/2030		
● < 8% Capacity Factor	Uniform fuels : 170 lb CO_2/MMBtu for oil-fired sources and a presumptive standard of 130 lb CO_2/MMBtu for natural gas-fired sources		
Natural Gas			
111(b) - New NGCC[*2]			
● Base Load > 40%	Highly efficient generation/best O&M practices 800 lb CO2/MWh for > 2,000 MMBtu/h Units 900 lb CO2/MWh for < 2,000 MMBtu/h Units	CCS[4] at 90% capture rate 100 lb CO2/MWh for > 2,000 MMBtu/h Units 110 lb CO2/MWh for < 2,000 MMBtu/h Units	
111(b) - New CT[*2]			
● Intermediate CT > 20% CF to ≤ 40% CF	Efficient Operation 1,170 lb CO_2/MWh		
● Low Utilization (CT)** ≤ 20% CF	Use of clean fuels (NG, Nos. 1 & 2 fuel oil): 20% annual CF restriction 120-160 lb CO_2/MMBtu		

*States set emissions limits for existing units under Clean Air Act § 111(d) that reflect EPA's BSER. Under Clean Air Act § 111(b), EPA sets emissions limits based on its BSER determination for new units.
**Actual emissions limits will be unit specific. States will set these limits using a unit-specific baseline annual emissions rate. For standard setting and compliance purposes, that rate is determined by taking the annual pounds of CO2 emitted and dividing it by the annual total Mwhs produced.

[1] A covered EGU is not required to use the technology indentified as BSER, but instead to achieve an emissions rate equivalent to using the BSER. For existing units, the regulations would allow states to authorize the use of various compliance flexibility tools to meet the standards (e.g. averaging, trading, mass-based approaches, etc.)
[2] New source standards are effective upon proposal, which is the date of *Federal Register* publication May 23, 2023.
[3] EGU: Electric Generating Unit
[4] CCS: Carbon Capture and Storage

TABLE 61: EPA CARBON RULES.[74]

8.1.3 Regional Haze Rule

The EPA published a set of regulations in the late 1990s that aim to reduce the number of visibility-impairing particles in the air over time. This set of regulations is called the Regional Haze Rule. Currently, the regulations require states to submit periodic comprehensive revisions of state implementation plans addressing regional haze visibility impairment.

On August 10, 2022, Montana DEQ submitted its plan that fulfills the RHR requirements by establishing long-term strategies to achieve the 2028 reasonable progress goals. This plan does not require NorthWestern to implement additional controls or incur additional costs.

[74] Source: Edison Electric Institute (EEI), Appendix A, "Clean Air Act Section 111 Final Rules". https://images.magnetmail.net/documents/clients/EEI_/2024-04/cmysh0zo.qcv/Appendix_A_111_Rules.pdf

On September 29, 2025, EPA issued an Advance NOPR to solicit information and request comment to assist in the development of regulatory changes pertaining to the implementation and structure of the RHR.

NorthWestern did not include additional costs related to RHR compliance in the modeling.

8.1.4 Coal Combustion Residuals

The Disposal of Coal Combustion Residuals (CCR) from Electric Utilities final rule was finalized in April 2015, providing requirements for the disposal of coal ash from coal-fired plants. The rule establishes requirements for new and existing CCR landfills and surface impoundments. The requirements also cover structural integrity of impoundments, groundwater protection, operating criteria, record keeping, and information disclosure.

In August 2012, Talen Energy and the Montana DEQ signed an Administrative Order on Consent Regarding Impacts from Wastewater Facilities (AOC). The AOC sets up a comprehensive program for investigation, interim response, remediation, and closure of the holding ponds at Colstrip and covers the same facilities required to comply with the CCR rule. Due to this, the Colstrip facility is complying with the CCR rule. NorthWestern's share of the capital and financial assurance costs associated with the AOC are incorporated in the cost structure for 222 MW Colstrip and scaled for the continued operation of the Avista share, noting the existing requirements stay with Avista. NorthWestern does not expect additional material cost impacts related to CCR compliance. Therefore, no additional costs related to CCR compliance are included in the modeling.

8.1.5 Cost of Carbon

This IRP does not include a carbon adder in either the base case or sensitivity scenarios. While carbon pricing is frequently discussed and used in several jurisdictions as a potential regulatory or market-based approach to reducing GHG emissions in the electric sector, there are compelling reasons why it was excluded entirely from the modeling framework for this IRP cycle. Montana does not currently impose any form of carbon tax, cap-and-trade program, or carbon emissions fee. SPP and WEIM do not have active or imminent carbon pricing mechanisms other than compliance with California's cap-and-trade program for California imports. Given the lack of any established or proposed carbon tax in the jurisdictions where NorthWestern operates or transacts, introducing a hypothetical carbon cost would be speculative.

To address emissions-related risk in a more targeted and policy-relevant way, this IRP includes alternative scenarios that explicitly limit the buildout of carbon-emitting resources. Specifically, Sensitivity N in Section 7.7.14 limited resource selection to solely carbon free candidate resources, and the Base Case in which no new fossil fuel candidate resources after 2035 are selected, shown in Section 7.8.1, to evaluate the long-term system impacts of decarbonization trajectories without relying on speculative carbon price assumptions. These cases offer a practical and transparent means of testing portfolio resilience under evolving emissions policies, while still maintaining a focus on reliability and customer cost. If there is market certainty, proposed federal policies, or requirements by regulatory, NorthWestern can implement carbon pricing scenarios.

8.1.6 Summary

NorthWestern's planning process will continue to be impacted by environmental regulations and legislation that will affect current and future thermal generation resources. Providing reliable, cost-effective energy in an environmentally safe manner remains one of NorthWestern's commitments.

NorthWestern will continue to comply with environmental statutes and guidelines while fulfilling NorthWestern's responsibility to customers.

8.2 Extreme Weather Events

Extreme weather events are occurring with increasing frequency and severity across the Pacific Northwest, introducing additional uncertainty for both electric demand and resource performance during critical periods. These changing conditions can elevate peak loads during heat waves or cold snaps and can reduce the availability of wind, solar, and hydropower resources during periods of low wind, limited solar insolation, or altered hydrological timing.

To address this uncertainty within a structured and standardized framework, this IRP relies on NorthWestern's implementation of WRAP. WRAP establishes regional reliability standards, including a 0.1 LOLE[75] target, meaning the regional system is planned such that firm-load curtailments are expected to be no more than one day in ten years. As part of the 0.1 LOLE target, WRAP identifies the required monthly summer and winter PRM for binding seasons [76]. The PRM provides the necessary capacity to account for uncertainty related to extreme weather, generator outages, and variable renewable output. Regional diversity benefits within WRAP further reduce localized risk by enabling coordinated use of surplus capacity among participating balancing authorities. More details on how NorthWestern implements WRAP, including planning for the worst case load + PRM month, is found in section 7.2 Resource Accreditation.

Within this IRP, NorthWestern has not conducted formal multi-day extreme-weather stress-test simulations. Multi-day stress-test simulations are used for emergency preparedness and resilience, not portfolio planning. Instead, this IRP incorporates historical resource performance and NorthWestern's accreditation framework to reasonably manage weather-related reliability risk without unnecessarily increasing customer costs through excessive over-procurement.

8.3 Achieving a Timely Commercial Operation Date

8.3.1 Regulatory Requirements

In the 2025 legislative session, the Montana Legislature mandated that utilities conduct competitive solicitations monitored by an independent monitor before acquiring new resources, except in the case of short-term resources or opportunity resources. This mandatory process will take at least one year for the resource selection process before a contract could be executed. Unless NorthWestern procured long-term capacity from an existing resource, there would be a minimum of four years from the RFP initiation before NorthWestern could acquire newly constructed, incremental generation, noting it takes at least three years to secure obtaining permitting and interconnection, equipment, and to build and construct the facility. NorthWestern did include a 2030 build constraint for all candidate resources stated in Section 7.7.1, with the exception of SMRs, which were constrained due to technology availability to an operational date of 2035 as stated in Section 7.1.2.

8.3.2 Supply Chain

Another limitation on NorthWestern's ability to acquire generation is global and domestic supply-chain disruptions. These disruptions continue to affect the cost and delivery timelines for critical generation components, including turbines, inverters, transformers, and control systems. Manufacturing lead times for gas turbines and LDES have lengthened considerably, while renewable and battery projects face

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[75] https://www.westernpowerpool.org/private-media/documents/2026-2027_Advance_Assessment_Study_Scope_Detailed_Report.pdf
[76] https://www.westernpowerpool.org/news/take-a-closer-look-at-the-wrap-operations-program

increasing interconnection queue backlogs, tariffs limiting manufacturing, and overall limited transmission availability. Inflationary pressures on materials such as steel, copper, and semiconductors, combined with high labor demand, can further extend project schedules and financing risk. NorthWestern did inherently model supply chain risks into the modeling period for all candidate resources due to the 2030 and 2035 build constraints.

8.4 Emerging Technology Timelines

NorthWestern's ability to acquire generation with emerging technology is dependent upon development of that emerging technology. While near-term procurement remains focused on proven, commercially available resources, the Company is actively monitoring the maturity, policy environment, and commercialization timelines for advanced nuclear and LDES that could contribute to the future resource portfolio. The timeline for emerging technologies presents inherent risk due to frequently encountering uncertain development, permitting, and construction durations, resulting in limited confidence regarding when the technology will achieve commercial readiness and reliable large-scale performance.

8.4.1 Nuclear Timeline

SMRs and advanced nuclear technologies are progressing through design certification and early licensing phases with the U.S. NRC. Current timelines indicate that the first wave of commercially viable SMRs could begin operation in the early-to-mid 2030s, with broader deployment potential extending into the 2035–2045 period.

However, early deployment remains constrained by licensing complexity, financing uncertainty, and limited manufacturing supply chains. NorthWestern continues to monitor vendor readiness, federal incentives under the IRA, and potential partnerships with regional utilities or private businesses pursuing demonstration projects. Given these development trajectories, early licensing and environmental permitting will be key in reducing potential delays should nuclear be selected for a future capacity need. NorthWestern included SMRs as a candidate resource as stated in Section 7.1.2; however, the COD was delayed until 2035 for IRP planning purposes.

8.4.2 Long-Duration Energy Storage Timeline

Iron-air and thermal storage technologies are in pilot demonstration status today, with cost declines projected through the mid-2030s as domestic manufacturing scales. NorthWestern will continue to monitor LDES opportunities, including Iron Air batteries as well as other technologies including gravity-based systems, pumped hydro, and flow batteries (usually limited to about 10 hours). LDES was added as a candidate resource in the modeling for this IRP, as stated in Section 7.1.4, with the model to select the resource with an in-service date of 2030 or later.

8.5 Commodity Price

Wholesale energy prices across the Western Interconnection remain closely linked to natural gas market dynamics, which continue to be the dominant marginal fuel for electricity generation. Variability in gas prices directly affects both near-term power market costs and long-term resource planning assumptions. Natural gas expansion costs, including new pipeline capacity, compressor upgrades, and interconnection infrastructure, have risen due to labor constraints, materials inflation, and heightened environmental review requirements. These expansion-related costs can increase delivered fuel prices. Meanwhile, commodity costs remain exposed to upstream production volatility, storage levels, and seasonal weather patterns that drive heating and electric-generation demand.

NorthWestern evaluated commodity price sensitivities F, G, H, and I for natural gas and electric power prices to assess portfolio performance under a range of commodity price conditions.

9 PORTFOLIO RESULTS SUMMARY, KEY FINDINGS, AND ASSOCIATED ACTION PLAN

9.1 Portfolio Results Summary

Category	Case	Total Added Nameplate Capacity % Difference from Base Case	20-yr NPV Cost ($M)	20-yr NPV Cost per Total Load (% Difference from Base Case)	20-yr CO_2 Intensity of Generation (% Difference from Base Case)
Base Case & Main Scenarios	A-BaseCase	0%	$5,658	0%	0%
	B-CSretMATS	-8%	$6,706	19%	-30%
	C-CScompMATS	0%	$6,092	8%	0%
	D-CSretGHG	16%	$6,170	9%	-26%
	E-CSret2035	-4%	$6,221	10%	-18%
Commodity	F-Power50	-7%	$6,467	14%	-4%
	G-Power150	-8%	$4,304	-24%	-3%
	H-NatGas50	-4%	$5,192	-8%	-3%
	I-NatGas150	1%	$6,124	8%	0%
Data Center	J-DC150	5%	$5,804	-13%	18%
	K-DC650	84%	$9,515	-2%	11%
	L-DC1160	119%	$13,288	4%	3%
Resource	M-NoCO2Lim	-12%	$5,528	-2%	5%
	N-CO2Free	27%	$5,955	5%	-3%
	O-wPseCS	27%	$4,812	-15%	18%
	P-NoAvaCS	8%	$6,303	11%	-17%
Other	Q-AddNPC300	3%	$5,557	-2%	2%
	R-IncDsmNem	16%	$5,090	-4%	1%

TABLE 62: SUMMARY OF SCENARIO AND SENSITIVITY RESULTS IN UNITS OF PERCENT DIFFERENCE.

9.2 Major Findings

NorthWestern's 2026 IRP modeling results demonstrate winter capacity needs beginning in 2027, the critical reliability role that Colstrip continues to play, and the increasing importance of transmission expansion, large-load planning, and emerging technologies. The analysis also shows that demand-side resources provide value but are not sufficient on their own to meet reliability needs, particularly under large-load growth sensitives. The following sections summarize these major findings.

Capacity Need in 2027 and Early Colstrip Retirement

NorthWestern's current portfolio meets 2026 WRAP planning-reserve obligations, aided by the addition of the YCGS and the acquisition of Avista's 222-MW Colstrip shares (Avista 222 MW) and existing capacity contracts. Under NorthWestern's 2025 planning assumptions, a winter capacity shortfall of approximately 23 MW emerges in the 2027–2028 period, increasing to nearly 200 MW following the expiration of a capacity contract.

Over the 20-year planning horizon, the capacity needs increase further as generating units reach the end of their book lives, particularly if Colstrip retires earlier than expected and/or large loads materialize faster than expected. Delays in constructing replacement resources could create reliability exposure even if total capacity appears adequate on paper.

Colstrip's Central Role

The modeling results confirm that early retirement of Colstrip is expensive to customers because replacing Colstrip's accredited capacity requires major capital investment. More specifically, as shown in Table 62, an early replacement of Colstrip in 2035 results in a 10% increase in 20-year net present value (NPV) portfolio costs. Therefore based on the assumptions and scenarios modeled, maintaining Colstrip through 2042 remains the lowest-cost option, noting there is uncertainty surrounding future MATS and GHG regulation.

Transmission and Regional Integration

Transmission expansion, notably the NPC, adds value by increasing import capability and providing access to additional markets for purchasing and selling energy. Specifically, the NPC study resulted in a 2% reduction in 20-yr NPV portfolio costs through energy market price variance in purchases and sales. Coordinated investment in additional interregional paths including NPC and M2I could provide future benefits, including access to lower energy costs and potential regional reliability benefits, when studied through WRAP's regional adequacy program.

Load Growth and Data Centers

Data center loads represent the most significant emerging source of uncertainty in load growth and an opportunity for Montana's energy system when coordinated with resource and infrastructure development. Modeling results indicate that under high-level, system-wide modeling assumptions, although additional generation is required to serve data center load, the resulting system-average cost per megawatt-hour generally declines or remains relatively stable relative to the Base Case portfolio due to economies of scale and improved asset utilization. Specifically, the modeling scenarios show a 13% reduction in cost per megawatt-hour (MWh) in the 150 MW scenario, a 2% reduction cost per MWh in the 600 MW scenario, and a modest 4% increase in the 1,160 MW scenario.

Demand-Side Management and Distributed Resources

DSM and NEM programs show savings across the portfolio based on modeled load reductions. While DSM measures are modeled as a reduction to the load forecast and achieve the cost-effective programs recommended in the NorthWestern Electric EE and DR Market Potential Study (May 2024 - Revised October 2025) in Appendix H, the IRP also includes a sensitivity with increased DSM and NEM. The costs associated with increased NEM participation, including potential system and cost-shift impacts, as well as increased DSM participation costs are not reflected in this sensitivity and will need to be evaluated through a separate analysis outside of this IRP.

Emerging Technologies

The modeling selected LDES (e.g., 100-hour iron-air batteries) and SMRs in most scenarios and sensitivities. Each technology has the potential to play a future reliability role, but near-term commercialization timelines and cost uncertainties will need to be closely analyzed.

9.3 Action Plan

The 2026 IRP identifies emerging needs related to winter reliability, regional coordination, transmission development, DA market participation, and large-load growth. These actions support responsible planning and transparency as NorthWestern prepares for the next IRP in 2029. None of these activities represent a commitment to procure resources; rather, they establish analytical steps and decision points to ensure customer affordability and reliable service.

Address Near-Term Reliability Needs

The capacity forecast illustrates a growing winter capacity deficit beginning in 2027–2029, with a larger need emerging in 2031–2032 under 2025 planning assumptions. NorthWestern will continue evaluating RA need and options to maintain RA, including resource options, initiating actions in 2026 to align and document parameters, characteristics, and resource attributes, evaluate potential of extending capacity contracts, and prepare for a competitive solicitation if warranted by system conditions and resource adequacy need. The process for competitive solicitation is further discussed in 9.3.2.

Strengthen Data-Driven Planning

Completion of AMI deployment will enhance visibility into load patterns by customer class and expand opportunities for demand flexibility and improved forecasting. NorthWestern will integrate interval data into load analysis and share insights with stakeholders to improve transparency and confidence in assumptions.

WRAP Binding Season & Accreditation

WRAP remains the regional adequacy framework that supports responsible planning through accreditation requirements and seasonal obligations. NorthWestern will continue preparing for binding implementation, expected to apply beginning in the Winter 2027/2028 operating season. NorthWestern will also quantify benefits associated with WRAP participation to support informed future planning and stakeholder engagement.

Continue Transmission Analysis

Transmission can enhance portfolio economics through improved access to lower-cost energy, greater operational flexibility, and potential regional capacity benefits. NorthWestern will continue evaluating the NPC, the potential M2I intertie, and other system enhancements while requesting regional analysis within the WRAP framework. This includes estimating transmission requirements needed to access WRAP-accredited resources and determining how new transmission investments could provide market efficiency and reliability value for customers.

Day-Ahead Market Participation

DA market participation may improve operational efficiency, scheduling certainty, and customer value. NorthWestern will continue assessing CAISO EDAM and SPP Markets+ to maintain optionality for future participation decisions.

Manage Data Center & Large-Load Growth

Data centers and other large industrial loads can meaningfully affect system planning, requiring additional firm capacity and potential transmission upgrades. NorthWestern will continue early coordination with developers and regulators to protect existing customers while supporting strategic development.

Note, if large-load development exceeds the range of scenarios evaluated, incremental resource need will be identified consistent with the framework established in this IRP.

Nuclear Resource Evaluation and Technology Readiness

SMRs and advanced nuclear designs continue to advance through federal licensing, vendor development, and early deployment efforts across North America. While still pre-commercial in terms of cost certainty and project execution risk, these technologies may offer long-duration, zero-carbon firm capacity in the future. NorthWestern will continue monitoring regulatory progress, licensing and siting pathways, federal incentives, regional planning discussions, partnerships, and market readiness, and will revisit feasibility, cost competitiveness, and potential siting considerations during the 2029 IRP cycle.

Monitor Emerging Technologies – Long-Duration Energy Storage & Geothermal

LDES technologies (such as 100-hour iron-air batteries) and advanced geothermal continue to show promise as future firm and flexible resources. However, commercialization timelines, cost uncertainty, permitting pathways, and site-specific feasibility considerations require ongoing evaluation. NorthWestern will monitor technology performance, cost trends, and demonstration project results and reassess these emerging options as part of the 2029 IRP.

Support Continued Operation of Colstrip Units 3 & 4

Colstrip Units 3 & 4 remain an important source of reliable, dispatchable capacity for Montana. NorthWestern will continue supporting ongoing operations while monitoring evolving federal and state environmental regulations, evaluating potential compliance requirements, and assessing cost and reliability value. NorthWestern will ensure that keeping Colstrip running remains cost-effective and supports system reliability as new large loads and industries connect to the grid.

Transition Toward Integrated Resource Planning

NorthWestern is advancing a transition toward fully integrated resource planning. This approach improves visibility into system constraints, supports more accurate planning for electrification and large-load growth, and strengthens coordination of demand-side resources with supply-side investments. Integrated planning also increases transparency and stakeholder engagement by ensuring that information is consistent across filings and decision processes. NorthWestern will continue developing data systems, analytical tools, and cross-functional processes to support this transition ahead of the 2029 IRP.

9.3.1 Action Plan Summary Table (2026–2029 Timeline)

Action Area	Next Steps	Timeline
Address Near-Term Reliability Needs	• Align and document resource parameters, characteristics, and attributes to inform future resource evaluations • Evaluate extensions of contracts • Prepare for capacity acquisition, such as a competitive capacity RFP if needed	Begin 2026; updates through 2029
Strengthen Data-Driven Planning	• Integrate AMI interval data into IRP modeling • Share insights with stakeholders	2026–2028
WRAP Binding Season & Accreditation	• Continue WRAP accreditation and methodology • Prepare for Winter 2027/2028 binding readiness • Quantify benefits of WRAP	2026–2028
Continue Transmission Analysis	• Evaluate NPC and potential M2I intertie • Engage with potential WRAP regional transmission analysis(s). • Assess transmission needs for access to WRAP resources.	2026–2028
Day-Ahead Market Participation	• Continue evaluation of CAISO EDAM and SPP Markets+ • Maintain participation optionality	2026–2028
Manage Data Center & Large-Load Growth	• Coordinate early with developers and regulators • Evaluate required firm capacity and transmission needs • Protect existing customers	Ongoing 2026–2029
Nuclear Resource Evaluation & Technology Readiness	• Monitor SMR and advanced nuclear development and licensing • Participate in regional and industry initiatives • Assess siting, cost, and feasibility; revisit readiness and portfolio role in 2029 IRP	2026–2029
Monitor Emerging Technologies (LDES, Advanced Geothermal)	• Monitor performance, demonstration projects, and cost trends • Reassess readiness and potential application in 2029 IRP	2026–2029
Support Continued Operation of Colstrip Units 3 & 4	• Monitor environmental regulatory requirements and compliance pathways	2026–2029
Transition Toward Integrated Resource Planning	• Develop coordinated planning across distribution, transmission, generation, and DSM. • Improve cross-functional modeling tools and data systems. • Enhance stakeholder engagement and alignment across processes.	2026–2029

TABLE 63: ACTION PLAN SUMMARY

9.3.2 Resource Acquisition

Consistent with Montana's Integrated Least-Cost Resource Planning and Acquisition Act and Commission rules implementing the Act, NorthWestern uses competitive solicitations to acquire resources. NorthWestern acquires opportunity resources, short-term resources, and purchases from Qualifying Facilities outside of the competitive solicitation process.

9.3.2.1 Competitive Solicitation Overview

If NorthWestern elects to pursue a competitive solicitation, the solicitation may describe the identified resource need using relevant parameters, characteristics, and attributes necessary to fill that need, while allowing bidders flexibility to propose different resource types or combinations capable of meeting the identified objectives.

NorthWestern will consider a variety of structures that satisfy the requirements in the RFP, such as power purchase agreements, acquisition of existing resources, build-transfer agreements, and engineer, procure, and construct proposals. NorthWestern will execute a contract for service with an independent evaluator, as required by statutes and rules.

Draft RFP

Prior to issuing a competitive solicitation, NorthWestern will submit a draft RFP to the Commission. The Commission will provide public notice of the draft RFP and an opportunity for comment.

RFP Release and Proposal Development

Upon issuance of a final RFP, NorthWestern will submit the RFP to the Commission and publicly announce the solicitation. Interested parties will be provided notice and instructions for participation.

Following distribution of the RFP, a proposal development period will commence. During this period, bidders may submit questions in accordance with communication protocols established in the RFP, participate in bidder conferences, and conduct reasonable due diligence activities, as applicable.

RFP Administration

NorthWestern may retain an RFP Administrator to manage the solicitation process. If retained, the RFP Administrator will serve as the primary point of contact for bidders and will enforce communication protocols to ensure proposal confidentiality and a fair evaluation process.

Independent Evaluator

Consistent with the Act, the Commission will select an Independent Evaluator to monitor, evaluate, and observe the competitive solicitation process. The Independent Evaluator will prepare a closing report.

Evaluation Considerations

Evaluation considerations may include, but are not limited to, the following categories:

- Levelized Costs: Planning-level assessment of project lifecycle costs and benefits, including delivered cost of capacity, expected capacity contribution, energy market attributes, non-fuel operations and maintenance costs, fuel or charging costs, and other relevant factors.
- Commercial Considerations: Review of proposed commercial structures and terms, including general alignment with standard contract frameworks, credit considerations, insurance coverage, safety practices, and execution considerations.

- Development Status: Consideration of the status, development approach, and anticipated timeline associated with the proposed resource, which may include interconnection and transmission arrangements, fuel or charging arrangements, permitting, site control, and execution planning supporting the proposed in-service timeframe.
- Technical Attributes: Assessment of the resource's technical characteristics and operating capabilities, including, as applicable, dispatchability, reliability, ancillary services capability, and technology maturity.

Based on the results of a competitive solicitation, NorthWestern may select none, one, or multiple proposals for further refinement, negotiation, or potential contracting.

10 EMERGING TECHNOLOGIES

10.1 Electric Vehicles

NorthWestern has continued to monitor EV adoption to understand and plan for the system and supply impacts of EVs and electric vehicle supply equipment (EVSE). Due to differences in EV charging equipment and the utilization of this equipment, it is helpful to examine these current and potential system and supply impacts in terms of two distinct domains – private and public charging.

Private charging accounts for approximately 80-90% of all EV charging and is generally performed during the afternoon and nighttime hours at homes, garages, parking lots, and businesses. This charging infrastructure typically uses “Level 1” (L1) or “Level 2” (L2) chargers which range from 1 to 20 kW.[77] Public charging infrastructure is primarily used during daytime hours by travelers and/or visitors travelling long distances who prefer to charge quickly near highway or interstate corridors. This infrastructure is largely comprised of “Level 3” (L3) or “Direct Current Fast Charger” (DCFC) equipment which ranges from 50 to 350 kW.[78]

In the context of NorthWestern’s Montana service territory, the growth of L1 and L2 charging is tied, in large part, to EV adoption rates within Montana whereas the utilization of public DCFC is more directly coupled with Montana’s travel and tourism trends and with national EV adoption rates. Due to these differences in utilization, growth, and electrical demands, NorthWestern has conducted separate analyses for private and public charging to evaluate the current and future impacts of EVs and EVSE on NorthWestern’s system.

To read more information about how NorthWestern is monitoring EV growth, please refer to Appendix F for the full analysis.

10.2 Geraldine Microgrid Project

The Geraldine Microgrid facility is a 2.45 MW / 9.79 MWH substation based rural reliability resource (RRR) located in Geraldine, MT, put into service in December of 2024. This facility provides a reliable automatic back-up source of electricity to the city of Geraldine and rural customer loads served by Geraldine Substation. In the event of an upstream transmission power outage, the Geraldine Microgrid facility can independently supply these customer loads with 4 – 12 hours of reliable electricity depending on the state of energy of the battery system and customer loading levels at the time of the transmission outage. This facility can also be utilized to provide back-up power during planned upstream transmission maintenance activities that would have traditionally caused planned power outages to be scheduled with customers.

In addition to providing reliable and automatic independent backup power to all area loads downstream of Geraldine Substation, the facility also has the ability to be remotely dispatched in order to supply 900 kW of power to the local utility grid for up to 7.5 hours while in grid-following mode in order to provide utility grid support services for a variety of future use cases.

10.3 Advanced Metering Infrastructure

Deployment of AMI across Montana was completed in 2025, providing a foundation for enhanced customer engagement and system planning. The system generates approximately 8.1 million records daily of data including, but not limited to, delivered, received, and net energy registers. This amount of

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77 https://www.energy.gov/eere/evgrid-assist-charts-and-figures

78 https://www.transportation.gov/rural/ev/toolkit/ev-basics/charging-speeds

data requires robust storage, processing, and analytical capabilities. To support this need, the Company transitioned its data platform in fall of 2025 from an Azure Datalake to Microsoft Fabric as the enterprise data warehouse and analytics platform. This technology choice provides a scalable and flexible environment to manage high-volume AMI data while enabling integration across multiple business functions.

By the next IRP cycle, the AMI platform will be fully operational and is expected to support a basis for bottom-up forecasting. Interval data at the customer level can be aggregated to build total system load forecasts, while also producing profiles and load shapes by customer class. This granularity can enable more accurate class-specific forecasting and improve the Company's ability to anticipate future system needs. A critical component of this platform is ensuring that customers have the ability to view and download their interval data, providing usage transparency. The goal is to have this available to customers in 2026. Beyond customer access, the same dataset will form an analytical backbone for energy supply planning, supporting load forecasting, capacity planning, and evaluation of alternative resource portfolios.

Looking forward, AMI data may also be leveraged to explore DSM and DR opportunities, including the ability to model targeted load reductions during system peaks, noting all programs shall adhere to regional resource adequacy planning requirements. Detailed interval data will allow evaluation of rate design strategies that may incentivize off-peak usage and improve system efficiency.

By the time of the next IRP filing, the AMI platform is expected to support and explain a set of analytical capabilities for long-term planning, ensuring greater use of data-driven insights in planning, operations, and regulatory policy.

10.4 Nuclear Resource Options

Nuclear energy technology has evolved through successive generations of reactor designs, each improving on safety, efficiency, reliability, economics, and sustainability. For this IRP, NorthWestern did evaluate a certain type of nuclear resource in modeling, an SMR. SMRs provide modular construction buildouts potentially fulfilling replacement of thermal resources, higher thermal efficiency, passive emergency cooling, and longer book life than other nuclear options. For more information on nuclear resources, including SMRs, refer to Appendix G.

NorthWestern continues to monitor advancements in nuclear generation and potential opportunities to incorporate this emerging technology further into future resource planning.

10.5 Hydrogen

Hydrogen is a clean fuel that is produced from a variety of resources already being used as energy sources, such as natural gas, renewable power like solar and wind, nuclear power, and biomass. Hydrogen fuel can be produced through many methods; the most common are natural gas reforming, and electrolysis. Natural gas reforming is a thermal process involving steam reacting with a hydrocarbon fuel to produce hydrogen. Electrolysis is where water is separated into oxygen and hydrogen.[79]

After the hydrogen is captured, it is stored in fuel cells. These cells have the capability to convert the chemical energy in hydrogen to electricity, leaving behind water and heat as the byproducts. This leaves hydrogen-powered fuel cells pollution free. According to the U.S. DOE, a conventional

[79] U.S. Department of Energy, "Hydrogen Fuel Basics," *Office of Energy Efficiency & Renewable Energy*, accessed July 17, 2025, https://www.energy.gov/eere/fuelcells/hydrogen-fuel-basics.

combustion-based power plant operates at efficiencies of 33-35%, while fuel cell systems operate at efficiencies up to 60%, even higher with cogeneration.[80]

Due to the cost and durability challenges that come with fuel cell commercialization, and still being relatively new in the researching phase, hydrogen as a candidate resource in modeling simulations was not included.

NorthWestern continues to monitor hydrogen advancements and potential opportunities to incorporate this emerging technology into future resource planning.

10.6 Enhanced Geothermal Systems

Enhanced Geothermal System (EGS) technology remains in the early stages of development. Currently, it is characterized by high costs and limited electricity output. For this IRP, NorthWestern evaluated cost data for geothermal electricity but did not include EGS as a candidate resource in modeling simulations due to its high costs and relatively low generation potential.

However, recent advancements suggest promising potential for EGS. New drilling techniques enable access to geothermal reservoirs at depths of 10,000 to 20,000 feet and temperatures ranging from 400°F to 600°F. Notably, Fervo Energy recently drilled the Sugarloaf well to a depth of 15,765 feet, achieving a reservoir temperature of 520°F[81]. The DOE has also supported multiple EGS demonstration projects, including 1.7 MW of generation at Desert Peak, Nevada, and 5.8 MW at The Geysers in Northern California. Ongoing DOE-funded work at a site in Milford, Utah, is focused on improving drilling rates and enhancing reservoir stimulation techniques[82].

NorthWestern continues to monitor EGS advancements and potential opportunities to incorporate this emerging technology into future resource planning.

[80] U.S. Department of Energy, *Hydrogen and Fuel Cell Technologies: Fuel Cell Technologies Office Fact Sheet*, Office of Energy Efficiency & Renewable Energy (July 2020), https://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/fct_h2_fuelcell_factsheet.pdf.
[81] https://www.businesswire.com/news/home/20250610223846/en/Fervo-Energy-Drill-15000-FT-500F-Geothermal-Well-Pushing-the-Envelope-for-EGS-Deployment

[82] https://www.energy.gov/eere/geothermal/enhanced-geothermal-systems

APPENDIX A – LIST OF ABBREVIATIONS

- AACE – American Association of Cost Estimating
- Act – Montana's Integrated Least-Cost Resource Planning and Acquisition Act
- AECO – Alberta Energy Company
- Aero – Aeroderivative Simple Cycle Combustion Turbine
- AFUDC – Allowance for Funds Used During Construction
- AGR – Advanced Gas-Cooled Reactor
- Aion – Aion Energy, LLC
- AMI – Advanced Metering Infrastructure
- aMW – Average Megawatt
- AOC – Administrative Order on Consent Regarding Impacts from Wastewater Facilities
- ARM – Administrative Rules of Montana
- ARS – Automated Resource Selection
- ATB – Annual Technology Baseline
- ATC – Available Transfer Capability
- BA – Balancing Authority
- BAA – Balancing Authority Area
- Bcf – Billion Cubic Feet
- BESS – Battery Energy Storage System
- BPA – Bonneville Power Administration
- Btu – British Thermal Unit
- BWR – Boiling Water Reactor
- CAISO – California Independent System Operator
- CC – Combined Cycle
- CCCT – Combined Cycle Combustion Turbine
- CCH – Capacity Critical Hours
- CCR – Coal Combustion Residuals
- CCS – Carbon Capture and Sequestration
- CELP – Colstrip Energy Limited Partnership
- CIG – Colorado Interstate Gas
- COD – Commercial Operation Date
- Commission – Montana Public Service Commission
- CONE – Cost of New Entry
- CT – Combustion Turbine
- CTS – Colstrip Transmission System
- DA – Day-Ahead
- DC – Direct Current
- DCFC – Direct Current Fast Charger
- DEQ – Department of Environmental Quality
- DGAP – Default Generation Aggregation Point
- DGGS – Dave Gates Generating Station
- DLC – Direct Load Control
- DNRC – Department of Natural Resources and Conservation

- DOE – Department of Energy
- DR – Demand Response
- DSM – Demand-Side Management
- EDAM – Extended Day-Ahead Market
- EFOF – Equivalent Forced Outage Factor
- EFOR – Effective Forced Outage Rates
- EGS – Enhanced Geothermal System
- EIA – U.S. Energy Information Administration
- EIM – Energy Imbalance Market
- ELAP – External Load Aggregation Point
- ELCC – Effective Load Carrying Capabilities
- ENU – Electrical Network Upgrades
- EPA – U.S. Environmental Protection Agency
- EPC – Engineering, Procurement, and Construction
- ETAC – Electric Technical Advisory Committee
- EV – Electric Vehicle
- EVSE – Electric Vehicle Supply Equipment
- FEOC – Foreign Entities of Concern
- FERC – Federal Energy Regulatory Commission
- fPM – Filterable Particulate Material
- FS – Forward Showing
- GCR/VHTR – Gas-Cooled Fast Reactor
- GHG – Greenhouse Gas
- GSL – General Service Lamp
- HALEU – High-Assay Low-Enriched Uranium
- HDD – Heating Degree Day
- HE – Hour Ending
- HPC – Havre Pipeline Company
- HVAC – Heating, Ventilating, and Cooling
- ICE – Intercontinental Exchange
- IDC – Interest During Construction
- IIJA – Infrastructure Investment and Jobs Act
- IPP – Independent Power Producers
- IRA – Inflation Reduction Act
- IRP – Montana Integrated Resource Plan
- ITC – Investment Tax Credit
- JCAF – Joint Capacity Attestation Form
- L1 – Level 1
- L2 – Level 2
- L3 – Level 3
- LDES – Long-Duration Energy Storage
- LED – Light-Emitting Diode
- LEU – Low-Enriched Uranium
- LFR – Lead-Cooled Fast Reactor
- Li-ion – Lithium Ion

- Lm/W – Lumens-per-Watt
- LMP – Locational Marginal Price
- LMR – Liquid Metal Fast Reactor
- LOLE – Loss of Load Expectation
- LOLP – Loss of Load Probability
- M2I – Montana to Idaho Project
- MATL – Montana Alberta Tie Line
- MATS – Mercury and Air Toxics Standards
- MCA – Montana Code Annotated
- MCFD – Thousand Cubic Feet per Day
- MEIC – Montana Environmental Information Center
- MEPPI – Mitsubishi Electric Power Products, Inc.
- Mid-C – Mid-Columbia Trading Hub
- MISO – Midwest Independent System Operator
- MOP – Minimum Operating Pool
- MRDAP – Montana Renewable Development Actions Plan
- MREA – Montana Renewable Energy Association
- MSR – Molten Salt Reactor
- MW – Megawatt
- MWh – Megawatt-hour
- NCDC – National Climate Data Center
- NEEA – Northwest Energy Efficiency Alliance
- NEM – Net Energy Metering
- NERC – North American Electric Reliability Corporation
- NLR – National Laboratory of the Rockies
- NOPR – Notice of Proposed Rulemaking
- NorthWestern or Company – Northwestern Energy
- NPC – North Plains Connector
- NPCII – North Plains Connector Interregional Innovation
- NPV – Net Present Value
- NRC – Nuclear Regulatory Commission
- NREL – National Renewable Energy Laboratory
- NWPCC – Northwest Power and Conservation Council
- O&M – Operations and Maintenance
- OATT – Open Access Transmission Tariff
- PAC – PacifiCorp
- PCM – Production Cost Model
- PFE – Prohibited Foreign Entities
- PHES – Pumped Hydroelectric Storage
- PHMSA – Pipeline and Hazardous Materials Safety Administration
- PNNL – Pacific Northwest National Laboratory
- PNUCC – Pacific Northwest Utilities Conference Committee
- POI – Point of Interconnection
- PPA – Power Purchase Agreement
- PRM – Planning Reserve Margin

- PST – Phase Shifting Transformers
- PTC – Production Tax Credit
- PTP – Point-to-Point
- PURPA - Public Utility Regulatory Policies Act
- PWR – Pressurized Water Reactor
- QCC – Qualifying Capacity Contribution
- QF – Qualifying Facility
- RA – Resource Adequacy
- RAS – Remedial Action Scheme
- RFP – Request for Proposals
- RHR – Regional Haze Rule
- RICE – Reciprocating Internal Combustion Engine
- ROR – Run-of-River
- RR – Revenue Requirement
- RS – Resource Sufficiency
- RTE – Round-Trip Efficiency
- RTO – Regional Transmission Organization
- SCWR – Supercritical Water-Cooled Reactor
- SFR – Sodium-Cooled Fast Reactor
- SMR – Small Modular Reactors
- Solar-pv – Solar Photovoltaic
- SPP – Southwest Power Pool
- STCC – Short-Term Capacity Contract
- TRC – Total Resource Cost
- TRM – Transmission Reliability Margin
- TTC – Total Transfer Capability
- USB – Universal System Benefits
- VER – Variable Energy Resource
- WACC – Weighted Average Cost of Capital
- WAPA – Western Area Power Administration
- WECC – Western Electricity Coordinating Council
- WEIM – Western Energy Imbalance Market
- WEIS – Western Energy Imbalance Service
- WIEM – Western Energy Imbalance Market
- WPP – Western Power Pool
- WRAP – Western Resource Adequacy Program
- YCGS – Yellowstone County Generating Station
- YELP – Yellowstone Energy Limited Partnership

APPENDIX B – PLANNING REQUIREMENTS

69-3-1201 Short title.

This part may be cited as the "Montana Integrated Least-Cost Resource Planning and Acquisition Act".

69-3-1202 Policy — planning.

(1)

(a) It is the policy of the state to supervise, regulate, and control public utilities. To the extent that it is consistent with the policy and in order to benefit society, the state requires efficient utility operations, efficient use of utility services, and efficient rates.

(b) It is further the policy of the state to encourage utilities to acquire resources using a competitive solicitation process and in a manner that will help ensure a clean, healthful, safe, and economically productive environment.

(2)

(a) The legislature finds that the commission may include in rates any costs that are associated with acquiring resources referred to in subsection (1) and that are consistent with this policy if the resources are actually used and useful for the convenience of the public.

(b) To advance this policy, the commission shall require long-range plans every 3 years from utilities that provide electric and natural gas service in a form and manner determined by the commission. The commission shall receive comments on the plans.

(3) This part does not constrain or limit the commission's existing statutory duties or responsibilities.

69-3-1203 Definitions.

As used in this part, unless the context requires otherwise, the following definitions apply:

(1) “Abandonment costs” means the costs incurred for resources acquired and abandoned pursuant to a plan.

(2) “Consumer counsel” means the consumer counsel provided for in *5-15-201*.

(3) “Demand-side management programs” means energy efficiency, energy conservation, load management, and demand response or any combination of these measures implemented by an electric utility.

(4) “Energy conservation” means the decrease in electricity requirements of specific customers during any selected time period, resulting in a reduction in end-use services.

(5) “Energy efficiency” means the decrease in electricity requirements of specific customers during any selected period with end-use services of those customers held constant.

(6) “Externalities” mean the impacts on society that are not directly borne by the producer in production and delivery activities, which due to imperfections in or the absence of markets are not accounted for in the producer’s production and pricing decisions.

(7) “Plan” means an integrated least-cost resource plan submitted by a utility in accordance with this part and the rules adopted under this part.

(8) “Planning costs” means the costs of evaluating the future demand for services and of evaluating alternative methods of satisfying future demand.

(9) “Planning period” means the future period for which a utility develops its plan, and the period over which net present value of revenue requirements for resources is calculated. For purposes of this part, the planning period is a minimum of 20 years and begins from the date the utility files its plan with the commission.

(10) “Portfolio development costs” means the costs of preparing a resource in a portfolio for prompt and timely acquisition of the resource.

(11) “Public utility” means a public utility, as defined in *69-3-101*, that provides electric or natural gas service. The term does not include municipal utilities.

69-3-1204 Integrated least-cost plan.

(1)

(a) The commission shall adopt rules requiring a public utility to prepare and file a plan at least every 3 years for meeting the requirements of its customers in the most cost-effective manner consistent with the public utility's obligation to serve and in accordance with this part.

(b) The rules must prescribe the content and the time for filing a plan.

(2)

(a) A plan must contain but is not limited to:

(i) an evaluation of the full range of cost-effective means for the public utility to meet the service requirements of its Montana customers, including conservation or similar improvements in the efficiency by which services are used and including demand-side management programs in accordance with *69-3-1209*;

(ii) an annual electric demand and energy forecast developed pursuant to commission rules that includes energy and demand forecasts for each year within the planning period and historical data, as required by commission rule;

(iii) an assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to commission rules;

(iv) an assessment of the need for additional resources and the utility's plan for acquiring resources;

(v) the proposed process the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive solicitation process in accordance with *69-3-1207*; and

(vi) descriptions of at least two alternate scenarios that can be used to represent the costs and benefits from increasing amounts of renewable energy resources and demand-side management programs, based on rules developed by the commission.

(b) The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, determinants, and any other inputs on which it relied to develop information required in subsection (2)(a).

(3)

(a) The commission may adopt rules providing guidelines to be used in preparing a plan and identifying the criteria to be used in determining cost-effectiveness.

(b) The criteria may include externalities associated with the acquisition of a resource by a public utility.

(c) The rules must establish the minimum filing requirements for acceptance of a plan by the commission for further review. If a plan does not meet the minimum filing requirements, it must be returned to the public utility with a list of filing requirements not met. A corrected plan must be submitted within the time established by the commission.

(4) A plan filed with the commission by a utility, as defined in *75-20-104*, must be provided to the department of environmental quality and the consumer counsel.

(5) Within 120 days of receipt of a complete plan, the commission:

(a) shall review the plan;

(b) shall publish a copy of the plan;

(c) shall allow for a minimum of 60 days for the public to comment on the plan; and

(d) shall provide public meetings in accordance with *69-3-1205*.

(6)

(a) The commission may identify deficiencies in the plan, including:

(i) any concerns of the commission regarding the public utility's compliance with commission rules; and

(ii) ways to remedy the concerns.

(b) The commission may engage independent engineering, financial, and management consultants or advisory services to evaluate a public utility's plan. The consultants shall demonstrate knowledge and experience with resource procurement and resource portfolio management, modeling, risk management, and engineering practices. The commission shall charge a fee to the public utility to pay for the costs of consultants or advisory services. These costs are recoverable in rates.

69-3-1205 Public comment — public meetings.

(1) When developing a plan in accordance with this part and prior to submitting a plan to the commission, a public utility shall hold at least four public meetings in the utility's Montana service territory to ensure a plan best meets the diverse goals of shareholders, ratepayers, and society.

(2) The public utility shall consider written and oral comments respecting the proposed plan received during public meetings or meetings of the resource planning advisory committee held pursuant to *69-3-1208*. The public utility shall summarize and respond to substantive comments received and file those as part of the plan.

(3) After a plan is submitted, the commission shall conduct two public meetings for the purpose of receiving comment on a plan. The commission or the department of public service regulation may comment on the plan. A comment by the commission or the department may not be construed as preapproval by the commission of rate treatment for any proposed resource.

(4) The department of environmental quality:

(a) shall review a plan submitted to the commission and comment on the need for new resources, the alternatives evaluated to meet the need, the environmental implications of the resource choices, and other related issues that it considers important. The department shall coordinate and deliver all comments from other executive branch agencies.

(b) may use a plan in the development of studies for a specific energy facility for which an application for a certificate of compliance is submitted under Title 75, chapter 20.

(5) The consumer counsel shall review and may comment on a submitted plan.

69-3-1206 Rate treatment.

(1) The commission may include in a public utility's rates:

(a) the cost of resources acquired in accordance with a plan;

(b) demand-side management programs established and implemented in accordance with *69-3-1209*;

(c) the cost-effective expenditures for improving the efficiency with which the public utility provides and its customers use utility services;

(d) the costs of complying with the planning requirements of this part; and

(e) the costs of complying with a competitive solicitation process conducted in accordance with *69-3-1207*.

(2) The commission may adopt rules establishing criteria governing the extent of recovery of abandonment costs.

(3) The commission may not approve a bonus or adder in the cost of a new resource acquired after [the effective date of this act] to provide additional compensation for costs such as environmental externalities unless the bonus or adder is necessary to compensate for a real and actual cost required by existing regulation or existing law.

69-3-1207 Competitive solicitation process — independent evaluator — Public Service Commission role.

(1)

(a) Except as provided in subsection (6), a public utility that intends to establish in rates for the acquisition, construction, or purchase of an electricity supply resource shall conduct a competitive solicitation process.

(b) A public utility may not prohibit a qualifying small power production facility as defined in *69-3-601* or another utility or supplier that owns an electricity supply resource or intends to construct an electricity supply resource from participating in a competitive solicitation process.

(c) An independent evaluator must be used to oversee a public utility's competitive solicitation. The commission shall select the independent evaluator pursuant to subsection (4).

(d) An independent evaluator:

(i) shall monitor the evaluation of bids pursuant to a competitive solicitation;

(ii) shall provide oversight to ensure a fair and transparent competitive solicitation;

(iii) must be familiar with competitive bid and evaluation processes; and

(iv) shall evaluate and document the process used by the public utility to solicit and evaluate bids received during a competitive solicitation.

(e) A public utility may conduct a competitive solicitation in conjunction with the development of an integrated least-cost plan in accordance with *69-3-1204*.

(2) A public utility that plans to conduct a competitive solicitation process shall submit the following information to the commission:

(a) a description of the competitive solicitation process that the public utility will use and proof of compliance with subsections (1)(b) and (1)(c), if applicable; and

(b) a complete draft of the proposal soliciting electricity supply resources, citing the requested resource parameters and inviting bids from all resource types.

(3) The commission shall provide notice and accept public comment regarding information received in accordance with subsection (2).

(4)

(a) Subject to public comments received pursuant to subsection (4)(b), the commission shall:

(i) solicit, evaluate, and maintain a list of independent evaluators for the competitive solicitation process;

(ii) develop a process to disqualify and remove from the list those independent evaluators who do not comply with established qualifications or who may have a conflict of interest;

(iii) update the list at least every 3 years; and

(iv) after information is submitted to the commission in accordance with subsection (2) and subject to rules adopted by the commission pursuant to subsection (4)(c), select an independent evaluator from the list.

(b) The commission shall accept public comment when developing and updating the list.

(c) On or before July 1, 2026, the commission shall adopt rules for:

(i) evaluating independent evaluators for inclusion on the list;

(ii) selecting an independent evaluator in accordance with this section;

(iii) implementing this subsection (4); and

(iv) prescribing the scope of work for the independent evaluator pursuant to the duties in [section 5].

(5)

(a) The commission may charge a fee to the public utility to pay for the costs of selecting and representing an independent evaluator. This fee must be deposited in the state special revenue fund to the credit of the department for expenses incurred selecting the independent evaluator. These costs are recoverable in rates.

(b) After the commission selects an independent evaluator in accordance with subsection (4), the public utility shall execute a contract for service with the independent evaluator. The contract must include the scope of work developed pursuant to subsection (4)(c)(iv) and the duties in [section 5].

(6) This section does not apply to:

(a) a request for proposals or purchase by a public utility intended solely to meet the short-term operational needs of the utility for a period of less than 12 months; or

(b) an application made to the commission by a public utility to acquire, construct, or purchase an opportunity resource.

(7) For the purposes of this section, "opportunity resource" means an electricity supply resource necessary to meet a need demonstrated in a plan in accordance with *69-3-1204(2)(a)(iv)* that is either new or existing and that remains unknown as to its availability for purchase until an opportunity to purchase arises.

69-3-1208 Resource planning — advisory committee.

(1) A public utility shall maintain a broad-based advisory committee to review, evaluate, and make recommendations on technical, economic, and policy issues related to a utility's electricity system.

(2) The committee may advise the utility on demand-side management, portfolio planning, and management and procurement completed in accordance with this part.

(3) The utility shall publish the committee membership.

(4) A committee meeting must be open to the public unless the majority of committee members vote to close the advisory meeting.

69-3-1209 Electric utility demand-side management programs.

(1) The commission may establish energy savings and peak demand reduction goals for an electric utility, taking into account the utility’s cost-effective demand-side management potential and the need for electricity resources.

(2) The commission shall permit electric utilities to implement cost-effective electricity demand-side management programs and conservation in accordance with 69-3-701 through 69-3-712 and this part to reduce the need for additional resources.

(3) Every 3 years, an electric utility shall submit a report to the commission describing the demand-side management programs and conservation implemented by the electric utility in the previous year. The report must document:

(a) program expenditures, including incentive payments;

(b) peak demand and energy savings impacts and the techniques used to estimate those impacts;

(c) avoided costs and the techniques used to estimate those costs;

(d) the estimated cost-effectiveness of the programs;

(e) the net economic benefits of the programs; and

(f) any other information required by the commission.

38.5.2020 GOAL AND POLICY

(1) Integrated least-cost resource planning and acquisition is an ongoing, dynamic, and flexible process that:

(a) manages the consequences of risk and uncertainty;

(b) integrates demand-side, distribution-side, and power resources to minimize the long-term total cost of service;

(c) considers a broad range of attributes in the evaluation of alternative resources and their cost-effectiveness;

(d) engages stakeholders and the public; and

(e) is transparent and reasonably understandable to stakeholders, the public, and the Commission.

(2) The goal of integrated least-cost resource planning and acquisition is to ensure public utilities meet their customers' needs for adequate, reliable, and efficient energy services at the lowest long-term total cost while managing risks and remaining financially sound. To achieve this goal, utilities shall plan to meet future customer demand and energy requirements through timely acquisition of a diverse mix of cost-effective resources, and shall actively pursue and acquire all cost-effective demand-side resources. The cost-effectiveness of all resource acquisitions will be evaluated with respect to long-term total costs, including scenarios based on societal costs.

(3) These rules implement the policy of the State of Montana concerning integrated least-cost resource planning and acquisition. Electric utilities are required to file resource plans and conduct planning and acquisition processes as outlined in the rules.

(4) The rules implement the Commission's regulatory objective of ensuring an efficient allocation of society's resources to provide adequate, reliable electricity services and just and reasonable rates for consumers at the lowest long-term total cost. In furtherance of this objective, utilities shall operate existing resources and acquire new resources only when needed and in a manner consistent with these rules.

(5) The rules establish requirements for resource planning and acquisition processes but do not specify planning and acquisition outcomes or mandate investment decisions. The rules identify ways for utilities to reduce and manage the risk of resource acquisition to shareholders, customers, and society.

(6) Utilities shall acquire resources through transparent, independently administered competitive resource solicitations whenever practicable, subject to *69-3-1207, MCA*.

(7) Integrated least-cost resource planning consistent with the rules may demonstrate that previously rate-based resources should be abandoned and replaced by new resources. If such situations occur, the Commission will determine the appropriate recovery of undepreciated, rate-based capital costs in separate, contested case proceedings.

(8) Evaluations of potential demand-side resources shall consider those resources cost-effective up to 110 percent of the utility's long-term avoided cost.

(9) Resource decisions have a significant impact on the public. Public utilities can best meet the respective goals of shareholders, customers, and society by meaningfully involving the public in resource planning and acquisition processes. The rules facilitate such involvement by requiring public utilities to conduct transparent planning and acquisition processes and thoroughly document the results of those processes in a manner that is reasonably understandable.

38.5.2021 DEFINITIONS

(1) "Action plan period" means the five-year period beginning with the calendar year after the filing of a resource plan.

(2) "Adequate" means, with respect to an electric system owned or controlled by a utility, the ability to supply the aggregate electrical demand and energy requirements of the utility's customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

(3) "Affiliate" means, for purposes of this rule, a parent, subsidiary, division, or the like, regardless of designation, owning or controlling the utility, owned or controlled by the utility, under common ownership with the utility, or under common control with the utility.

(4) "Assessment" means a documented process used by a utility to make informed judgments regarding elements of a resource plan and action plan based on the careful consideration of quantitative and qualitative information and the input of stakeholders, the public, and the advisory committee required in *69-3-1208, MCA*.

(5) "Cost" means the actual or forecast costs incurred to own, operate, and manage existing and potential new resources sufficient to provide adequate and reliable services over the planning period including, but not limited to, costs for:

(a) capital recovery;

(b) shareholder returns;

(c) debt;

(d) operations and maintenance;

(e) fuel and associated fuel delivery services or infrastructure;

(f) insurance;

(g) taxes, including tax credits;

(h) environmental remediation;

(i) permitting;

(j) land use and rights of way;

(k) decommissioning, abandonment, and securitization;

(l) contractual power purchases, however structured;

(m) incremental transmission and distribution, including losses and congestion;

(n) administration; and

(o) externalities.

(6) "Cost-effective" means that a project or resource is forecast:

(a) to be reliable and available within the time it is needed; and

(b) to meet or reduce the electric power demand of the intended consumers at an estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative project or resource, or any portion thereof.

(7) "Environmentally responsible" means explicitly recognizing and incorporating into resource plans, resource planning processes, and resource procurement the policy of the State of Montana to encourage utilities to acquire resources in a manner that will help ensure a clean, healthful, safe, and economically productive environment.

(8) "Externalities" has the meaning in *69-3-1203(6), MCA*.

(9) "Long-term" means a time period at least as long as the planning period.

(10) "Planning period" has the meaning in *69-3-1203(9), MCA*.

(11) "Reliable" means a power system that is adequate and can withstand sudden disturbances, such as electrical short circuits or unanticipated loss of system elements.

(12) "Resources" includes all of the following:

> **(a)** "Demand-Side resources" means any material, device, technology, educational program, rate design, practice, or facility alteration designed to result in reduced peak demand, increased energy efficiency, energy conservation, or shifting or management of electricity demand and energy consumption and includes combined heat and power used to displace space heating, water heating, or another load.
>
> **(b)** "Distribution-Side resources" means electrical generation or storage equipment located within a utility's distribution system, including real and personal property owned and controlled by utility customers and non-utility producers.
>
> **(c)** "Power resources" means wholesale power transactions, including bilateral contracts, tolling agreements, and spot purchases, and plants and equipment, including storage equipment, owned, leased, or controlled, in whole or in part, by a utility.

(13) "Service" means required and optional electricity and/or electricityrelated products or services provided by a utility to retail customers including metering, billing, distribution, transmission, generation, and generation-related services. Services include, but are not limited to, traditional electricity supply and delivery service, renewable energy-sourced offerings, interconnection and integration of distribution side and customer generators, net metering, demand and/or bill management programs, information-based services such as energy audits, transmission ancillary services, street lighting services, and other services for which a utility has filed or would be required to file a tariff.

(14) "Societal cost" means all costs to a utility plus externalities.

(15) "Stakeholder" means a member of the public (individual, corporation, organization, group, etc.) who may have an interest in, or may be affected by, these rules.

38.5.2022 PLAN CONTENTS

(1) Resource plans shall contain at least the following information:

(a) A description of any changes a utility has made to the content of its plan or its planning process in response to the Commission's comments on its last plan and how the changes affect the current plan, along with reasoned explanations for any Commission comment with which the utility disagrees. Cross-references shall be provided for all changes.

(b) Annual electricity demand and energy forecasts for each year of the planning period for each major rate or service class; an explanation of the forecasting method(s) and assumptions; and the historical customer counts, population data, load data, and end-use data used in the forecasting process, as applicable. Changes to the forecasting method(s) and assumptions used in the prior plan must be thoroughly explained.

(c) A description and graphical presentation of daily and seasonal electric demand and energy requirements for each major rate or service class, the variability of those requirements, and how the utility assessed historical trends, and the potential for future changes in the timing and variability of electric demand and energy requirements in the development of the plan.

(d) A description of the electric generating capability and characteristics of each of the utility's existing resources. The description must include the generator type and fuel source, nameplate capacity, effective load carrying capability or other probabilistic capacity contribution estimate, expected annual energy production, storage capability, capacity factor, forced outage rate, annual emissions of carbon dioxide, online date, and expected retirement date. The description must include any historical data used to develop the reported generating capabilities and characteristics. The description may be in table form with accompanying explanatory text, as necessary.

(e) A description of the current average annual variable cost or contract price for each of the utility's existing power resources, including storage resources, and the expected or projected average annual variable cost or contract prices at 5-year increments for the planning period. The description may be in table form with accompanying explanatory text, as necessary.

(f) A description of the aggregate load-serving capability and characteristics of existing programmatic demand-side resources within the utility's system and a forecast of aggregate capability over the planning period. The description must address each demand-side resource program offered and its total load-serving capabilities. The description may be in table form with accompanying explanatory text, as necessary. The description must provide the following historical information for each year since the utility's last plan:

(i) program expenditures;

(ii) incentive payments;

(iii) demand and energy savings and the methods and assumptions used to estimate the savings;

(iv) measures of the cost-effectiveness of the program, including avoided costs, and the techniques used to estimate those costs;

(v) annualized cost of saved energy and capacity and the techniques used to estimate those costs; and

(vi) estimates of the net economic benefit of the programs.

(g) A resource adequacy assessment based on existing resources and a description of the nature of the need for additional resources to achieve industry-standard adequacy standards or reserve margin requirements. The plan must completely and thoroughly describe the method(s) and assumptions used in the assessment, including the basis for the adequacy standard or reserve margin requirement and computer modeling and model validation procedures. The assessment must document energy and capacity deficits, their duration, frequency, and timing, given the energy and demand forecasts in (b) and resource capabilities in (d) and (f). In addition, the assessment must document energy and capacity deficits for scenarios that involve higher and lower forecasts of energy and demand requirements; alternative load profiles; and alternative performance levels for existing resources to account for the effects of, among other things, extreme weather events; demand-side and distribution-side resources; electrification; and price response.

(h) A description of a wide range of plausibly cost-effective resources that could be acquired to satisfy the need for additional resources identified in the results of the resource adequacy assessment in (g), including those that may become available through transmission system investments that enhance access to broader markets for power resources. The description shall include the electricity generating or load serving capabilities and characteristics of the resources including the technology; size; service life or contract length; performance attributes; costs including estimates of potential fuel delivery infrastructure and transmission system interconnection and network upgrade costs, and tax credits; and environmental impacts including water and land use and emissions. The description must explain the method(s) and assumptions used to identify potential resources and define their costs, generation or load serving capabilities, and other attributes. The description may be in table form with accompanying explanatory text, as necessary.

(i) An evaluation of the full range of cost-effective means of combining the resources in (h) with the continued or discontinued operation of existing resources to satisfy the need for additional resources identified in (g) at the lowest long-term total cost. The evaluation must consider a broad range of future customer electricity demand and energy requirements and risks related to uncertainty about future loads, resource costs and performance, and changes in public policy and environmental regulations. The evaluation must be designed to allow for a comparison of the longterm total costs and risks of acquiring alternative resources, or combinations of resources, to address the need identified in (g). The evaluation must include at least two scenarios that rely on increased renewable energy resources and demand-side resources pursuant to *69-3-1204(2)(a)(vi), MCA*. The plan must completely and thoroughly describe the results of the evaluation and document and justify the method(s) and assumptions used in the evaluation, including method(s) and assumptions used to determine cost-effectiveness and computer modeling and model validation procedures.

(j) For computer modeling used to perform the evaluation in (i):

(i) a thorough description of the basic design and purpose of the model;

(ii) a thorough description of the inputs and how the model uses inputs to produce outputs;

(iii) a thorough description of the decisions that were informed by the modeling and questions that were examined or answered by the modeling;

(iv) comprehensive descriptions of and data for modeling outputs and results;

(v) comprehensive, understandable explanations of the modeling results; and

(vi) a thorough description of the process by which a stakeholder can obtain inputs electronically in order to conduct alternative modeling.

(k) A description of the utility's plan for demand-side resource acquisition over the planning period, to the extent such resources are not directly included in the evaluation in (i). The description must include the utility's assessment of the cost-effective demand-side resource potential on its system, including the method(s) and assumptions used to determine cost-effectiveness.

(l) A description of the advisory committee required in *69-3-1208, MCA*, and a complete and thorough documentation of how the utility designated members and engaged the advisory committee to review and evaluate technical, economic, and policy issues related to the utility's system and the planning process, including all recommendations of the advisory committee and the utility's responses, and a copy of the work plan required in *ARM 38.5.2023*.

(m) A description of the public meetings conducted pursuant to *69-3-1205(1), MCA*, including a summary of comments, concerns, or other input received and how the utility responded.

(n) A description of the comments received on the draft plan published pursuant to *ARM 38.5.2023* and how they were considered, including a thorough description of modifications made to the draft plan in response to the comments or the reasons for making no modifications.

(o) A near-term action plan describing the steps the utility intends to take based on the results and conclusions of the planning process, including the evaluations in this rule. The action plan must describe the process the utility intends to use to acquire any resources or resource types, including the use of competitive solicitations.

(p) A description of how information about the mix of resources used to provide the demand and energy requirements of customers will be disseminated to them, including information about emissions and other environmental impacts, using itemized labeling, reporting, or other mechanisms as appropriate.

(2) Plans that do not satisfy the requirements of this rule and *69-3- 1204(2)(b), MCA* will be deemed deficient and returned to the utility pursuant to *69- 3-1204(3), MCA*.

38.5.2023 PLANNING PROCESS

(1) A utility shall designate and engage with an advisory committee according to *69-3-1208, MCA*. The utility shall meet with the advisory committee on a regular basis as it prepares resource plans. Utilities shall open meetings with the advisory committee to the public whenever possible, but may close meetings or portions of meetings when proprietary information is discussed or when necessary to enable the committee to provide a more complete review, evaluation, or recommendation. A utility shall engage with the committee before deciding to close a meeting to the public.

(2) In addition to the advisory committee, a utility shall engage stakeholders and the public during the process of preparing a resource plan. A utility must publicly notice engagement events at least 14 days in advance and provide meeting materials in advance to the greatest extent possible. A utility shall present to stakeholders in a transparent, understandable manner the results of completed steps in the planning process and plans for subsequent steps and shall provide an opportunity to comment on or request items to be addressed in a plan. A utility may combine meetings with the public, stakeholders, and the advisory committee.

(3) A utility shall engage a broad cross-section of its customers (based on demographic, geographic, and service classification characteristics), including representatives of customer segments with low, moderate, and fixed incomes and highly impacted communities, on issues related to future service and resources that may be of interest to non-experts.

(4) At the start of each planning cycle, a utility shall engage with the advisory committee and stakeholders to develop a work plan and timeline, including the frequency of meetings with the advisory committee, for completing the assessments and preparing plan contents required in *ARM 38.5.2022*. The work plan must include a structured process for submission of written inquiries and comments to the utility during the planning process and written responses by the utility. The work plan shall also address procedures for access by the advisory committee to the utility's planning model during the planning process.

(5) A utility shall publish a draft of its resource plan at least 70 days before filing the resource plan with the Commission and accept comments on the draft resource plan for at least 55 days.

(6) (6) A utility shall file a resource plan every three years.

38.5.2024 RESOURCE PROCUREMENT

(1) A utility's resource procurement processes shall be guided by the policy in *69-3-1202, MCA*, input from the public and the advisory committee provided for in *69-3-1208, MCA*, and comments of the Commission on the utility's most recent resource plan.

(2) Utilities shall use transparent, independently administered Competitive solicitations to acquire needed resources whenever practicable, subject to *69-3-1207, MCA*, and the Commission's rules. Utilities shall document decisions regarding the types of procurement processes used for later submission in applications for rate recovery where the prudence of procurement processes and resource decisions is examined.

(3) A utility shall notify the Commission of a decision to issue a competitive solicitation. The notice shall precede release of a draft of the solicitation by at least 20 days. Before issuing the solicitation, the utility shall submit a draft of the solicitation to the Commission in accordance with *69-3-1207, MCA*, with a thorough description of the input and recommendations of the advisory committee regarding the solicitation process and how the utility modified the solicitation process in response to the advisory committee's input and recommendations or, alternatively, the basis for not modifying the process. Upon notification of a utility's intent to issue a solicitation, the Commission will open a docket for purposes of receiving the draft solicitation and accepting public comment on the draft solicitation. The Commission shall provide notice to the public of the receipt of the draft solicitation and provide 45 days for interested persons to file written comments. The utility shall not issue the final solicitation until at least 70 days after submitting the draft solicitation. Upon issuing the final solicitation, the utility shall concurrently submit the solicitation to the Commission in the docket assigned to the draft solicitation.

(4) A utility shall provide all proposed and final scoring criteria and metrics in the draft and final competitive solicitations filed with the Commission.

(5) Utilities shall consider the usefulness of competitive solicitations for identifying and acquiring demand-side and distribution-side resources, but should also leverage their unique knowledge of their customers' demand characteristics to evaluate cost-effective resource potential and design programs for acquisition.

APPENDIX C – RULES CHECKLIST

38.5.2022	Description	Section
1	Resource plans shall contain at least the following information:	See below.
a	A description of any changes a utility has made to the content of its plan or its planning process in response to the Commission's comments on its last plan and how the changes affect the current plan, along with reasoned explanations for any Commission comment with which the utility disagrees. Cross-references shall be provided for all changes.	Section 2.2
b	Annual electricity demand and energy forecasts for each year of the planning period for each major rate or service class; an explanation of the forecasting method(s) and assumptions; and the historical customer counts, population data, load data, and end-use data used in the forecasting process, as applicable. Changes to the forecasting method(s) and assumptions used in the prior plan must be thoroughly explained.	See below.
	• annual demand (peak) forecasts for each year of the planning period for each major rate class	Section 4.1.6
	• annual energy forecasts for each year of the planning period for each major rate class; • an explanation of the forecasting method(s) and assumptions; • end-use data used in the forecasting process; • changes to the forecasting method(s) and assumptions used in the prior plan must be thoroughly explained.	Section 4.1.1
	• historical customer counts used in the forecasting process; • population data used in the forecasting process	Section 4.1.2
c	A description of daily and seasonal electric demand and energy requirements for each major rate or service class, the variability of those requirements, and how the utility assessed historical trends, and the potential for future changes in the timing and variability of electric demand and energy requirements in the development of the plan. A graphical presentation of daily and seasonal electric demand and energy requirements for each major rate or service class, the variability of those requirements, and how the utility assessed historical trends, and the potential for future changes in the timing and variability of electric demand and energy requirements in the development of the plan.	Section 4.1.3, 4.1.4, 4.1.6

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38.5.2022	Description	Section
d	A description of the electric generating capability and characteristics of each of the utility's existing resources. The description must include the generator type and fuel source, nameplate capacity, effective load carrying capability or other probabilistic capacity contribution estimate, expected annual energy production, storage capability, capacity factor, forced outage rate, annual emissions of carbon dioxide, online date, and expected retirement date. The description must include any historical data used to develop the reported generating capabilities and characteristics. The description may be in table form with accompanying explanatory text, as necessary.	See below.
d	• generator type and fuel source; • nameplate capacity; • storage capability, • capacity factor; • annual emissions of carbon dioxide, • online date; • expected retirement date	Section 5.2, 5.3, 5.4, Appendix H
d	• effective load carrying capability or other probabilistic capacity contribution estimate	Section 7.2.1
d	• expected annual energy production;	Section 7.8.1, Appendix E
d	• forced outage rate,	Section 7.2.1
e	A description of the current average annual variable cost or contract price for each of the utility's existing power resources, including storage resources, and the expected or projected average annual variable cost or contract prices at 5-year increments for the planning period. The description may be in table form with accompanying explanatory text, as necessary.	See below.
e	• current average annual variable cost or contract price for each of the utility's existing power resources	Section 5.2, 5.3, 5.4
e	• the expected or projected average annual variable cost or contract prices at 5-year increments	Section 7.8.1

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38.5.2022	Description	Section
f	A description of the aggregate load-serving capability and characteristics of existing programmatic demand-side resources within the utility's system and a forecast of aggregate capability over the planning period. The description must address each demand-side resource program offered and its total load-serving capabilities. The description may be in table form with accompanying explanatory text, as necessary. The description must provide the following historical information for each year since the utility's last plan: (i) program expenditures; (ii) incentive payments; (iii) demand and energy savings and the methods and assumptions used to estimate the savings; (iv) measures of the cost-effectiveness of the program, including avoided costs, and techniques used to estimate those costs; (v) annualized cost of saved energy and capacity and the techniques used to estimate those costs; and (vi) estimates of the net economic benefit of the programs.	See below.
	program expenditures for each year since the utility's last plan	Section 4.2.7
	incentive payments for each year since the utility's last plan	Section 4.2.7
	demand and energy savings and the methods and assumptions used to estimate the savings for each year since the utility's last plan	Section 4.2.7
	measures of the cost-effectiveness of the program, including avoided costs, and techniques used to estimate those costs;	Section 4.2.4 and 4.2.7
	annualized cost of saved energy and capacity and the techniques used to estimate those costs for each year since the utility's last plan	Section 4.2.7
	estimates of the net economic benefit of the programs for each year since the utility's last plan	Section 4.2.7

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38.5.2022	Description	Section
g	A resource adequacy assessment based on existing resources and a description of the nature of the need for additional resources to achieve industry-standard adequacy standards or reserve margin requirements. The plan must completely and thoroughly describe the method(s) and assumptions used in the assessment, including the basis for the adequacy standard or reserve margin requirement and computer modeling and model validation procedures. The assessment must document energy and capacity deficits, their duration, frequency, and timing, given the energy and demand forecasts in (b) and resource capabilities in (d) and (f). In addition, the assessment must document energy and capacity deficits for scenarios that involve higher and lower forecasts of energy and demand requirements; alternative load profiles; and alternative performance levels for existing resources to account for the effects of, among other things, extreme weather events; demand-side and distribution-side resources; electrification; and price response.	See below
	• A resource adequacy assessment based on existing resources and a description of the nature of the need for additional resources to achieve industry-standard adequacy standards or reserve margin requirements.	Section 7.3
	• The plan must completely and thoroughly describe the method(s) and assumptions used in the assessment, including the basis for the adequacy standard or reserve margin requirement and computer modeling and model validation procedures.	Section 7.6
	• The assessment must document energy and capacity deficits, their duration, frequency, and timing, given the energy and demand forecasts in (b) and resource capabilities in (d) and (f).	Section 7.3, 7.8.1, and Appendix E
	• In addition, the assessment must document energy and capacity deficits for scenarios that involve higher and lower forecasts of energy and demand requirements; alternative load profiles; and alternative performance levels for existing resources to account for the effects of, among other things, extreme weather events; demand-side and distribution-side resources; electrification; and price response.	Section 7.7 and 7.8, Appendix E, Appendix H

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38.5.2022	Description	Section
h	A description of a wide range of plausibly cost-effective resources that could be acquired to satisfy the need for additional resources identified in the results of the resource adequacy assessment in (g), including those that may become available through transmission system investments that enhance access to broader markets for power resources. The description shall include the electricity generating or load serving capabilities and characteristics of the resources including the technology; size; service life or contract length; performance attributes; costs including estimates of potential fuel delivery infrastructure and transmission system interconnection and network upgrade costs, and tax credits; and environmental impacts including water and land use and emissions. The description must explain the method(s) and assumptions used to identify potential resources and define their costs, generation or load serving capabilities, and other attributes. The description may be in table form with accompanying explanatory text, as necessary.	See below
	• electricity generating or load serving capabilities and characteristics of the resources including the technology; size; service life or contract length; performance attributes;	Section 7.1, 7.2.2
	• costs including estimates of potential fuel delivery infrastructure and transmission system interconnection and network upgrade costs, and tax credits; and	Section 7.1.6.3, 7.1.6.2, 7.1.6.1
	• environmental impacts including water and land use and emissions	Section 7.1
i	An evaluation of the full range of cost-effective means of combining the resources in (h) with the continued or discontinued operation of existing resources to satisfy the need for additional resources identified in (g) at the lowest long-term total cost. The evaluation must consider a broad range of future customer electricity demand and energy requirements and risks related to uncertainty about future loads, resource costs and performance, and changes in public policy and environmental regulations. The evaluation must be designed to allow for a comparison of the long-term total costs and risks of acquiring alternative resources, or combinations of resources, to address the need identified in (g). The evaluation must include at least two scenarios that rely on increased renewable energy resources and demand-side resources pursuant to 69-3-1204(2)(a)(vi), MCA. The plan must completely and thoroughly describe the results of the evaluation and document and justify the method(s) and assumptions used in the evaluation, including method(s) and assumptions used to determine cost-effectiveness and computer modeling and model validation procedures.	Section 7.7 and 7.8

(continued on next page)

38.5.2022	Description	Section
j	For computer modeling used to perform the evaluation in (i): (i) a thorough description of the basic design and purpose of the model; (ii) a thorough description of the inputs and how the model uses inputs to produce outputs; (iii) a thorough description of the decisions that were informed by the modeling and questions that were examined or answered by the modeling; (iv) comprehensive descriptions of and data for modeling outputs and results; (v) comprehensive, understandable explanations of the modeling results; and (vi) a thorough description of the process by which a stakeholder can obtain inputs electronically in order to conduct alternative modeling.	See below
	(i) a thorough description of the basic design and purpose of the model;	Section 7.6
	(ii) a thorough description of the inputs and how the model uses inputs to produce outputs;	Chapter 7
	(iii) a thorough description of the decisions that were informed by the modeling and questions that were examined or answered by the modeling;	Section 7.5, Chapter 9
	(iv) comprehensive descriptions of and data for modeling outputs and results;	Section 7.7 and 7.8, Appendix H
	(v) comprehensive, understandable explanations of the modeling results; and	Section 7.7, 7.8, 7.9, 9.1
	(vi) a thorough description of the process by which a stakeholder can obtain inputs electronically in order to conduct alternative modeling.	Section 7.6.3
k	A description of the utility's plan for demand-side resources acquisition over the planning period, to the extent such resources are not directly included in the evaluation in (i). The description must include the utility's assessment of the cost-effective demand-side resource potential on its system, including the method(s) and assumptions used to determine cost-effectiveness.	Section 4.2
l	A description of the advisory committee required in 69-3-1208, MCA, a complete and thorough documentation of how the utility designated members and engaged the advisory committee to review and evaluate technical, economic, and policy issues related to the utility's system and the planning process, including all recommendations of the advisory committee and the utility's responses, and a copy of the work plan required in ARM 38.5.2023.	Section 2.2.1.1
m	A description of the public meetings conducted pursuant to 69-3-1205(1), MCA, including a summary of comments, concerns, or other input received and how the utility responded.	Section 2.2.1.4, 2.2.2
n	A description of the comments received on the draft plan published pursuant to ARM 38.5.2023 and how they were considered including a thorough description of modifications made to the draft plan in response to the comments or the reasons for making no modifications.	Section 2.2.2

(continued on next page)

38.5.2022	Description	Section
o	A near-term action plan describing the steps the utility intends to take based on the results and conclusions of the planning process, including the evaluations in this rule. The action plan must describe the process the utility intends to use to acquire any resources or resource types, including the use of competitive solicitations.	Section 9.3
p	A description of how information about the mix of resources used to provide the demand and energy requirements of customers will be disseminated to them, including information about emissions and other environmental impacts, using itemized labeling, reporting, or other mechanisms as appropriate.	Chapter 5-Introduction

APPENDIX D– 2026 MT INTEGRATED RESOURCE PLAN WORK PLAN

INTRODUCTION:

Integrated Least-Cost Resource Planning and Acquisition is a continuous, adaptive, and systematic process that optimizes energy resource planning and procurement by: managing risk and uncertainty, integrating demand-side, distribution-side, and supply-side resources to minimize the long-term total cost of service, evaluating alternative resources using a broad range of attributes to determine cost-effectiveness, engaging stakeholders and the public throughout the planning process, and maintaining transparency and clarity for stakeholders, the public, and regulatory authorities.

Key Components of Integrated Least-Cost Resource Planning and Acquisition:

- Load Forecasting
- Existing Portfolio
- Candidate Resources
- Resource Adequacy
- Price Forecasting
- Market Interactions
- Transmission
- Regulatory Framework
- Risk

This Work Plan serves as a guide for completing the assessments and preparing plan contents required in ARM 38.5.2022. NorthWestern's process for developing the 2026 IRP is similar to its process for the 2023 IRP process except that NorthWestern has separated the ETAC from broader stakeholder engagement as well as updates to our presence on our website, as described below. By having both the Stakeholder Working Group (SWG) and ETAC, NorthWestern ensures that the IRP process is both technically robust and reflective of the broader public interest. In addition, NorthWestern will publish a complete Draft IRP no later than December 30, 2025, and receive public comments before filing the final IRP no later than April 30, 2026.

ETAC is an advisory body established by NorthWestern to provide input and recommendations on various issues related to the electricity system as part of the development of the IRP process. ETAC membership was selected to balance the interests and expertise from consumer advocacy groups, government agencies, business concerns, and academia in areas such as residential affordability (including low-income), economic development, environmental quality, regional power and transmission markets, consumer interests, and regulatory oversight. Specifically, ETAC is comprised of 6-8 entities who are able to serve in an advisory role based on their experience. The primary goal of ETAC is to function as technical advisors through discussion, education, and collaboration on matters related to Integrated Least-Cost Resource Planning and Acquisition. ETAC members will be granted access to

PowerSIMM, the modeling software utilized for Northwestern's resource planning, via login credentials to help better understand and provide constructive feedback. By involving a wide range of stakeholders, ETAC helps NorthWestern make more informed decisions that reflect the needs and priorities of its customers and the communities it serves.

The SWG is a working group developed to serve as a platform for a broad range of perspectives to inform the development of the IRP that align with the best interests of NorthWestern's customers and stakeholders. The mission of the SWG is to facilitate open dialogue around NorthWestern's IRP, providing opportunities to share diverse opinions on the planning process, analysis, and contents. The SWG is distinct from ETAC. While ETAC provides technical expertise and recommendations on issues related to the electric system, SWG offers a broader range of perspectives, including those from non-technical backgrounds. The SWG focuses on ensuring transparency, inclusiveness, and a comprehensive understanding of how IRP decisions affect different segments of the population. To ensure effective collaboration, the SWG is limited to a maximum of 20 members, representing various sectors. This cap ensures that the group remains small enough to facilitate in-depth discussions while being large enough to represent diverse viewpoints. NorthWestern will utilize an application for interested individuals and select SWG members based on criteria including diversity of perspectives, relevant expertise, commitment to the process, geographic representation, and stakeholder impact. The selection process aims to ensure a comprehensive and representative group that can contribute meaningfully to the IRP development.

Furthermore, to address comments received in the last planning cycle NorthWestern has made updates to our website in an effort to help support effective communication and collaboration with our stakeholders and the public. These key improvements, as described below, aim to enhance its robustness and functionality. Key improvements include:

- A dedicated Feedback Form has been implemented to facilitate structured input from users, enabling the collection of targeted insights to inform continuous improvement
- All relevant ETAC meeting materials are now readily accessible through the IRP Library section of our website, promoting transparency and fostering informed participation
- Easier access to the MT Electric Supply Planning page by placing it under the About Us tab on the website

Workplan:

Phase 1: Data Collection and Stakeholder Identification

Timeline: January 2023 – April 2025

Objective:

Define the Scope of the Integrated Resource Plan, identify stakeholders and gather necessary data.

Tasks:

1. Data Collection and Analysis
2. Establish Planning Assumptions
3. Stakeholder Identification and Engagement

Key Milestones

- Identify Electric Technical Advisory Committee members: December 2023
- Identify Stakeholder Working Group Members: April 2025
- Establish Planning Assumptions: April 2025

Phase 2: Electric Technical Advisory Committee and Stakeholder Working Group

Timeline: December 2023 – March 2025

Objective:

Engage

Tasks:

1. Establish Electric Technical Advisory Committee
2. Establish Stakeholder Working Group
3. Provide PowerSIMM Access to ETAC members

Key Milestones

- Establish Electric Technical Advisory Committee and Stakeholder Working Group: May 2025

2026 MT - ETAC & SWG Meeting Schedule (Tentative – Subject to Change)

Meeting	Date	Time	Topics
1	December 5, 2023	0930-1130	Introductions Overview Expectations
2	March 27, 2024	0930-1130	IRP Workplan Development ETAC Timeline Stakeholder Engagement Plan PowerSimm Modeling and ETAC
3	June 27, 2024	0930-1200	Review Final IRP Workplan Stakeholder Engagement #1 Discussion Modeling scenarios
4	September 18, 2024	0930-1200	PowerSimm Education Price Forecasting
5	December 18, 2024	0930-1200	Modeling Inputs Load Forecasting New Resource Cost Modeling Modeling Scenarios PowerSimm Access
6	March 26, 2025	0930-1230	Stakeholder Working Group Updated IRP Work Plan WECC – Resource Adequacy Discussion New Resource Cost Modeling Modeling Scenarios PowerSimm
**	June 9, 2025	0900-1600	Introductions What is an IRP? Scenarios and Sensitivities Candidate Resources Activity Load Forecasting DSM Transmission Overview Western Resource Adequacy Program 2023 IRP feedback from stakeholders 2026 IRP Workplan Review
7	June 25, 2025	0930-1230	Stakeholder Working Group Form Energy PowerSimm Login Website Updates Costs Discussion Updates
**	July 2025	0900-1600	TBD

Meeting	Date	Time	Topics
8	August 28, 2025	0930-1230	Asset Management VP Comments Stakeholder Working Group Scenario/Sensitivity updates PowerSimm Preliminary ARS Results
9	October 29, 2025	0930-1230	Progress Update
**	October 2025	TBD	PowerSimm Preliminary ARS Results Progress Update
***	November 2025 (Bozeman)	TBD	IRP Presentation
***	November 2025 (Helena)	TBD	IRP Presentation
10	December 3, 2025	0930-1230	PowerSimm Final ARS Results Draft IRP
***	December 2025 (Missoula)	TBD	IRP Presentation
***	December 2025 (Great Falls)	TBD	IRP Presentation
11	December 29, 2025	0930-1230	Presentation of Final Draft IRP
****	December 30, 2025 (Butte)		PRESENTATION ONLY Presentation of Final Draft IRP
*	April 31, 2026	N/A	MT IRP 2026 Filing with MPSC

* Denotes the Date for Anticipated 2026 MT IRP filing with Montana Public Service Commission

** Denotes Stakeholder Working Group

***Denotes Public Session

****Denotes Public Webinar

Phase 3: Demand Forecasting and Resource Assessment

Timeline: December 2024– June 2025

Objective:

Assess future energy demand, evaluate existing portfolio, and potential candidate resources.

Tasks:

1. Load Forecasting including DSM Programs
2. Perform generation resource assessments
3. Evaluate demand response potential.

Key Milestones

- Load Forecasting and Resource Assessment: April 2025
- Scenario Development: April 2025

Phase 4: Candidate Resource Development and PowerSIMM Modeling

Timeline: December 2024 – December 2025

Objective:

Develop and complete capacity expansion and production cost modeling using PowerSIMM.

Tasks:

1. Define candidate resources and acquire costs
2. Develop scenarios and sensitivities
    a. Incorporate transmission considerations
    b. Quantify environmental externalities
3. Update PowerSIMM model
4. Perform scenario modeling

Key Milestones

- Establish Candidate Resources: April 2025
- Preliminary Modeling Complete: September 2025
- Final Modeling Complete: December 2025

Phase 5: Stakeholder Consultation and Feedback

Timeline: June 2025 – March 2026

Objective:

Engage stakeholders to review and refine the IRP deliverables.

Tasks:

1. Engage internal and external stakeholders for feedback
2. Document comments and responses
3. Review feedback and make adjustments as necessary

Key Milestones

- Internal and External Stakeholder Reviews: October 2025
- Engage Public for Feedback: October 2025

Phase 6: Reporting and Final Recommendations

Timeline: June 2025 – April 2026

Objective:

Finalize the IRP and present recommendations.

Tasks:

1. Prepare final report, clearly detailing compliance with regulatory and statutory requirements
2. Submit for internal review and approval

3. File with MPSC

Key Milestones

- Draft Plan Complete: September 2025
- Final Plan Complete: December 2025
- Internal and External Stakeholder Reviews: December 2025
- Open period for Public Comment: January 2026
- File MT 2026 Integrated Resource Plan with Montana Public Service Commission: April 2026

Comment Tracker Overview and Process

Purpose

To ensure clear and consistent communication between stakeholders and the NorthWestern during the planning process.

1. Submission Process

1.1 Accepted Formats

ETAC, Stakeholders, and the Public may submit written inquiries and comments via:

- **Online Form** (preferred method):
  - IRP Feedback Form posted on NorthWestern's Montana electric supply planning website (link below)
    - https://www.northwesternenergy.com/about-us/gas-electric/montana-electric-supply-planning/feedback-form-electric-supply-meeting
  - Each submission should include:
    - Name and affiliation
    - Contact information
    - Specific question or comment
    - Reference to category (e.g., Planning Process, Forecast, Markets, Transmission, Modeling Inputs, Candidate Resources, Cost Analysis, etc.)
    - Indication if a response is requested
- **Email:**
  - Preferred for ETAC and Stakeholder Comments Only
  - Email: nweetac@northwestern.com

1.2 Submission Timeframes:

- Written comments and inquiries may be submitted at any point prior to the formal draft IRP release.
- For formal comment periods (e.g., post-draft IRP release), submissions must be received by the posted deadline to be considered for the record.
- Inquiries submitted outside of formal comment windows may be responded to at the utility's discretion or addressed in future stakeholder engagement sessions.

2. Utility Response Process

2.1 Acknowledgement in Comment Tracker

NorthWestern will upload comment tracker prior to each ETAC session.

2.2 Response Timeline

- Responses will be provided by the next ETAC session unless specific questions reference inputs, costs, or other items that have yet to be refined. If this is the case, questions will be answered after the appropriate input and final decisions are made.

2.3 Responses

- Along with the comments, responses will be posted publicly on NorthWestern's website.

3. Recordkeeping and Transparency

- All comments formally submitted will be tracked and responded to in the comment tracker. This will become an appendix to the IRP.

4. Confidential Information

- If a question involves confidential or proprietary information, a response indicating this is confidential will be provided.

APPENDIX E– PCM RESULTS FOR ALL SCENARIOS AND SENSITIVITES

1 PCM RESULTS: SCENARIO B – COLSTRIP RETIRES TO COMPLY WITH MATS

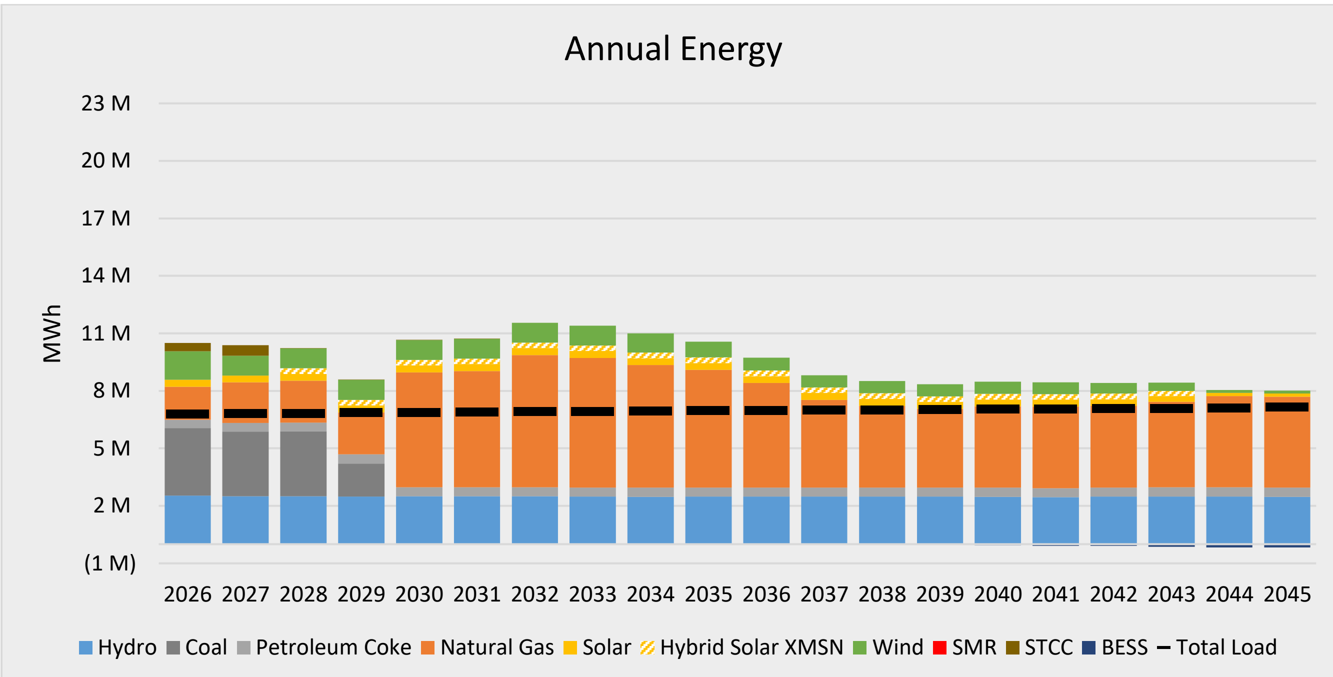

FIGURE 134: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO B.

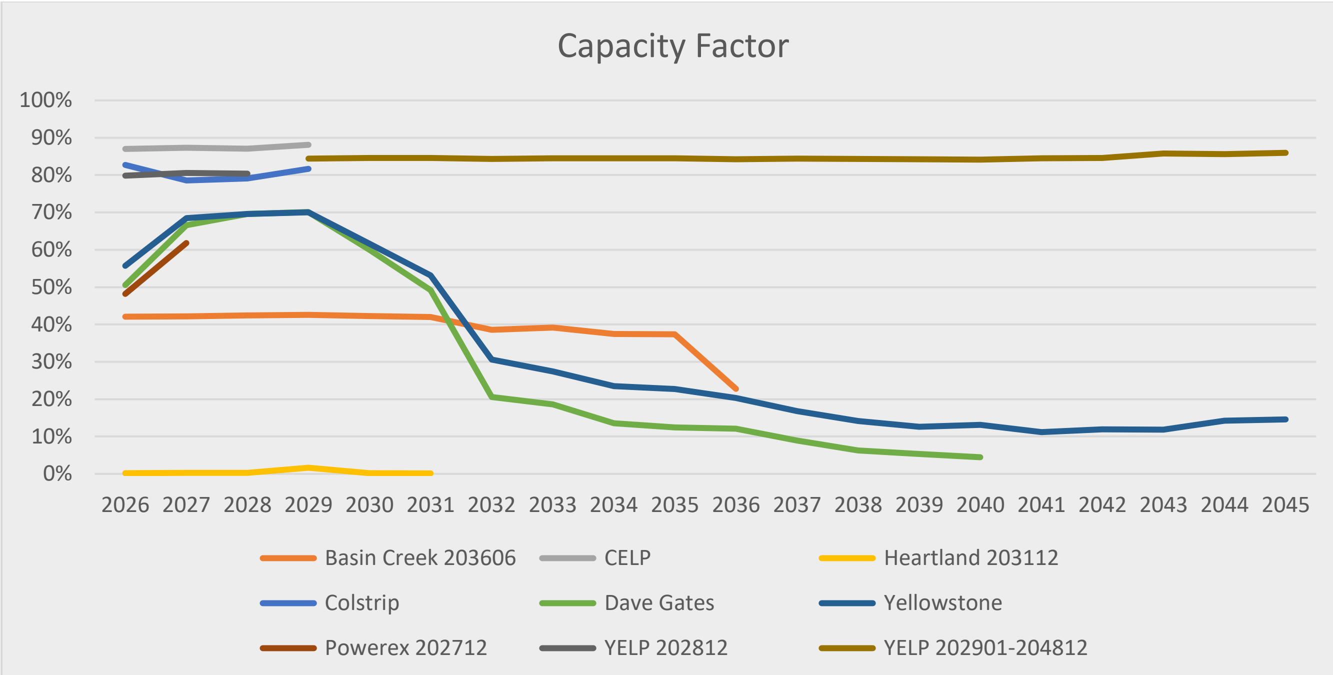

FIGURE 135: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO B.

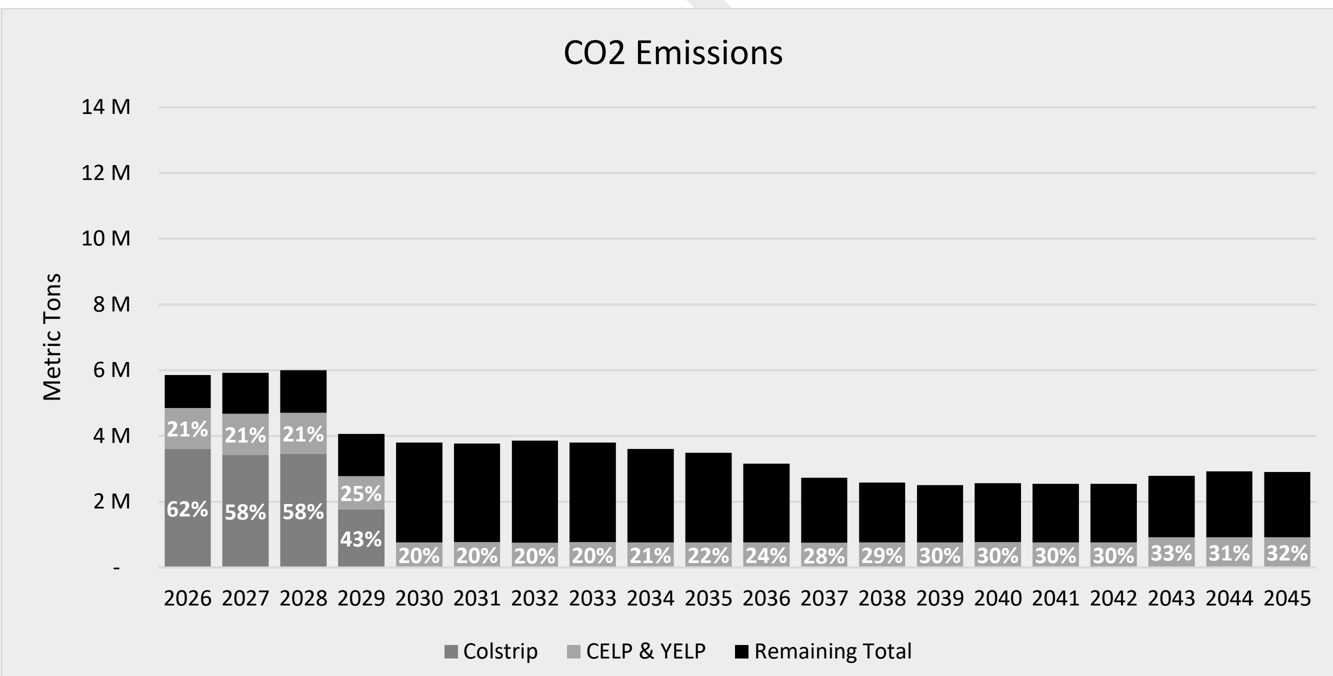

FIGURE 136: EMISSIONS FOR PCM RESULTS OF SCENARIO B.

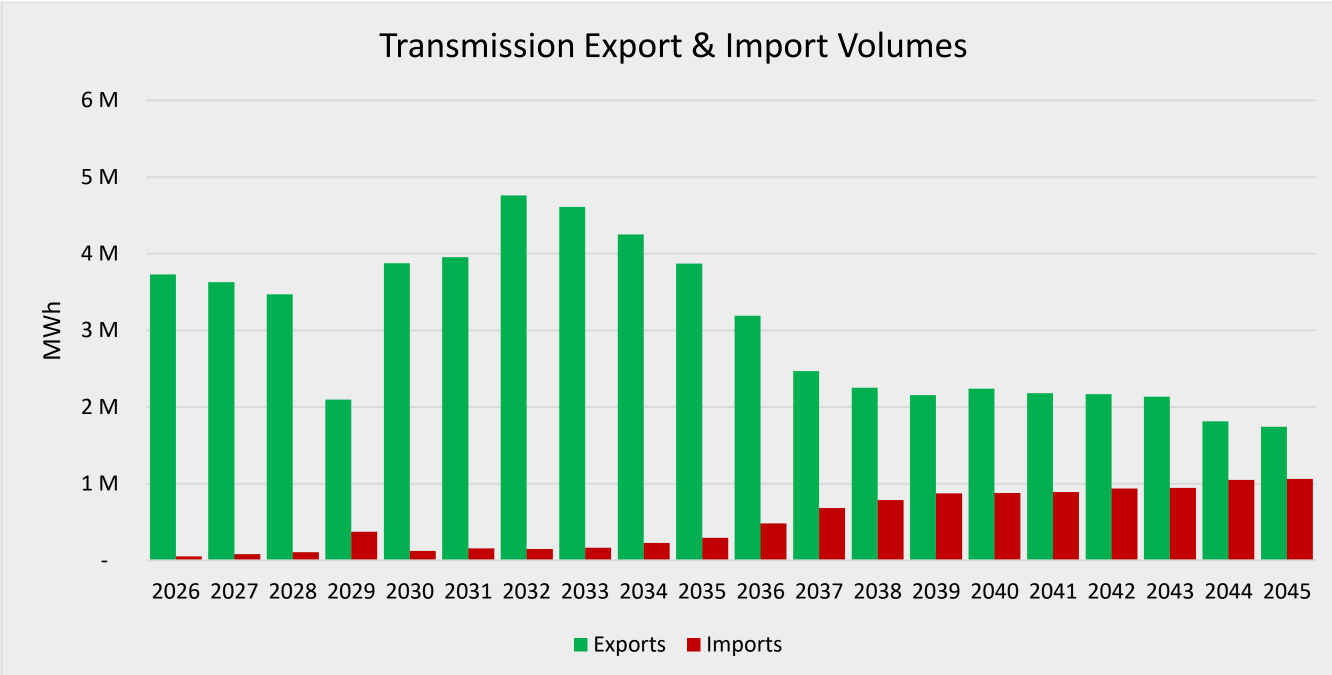

FIGURE 137: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO B.

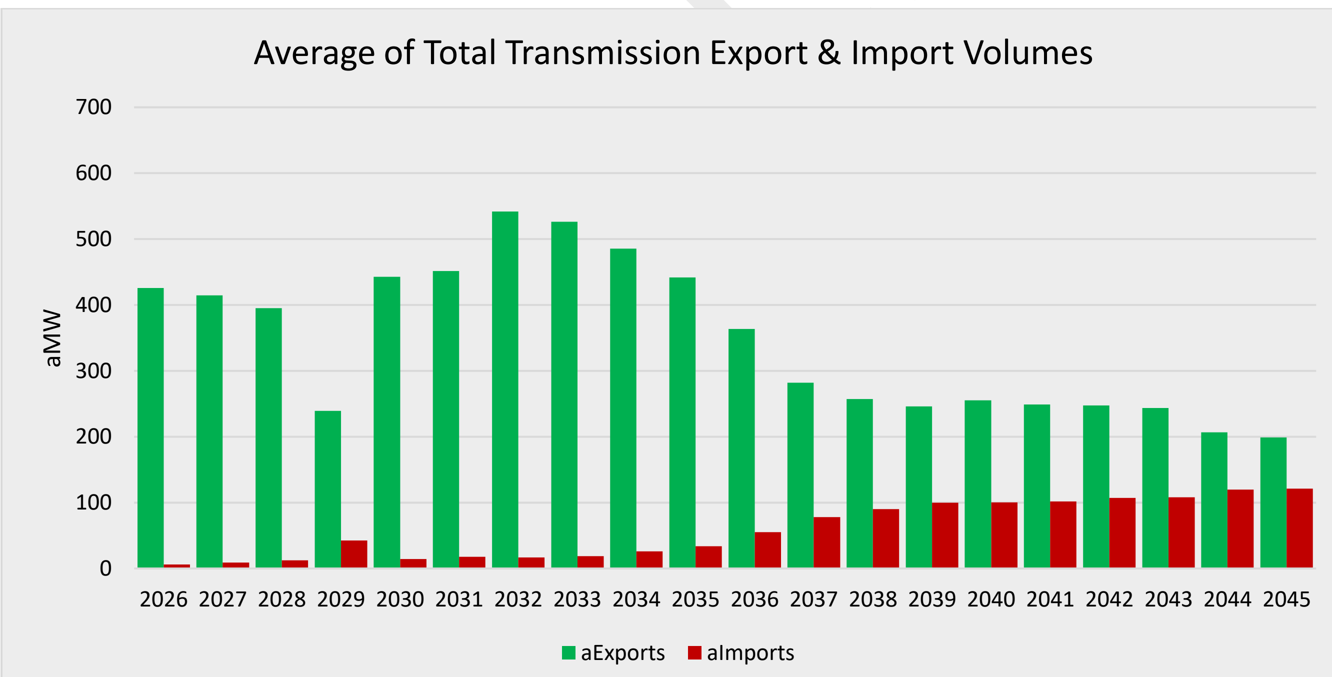

FIGURE 138: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO B.

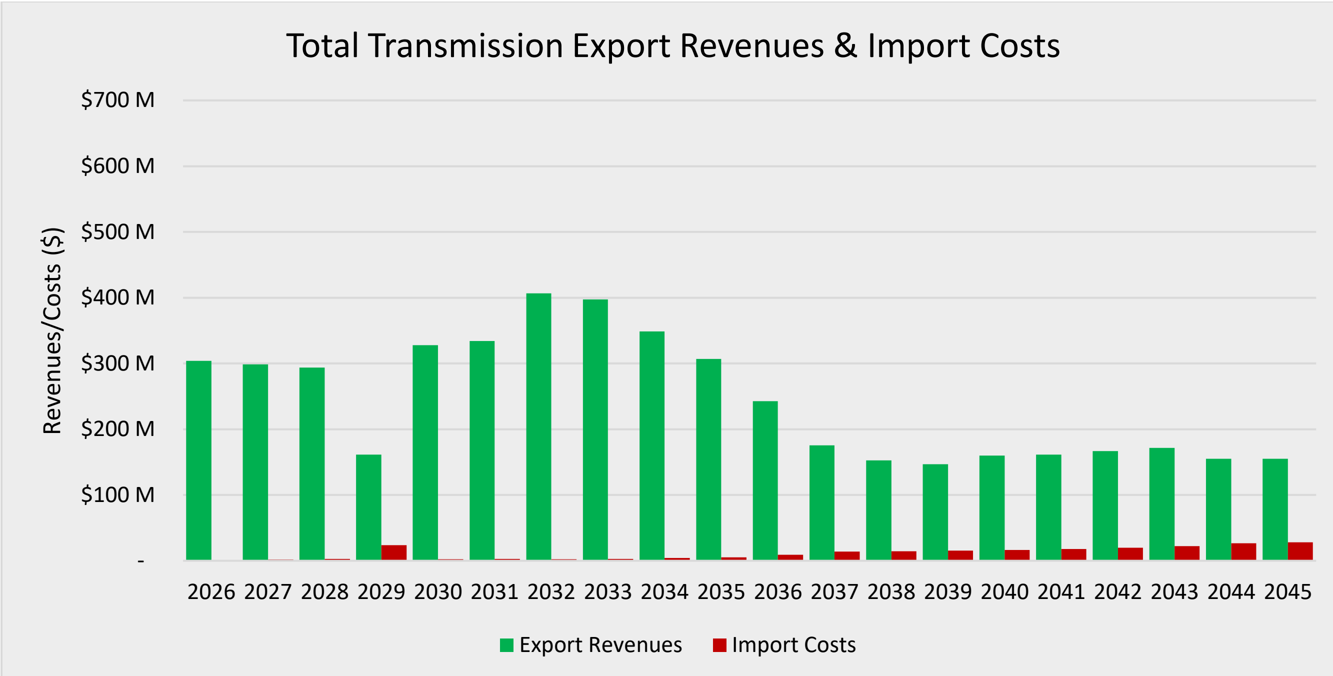

FIGURE 139: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO B.

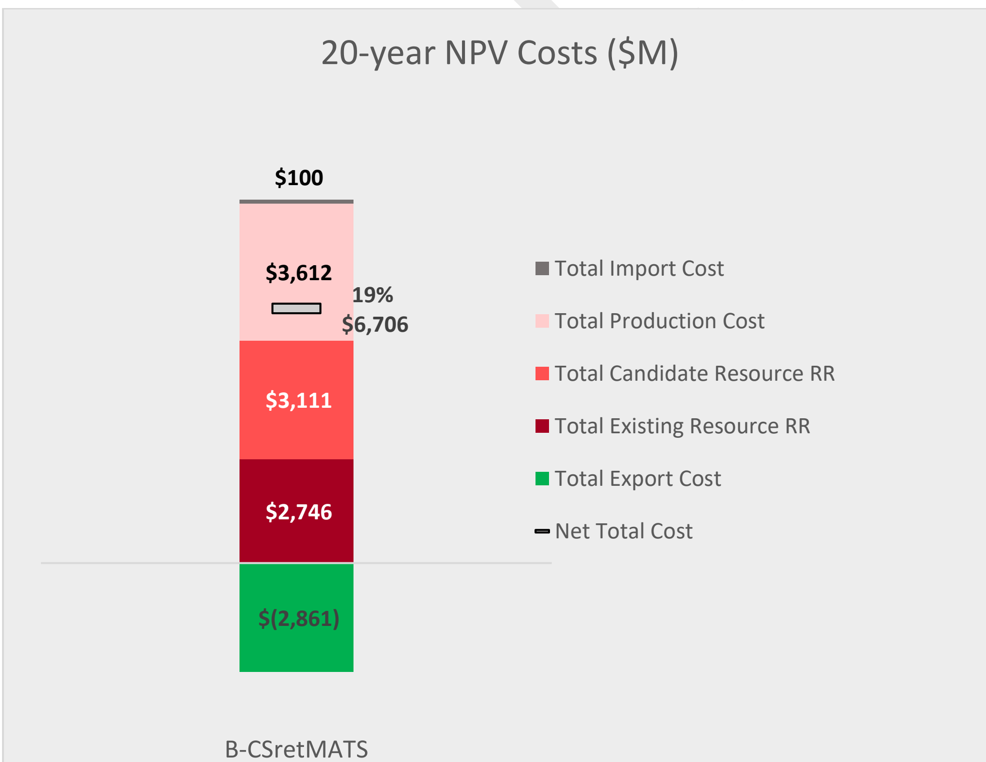

FIGURE 140: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO B.

2 PCM RESULTS: SCENARIO C – COLSTRIP COMPLIES WITH MATS VIA BAGHOUSE

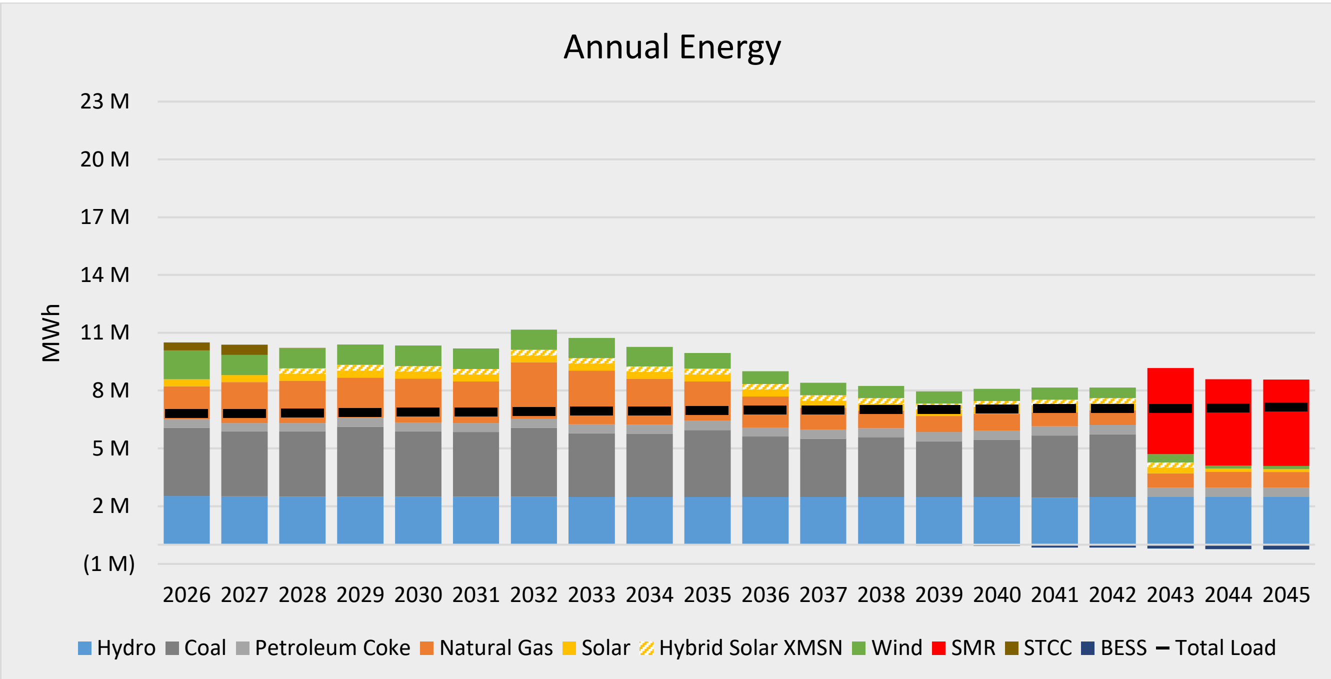

FIGURE 141: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO C.

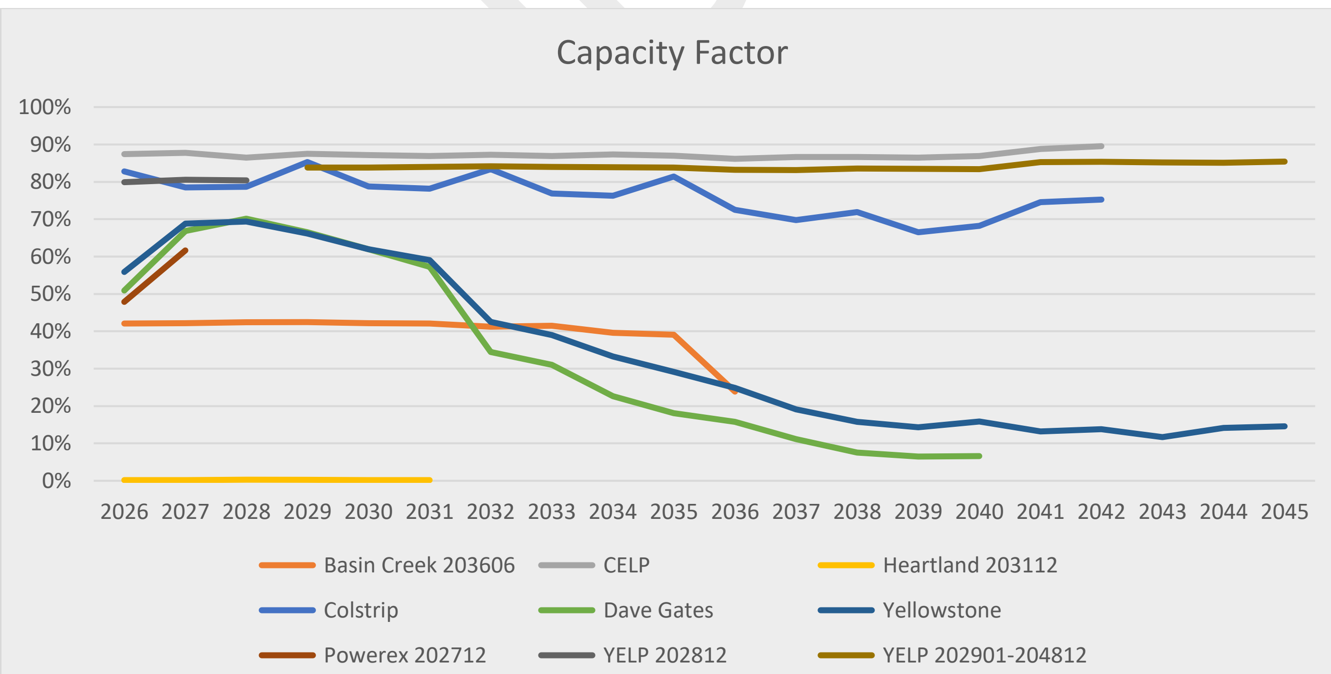

FIGURE 142: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO C.

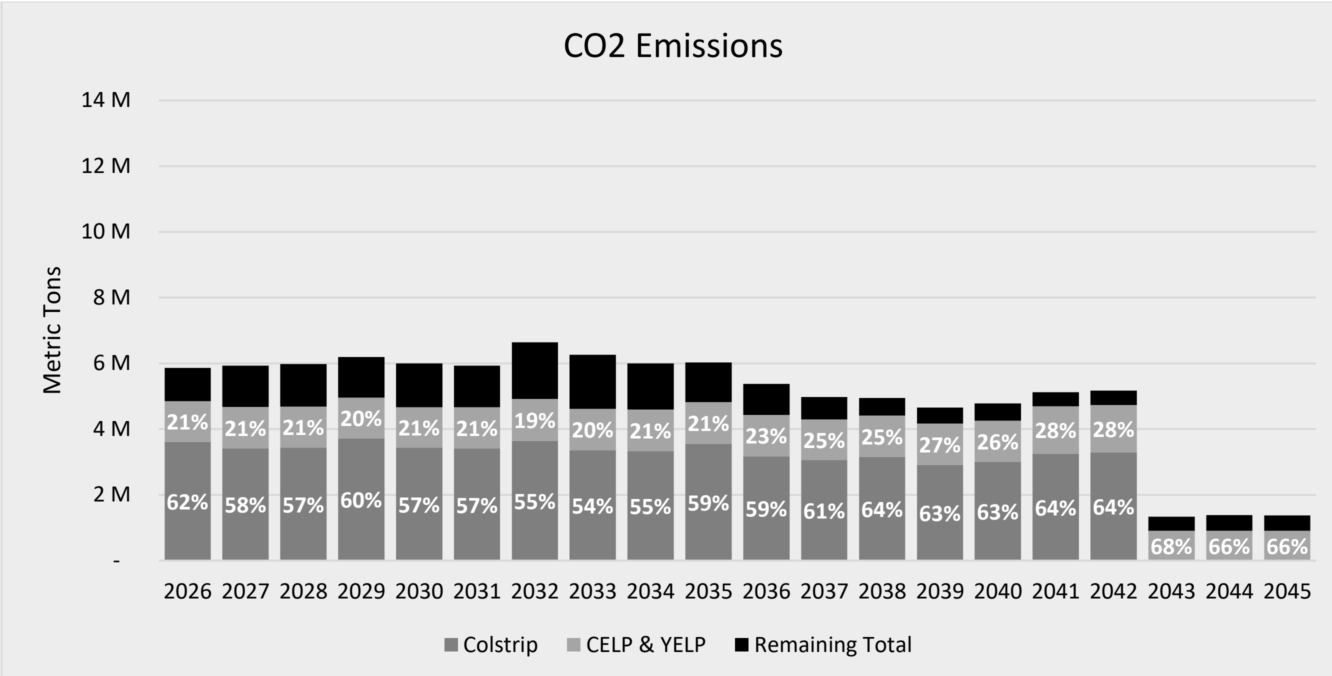

FIGURE 143: EMISSIONS FOR PCM RESULTS OF SCENARIO C.

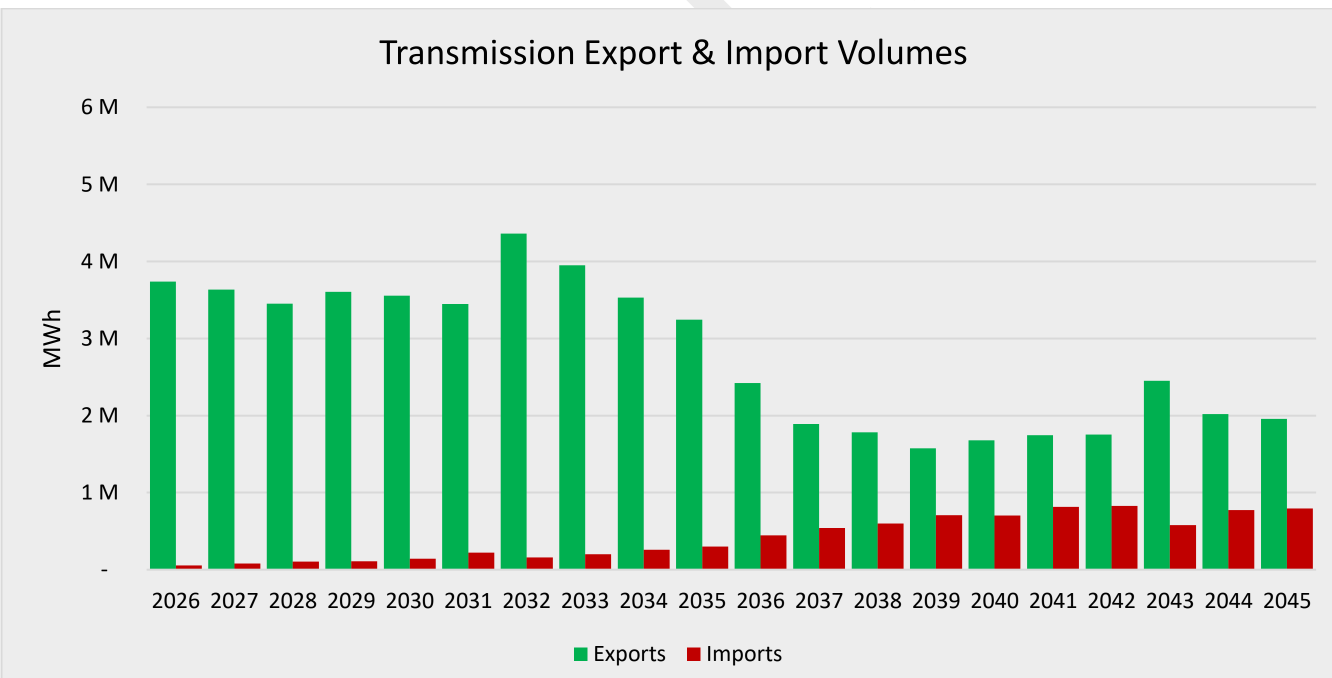

FIGURE 144: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO C.

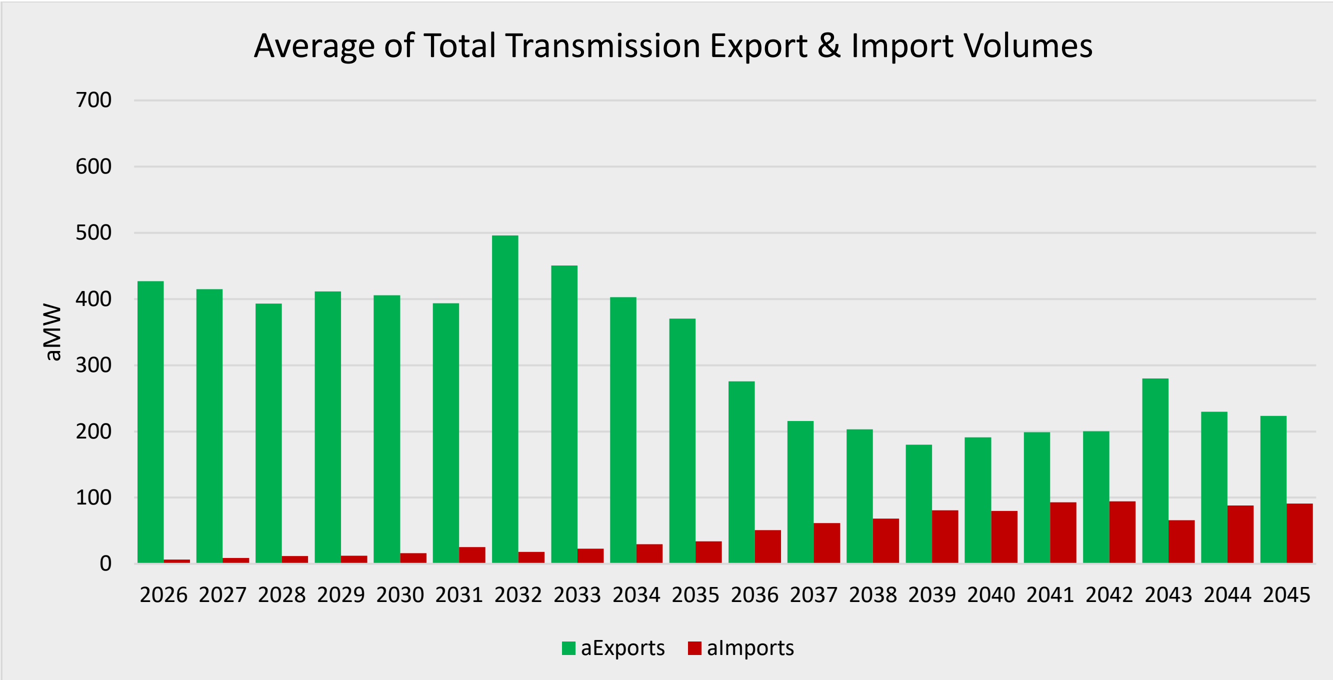

FIGURE 145: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO C.

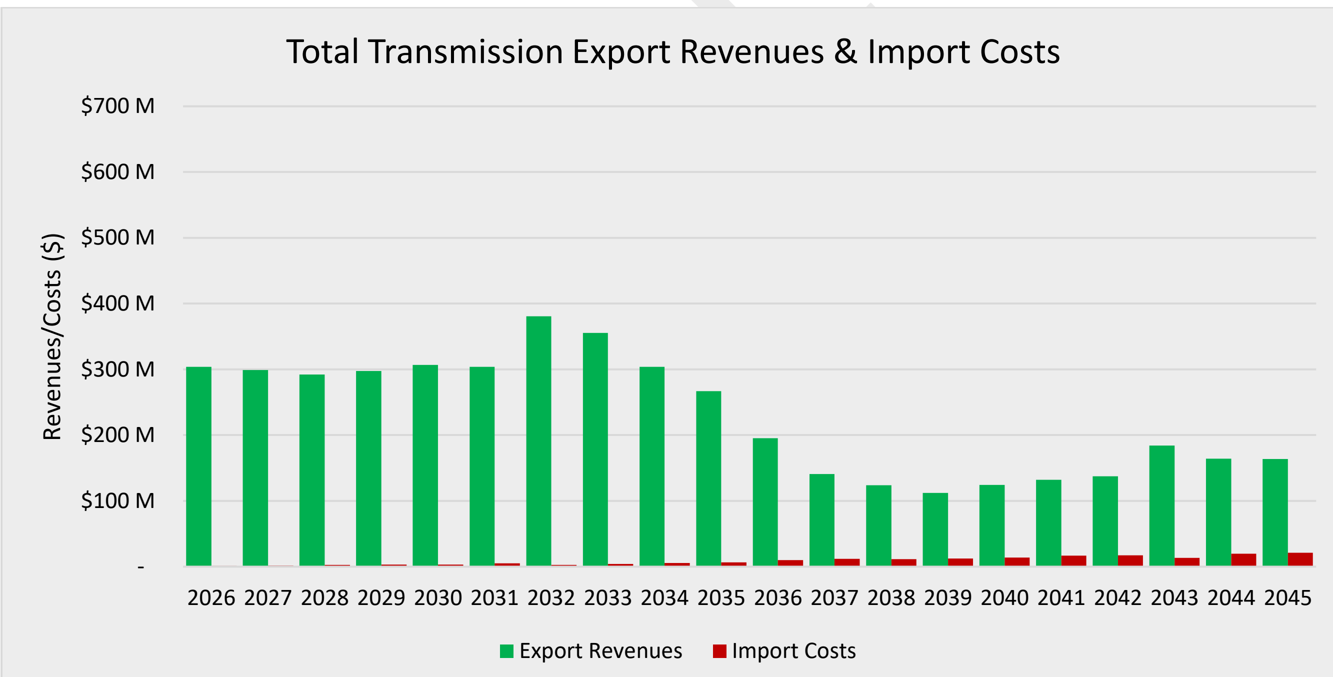

FIGURE 146: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO C.

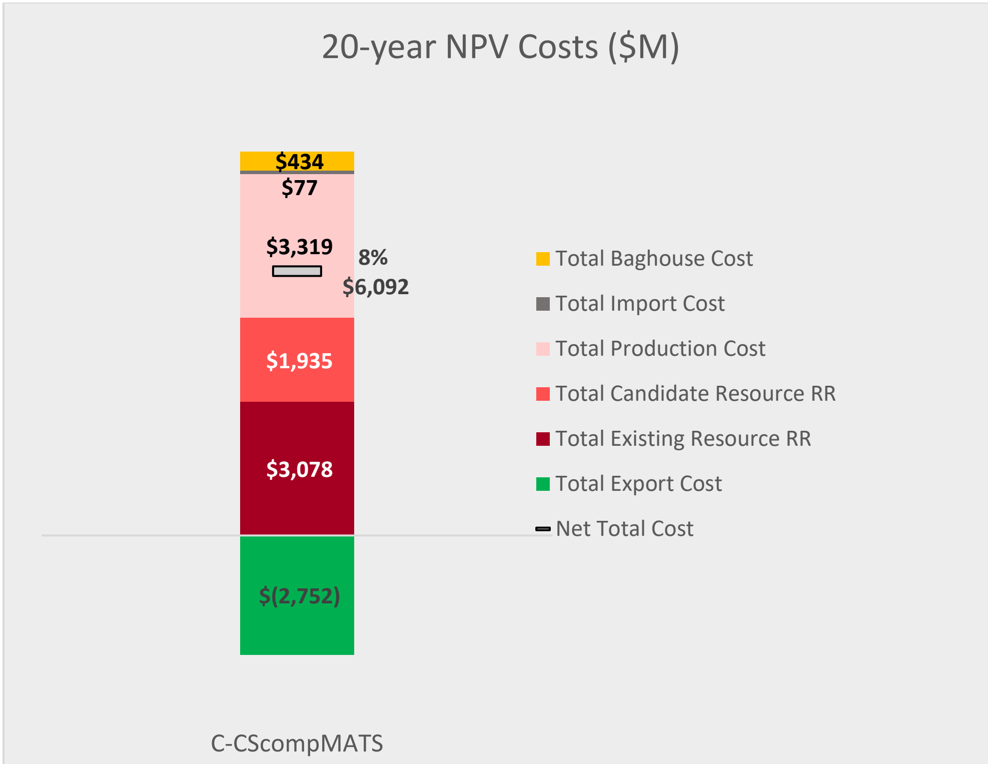

FIGURE 147: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO C.

3 PCM RESULTS: SCENARIO D – COLSTRIP RETIRES TO COMPLY WITH GHG

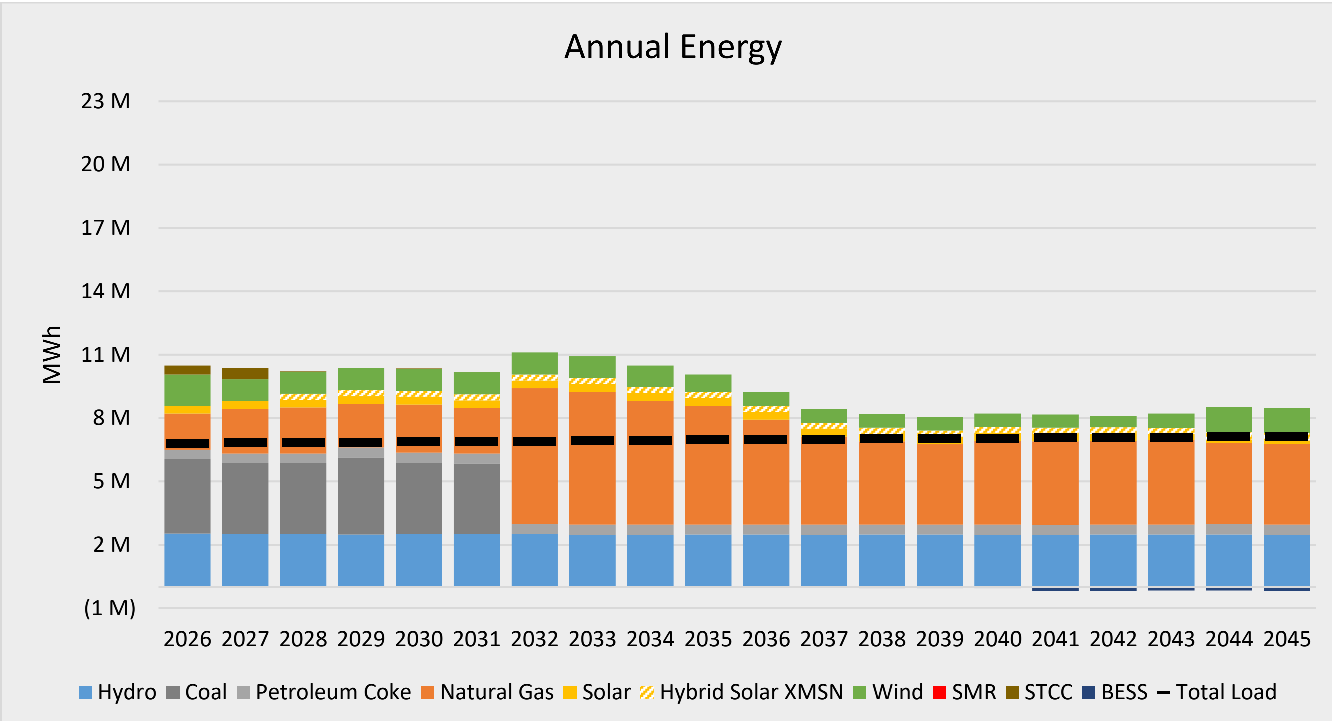

FIGURE 148: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO D.

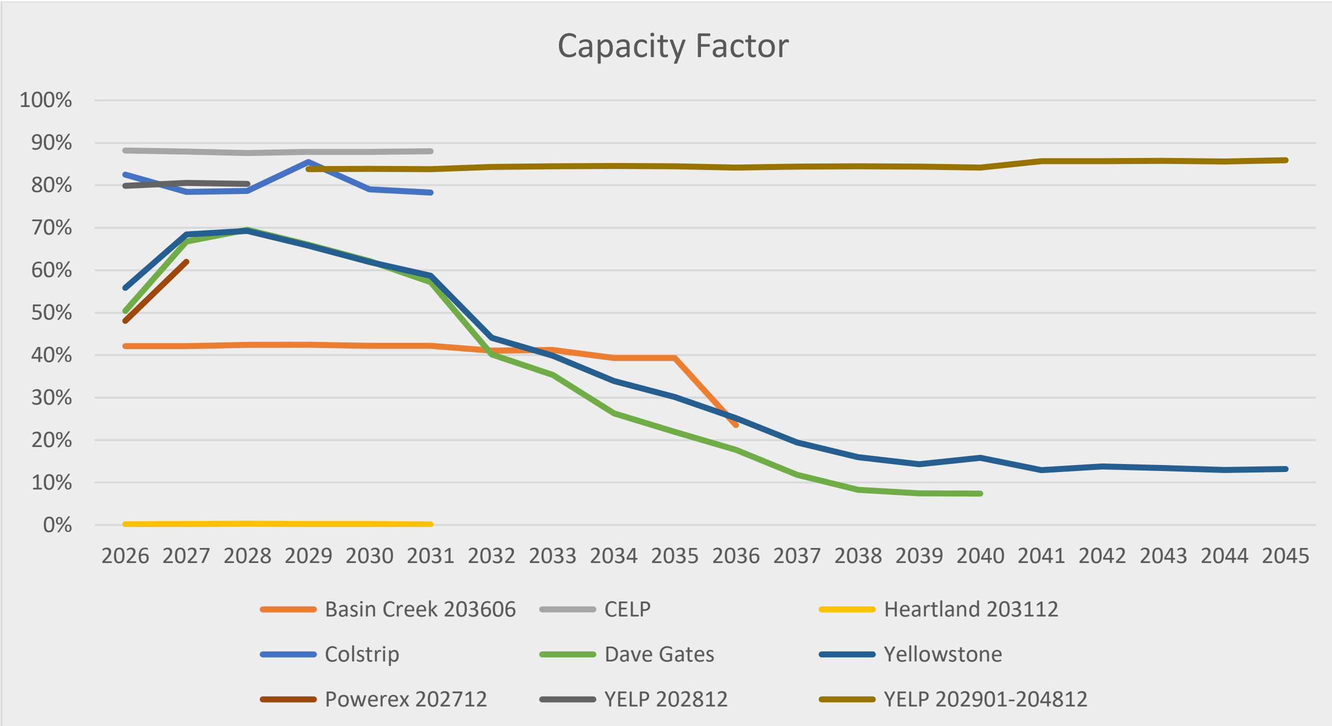

FIGURE 149: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO D.

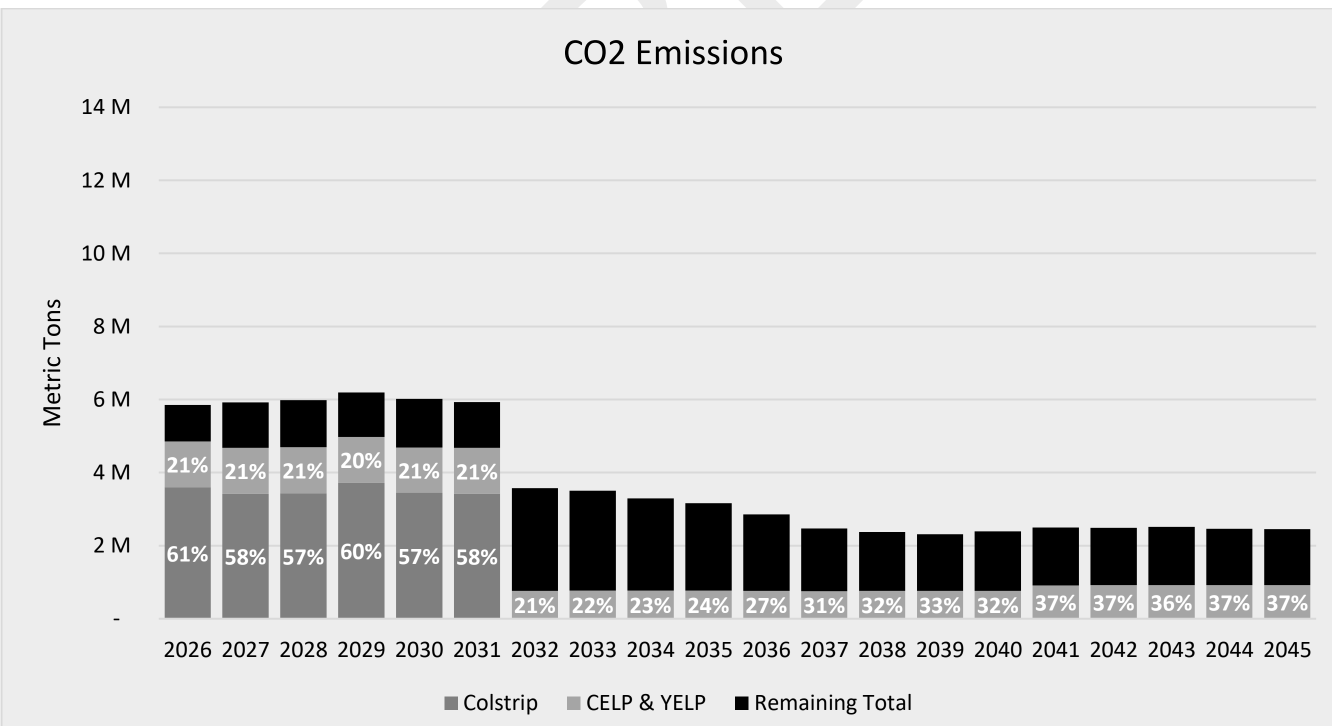

FIGURE 150: EMISSIONS FOR PCM RESULTS OF SCENARIO D.

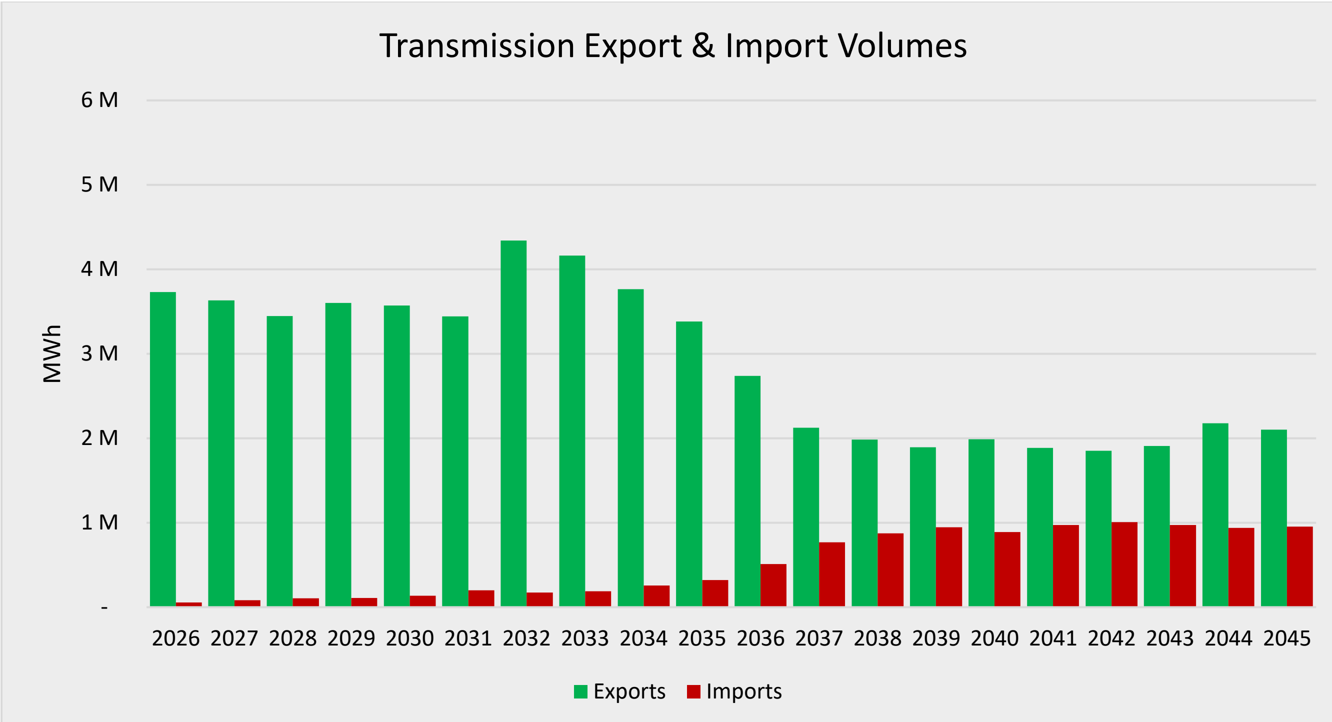

FIGURE 151: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO D.

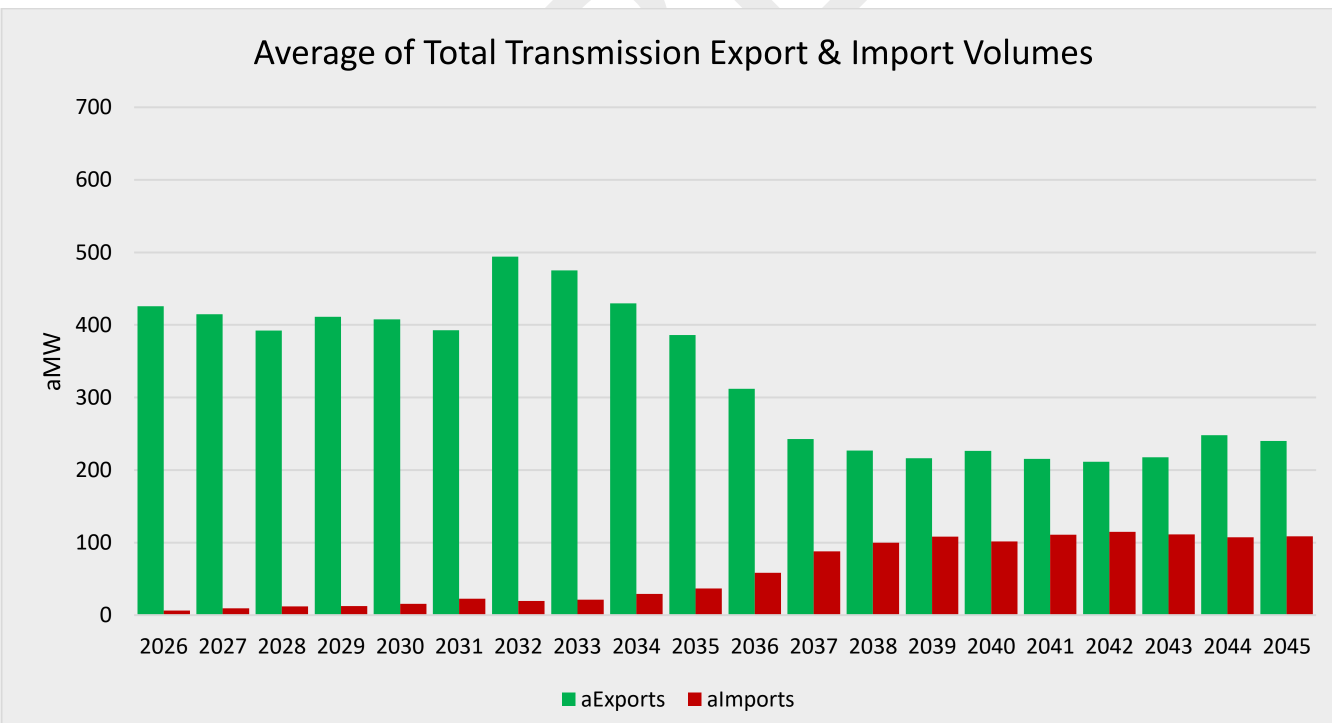

FIGURE 152: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO D.

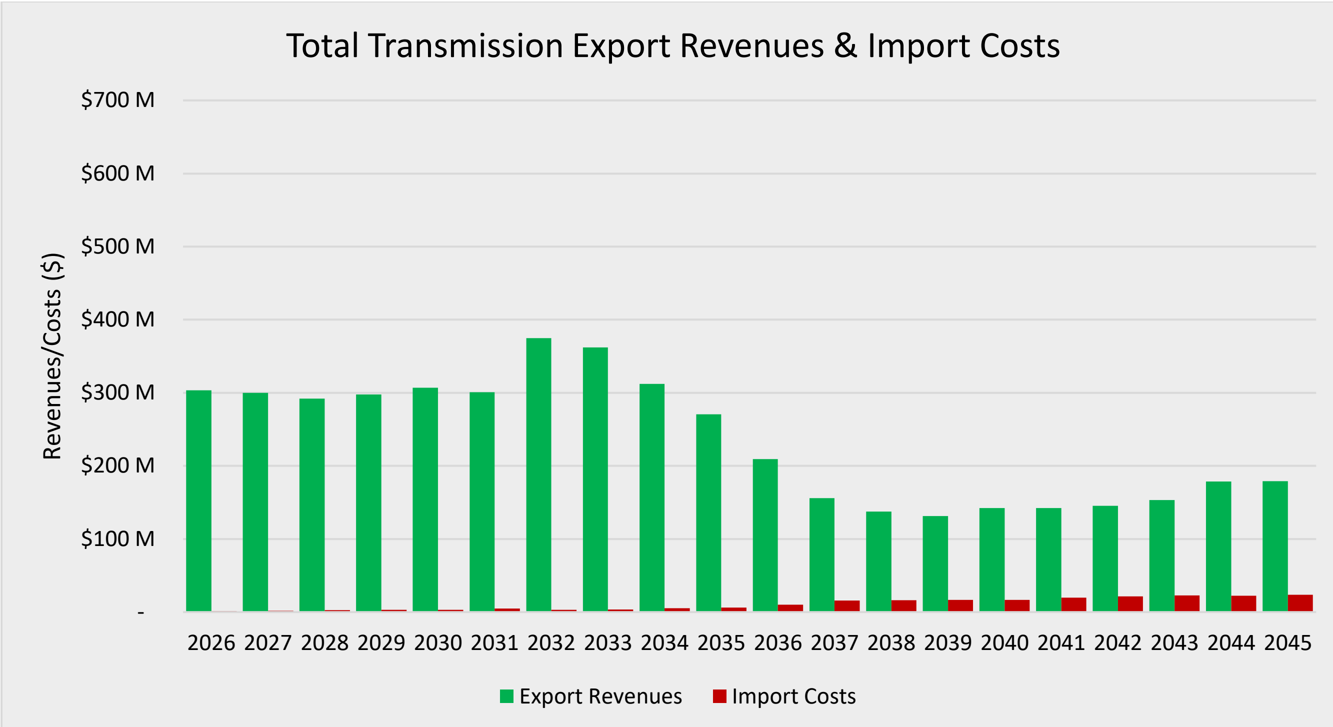

FIGURE 153: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO D.

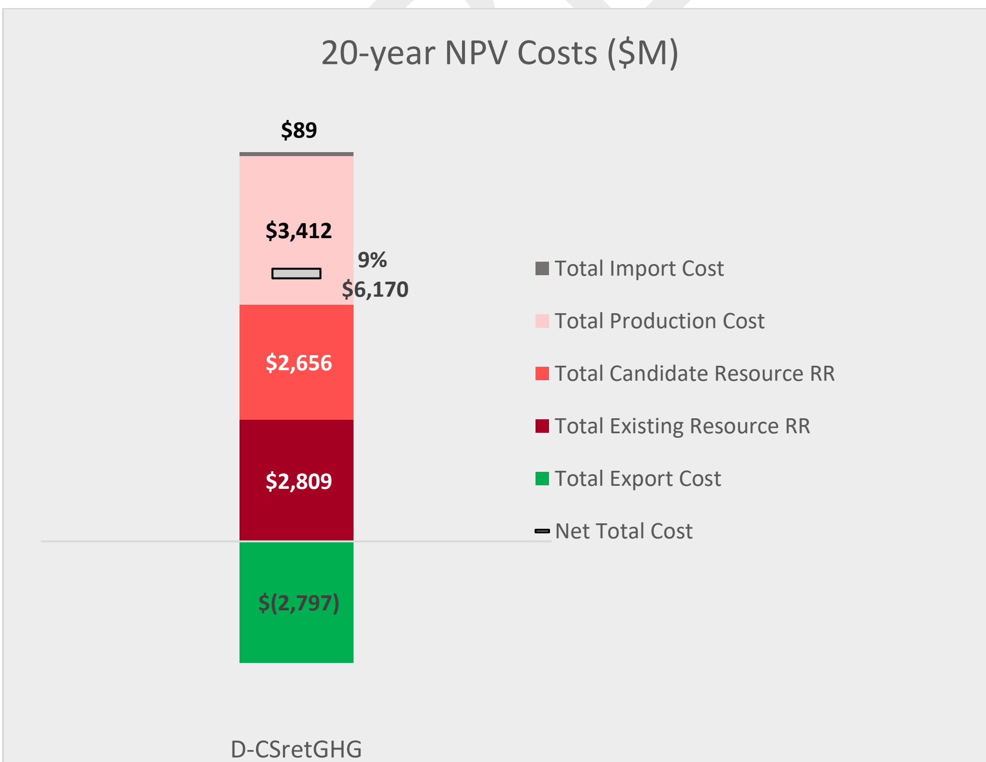

FIGURE 154: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO D.

4 PCM RESULTS: SCENARIO E – COLSTRIP RETIRES IN 2035

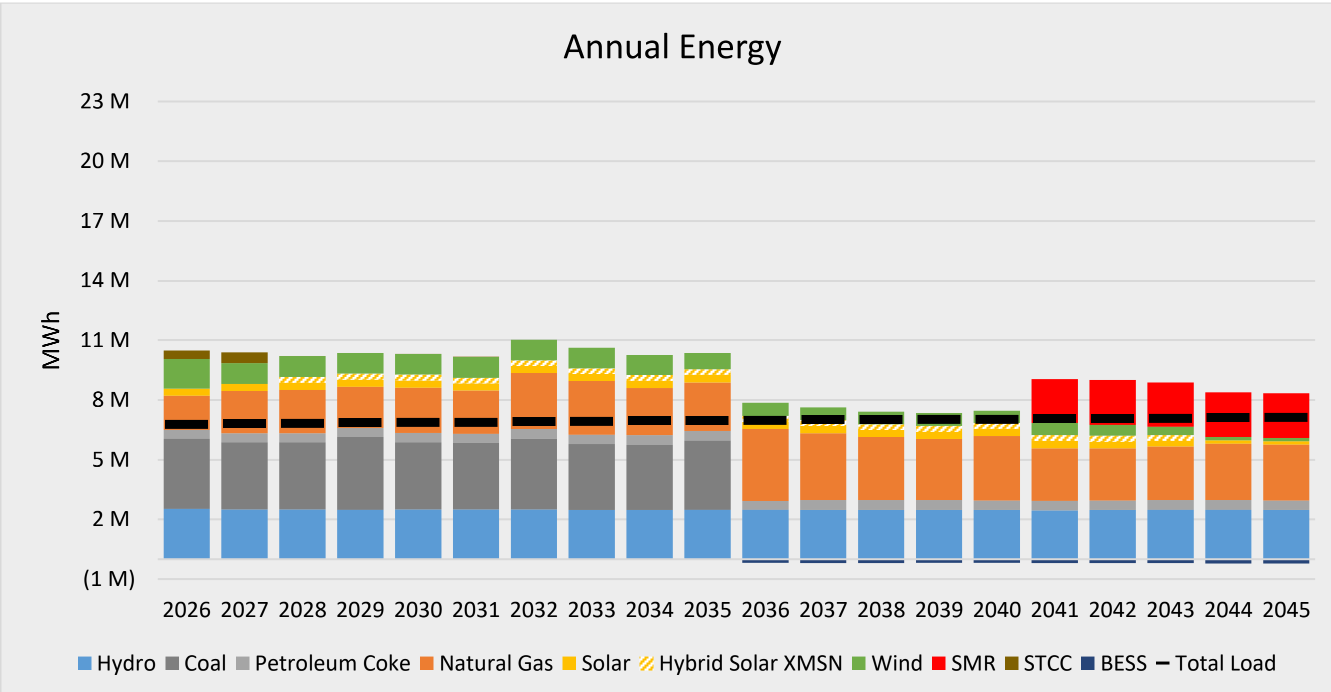

FIGURE 155: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO E.

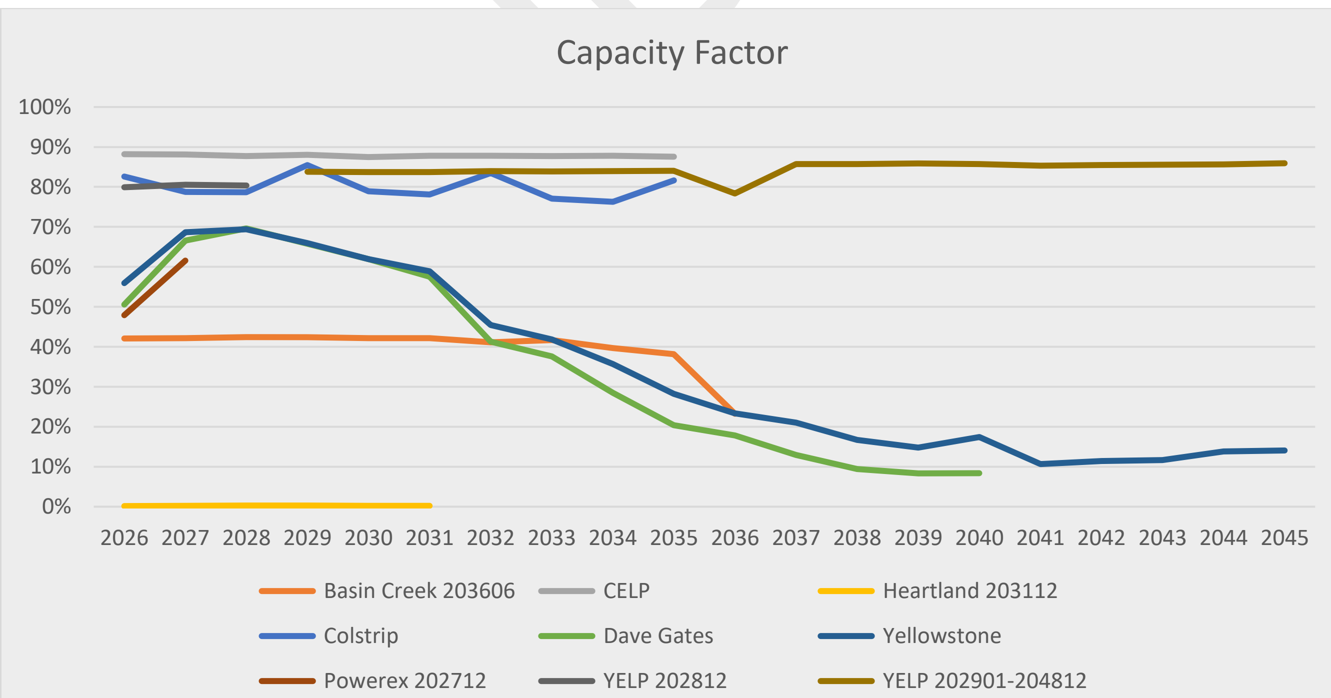

FIGURE 156: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO E.

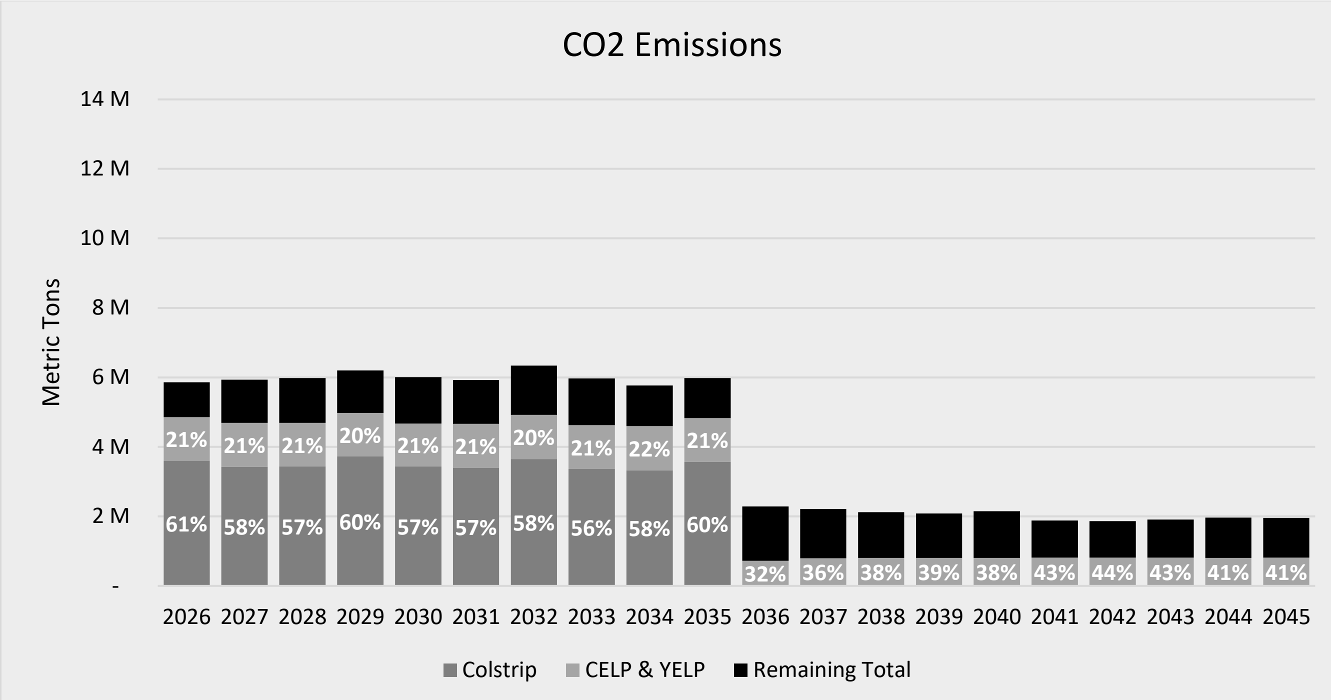

FIGURE 157: EMISSIONS FOR PCM RESULTS OF SCENARIO E.

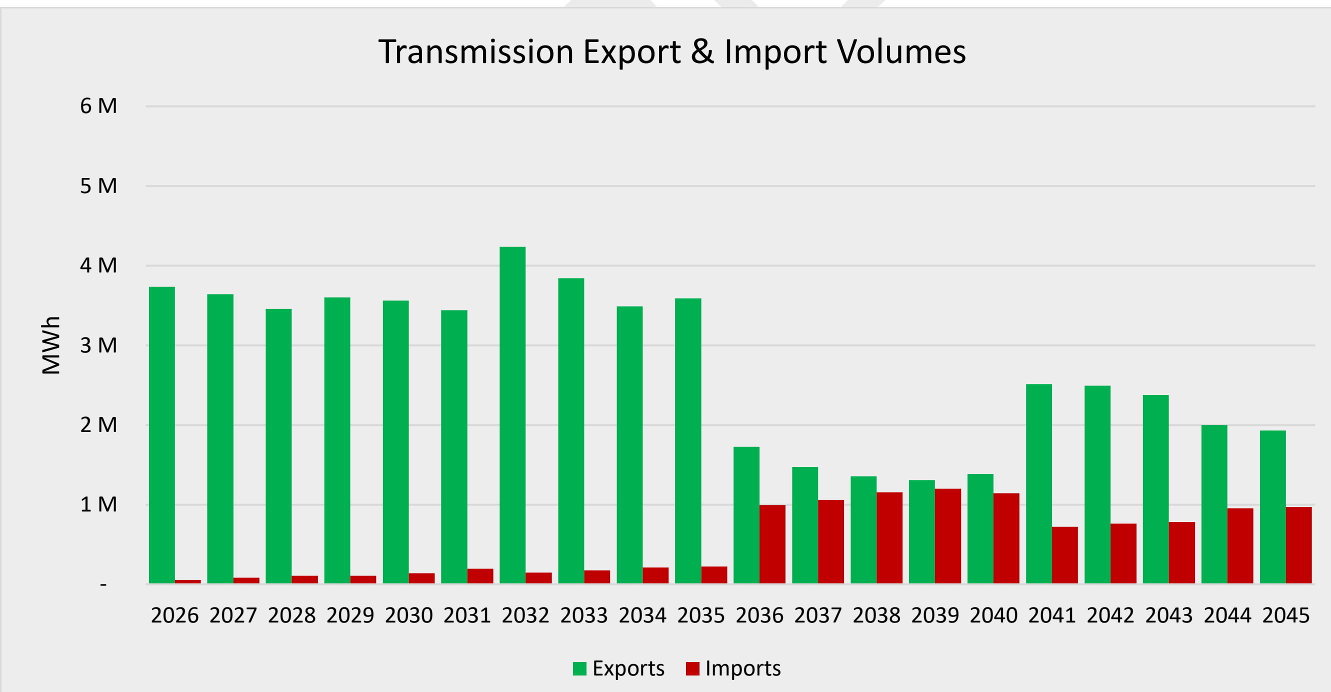

FIGURE 158: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO E.

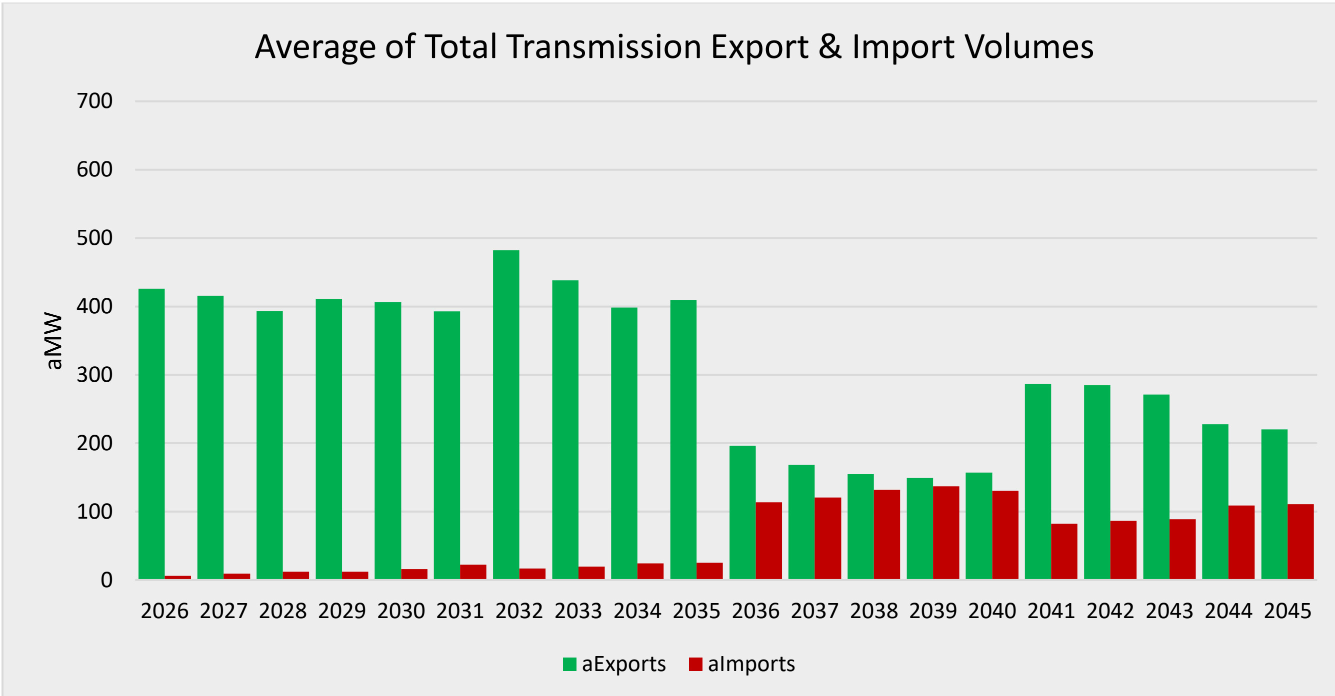

FIGURE 159: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO E.

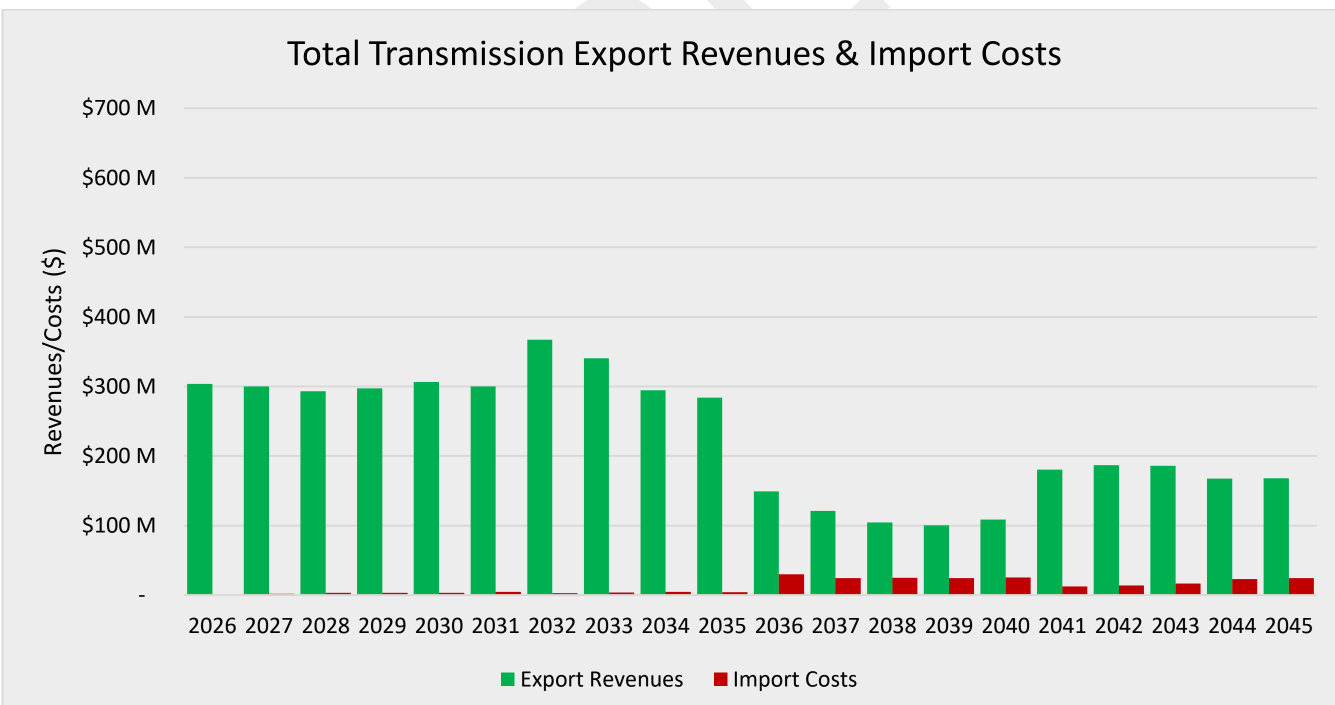

FIGURE 160: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO E.

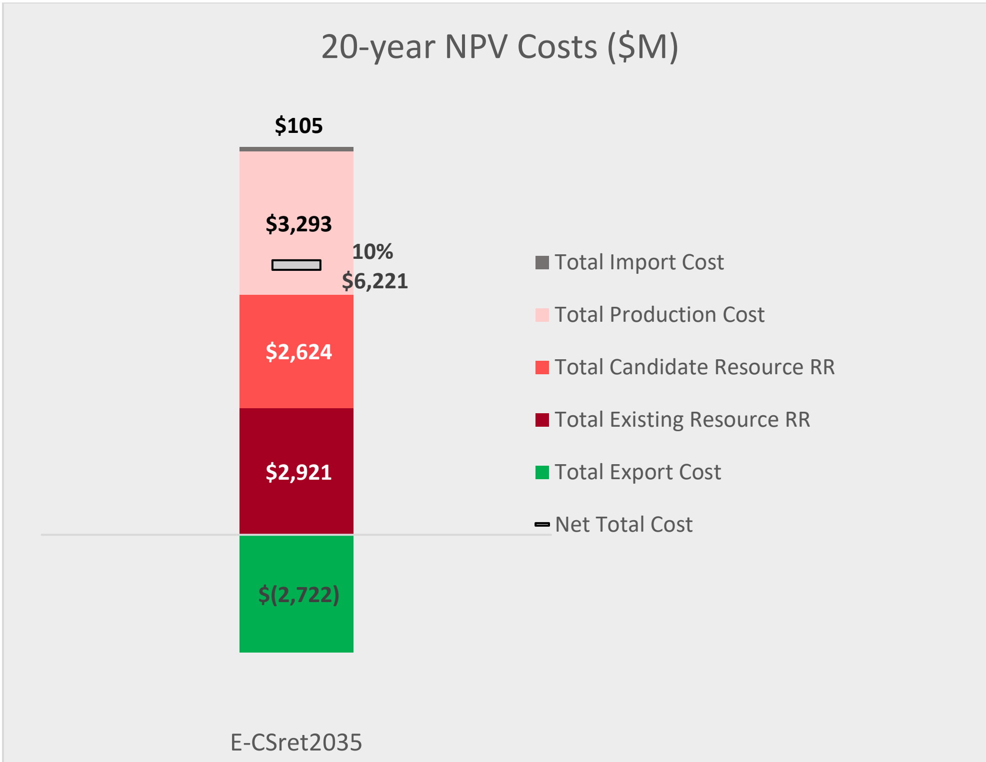

FIGURE 161: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO E.

5 PCM RESULTS: SCENARIO F – POWER PRICE FORECAST REDUCED BY 50%

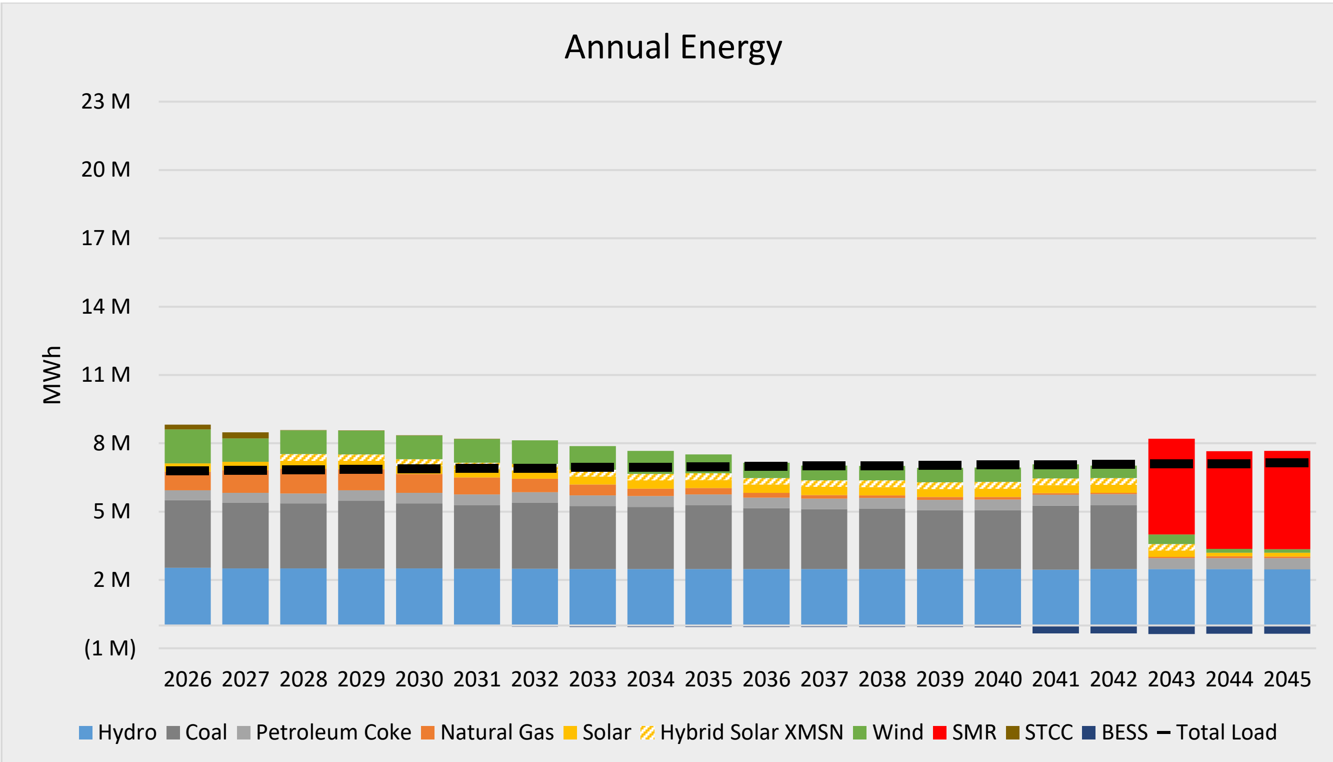

FIGURE 162: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO F.

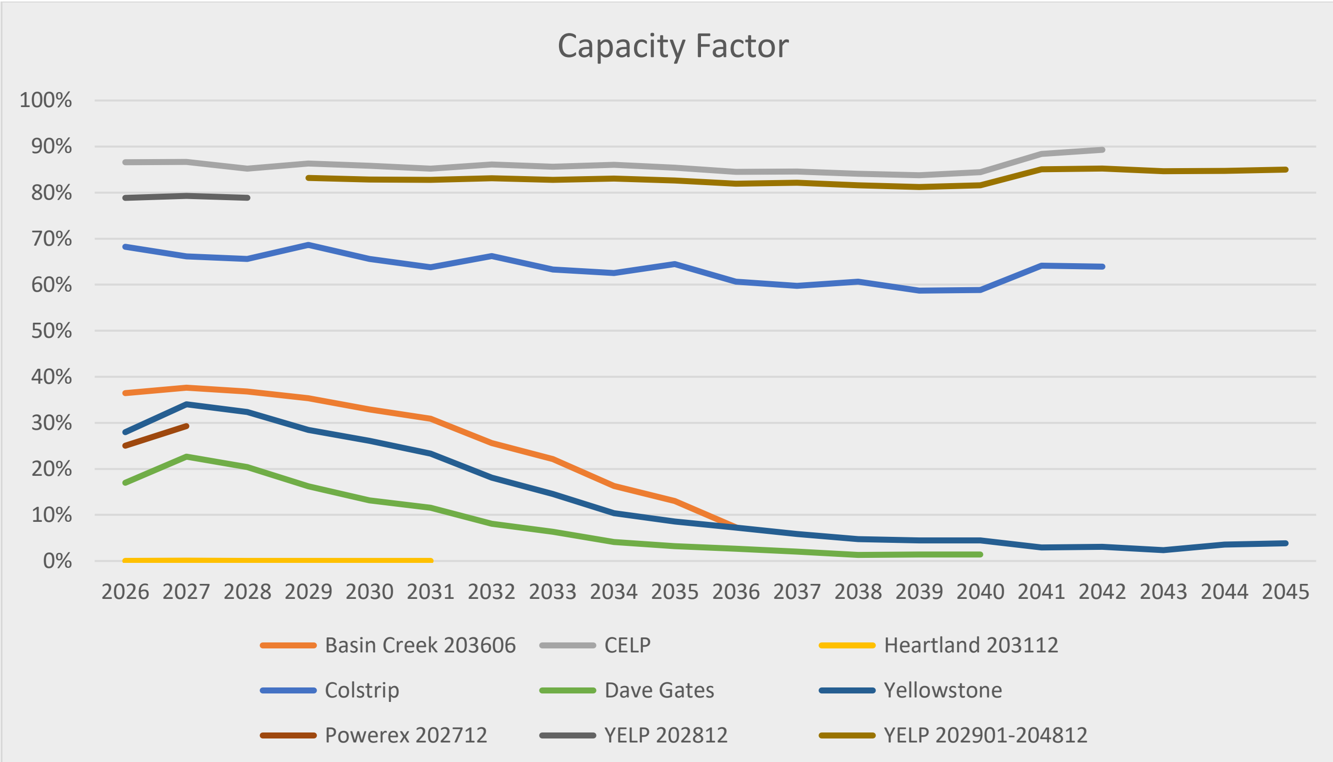

FIGURE 163: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO F.

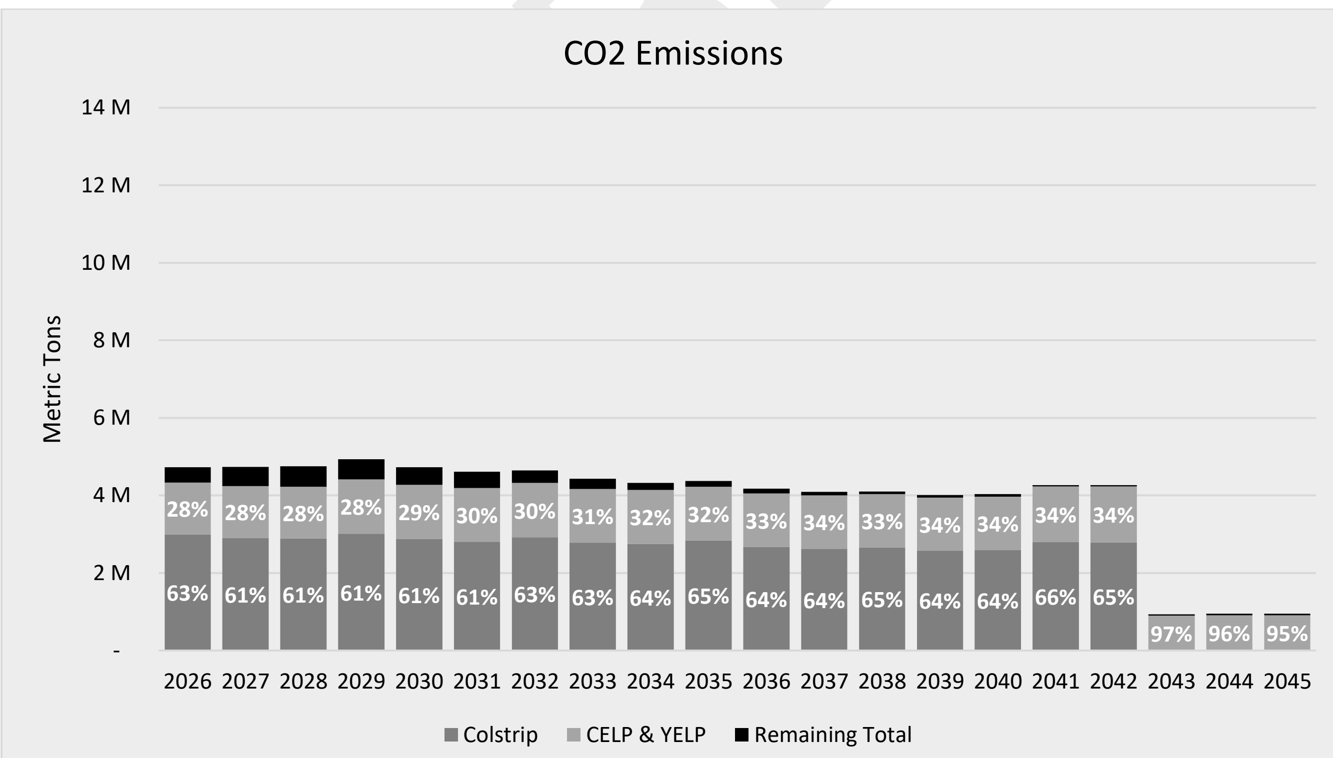

FIGURE 164: EMISSIONS FOR PCM RESULTS OF SCENARIO F.

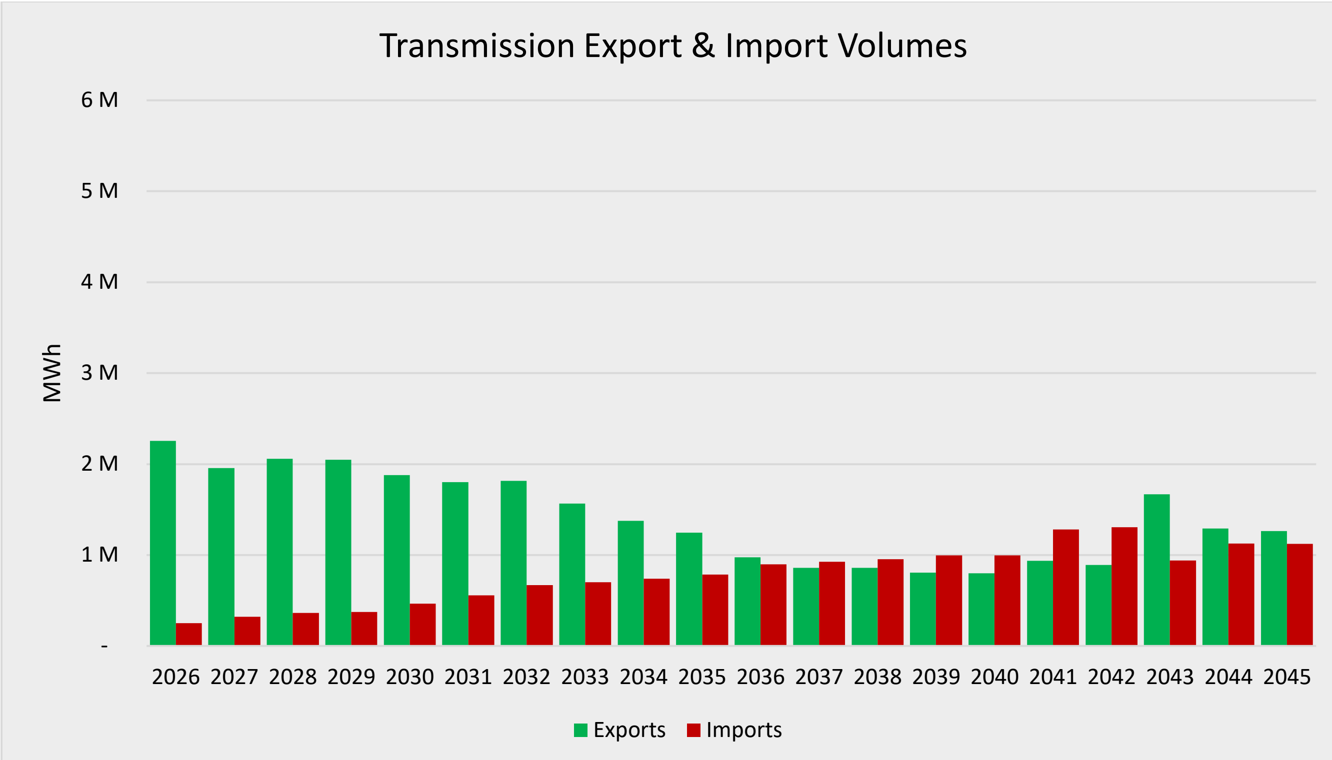

FIGURE 165: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO F.

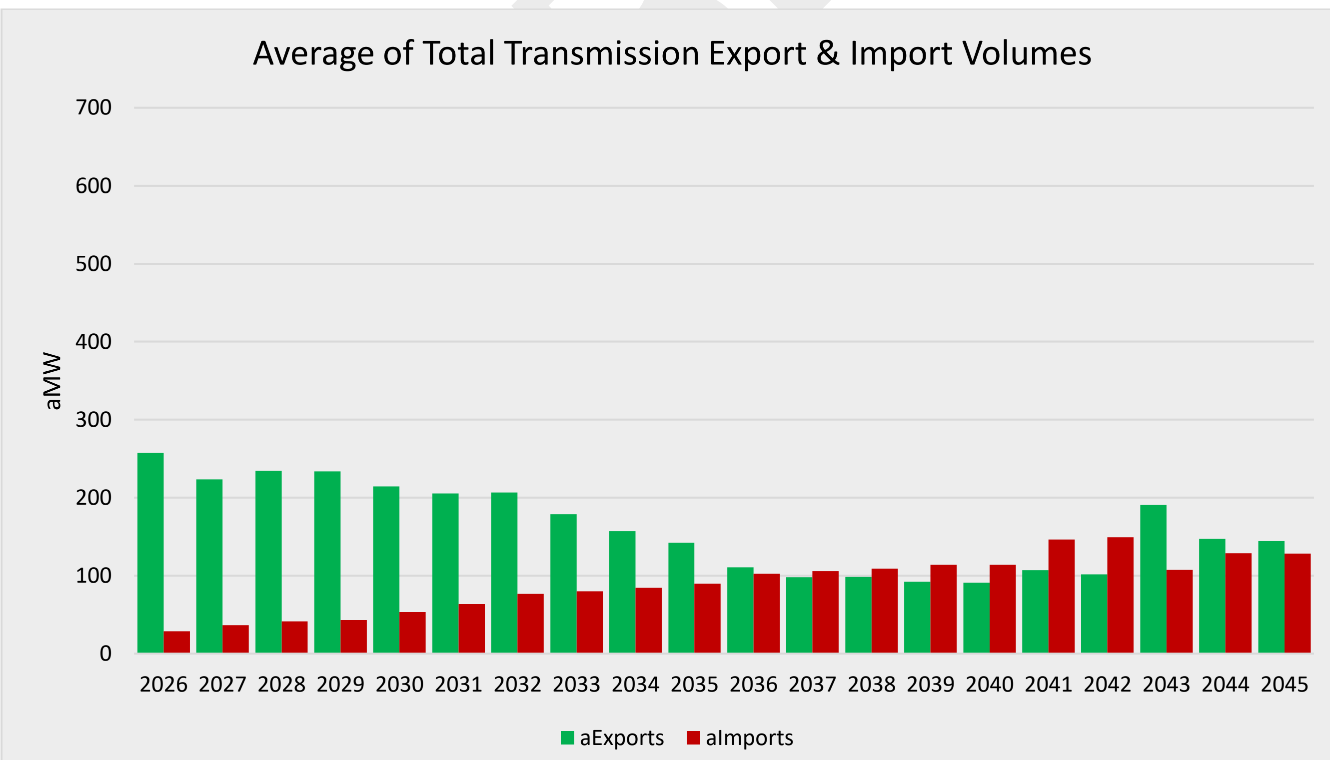

FIGURE 166: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO F.

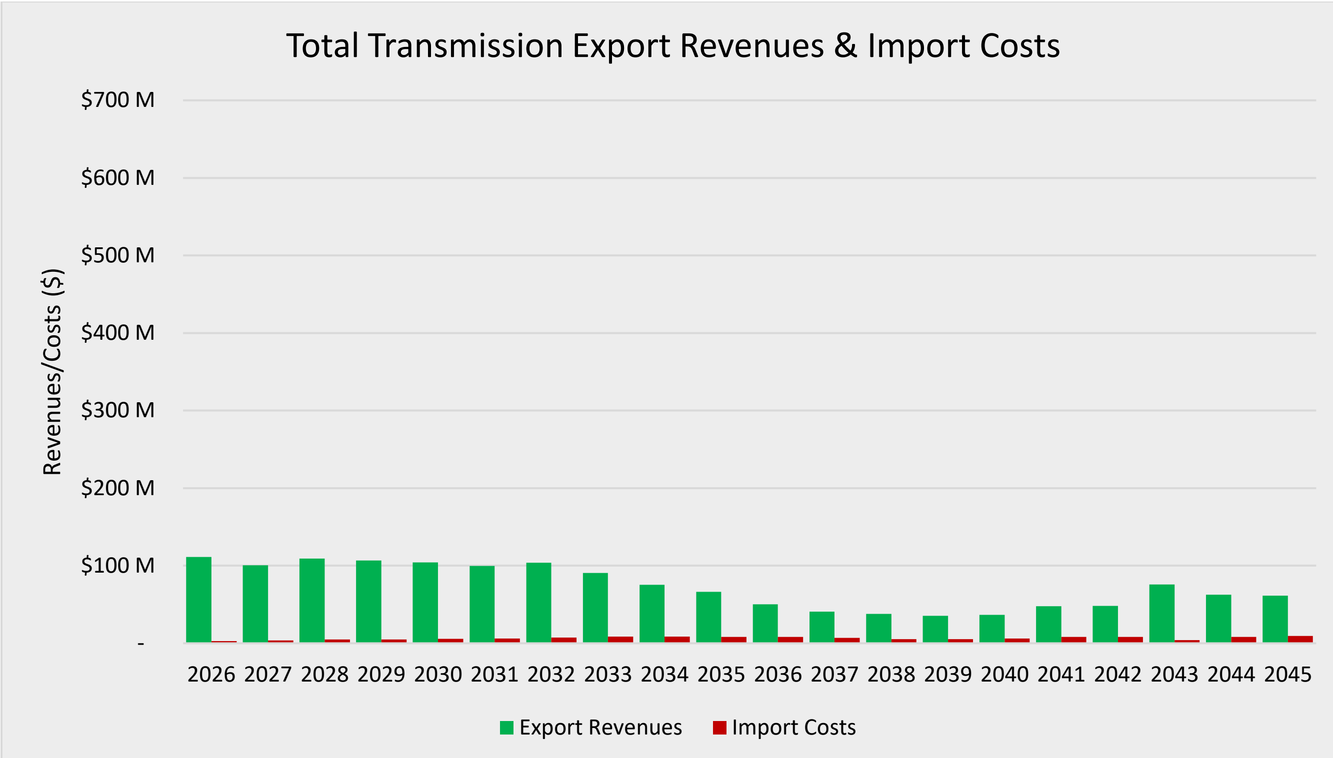

FIGURE 167: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO F.

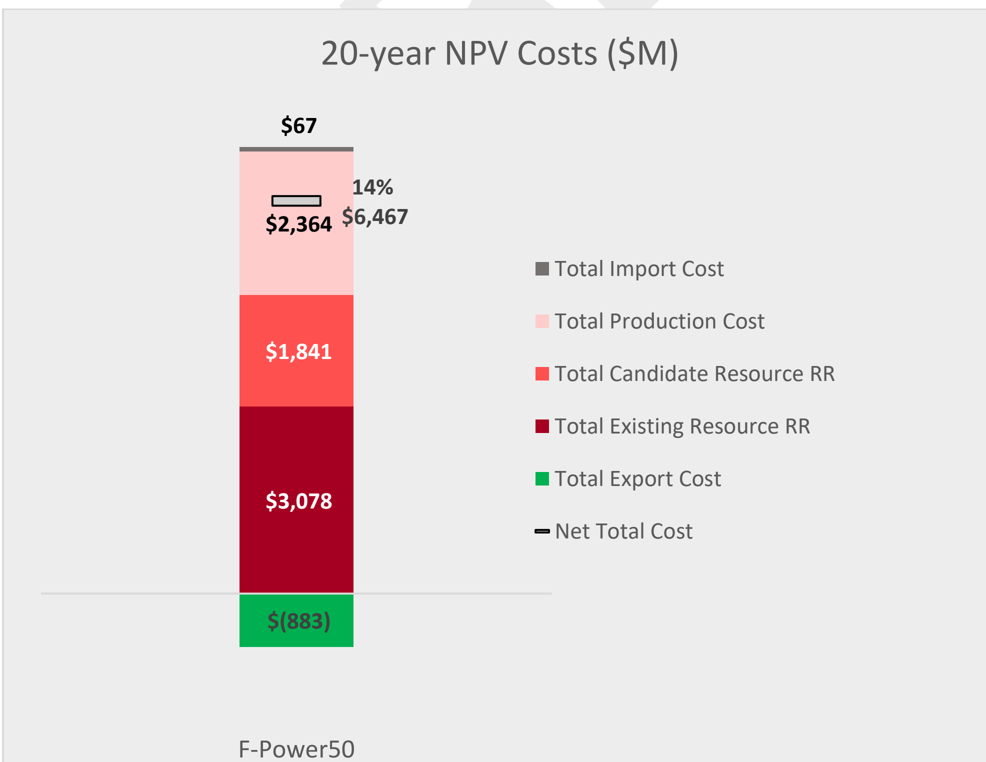

FIGURE 168: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO F.

6 PCM RESULTS: SCENARIO G – POWER PRICE FORECAST INCREASED BY 50%

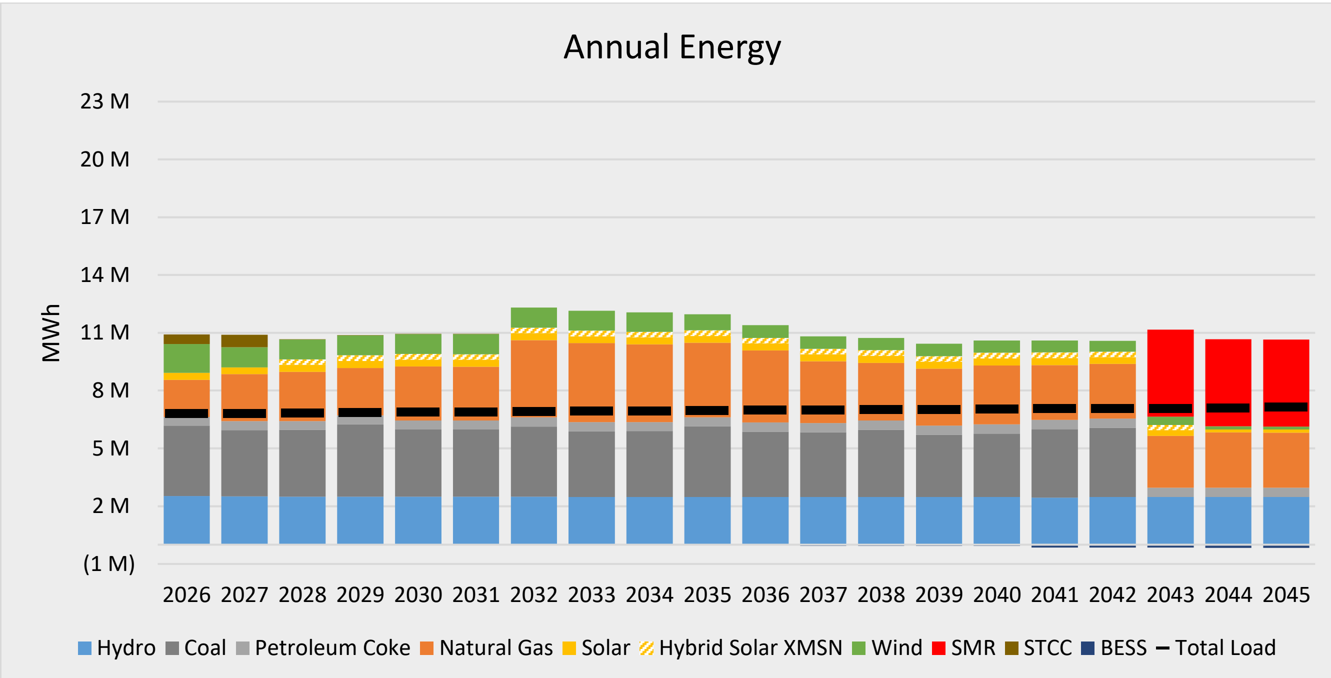

FIGURE 169: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO G.

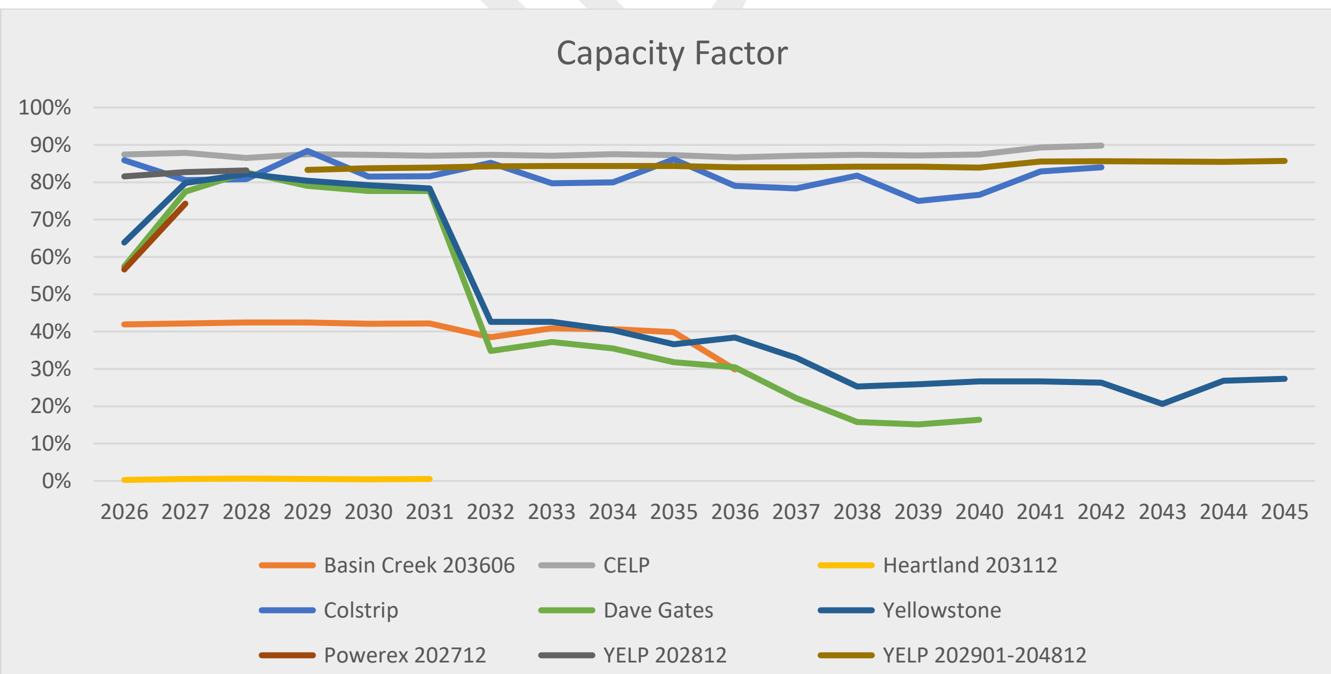

FIGURE 170: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO G.

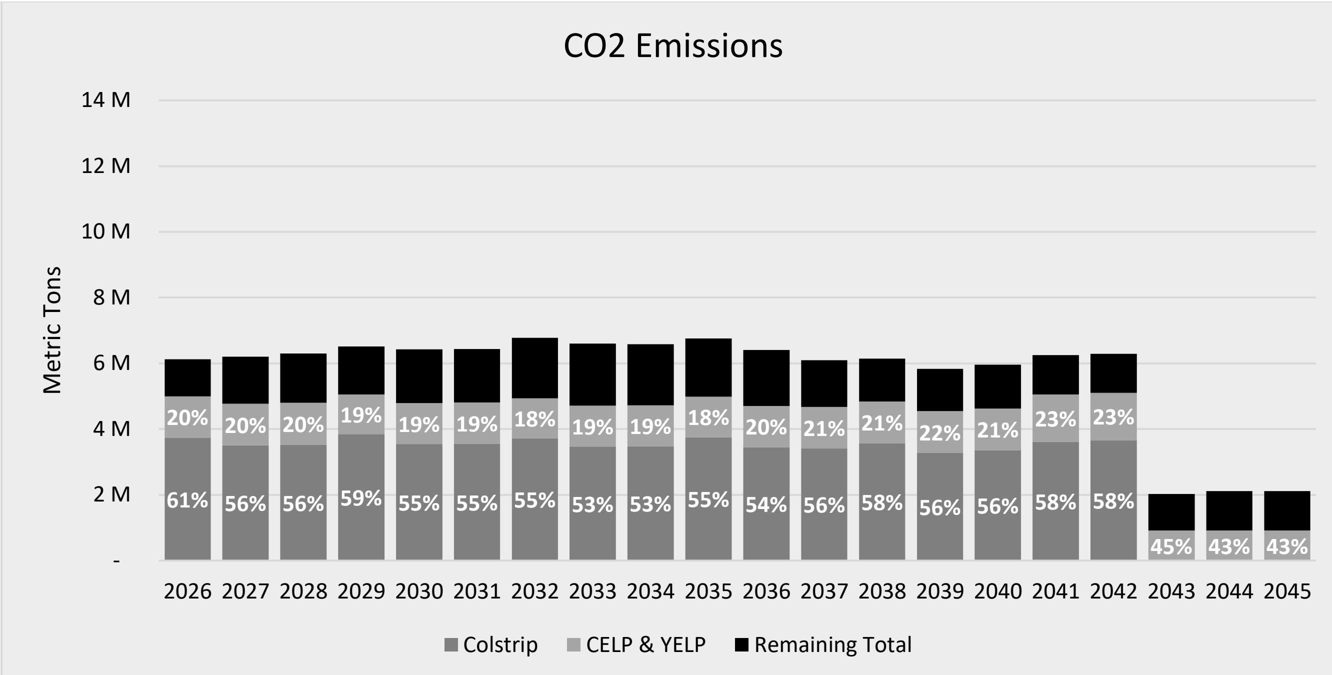

FIGURE 171: EMISSIONS FOR PCM RESULTS OF SCENARIO G.

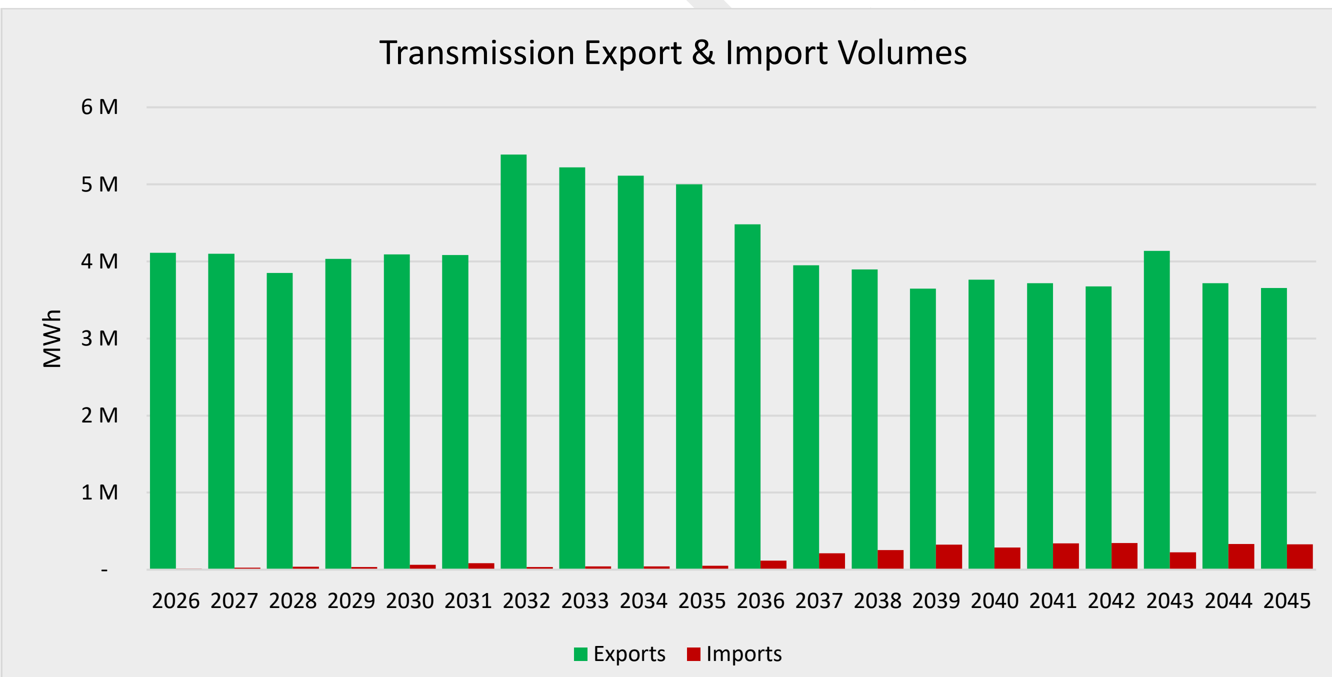

FIGURE 172: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO G.

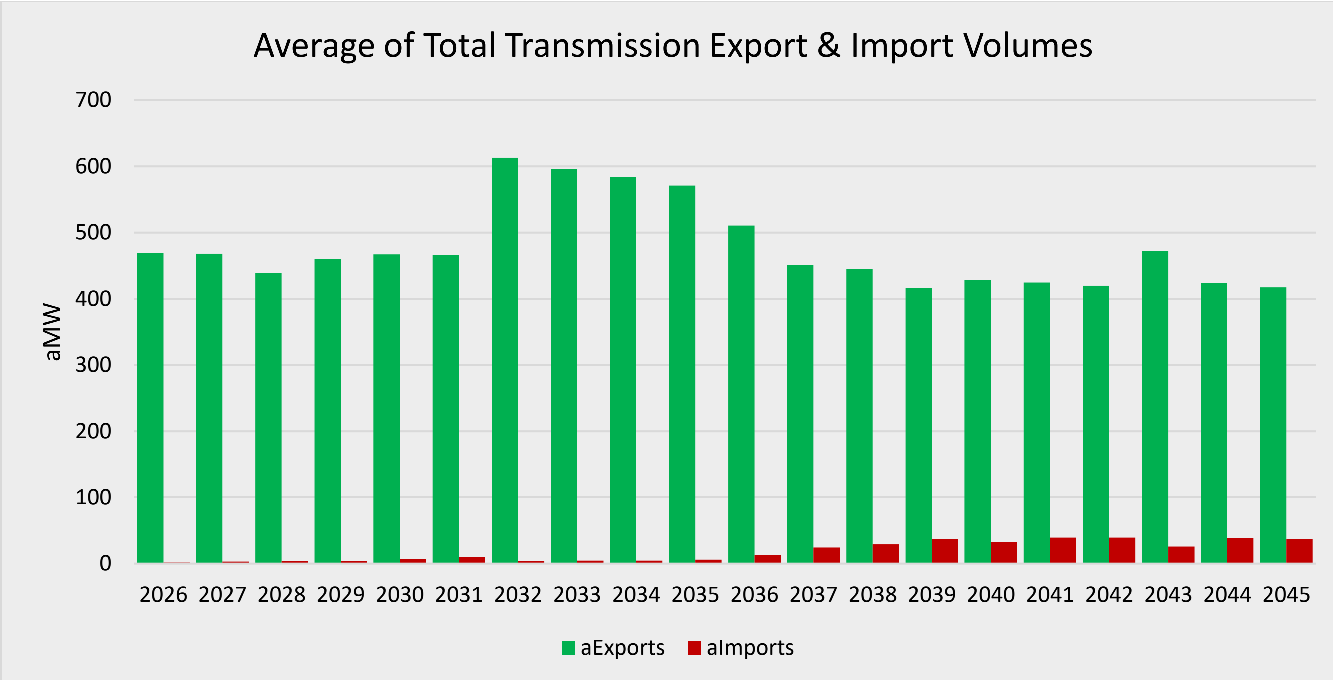

FIGURE 173: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO G.

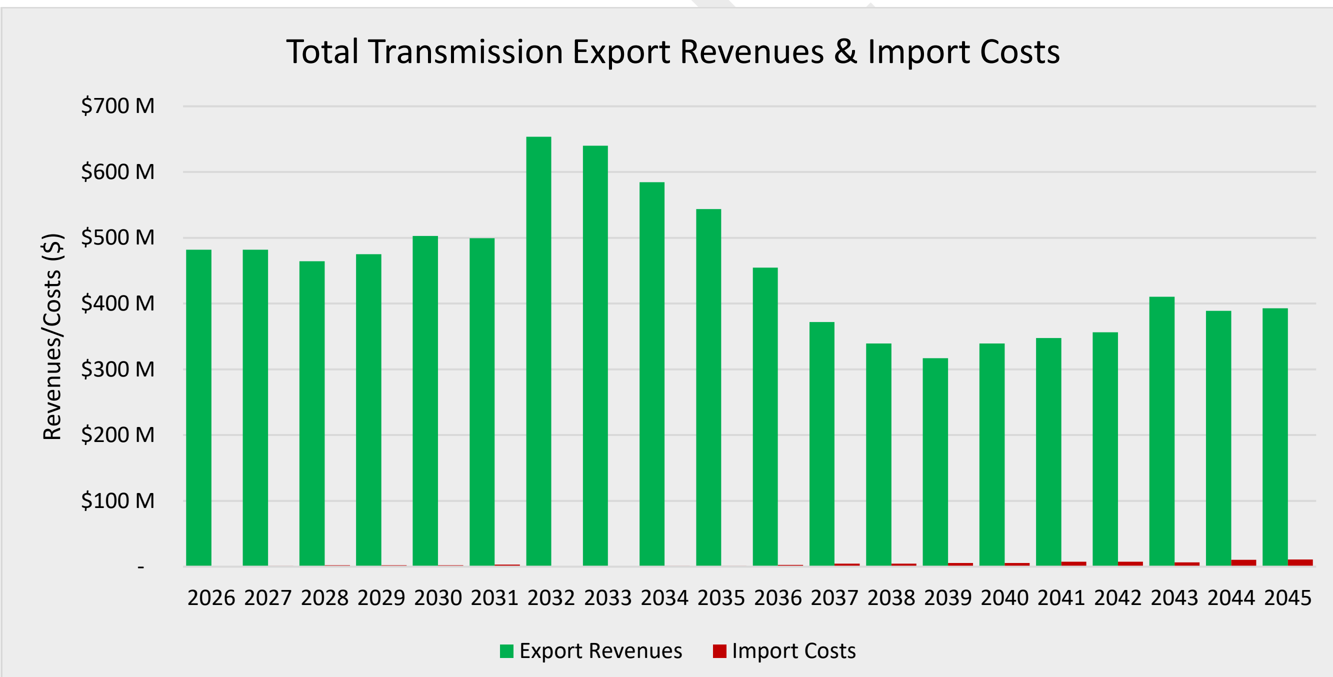

FIGURE 174: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO G.

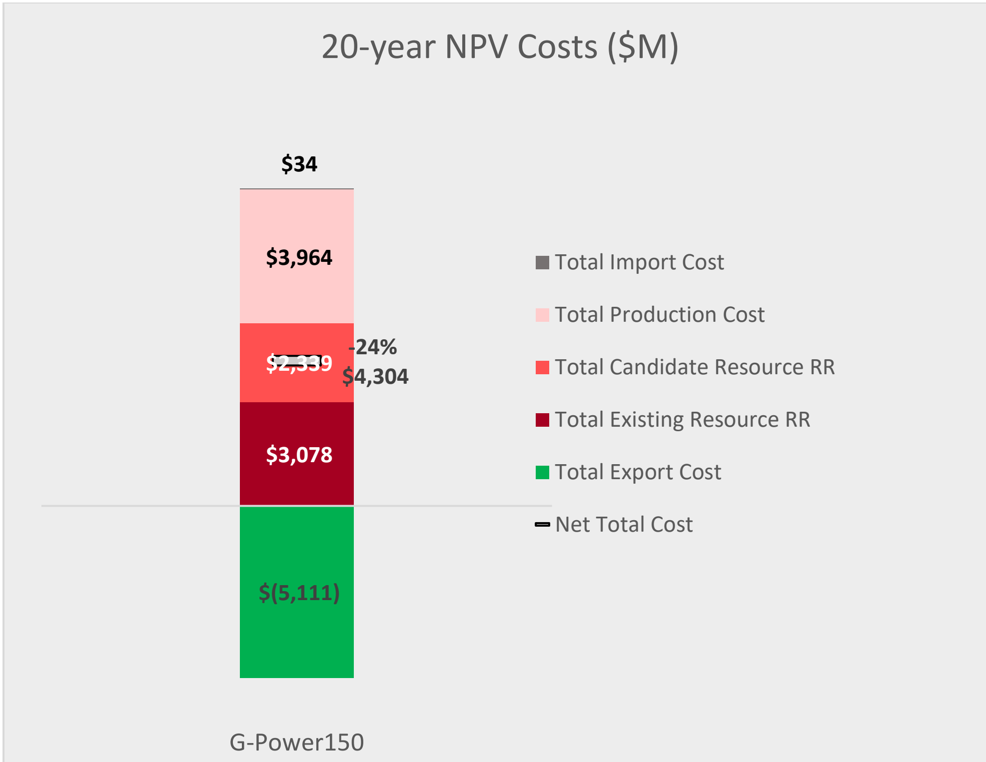

FIGURE 175: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO G.

7 PCM RESULTS: SCENARIO H – NATURAL GAS PRICE FORECAST REDUCED BY 50%

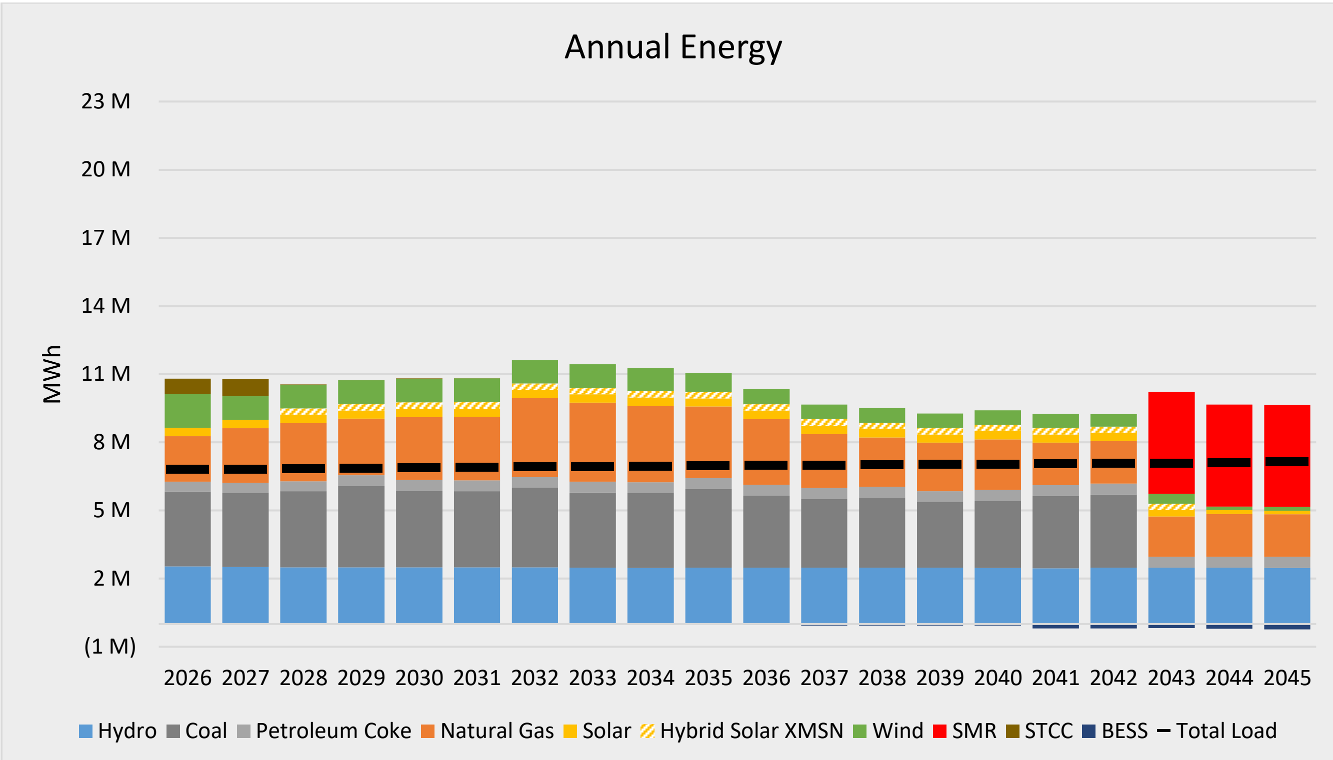

FIGURE 176: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO H.

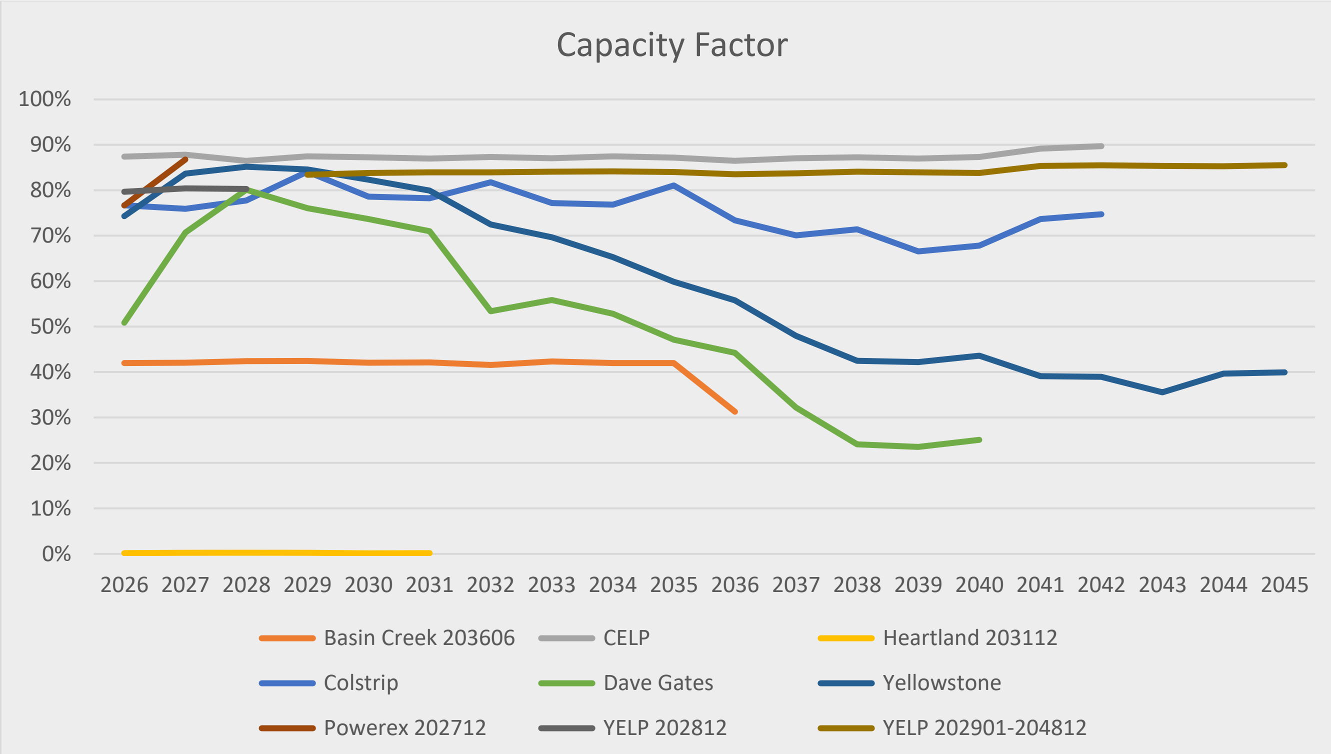

FIGURE 177: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO H.

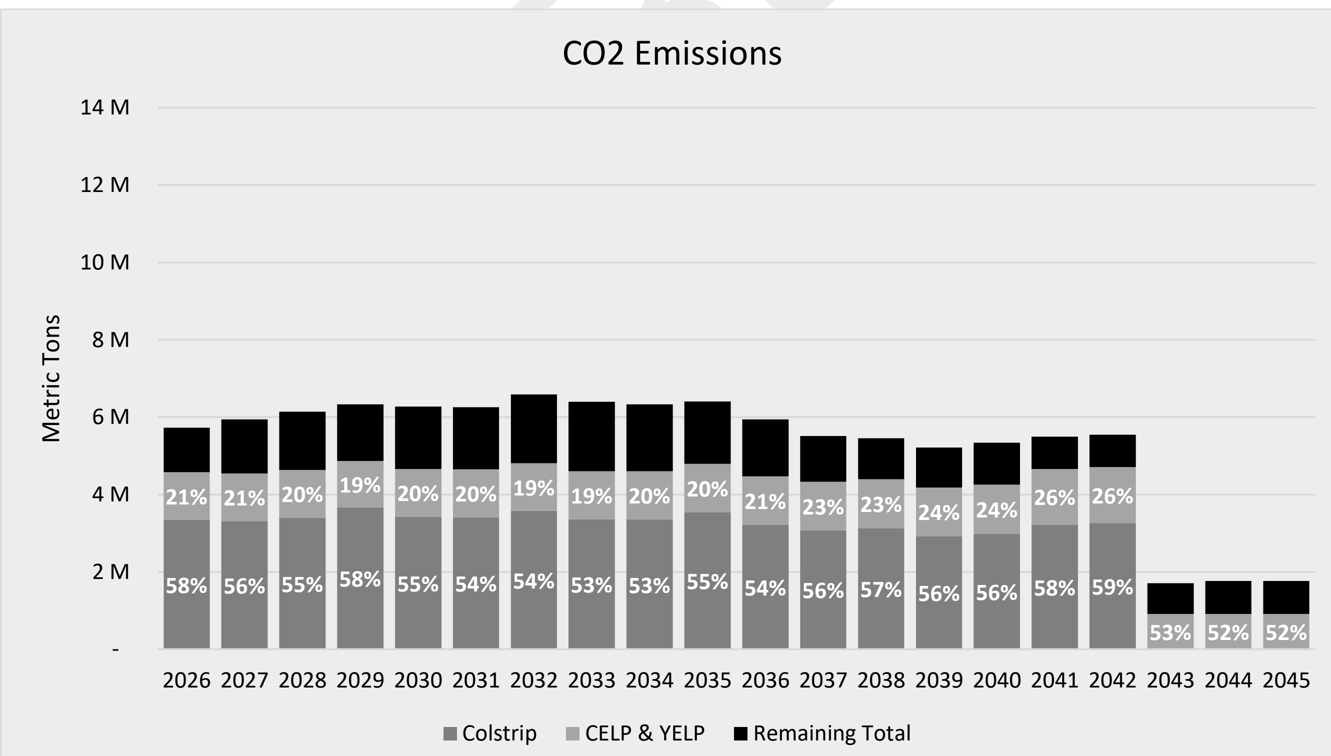

FIGURE 178: EMISSIONS FOR PCM RESULTS OF SCENARIO H.

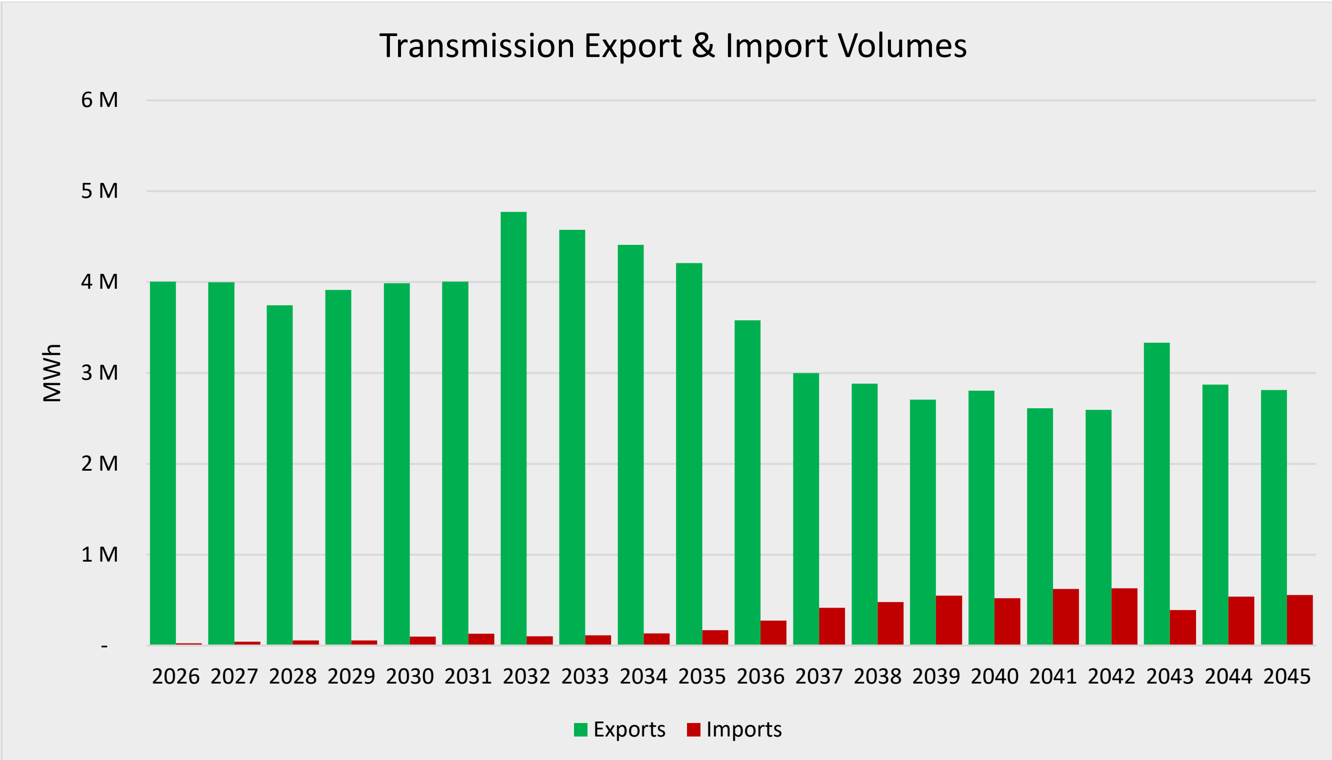

FIGURE 179: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO H.

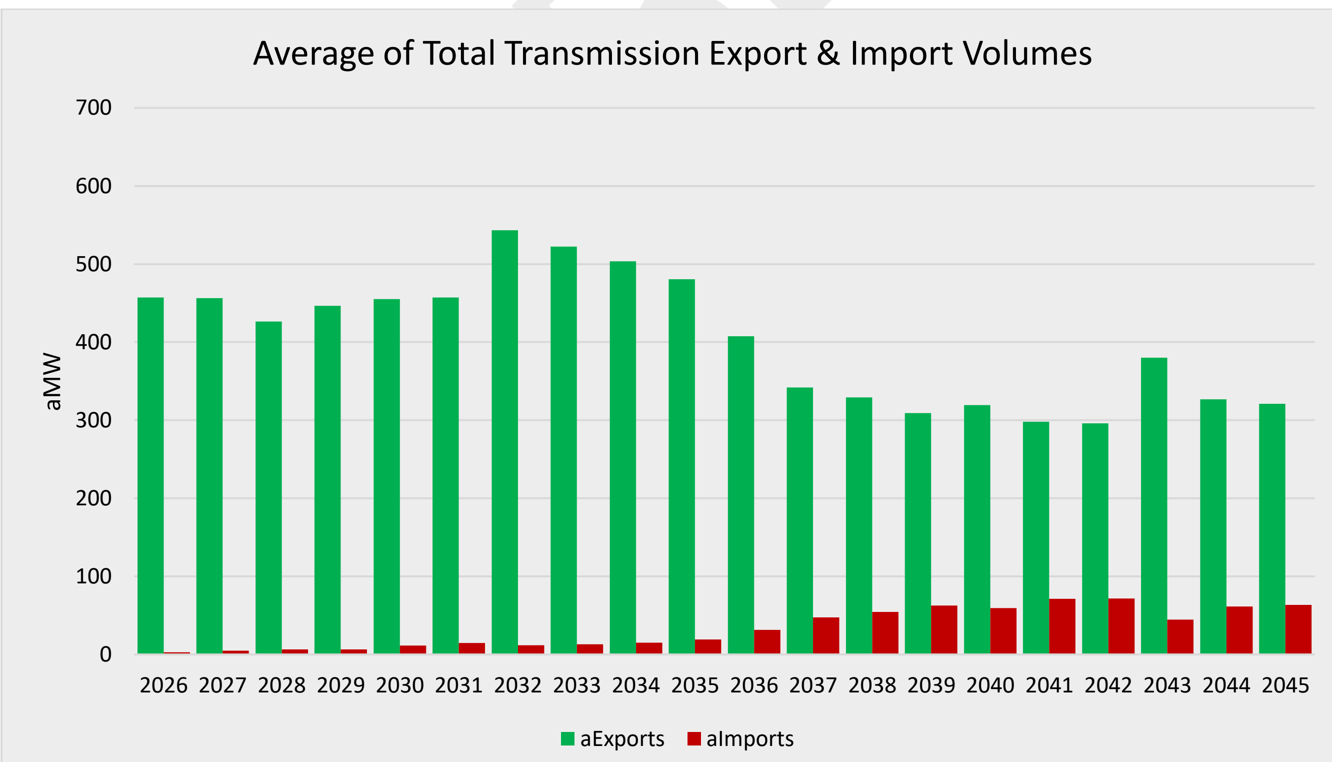

FIGURE 180: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO H.

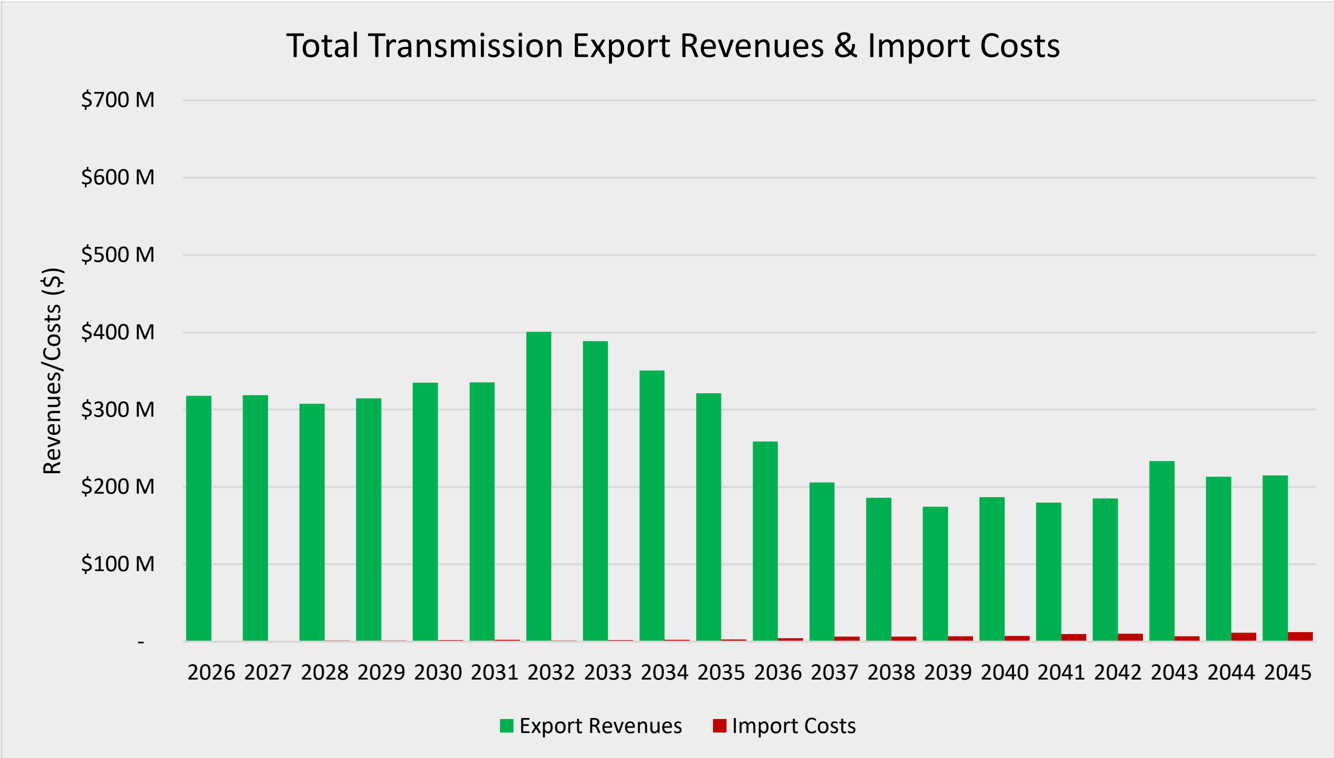

FIGURE 181: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO H.

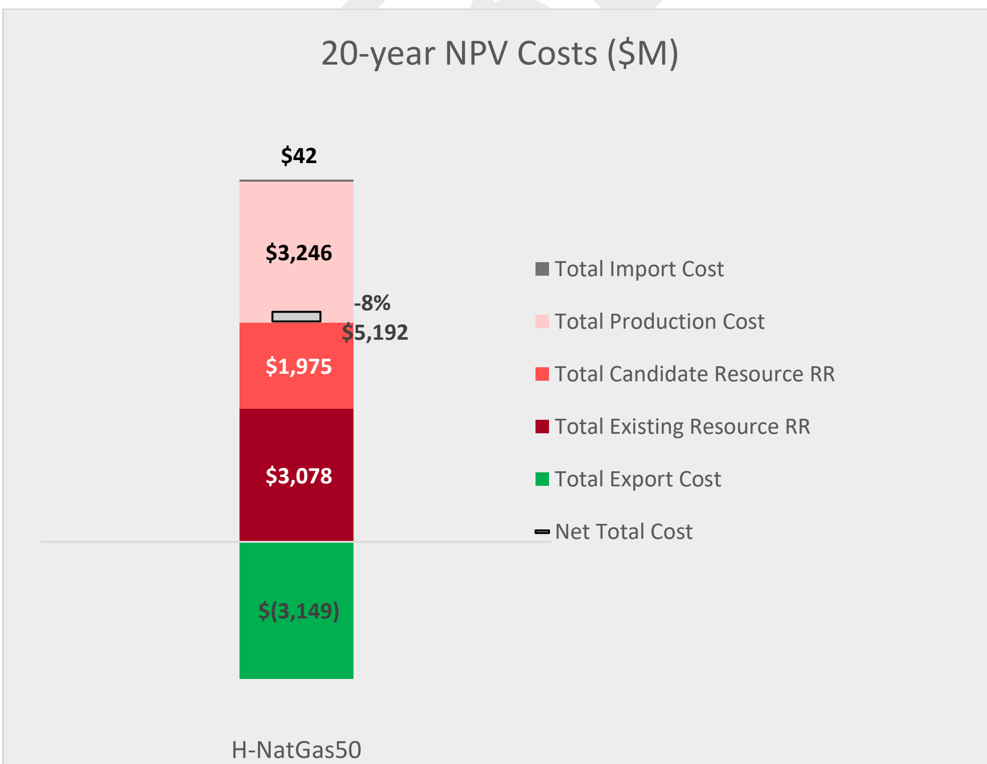

FIGURE 182: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO H.

8 PCM RESULTS: SCENARIO I – NATURAL GAS PRICE FORECAST INCREASED BY 50%

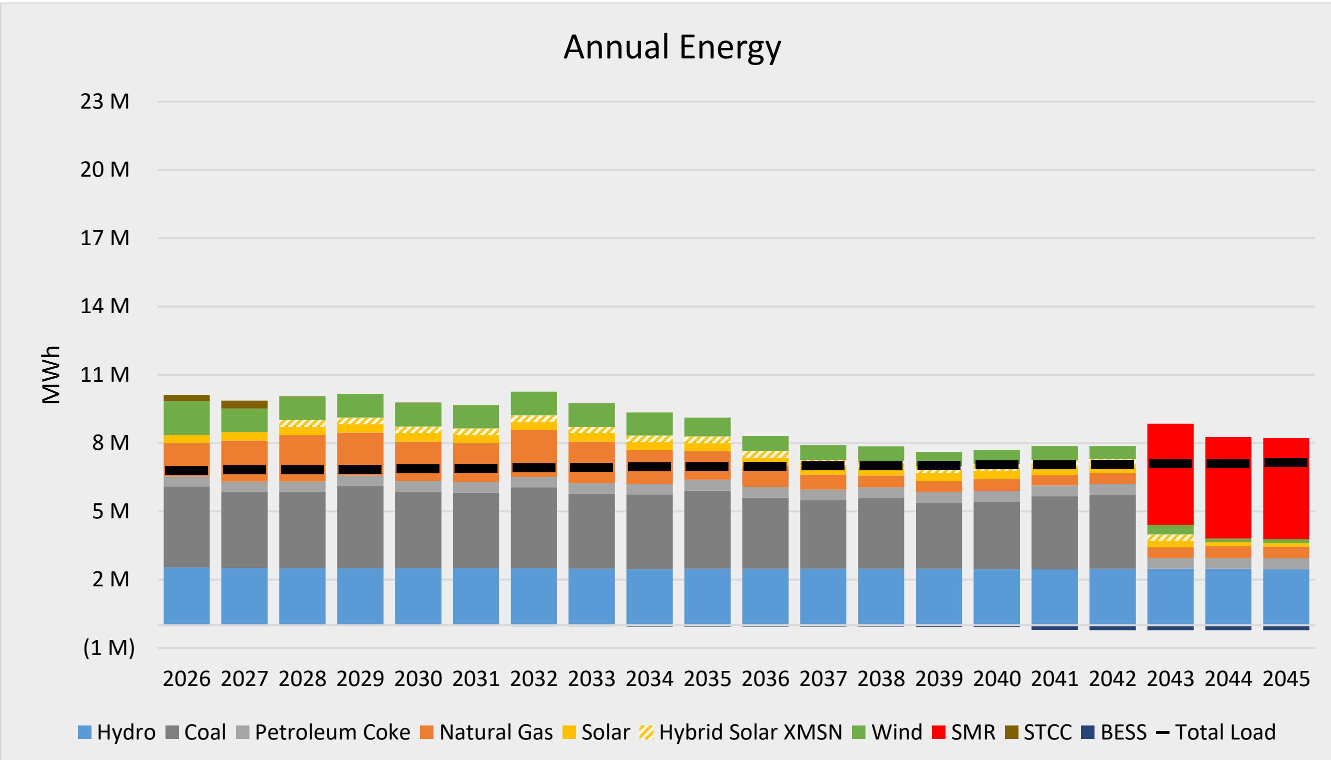

FIGURE 183: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO I.

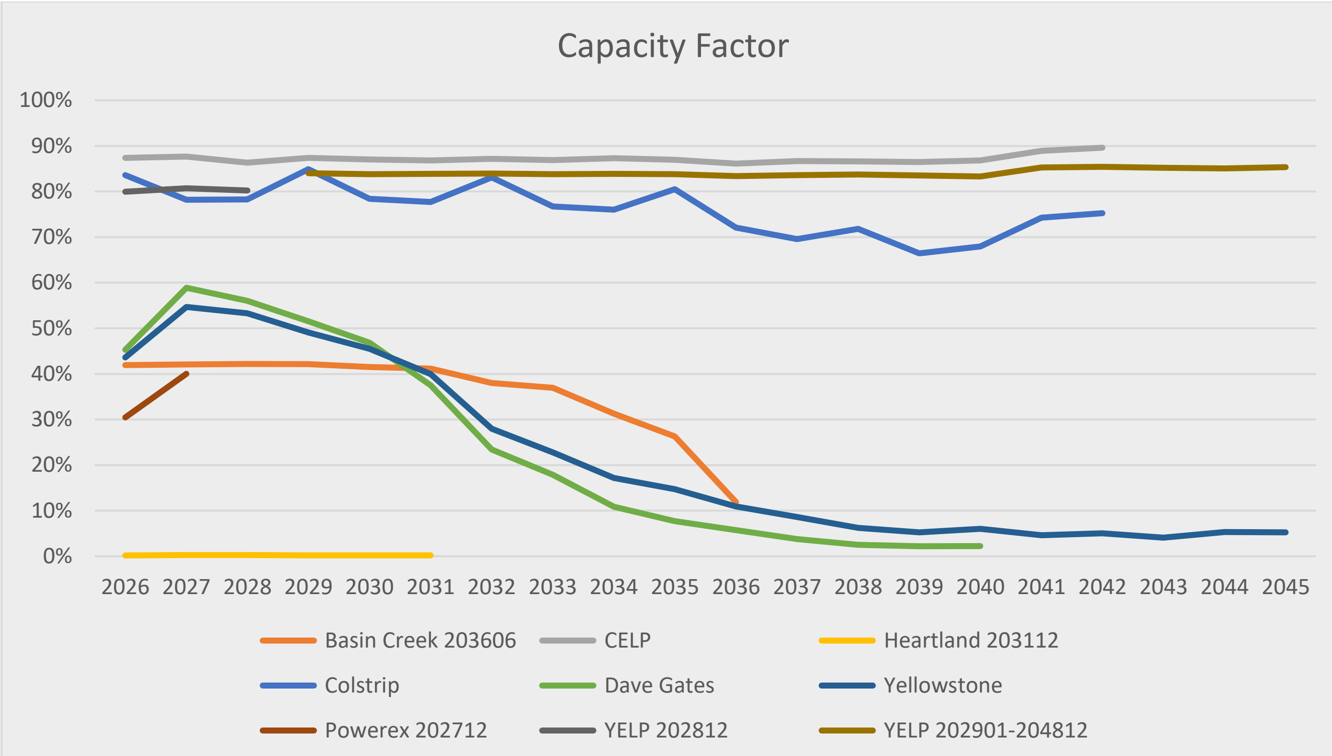

FIGURE 184: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO I.

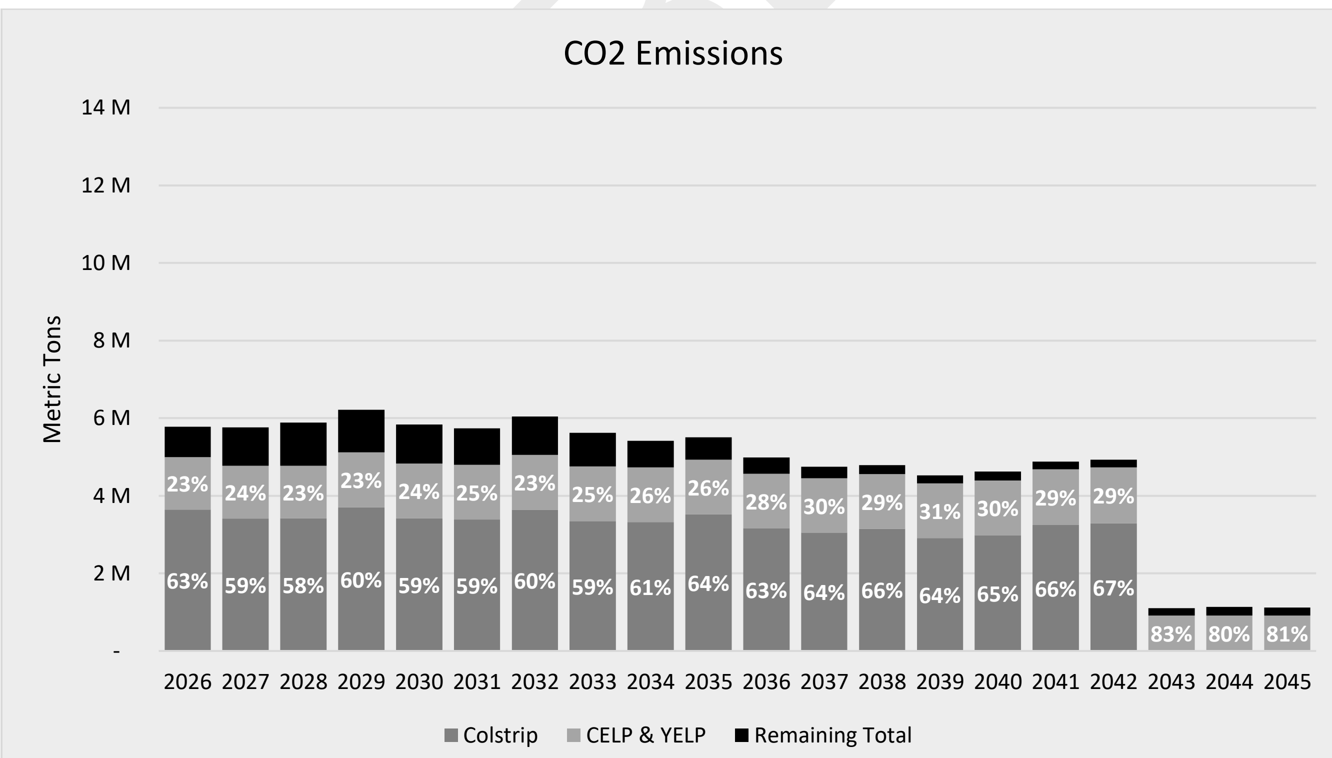

FIGURE 185: EMISSIONS FOR PCM RESULTS OF SCENARIO I.

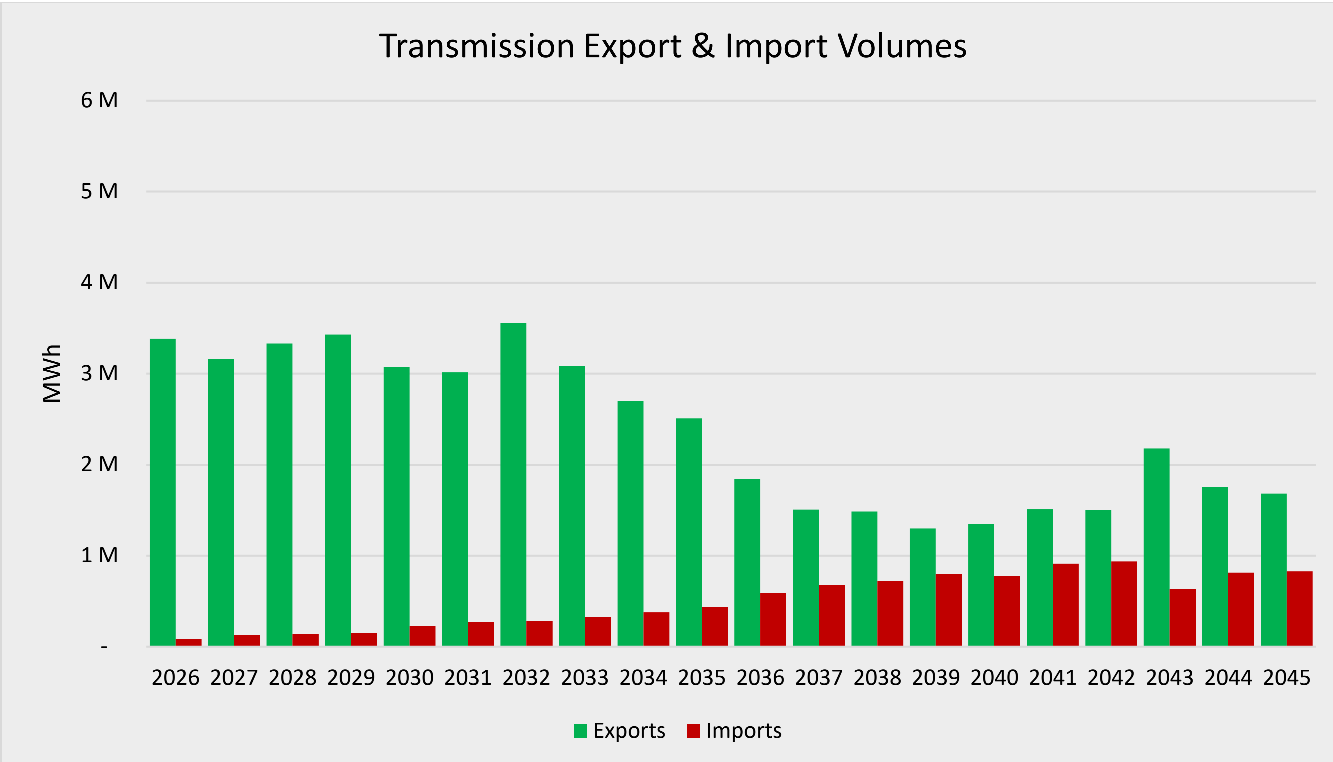

FIGURE 186: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO I.

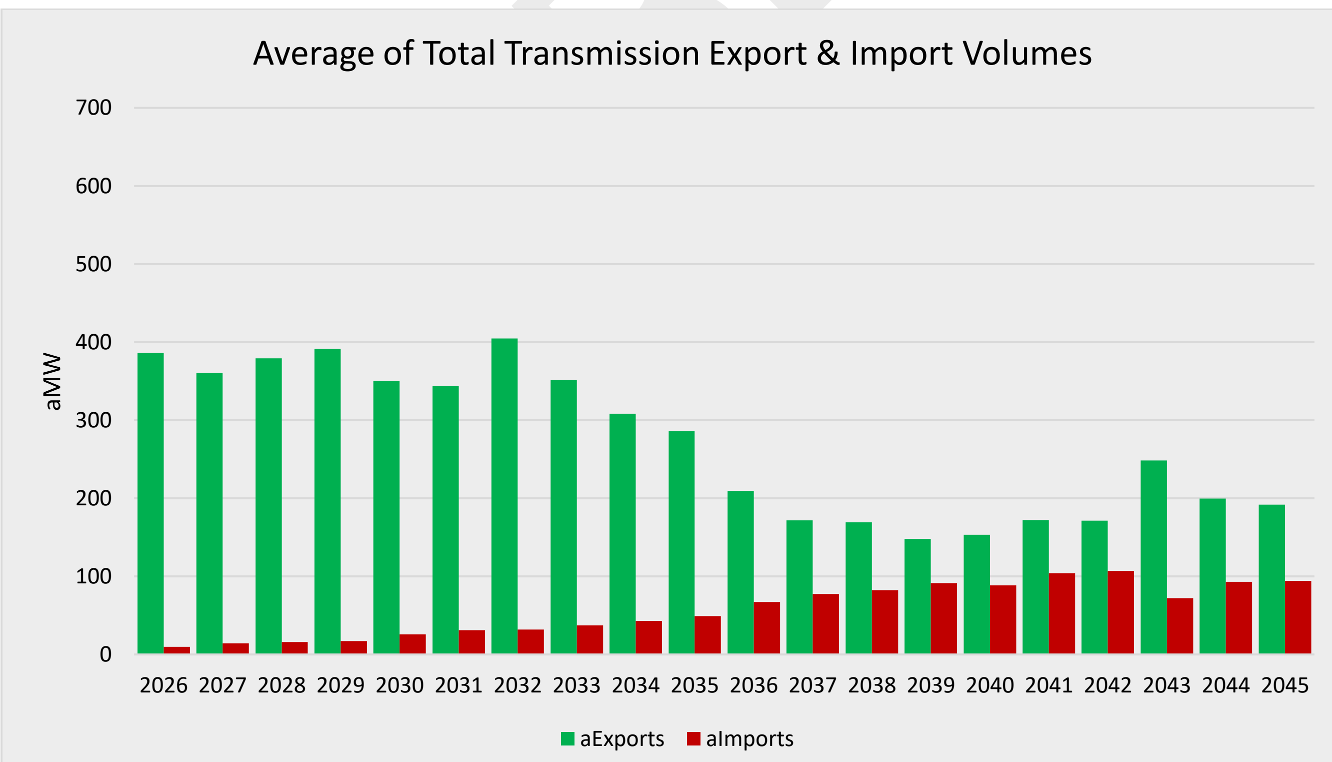

FIGURE 187: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO I.

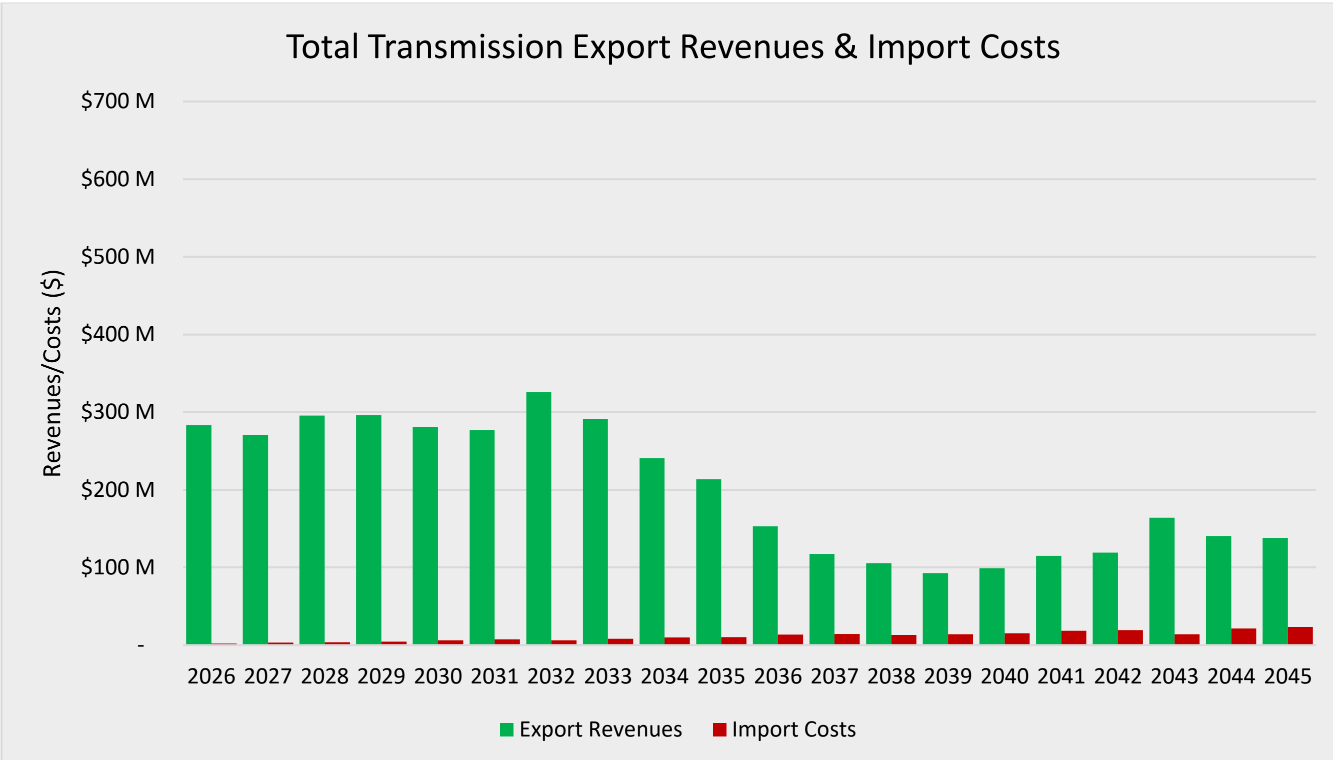

FIGURE 188: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO I.

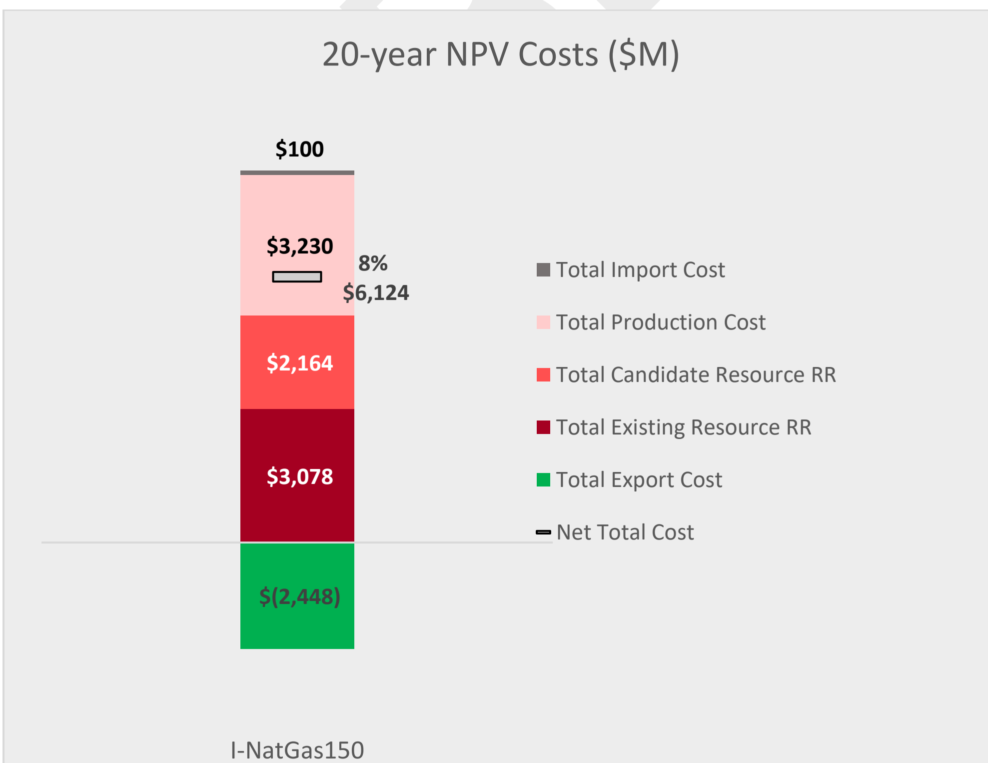

FIGURE 189: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO I.

9 PCM RESULTS: SCENARIO J – ADD 150 MW OF DATA CENTER LOAD

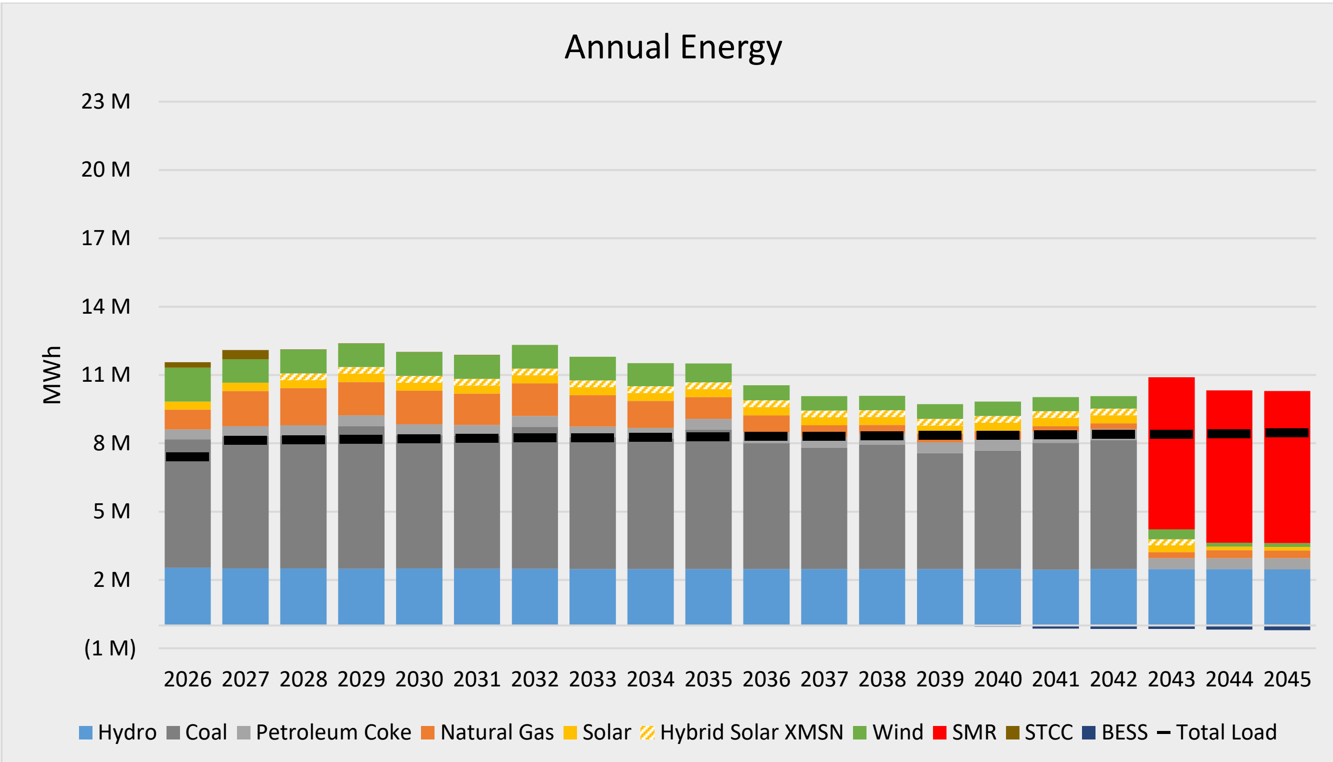

FIGURE 190: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO J.

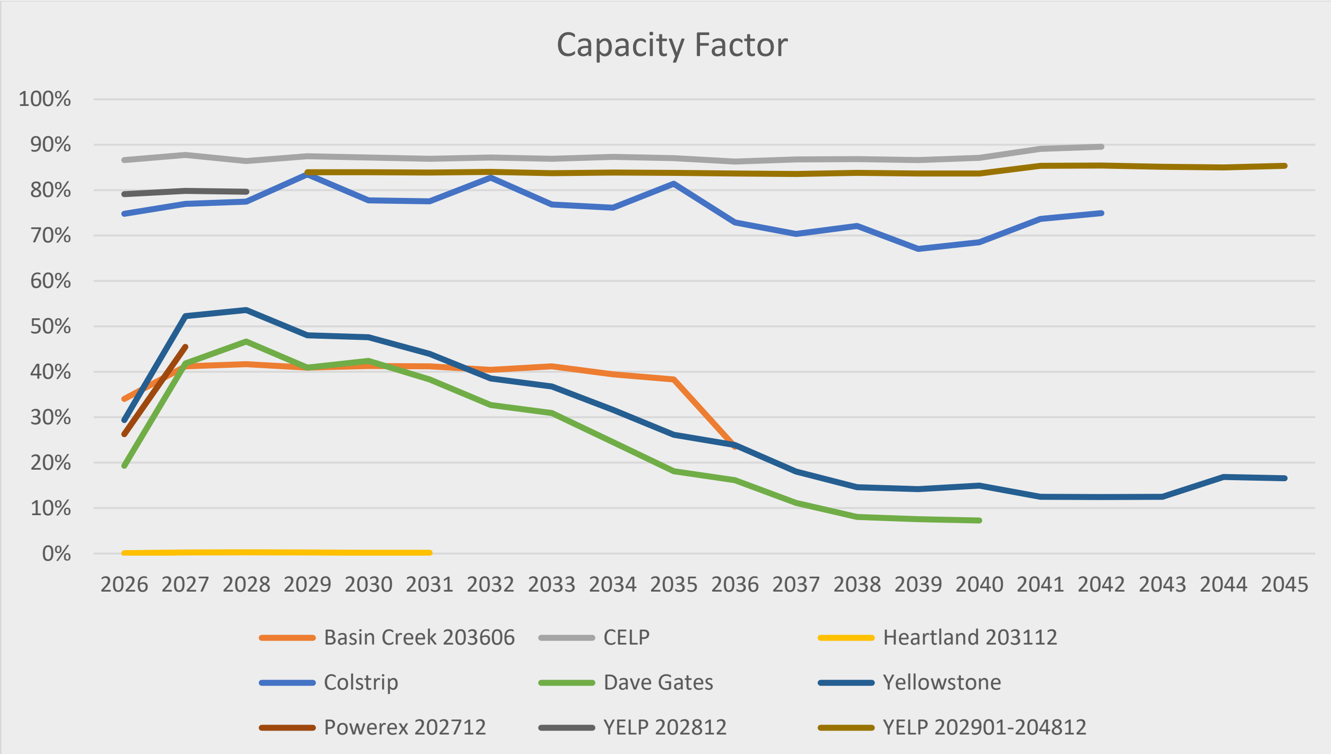

FIGURE 191: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO J.

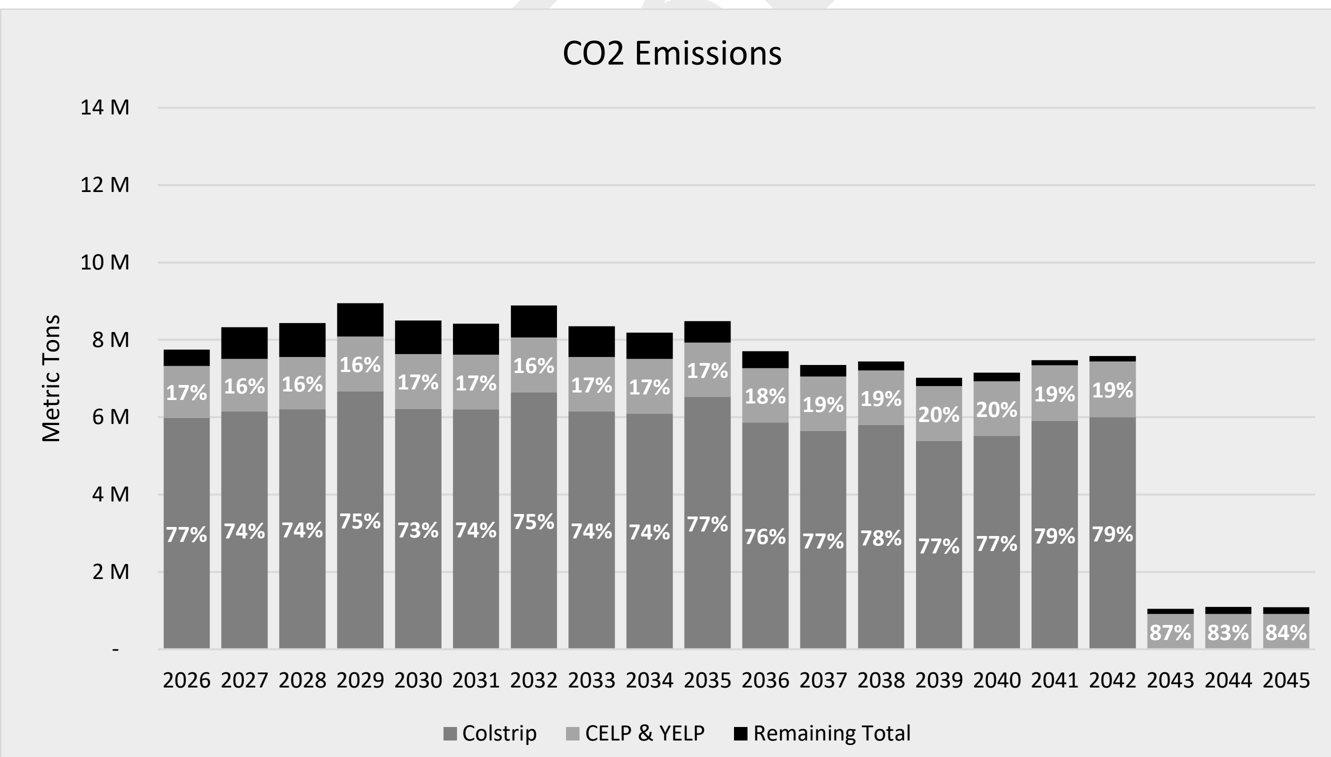

FIGURE 192: EMISSIONS FOR PCM RESULTS OF SCENARIO J.

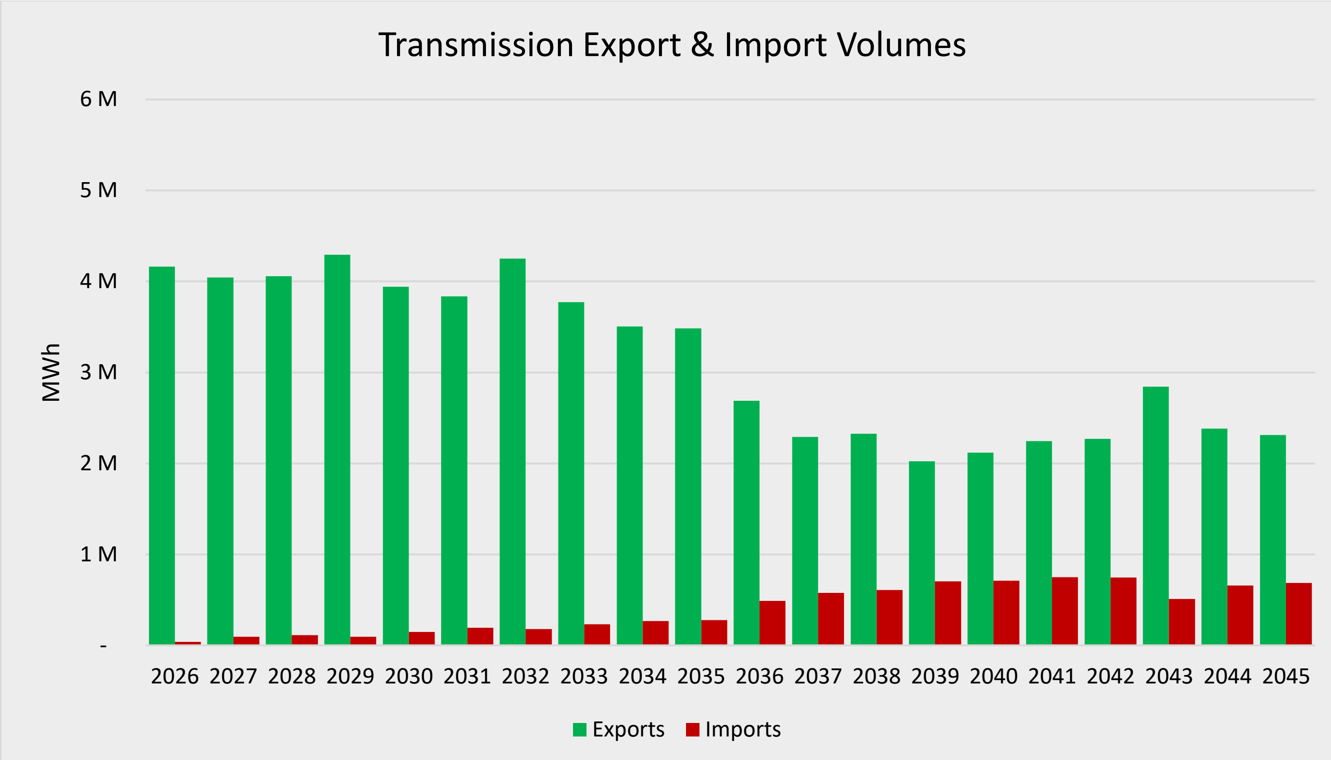

FIGURE 193: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO J.

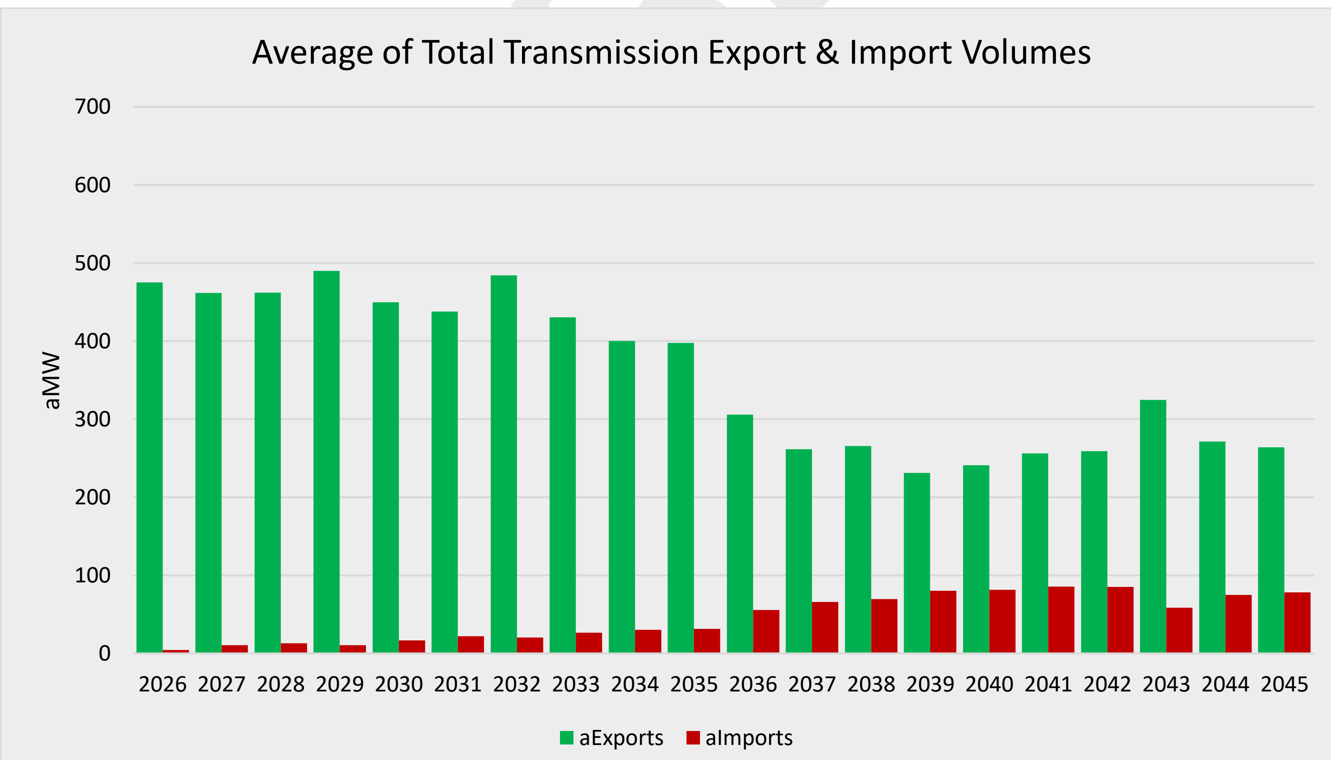

FIGURE 194: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO J.

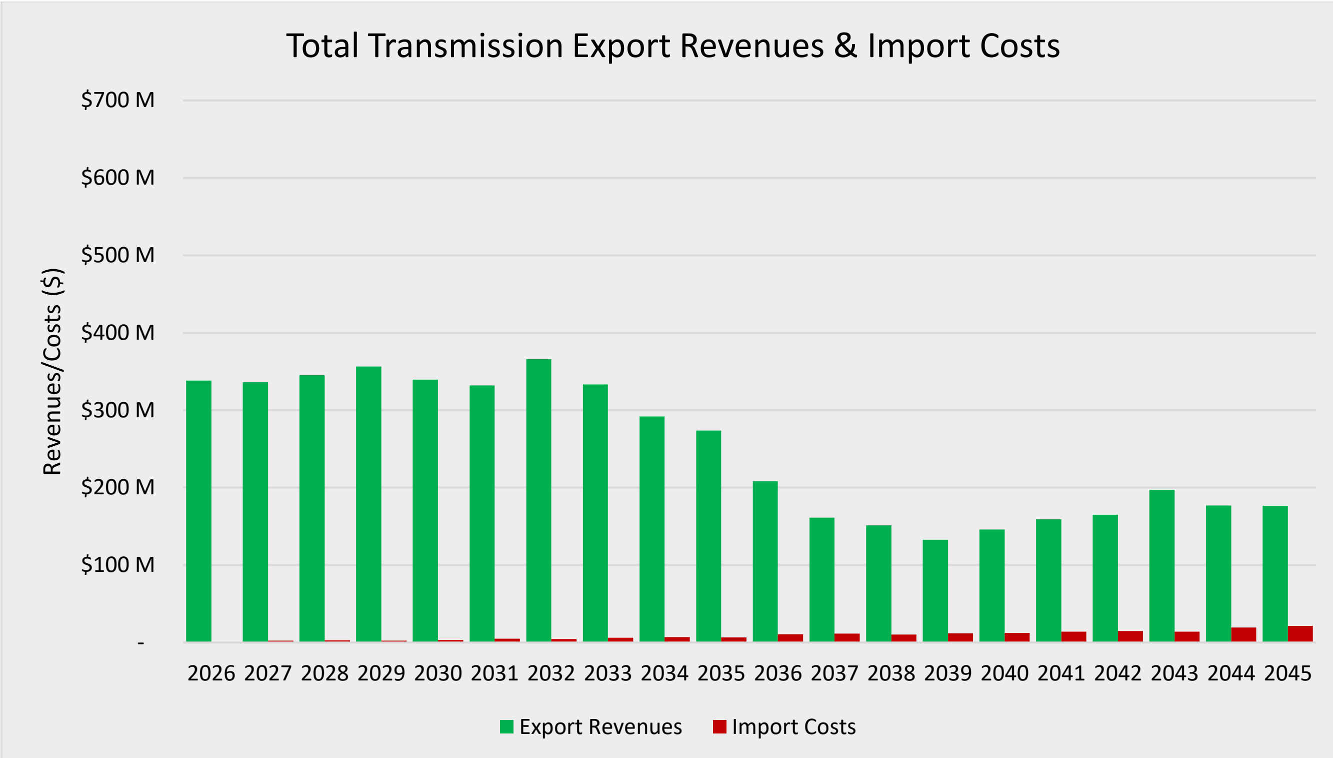

FIGURE 195: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO J.

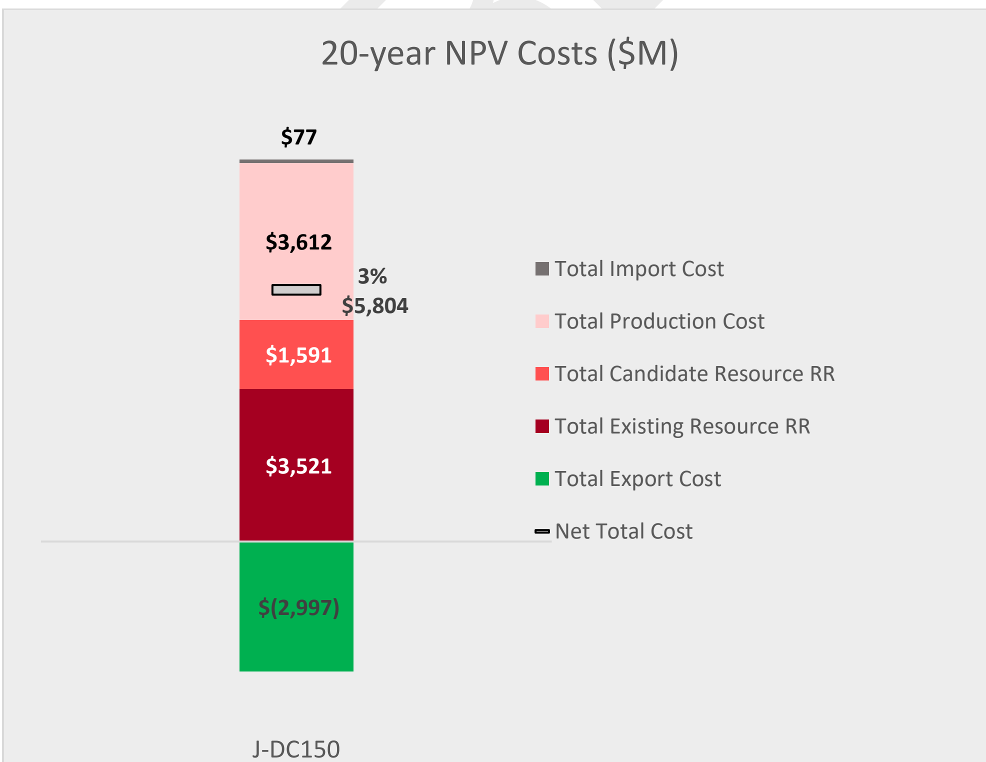

FIGURE 196: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO J.

10 PCM RESULTS: SCENARIO K – ADD 650 MW OF DATA CENTER LOAD

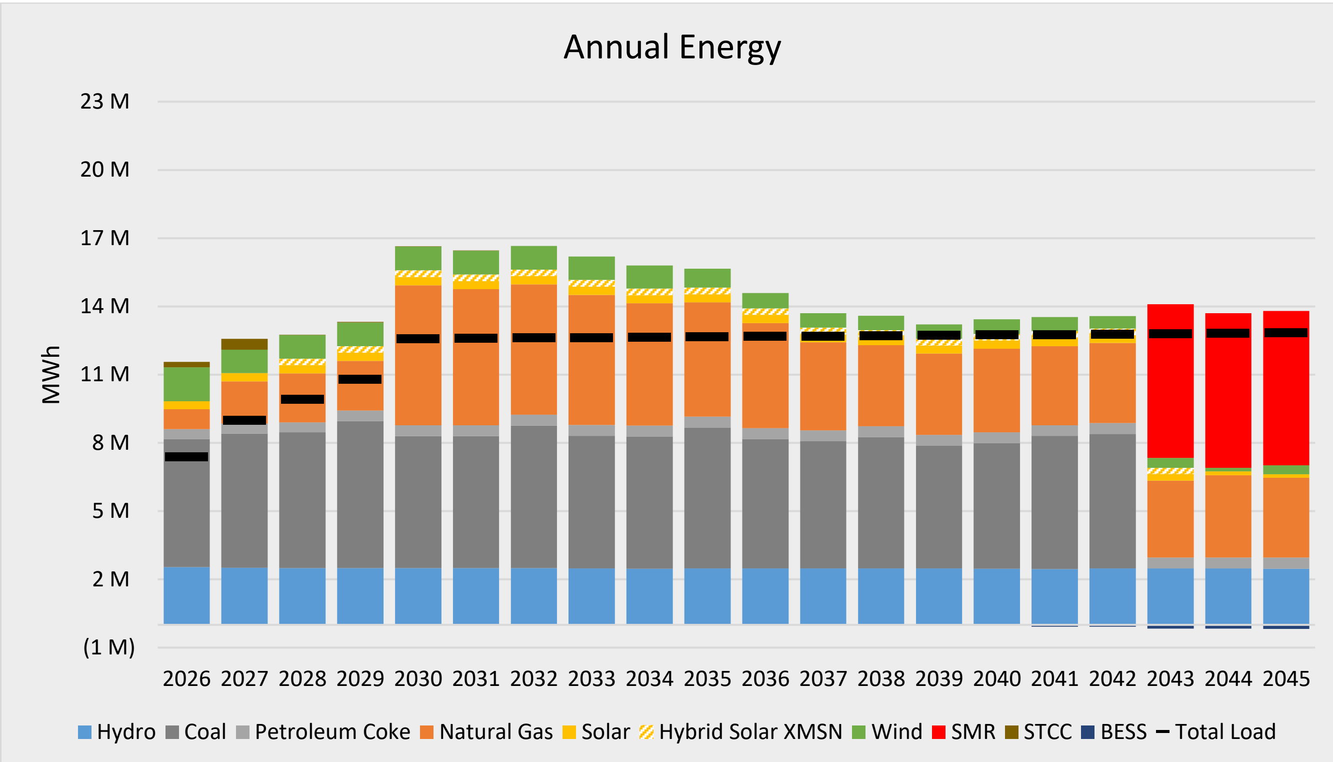

FIGURE 197: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO K.

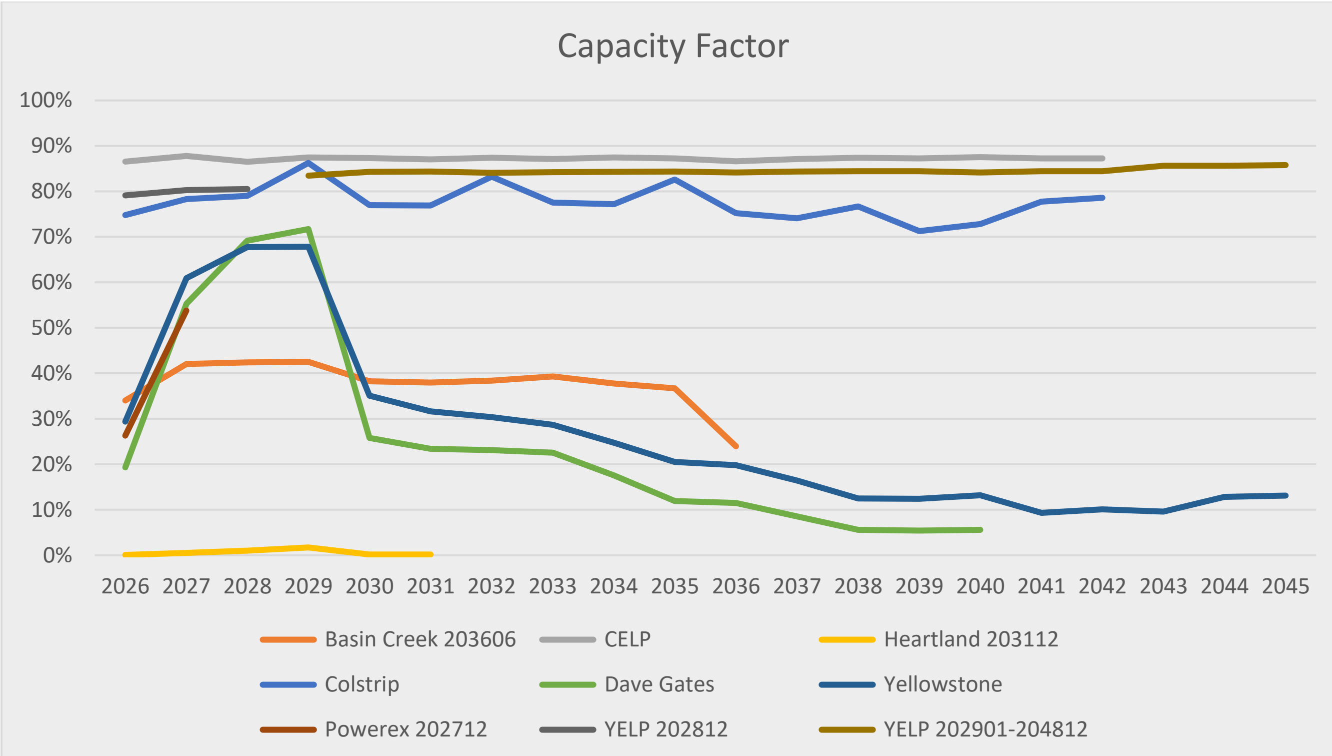

FIGURE 198: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO K.

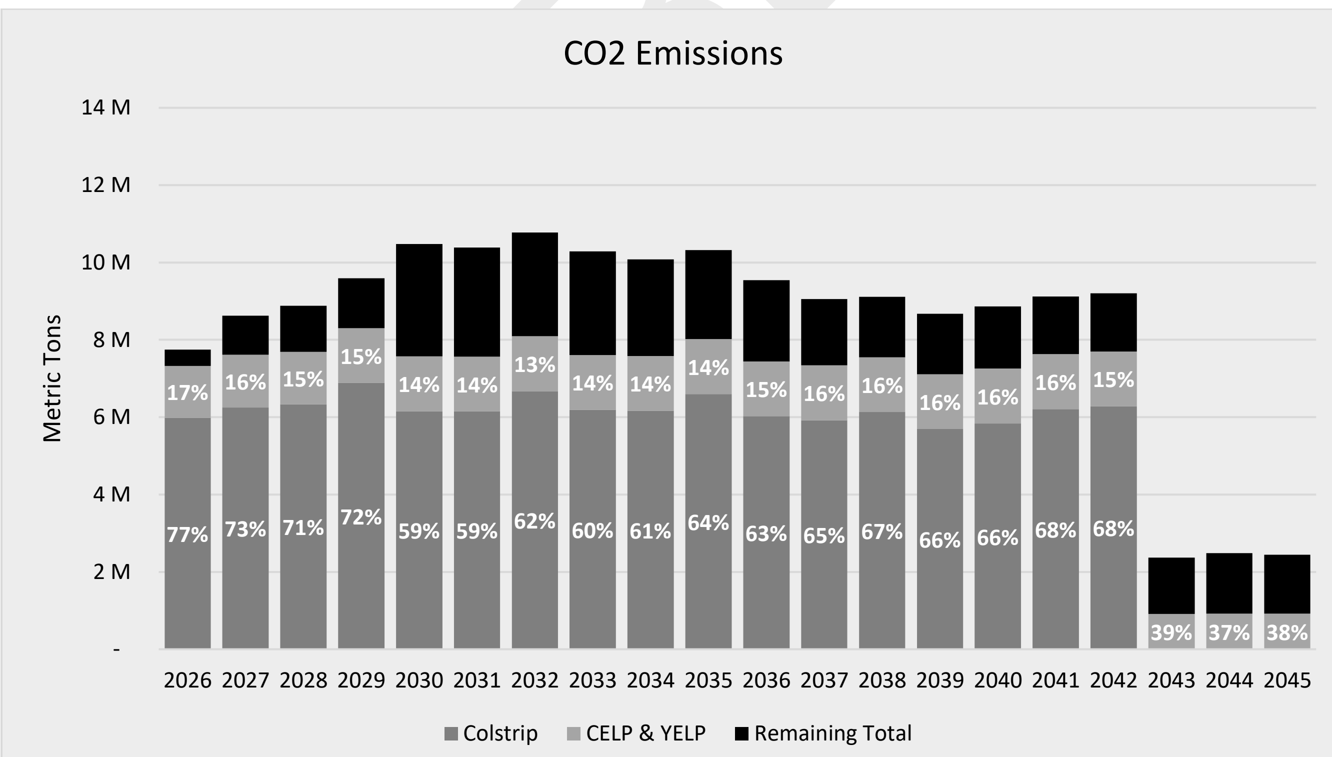

FIGURE 199: EMISSIONS FOR PCM RESULTS OF SCENARIO K.

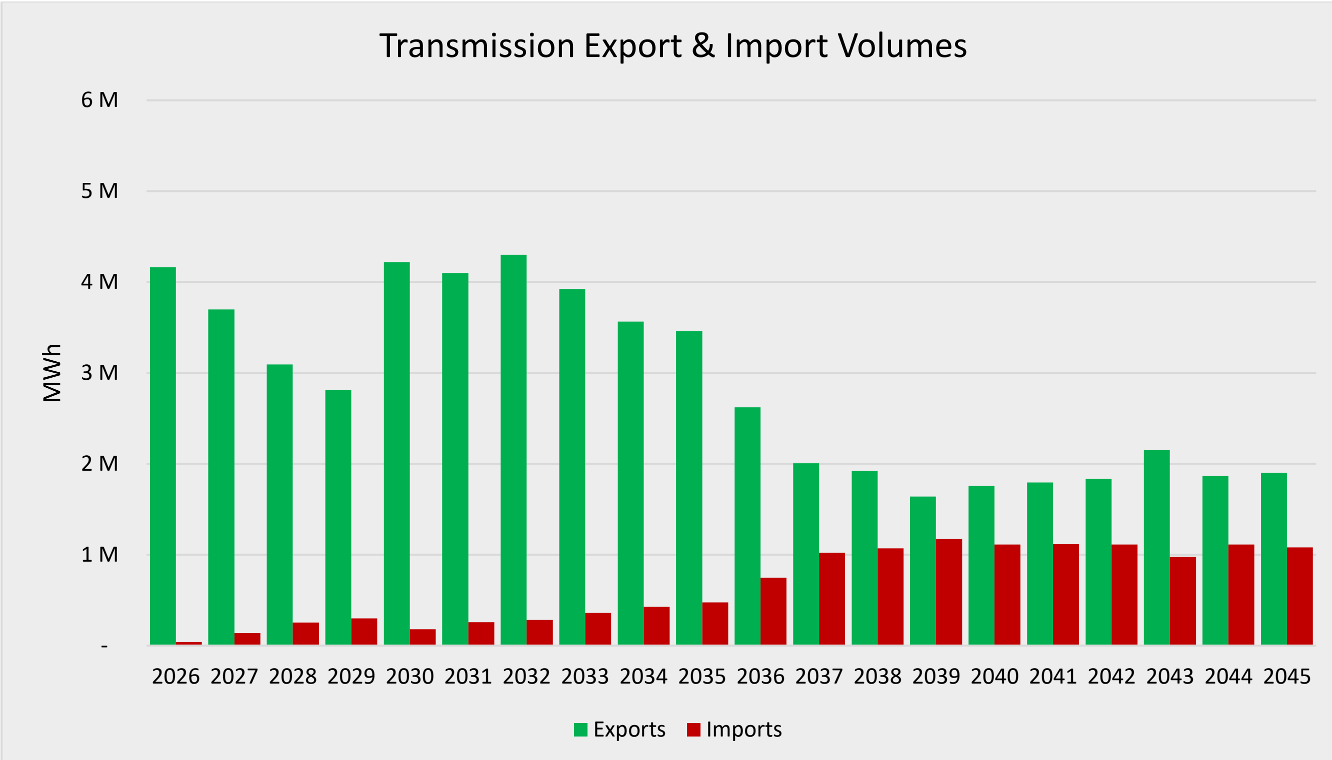

FIGURE 200: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO K.

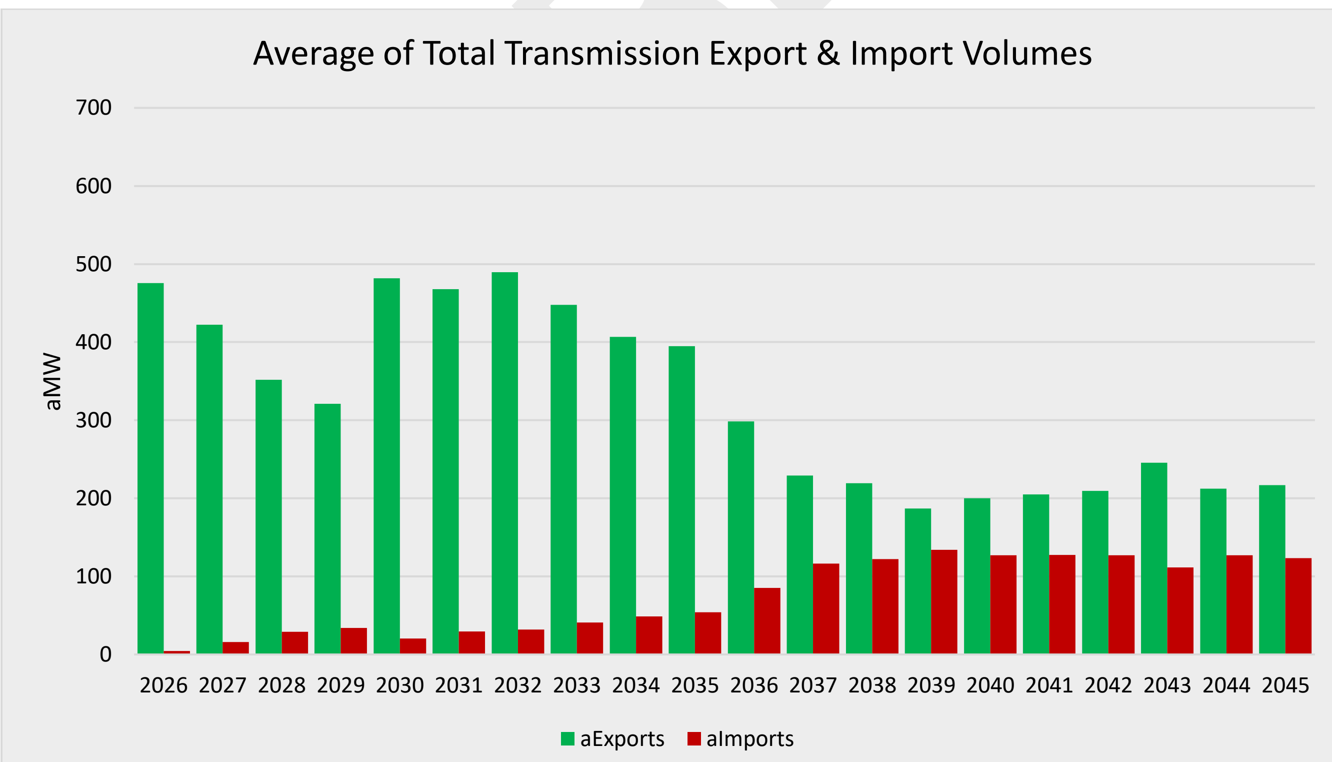

FIGURE 201: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO K.

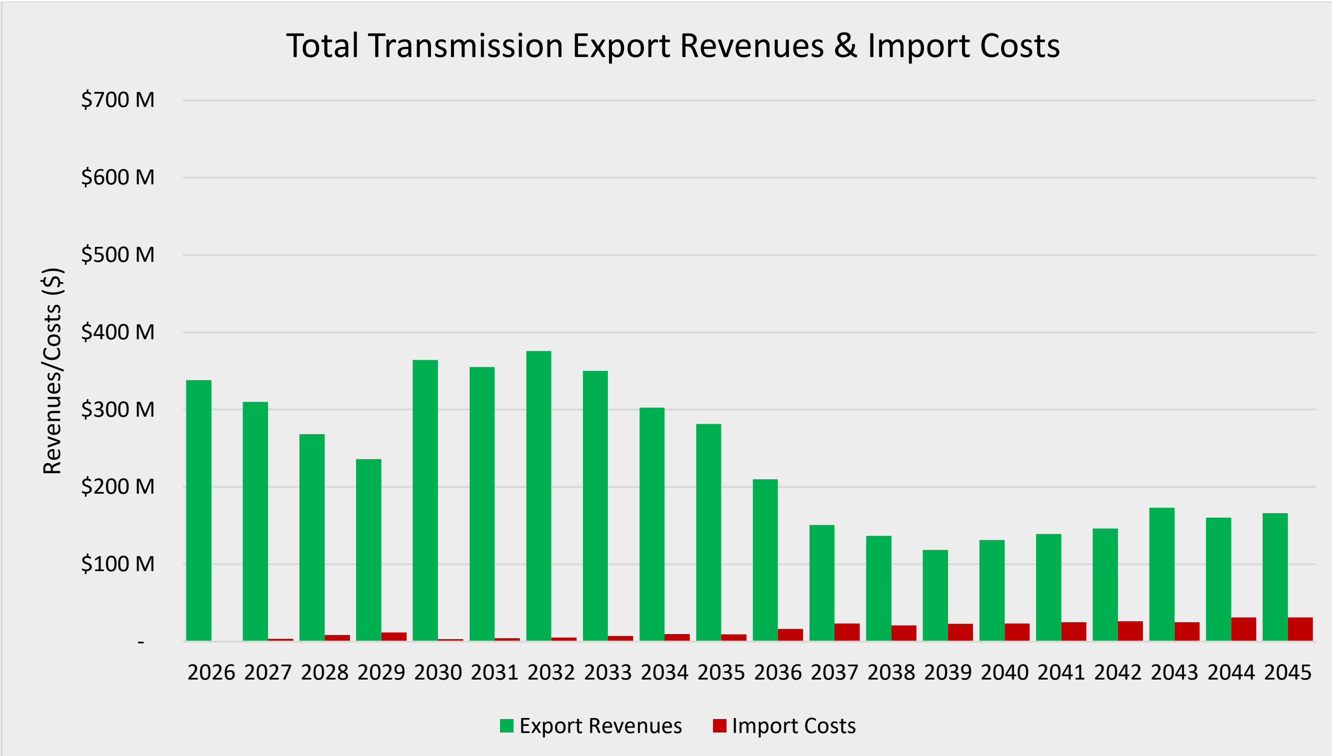

FIGURE 202: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO K.

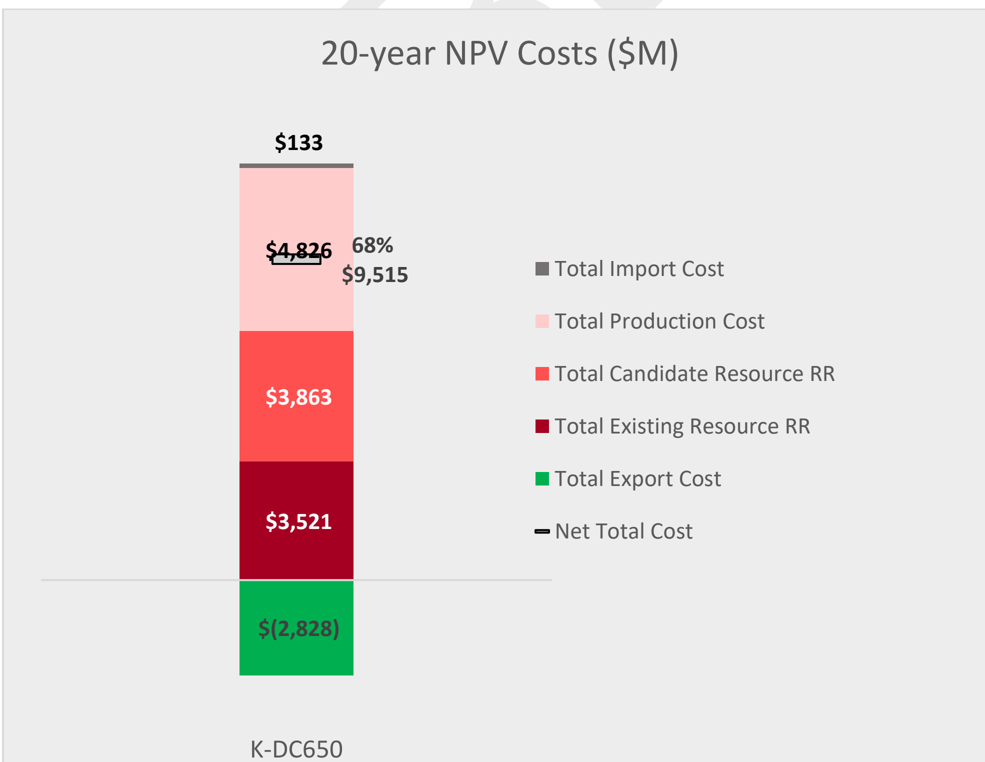

FIGURE 203: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO K.

11 PCM RESULTS: SCENARIO L – ADD 1,160 MW OF DATA CENTER LOAD

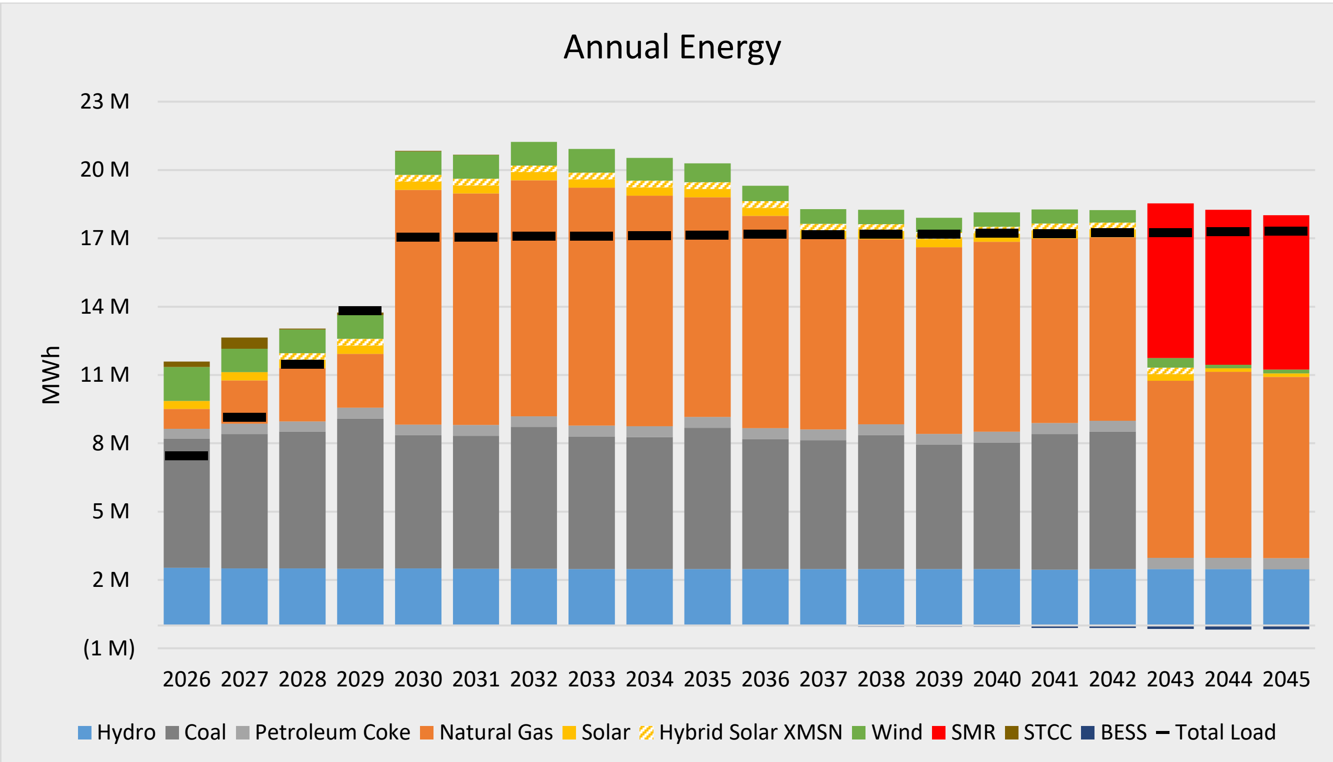

FIGURE 204: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO L.

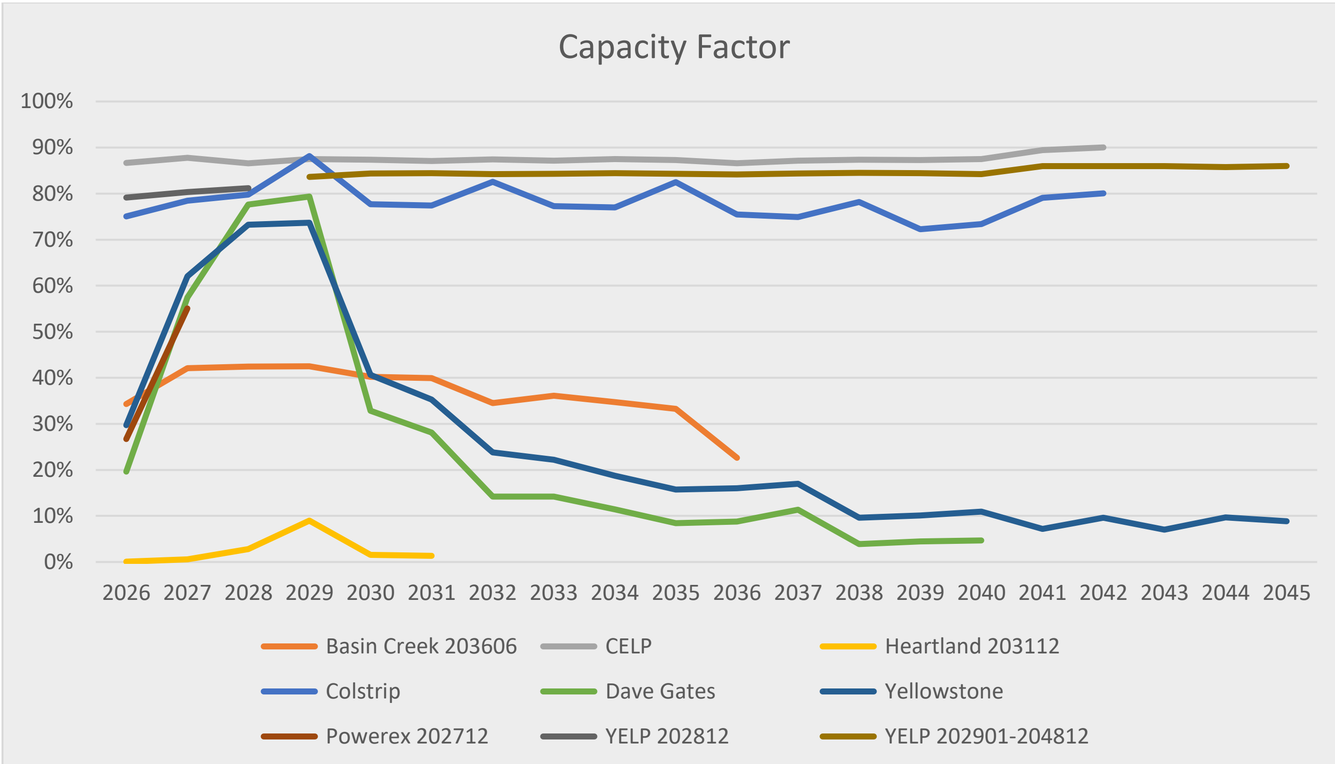

FIGURE 205: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO L.

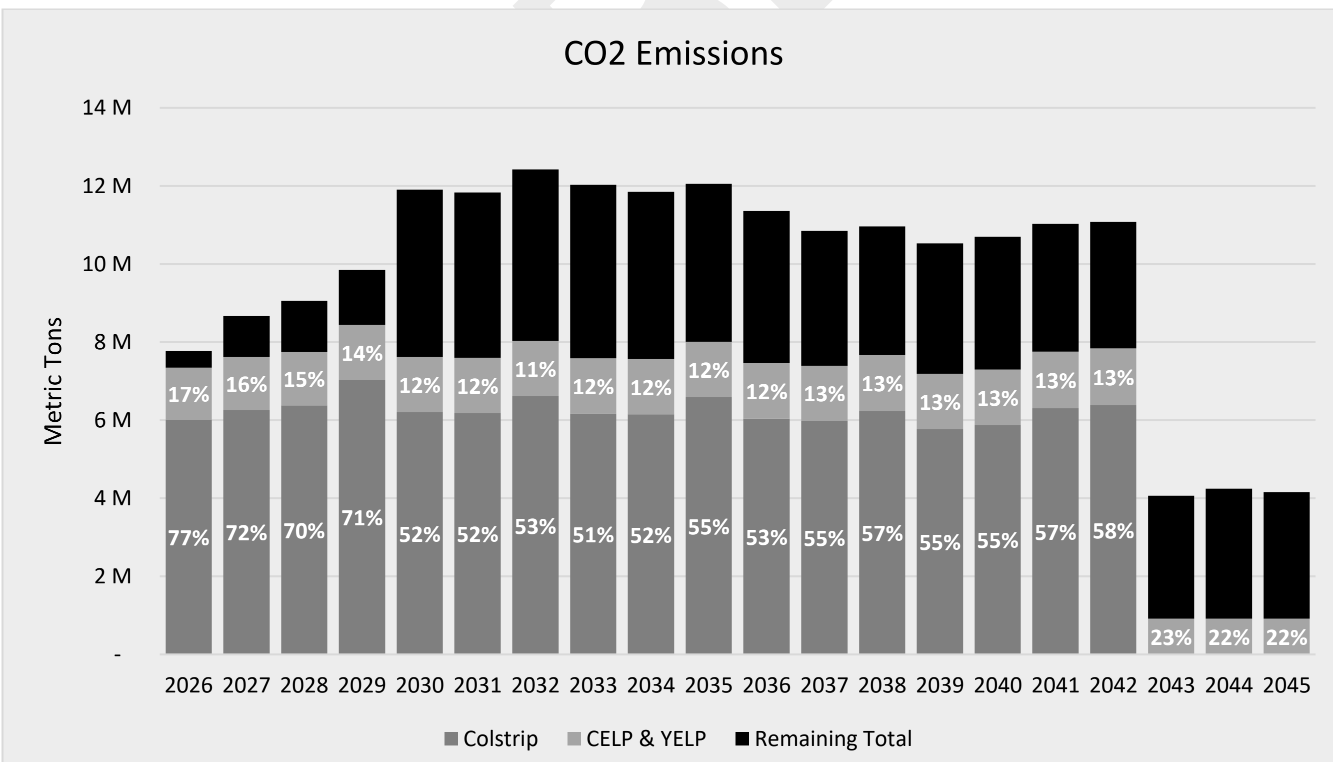

FIGURE 206: EMISSIONS FOR PCM RESULTS OF SCENARIO L.

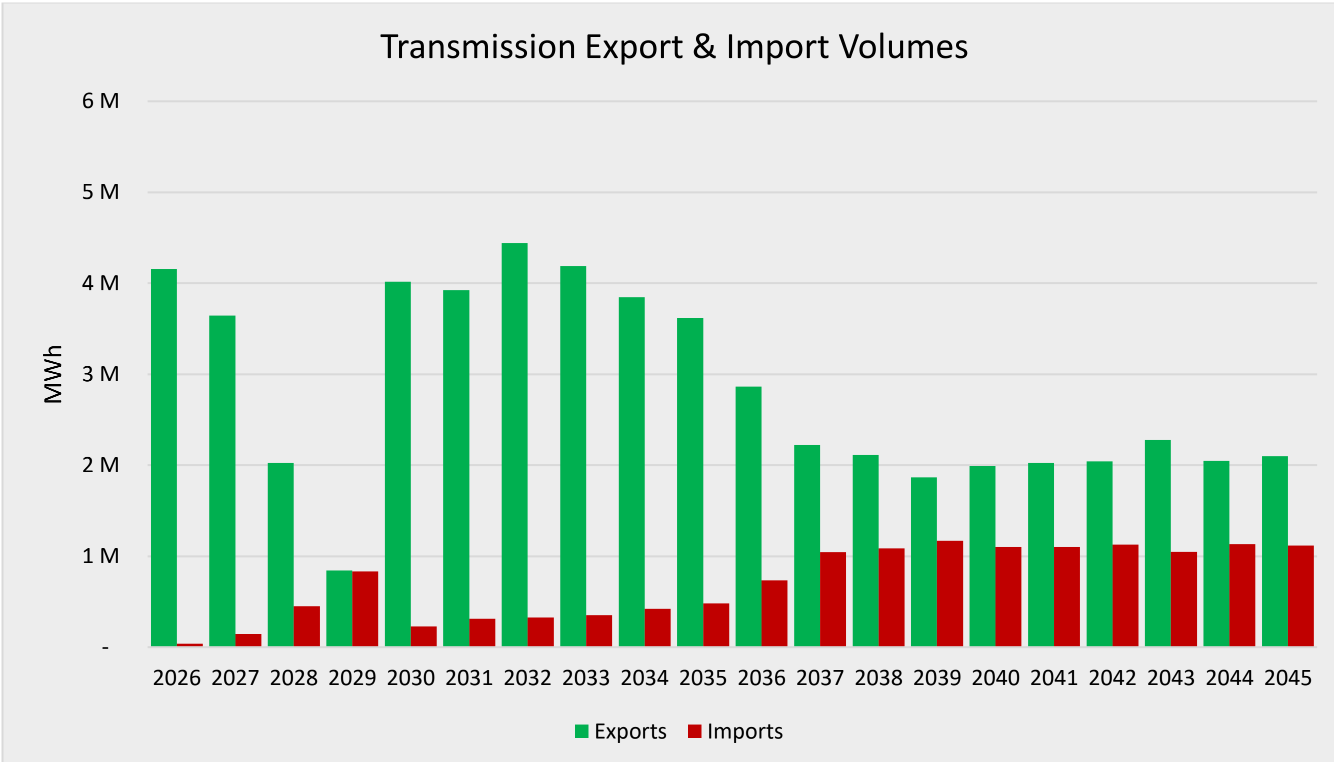

FIGURE 207: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO L.

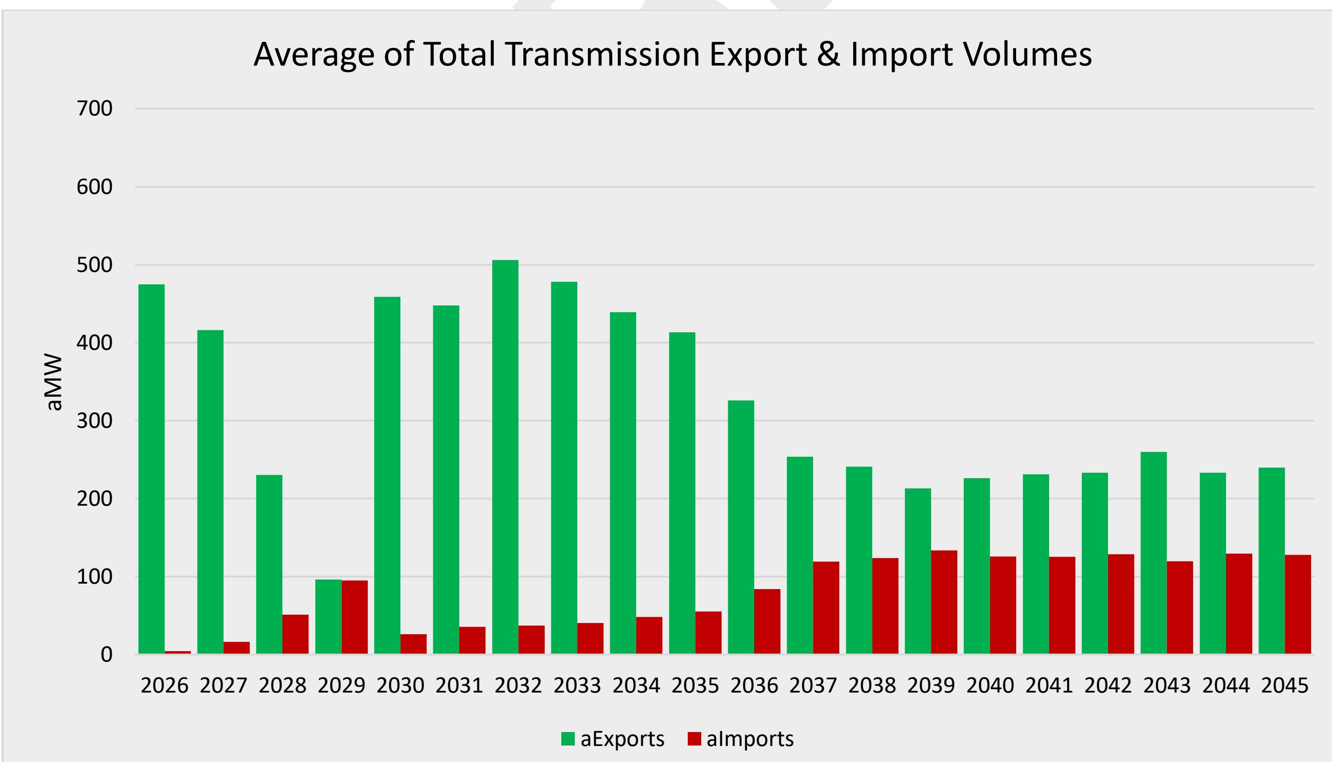

FIGURE 208: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO L.

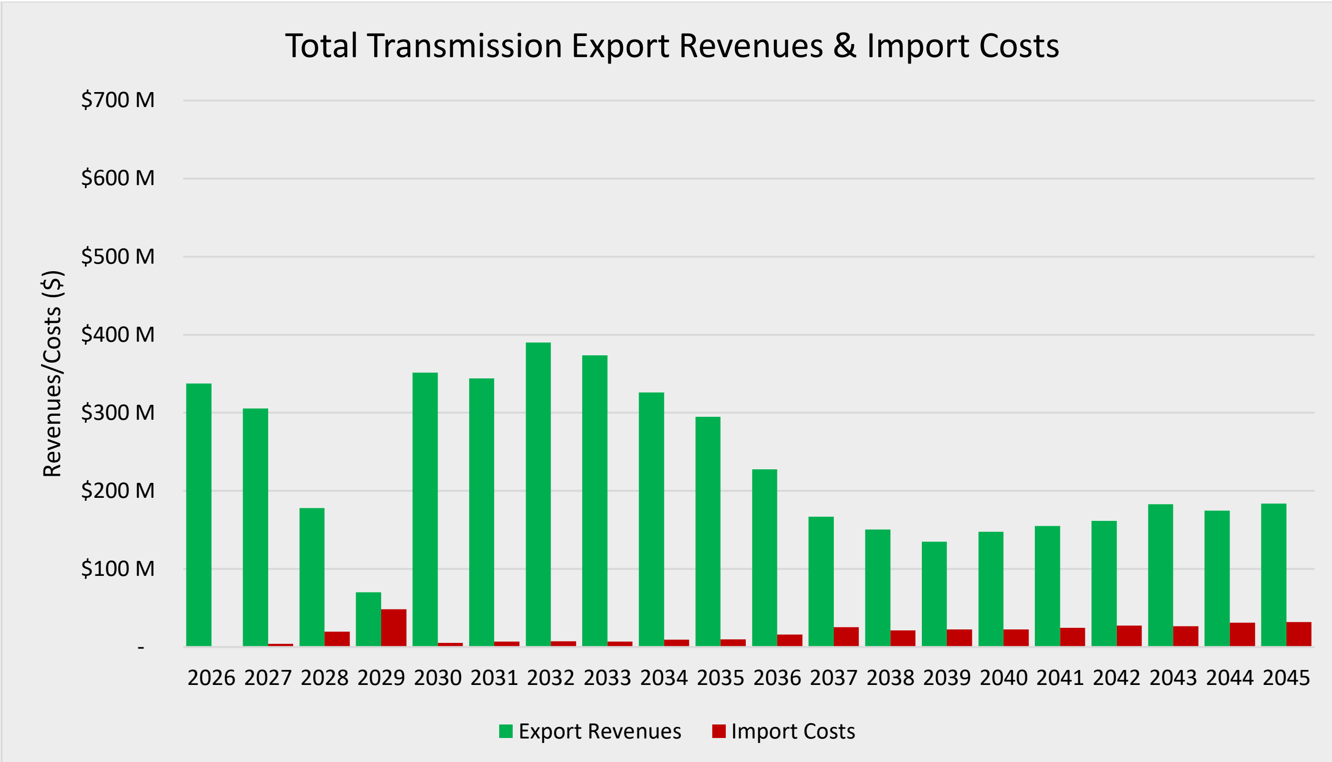

FIGURE 209: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO L.

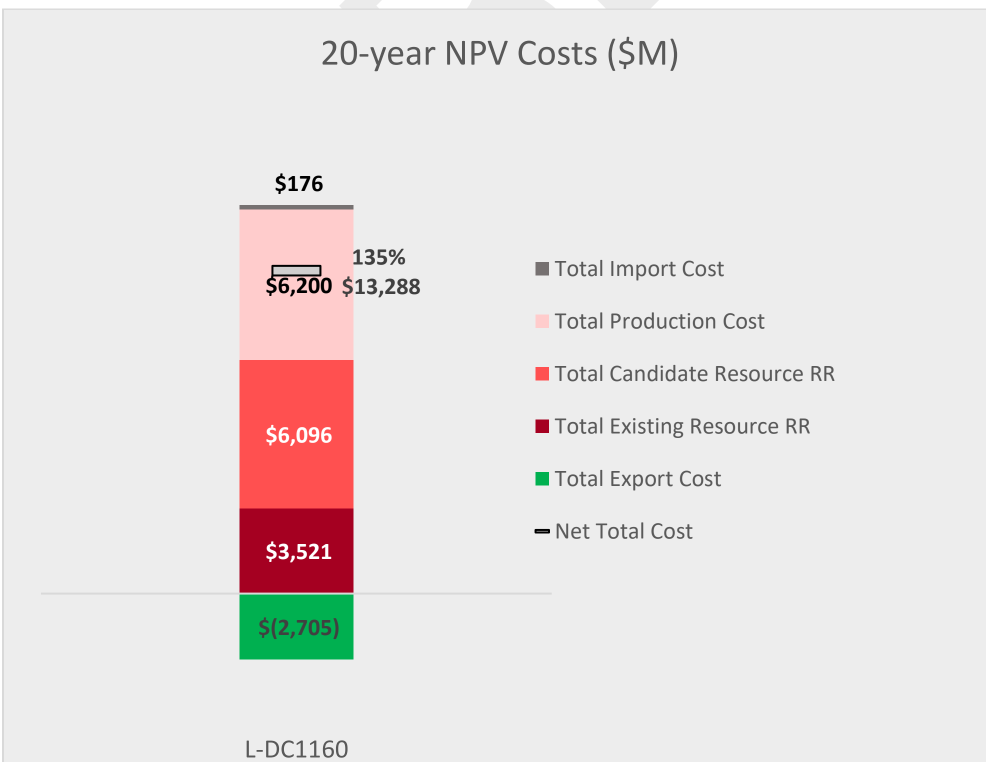

FIGURE 210: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO L.

12 PCM RESULTS: SCENARIO M – NO LIMITATION ON CARBON EMITTING RESOURCES

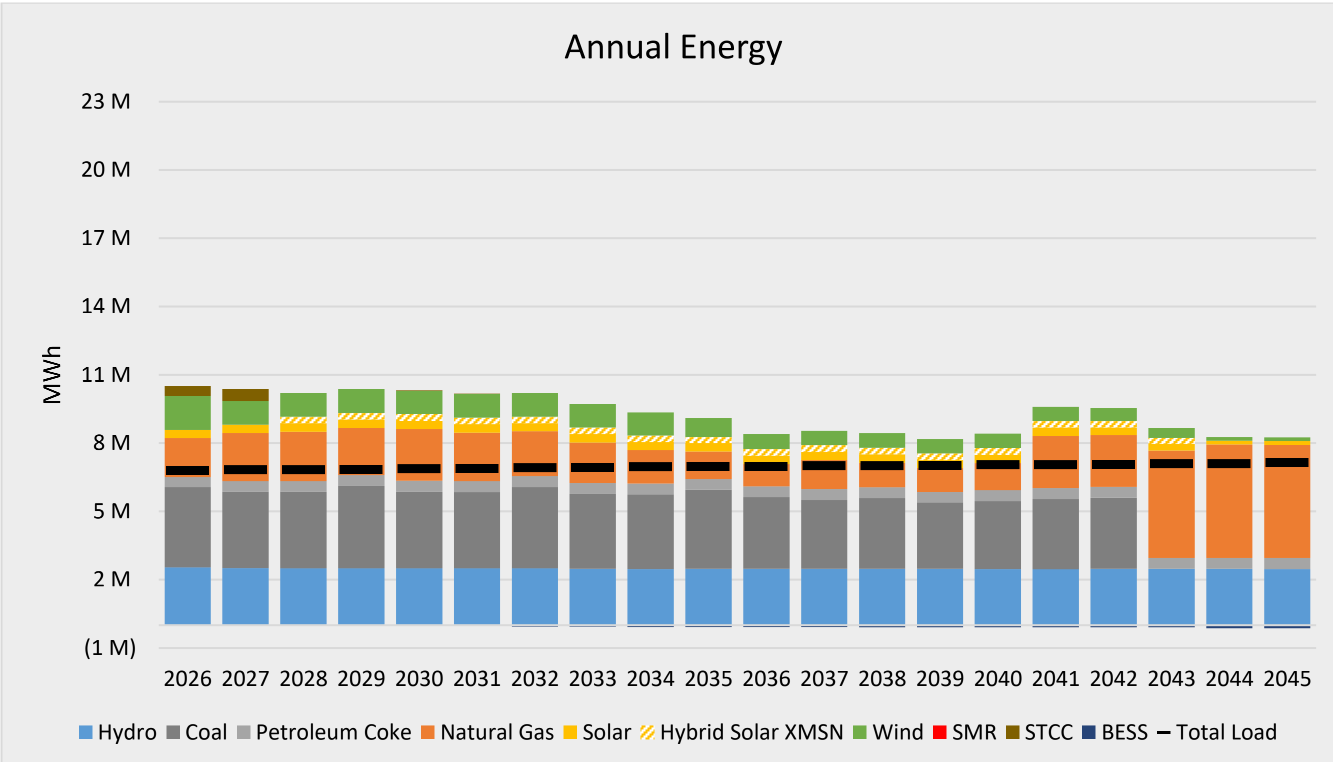

FIGURE 211: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO M.

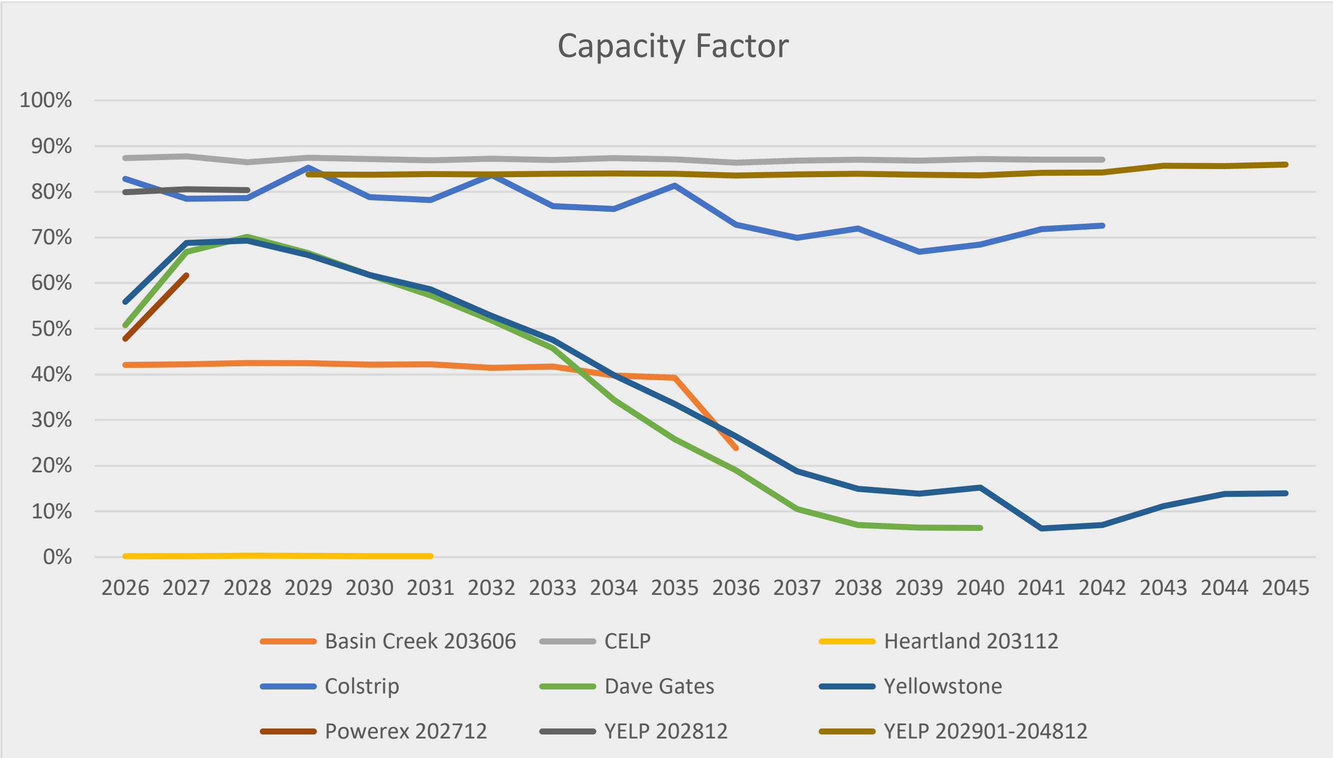

FIGURE 212: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO M.

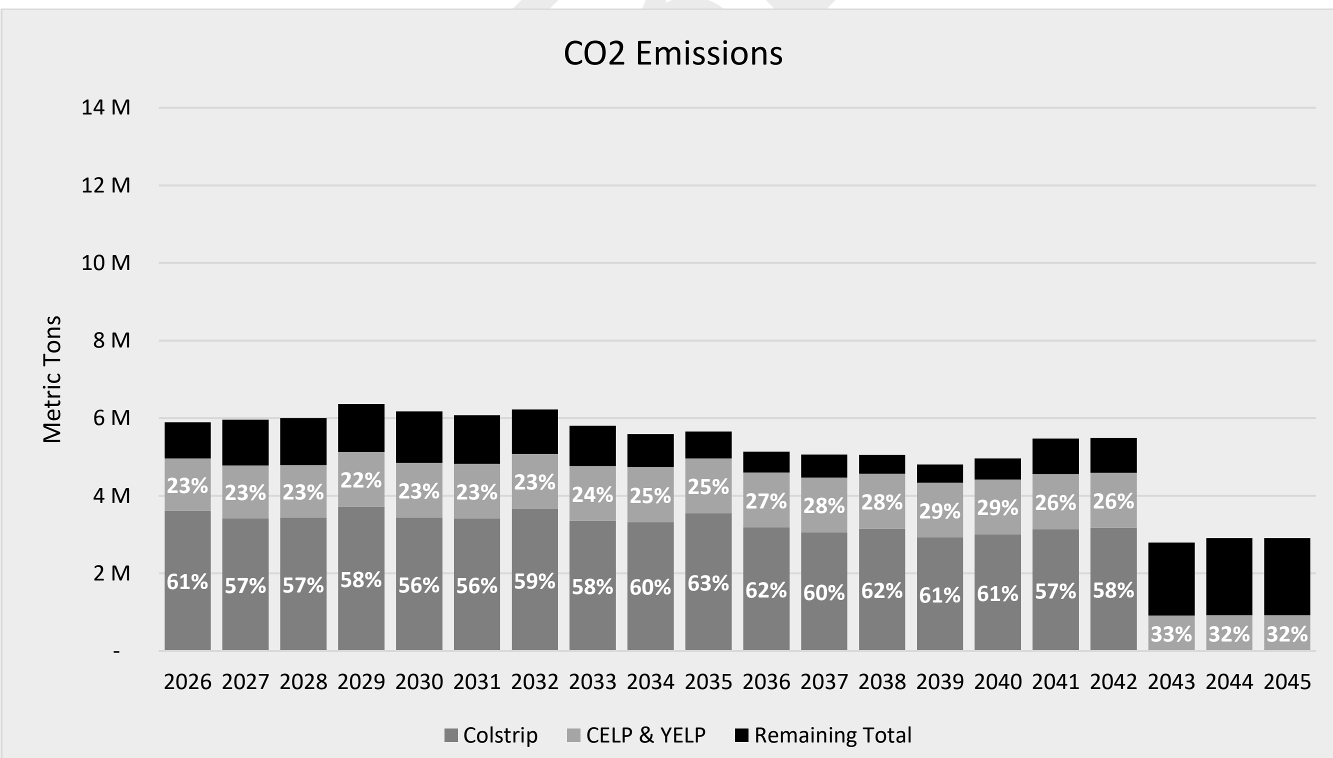

FIGURE 213: EMISSIONS FOR PCM RESULTS OF SCENARIO M.

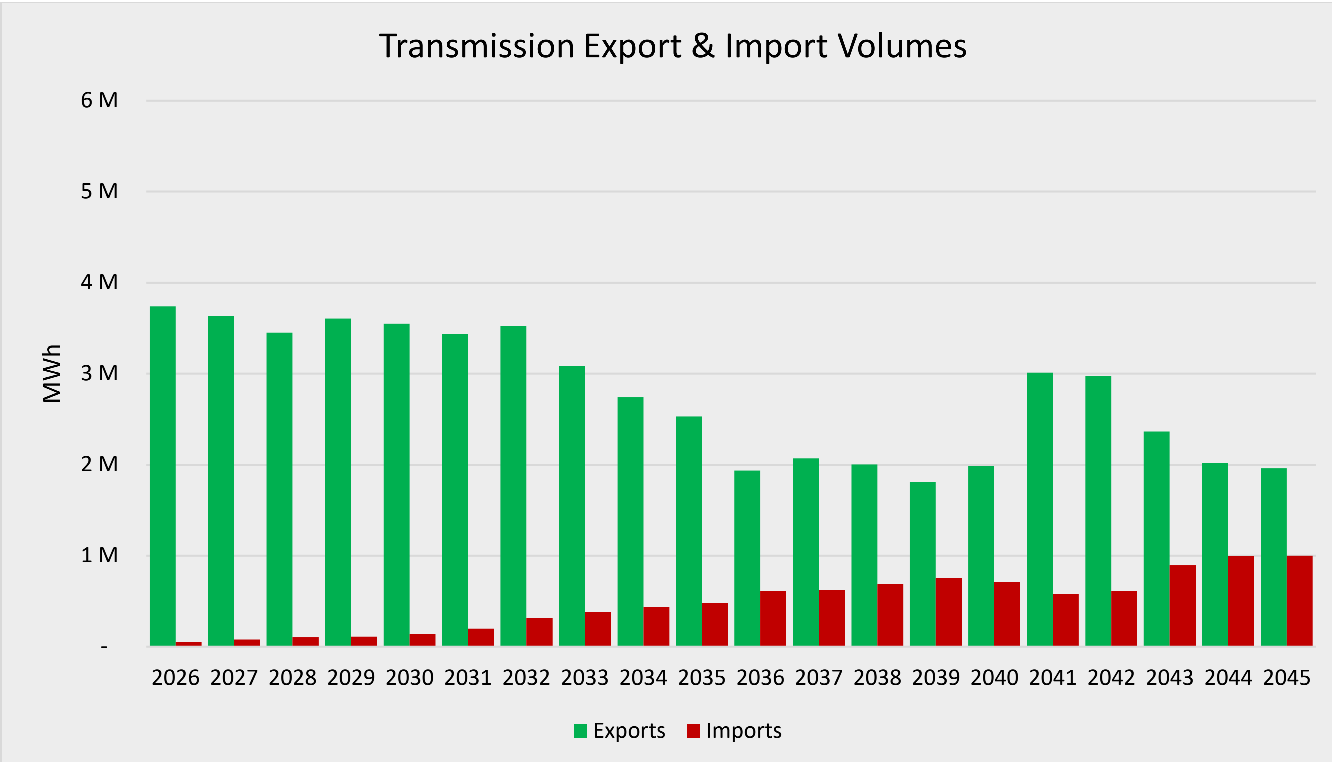

FIGURE 214: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO M.

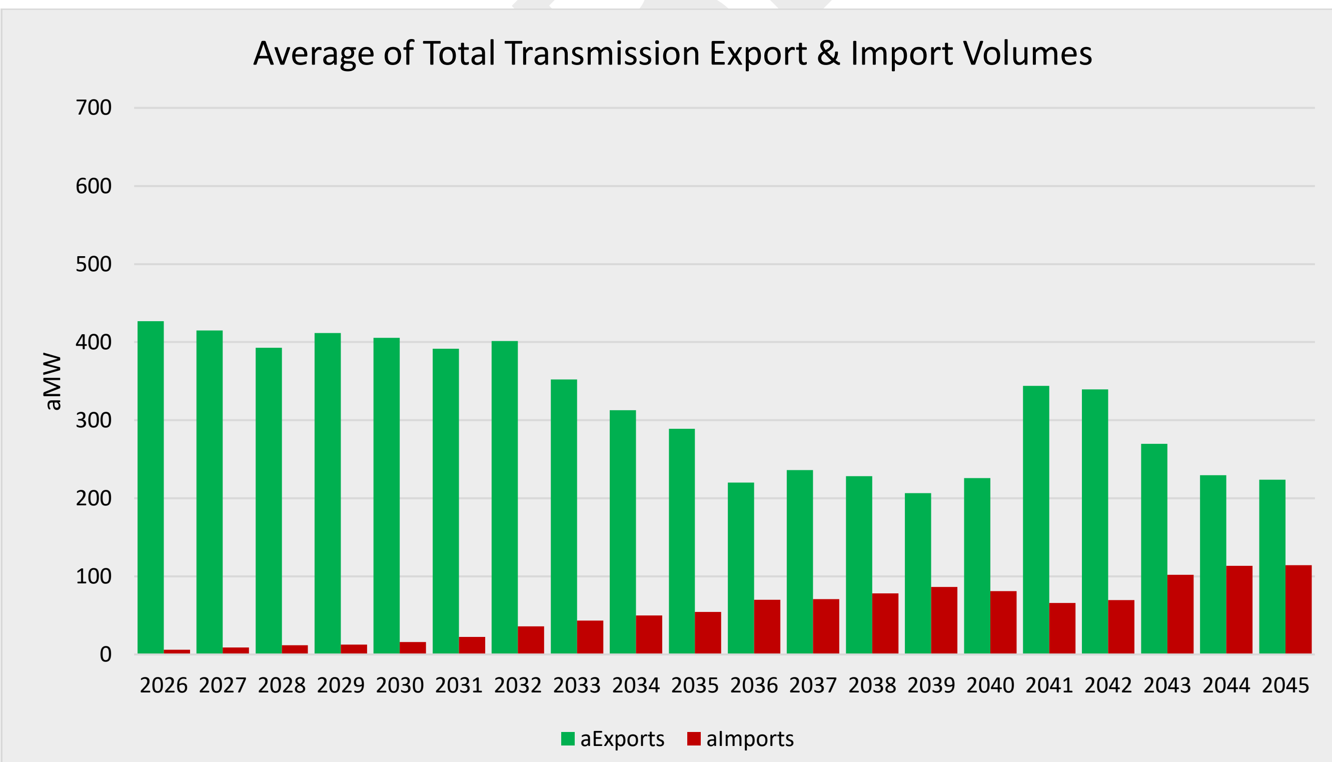

FIGURE 215: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO M.

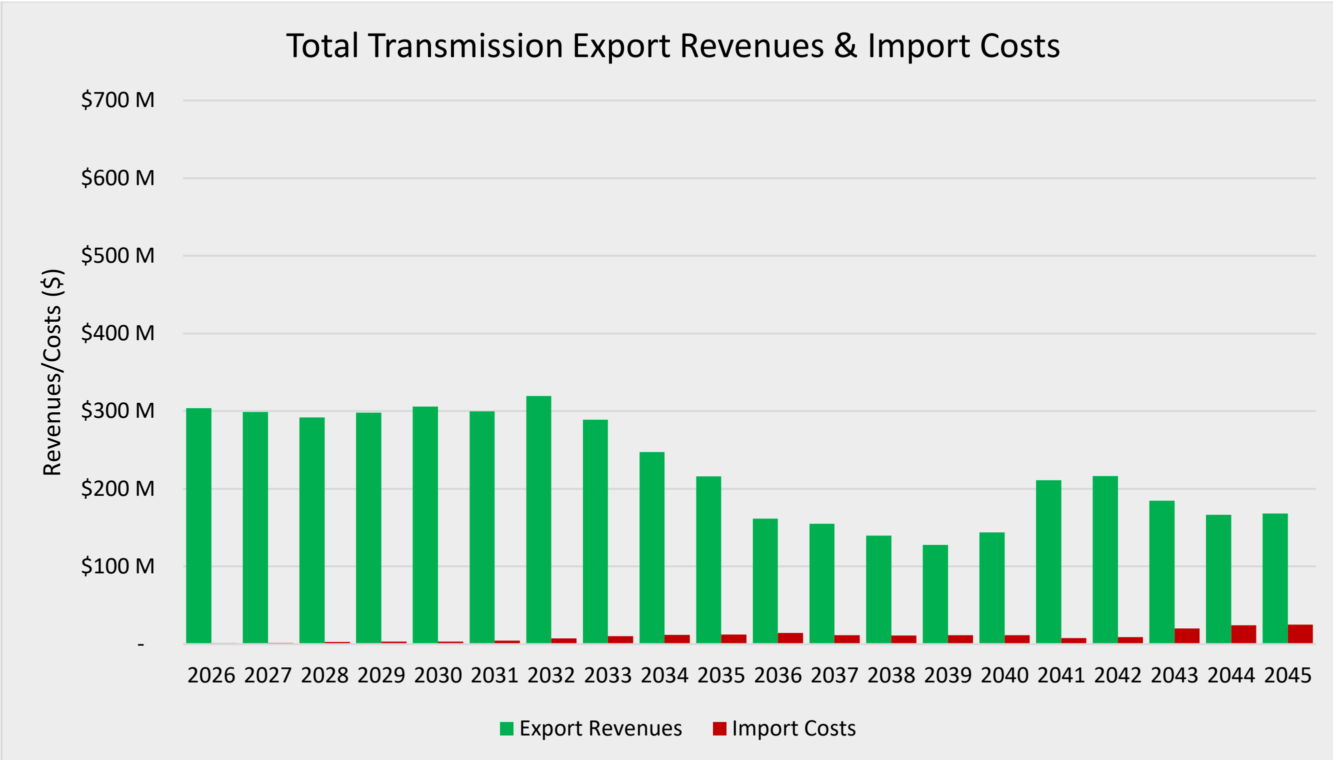

FIGURE 216: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO M.

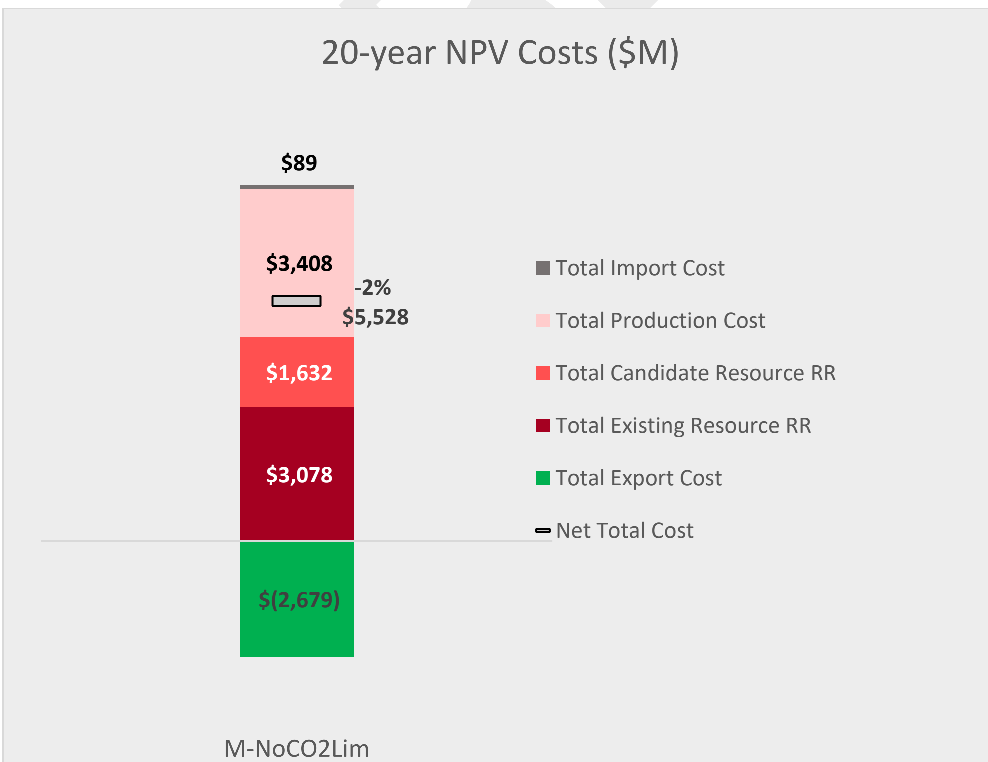

FIGURE 217: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO M.

13 PCM RESULTS: SCENARIO N – CARBON FREE CANDIDATE RESOURCES ONLY

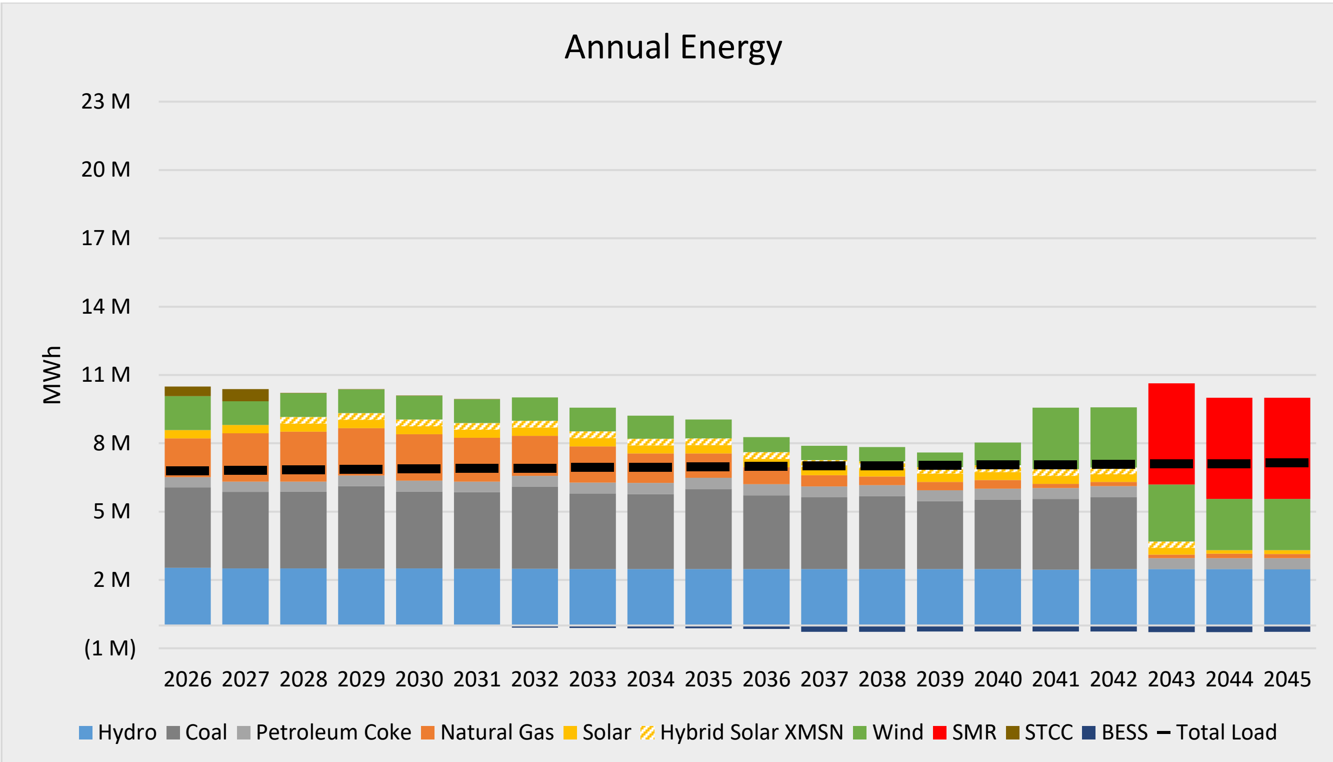

FIGURE 218: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO N.

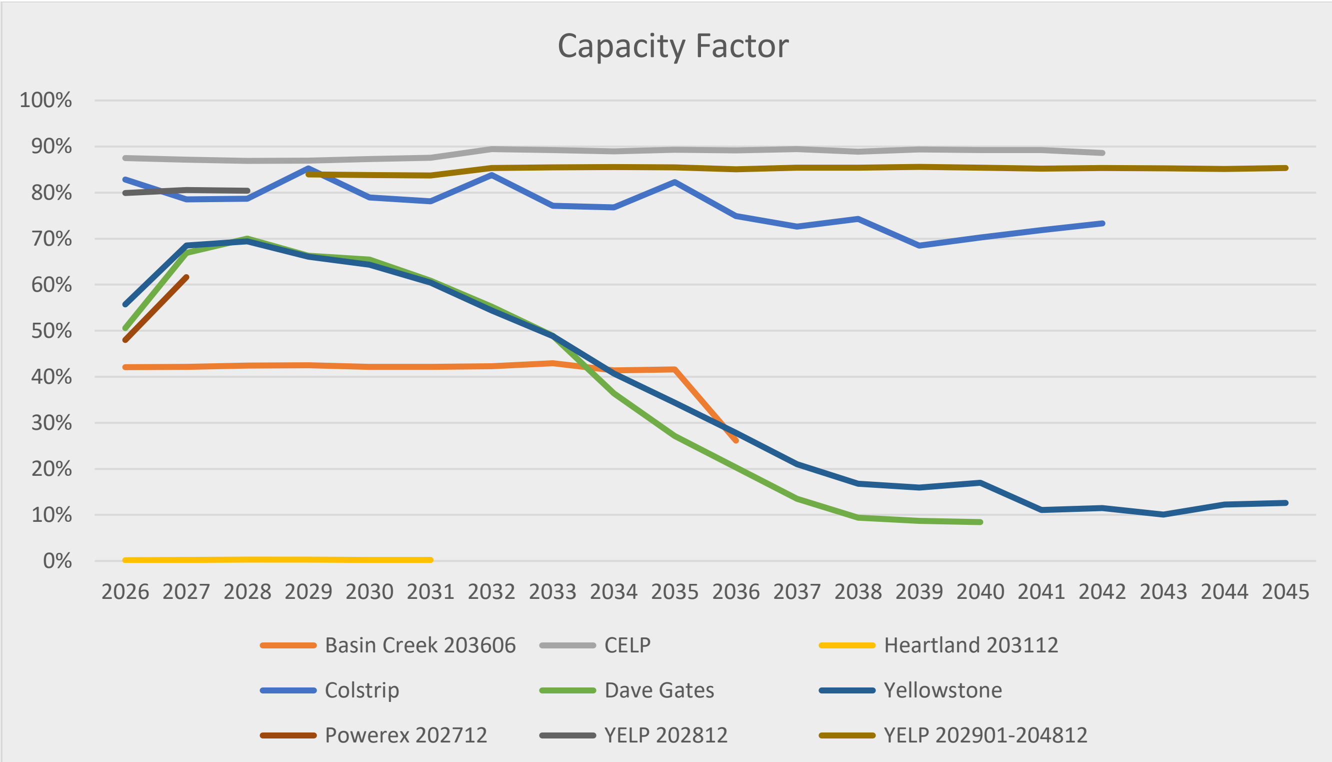

FIGURE 219: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO N.

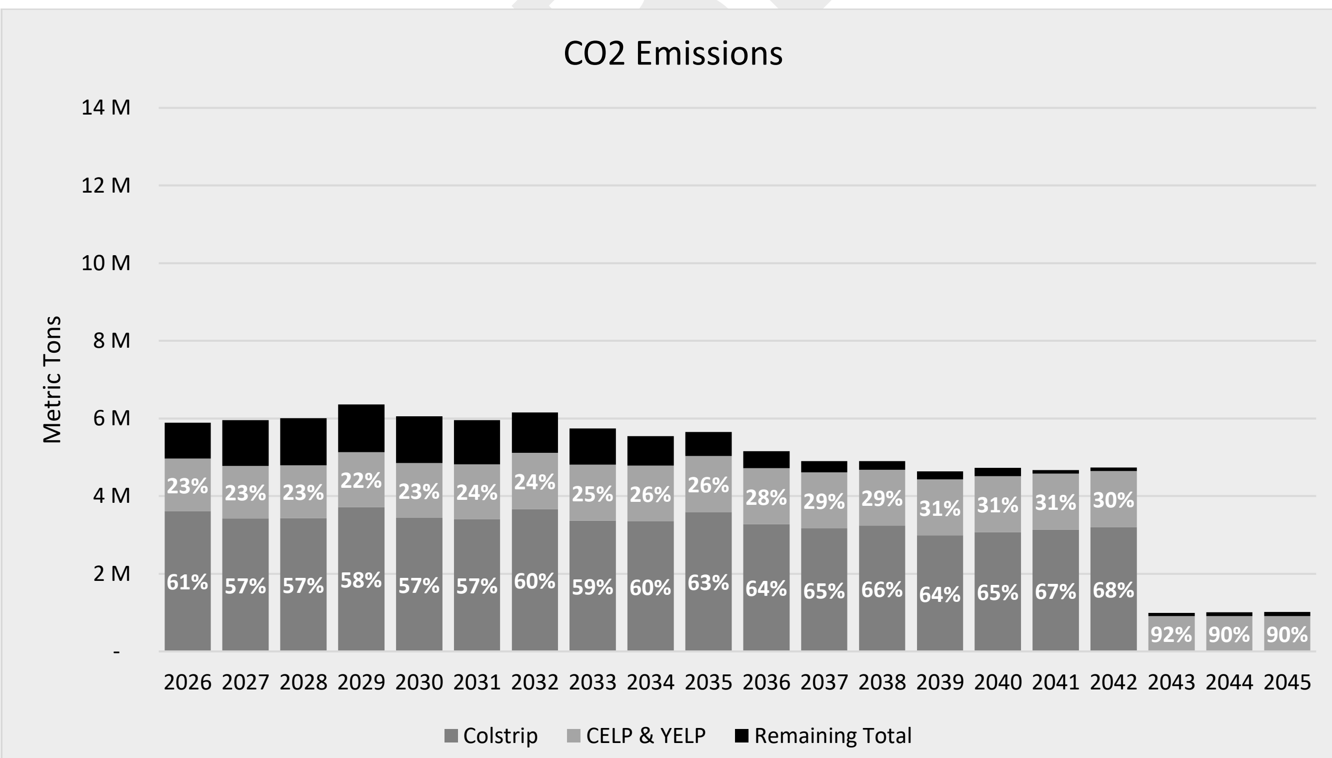

FIGURE 220: EMISSIONS FOR PCM RESULTS OF SCENARIO N.

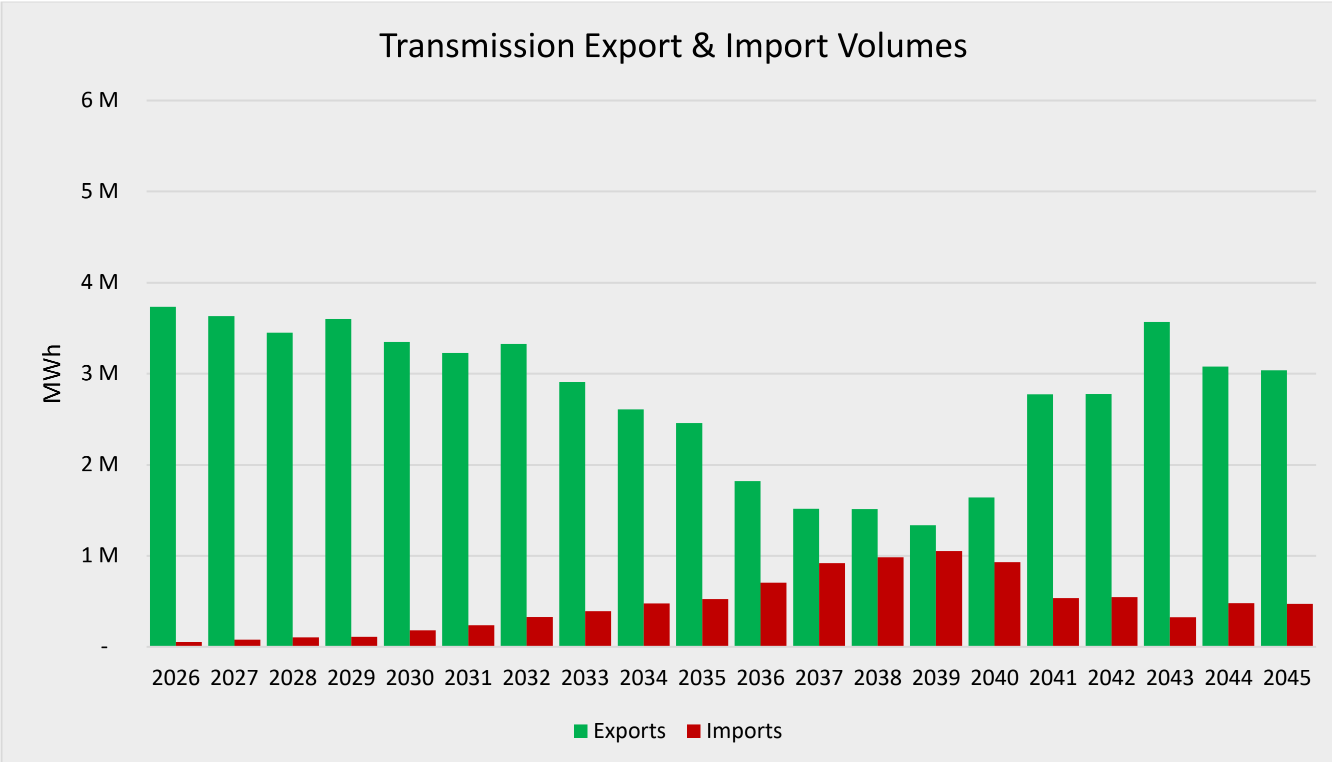

FIGURE 221: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO N.

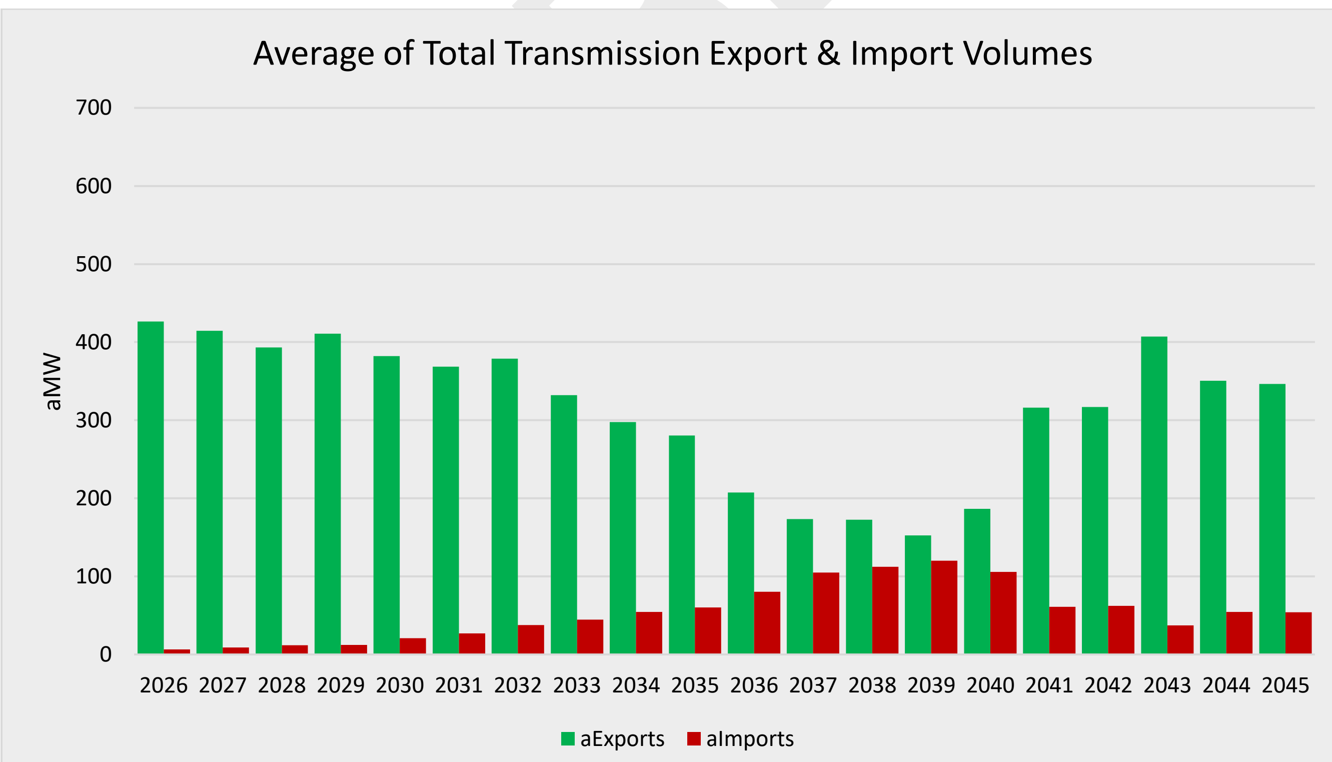

FIGURE 222: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO N.

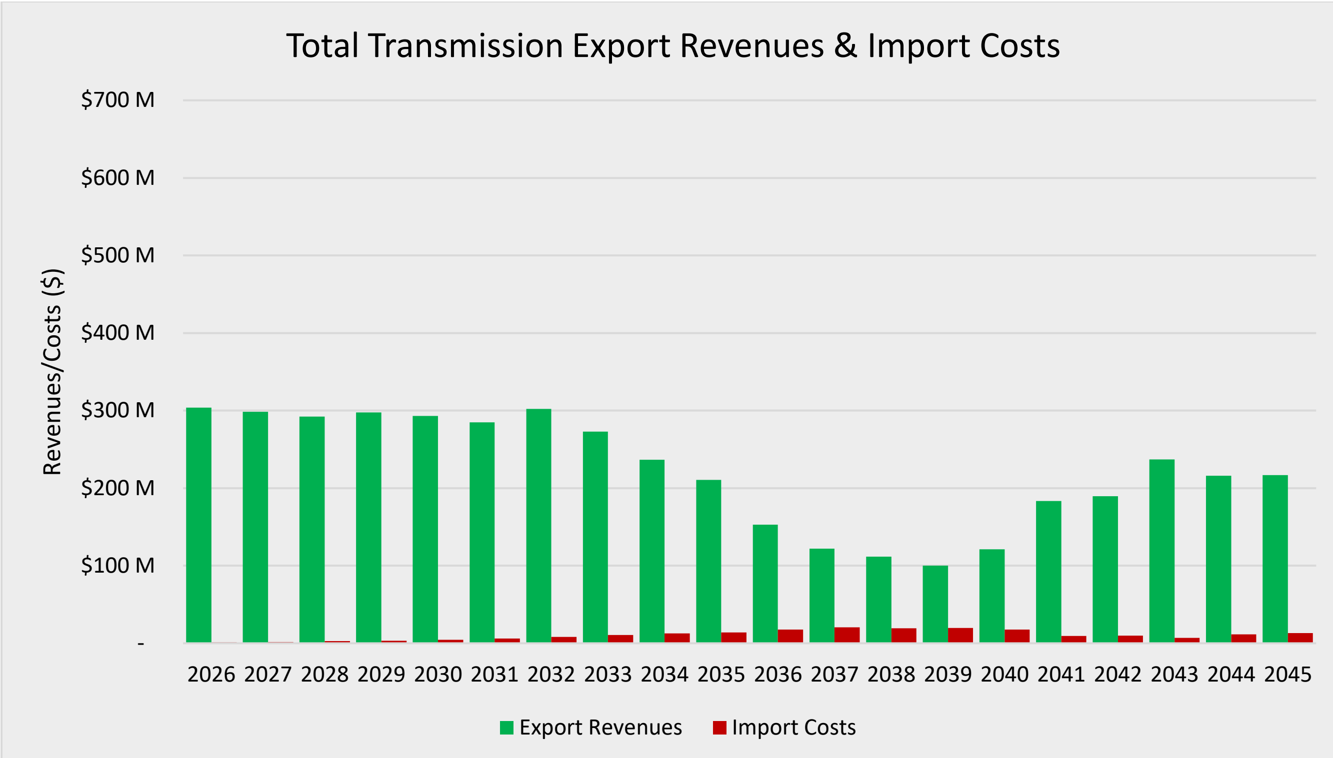

FIGURE 223: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO N.

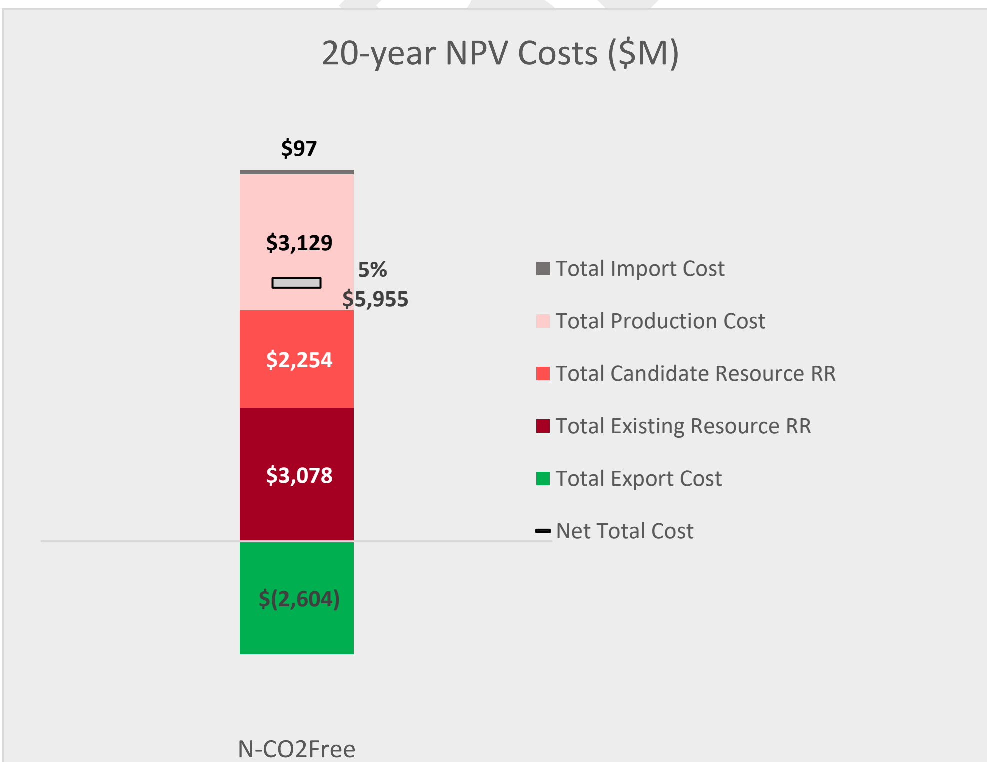

FIGURE 224: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO N.

14 PCM RESULTS: SCENARIO O – PSE COLSTRIP SHARE IS USED FOR RETAIL LOAD

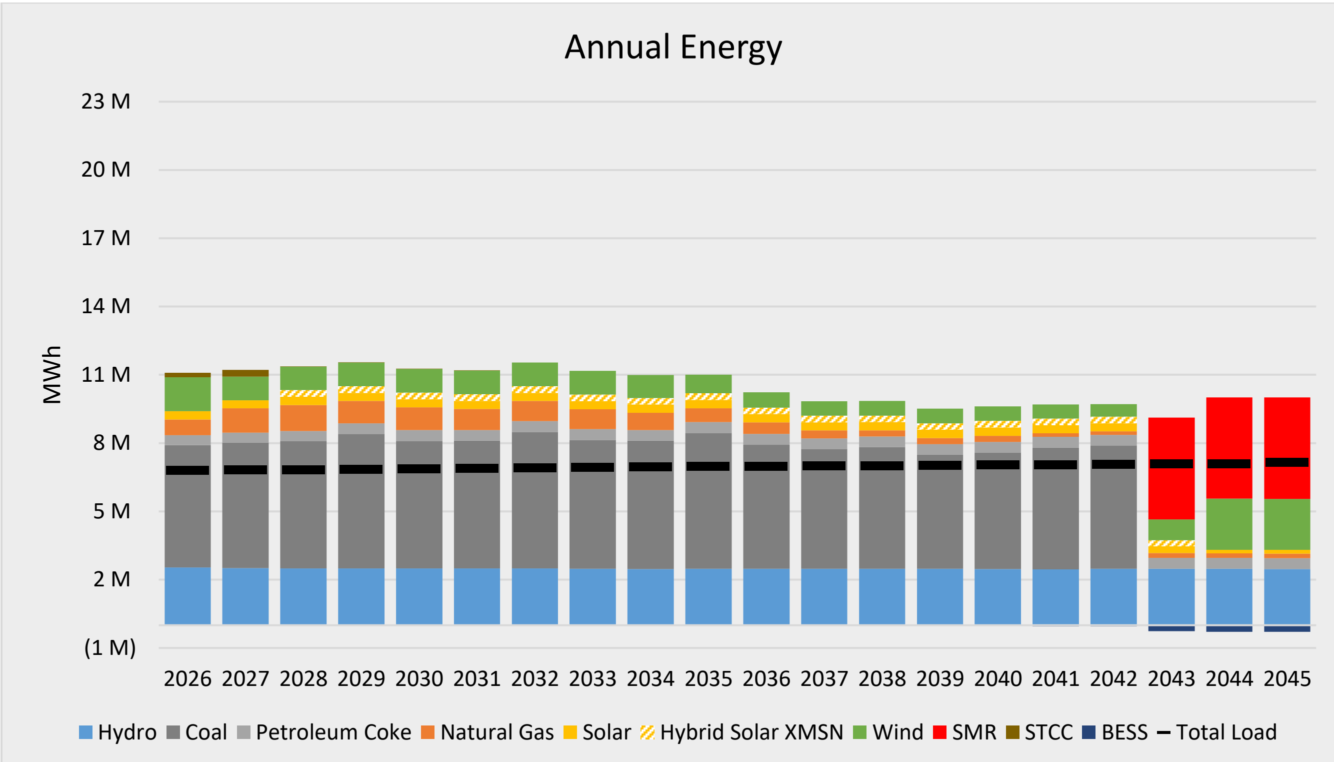

FIGURE 225: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO O.

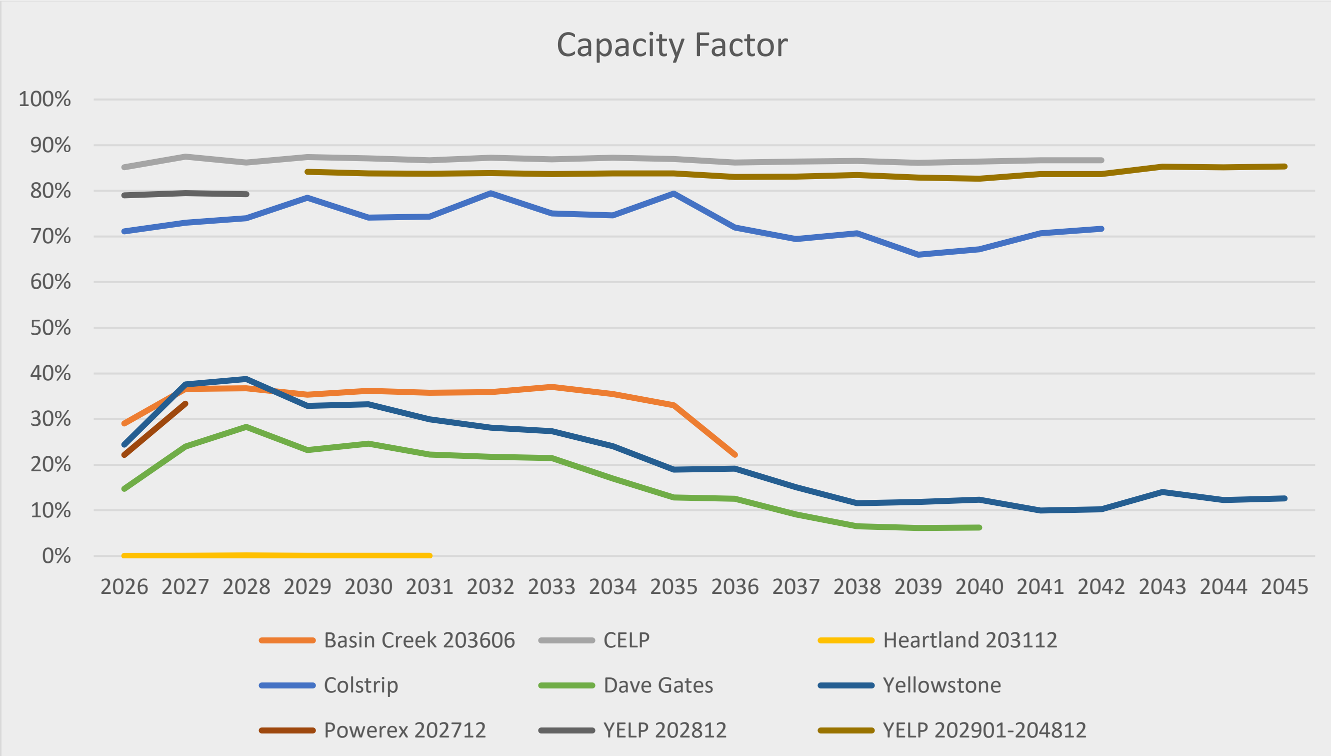

FIGURE 226: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO O.

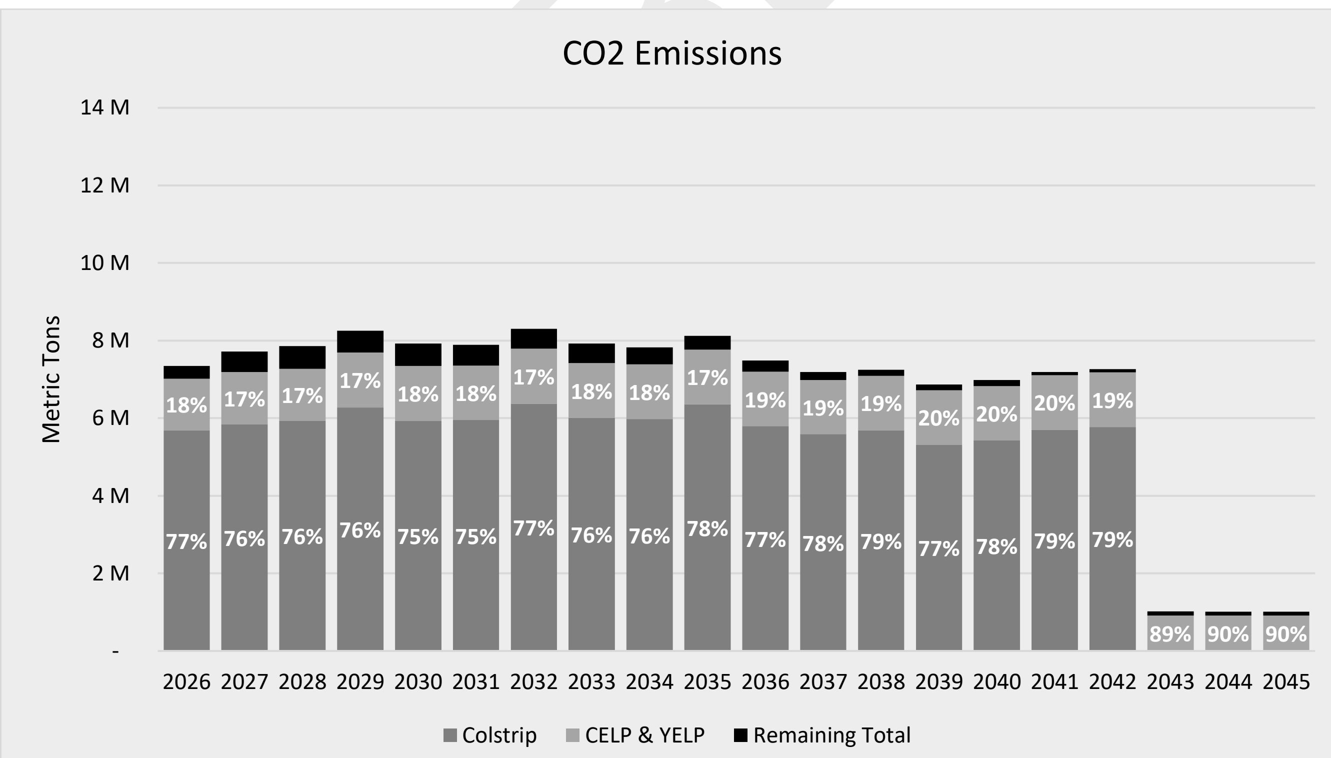

FIGURE 227: EMISSIONS FOR PCM RESULTS OF SCENARIO O.

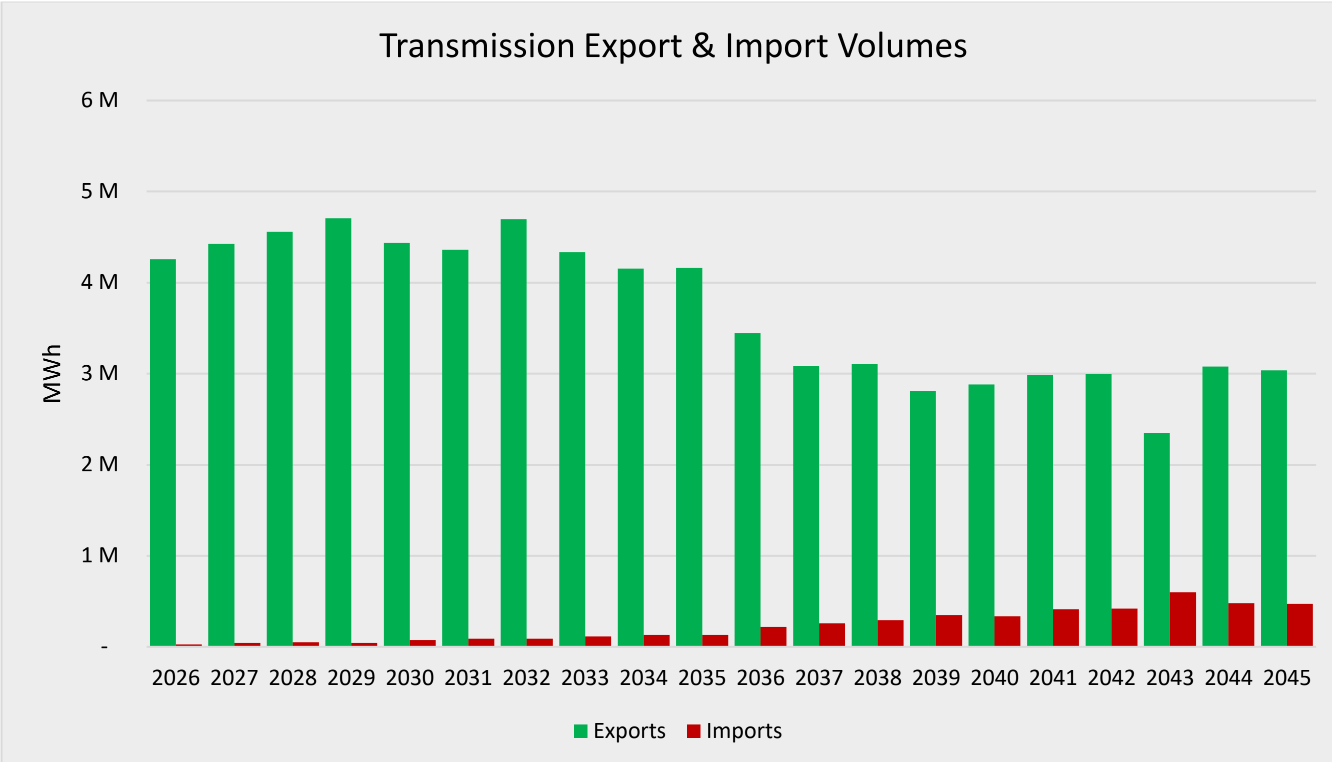

FIGURE 228: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO O.

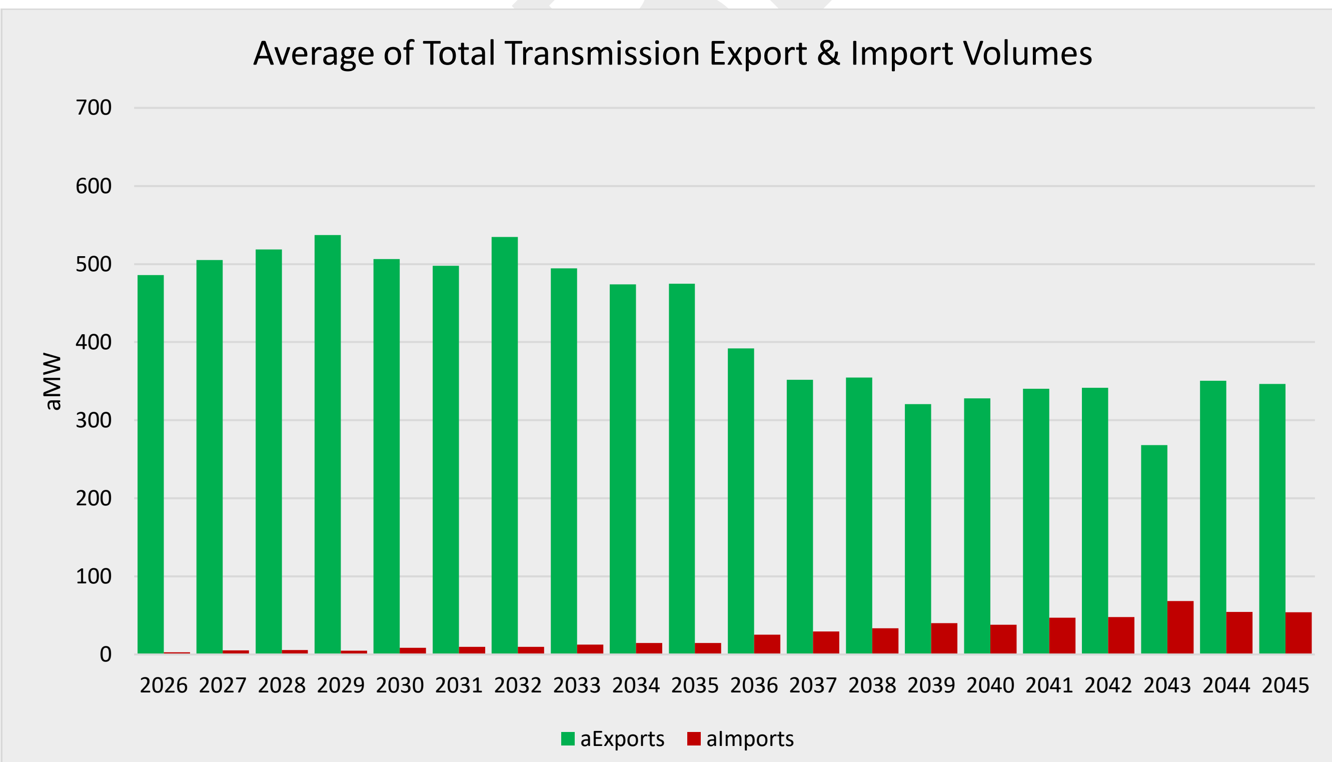

FIGURE 229: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO O.

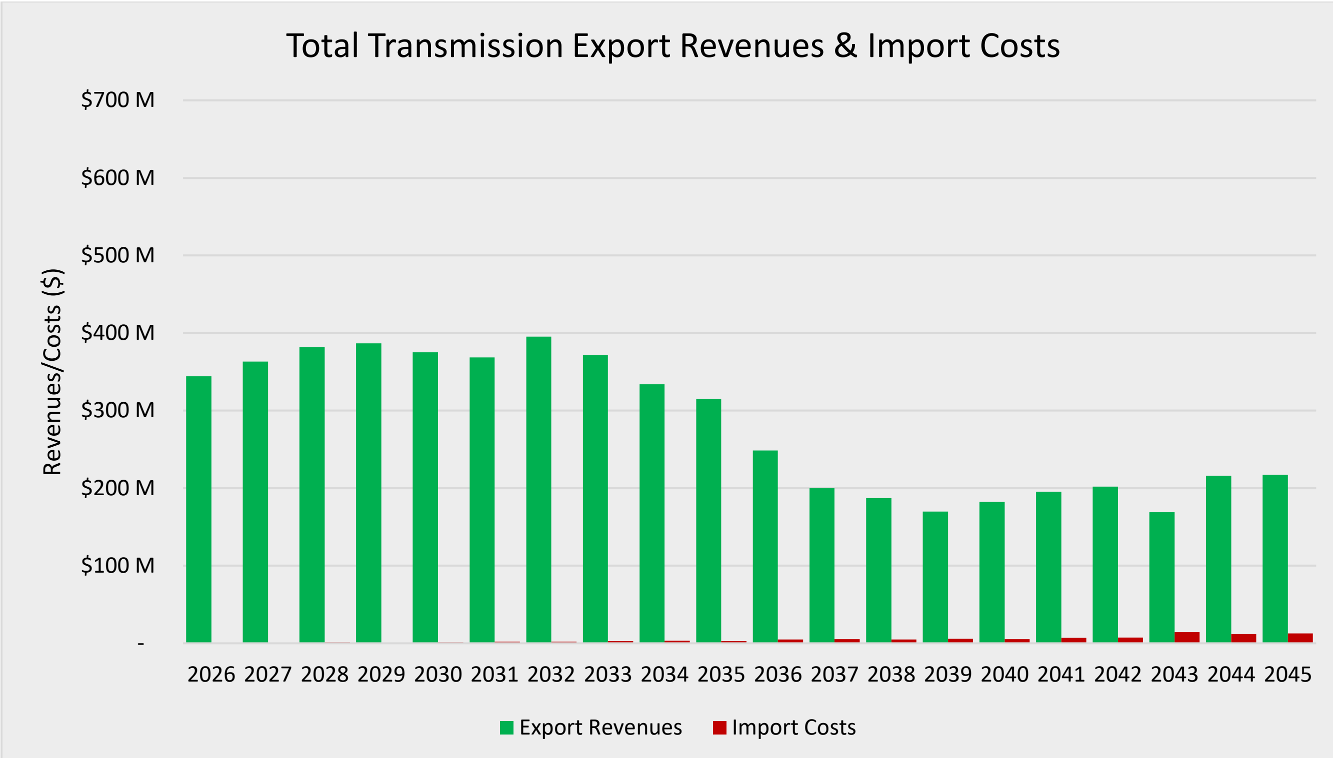

FIGURE 230: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO O.

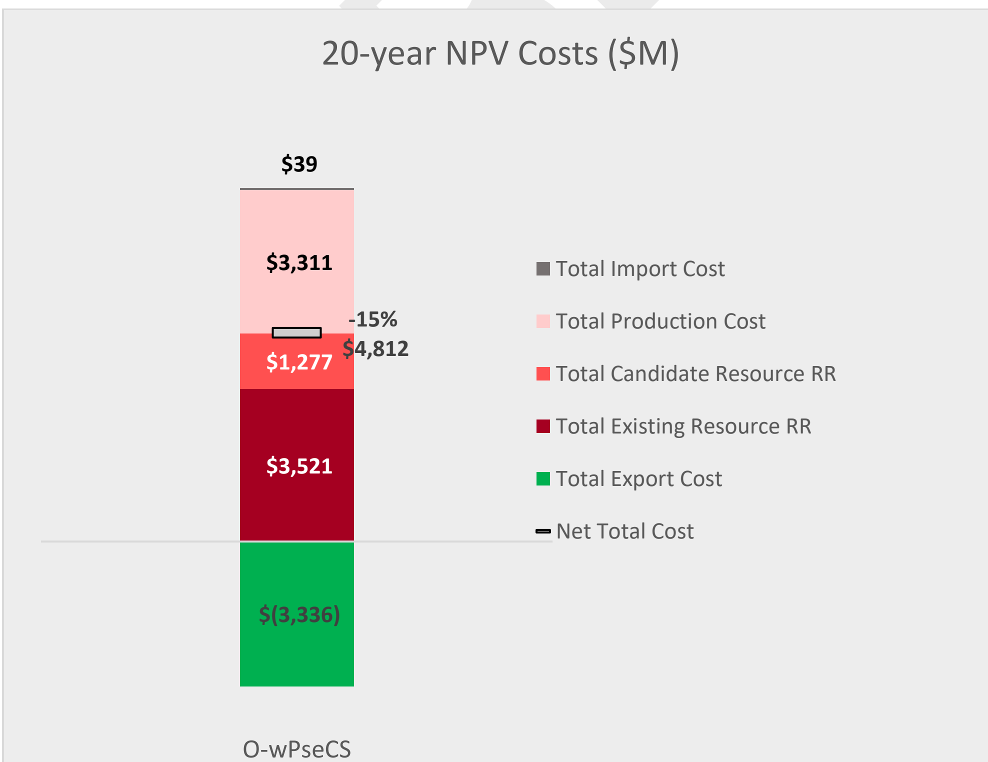

FIGURE 231: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO O.

15 PCM RESULTS: SCENARIO P – AVISTA'S COLSTRIP SHARES ARE NOT ACQUIRED

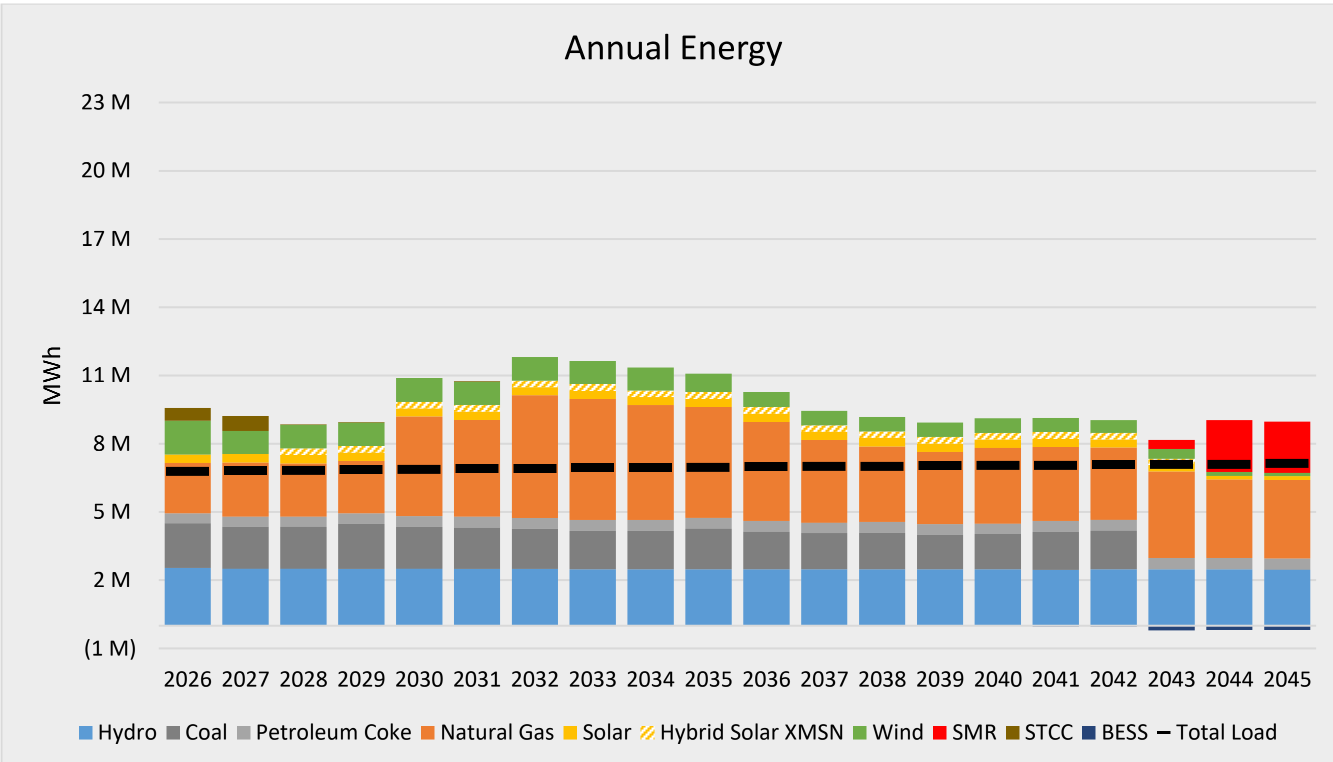

FIGURE 232: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO P.

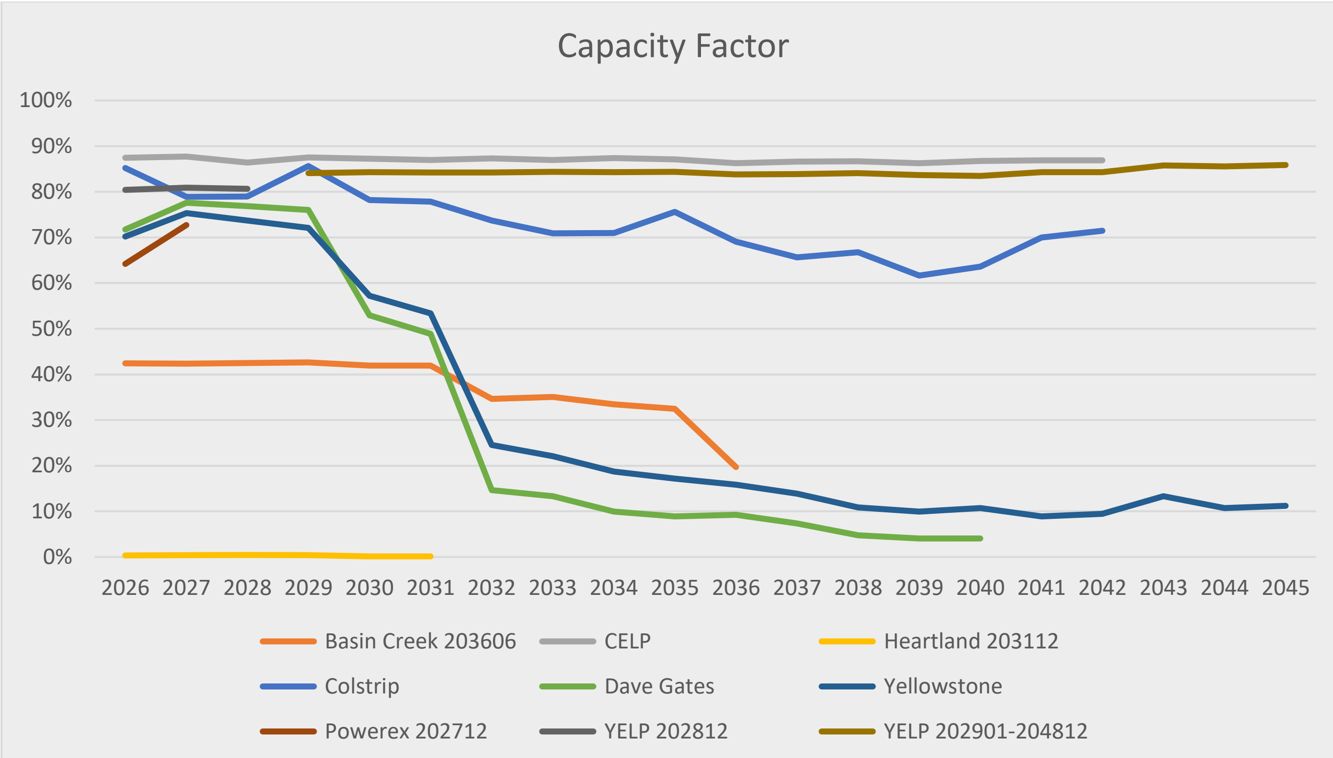

FIGURE 233: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO P.

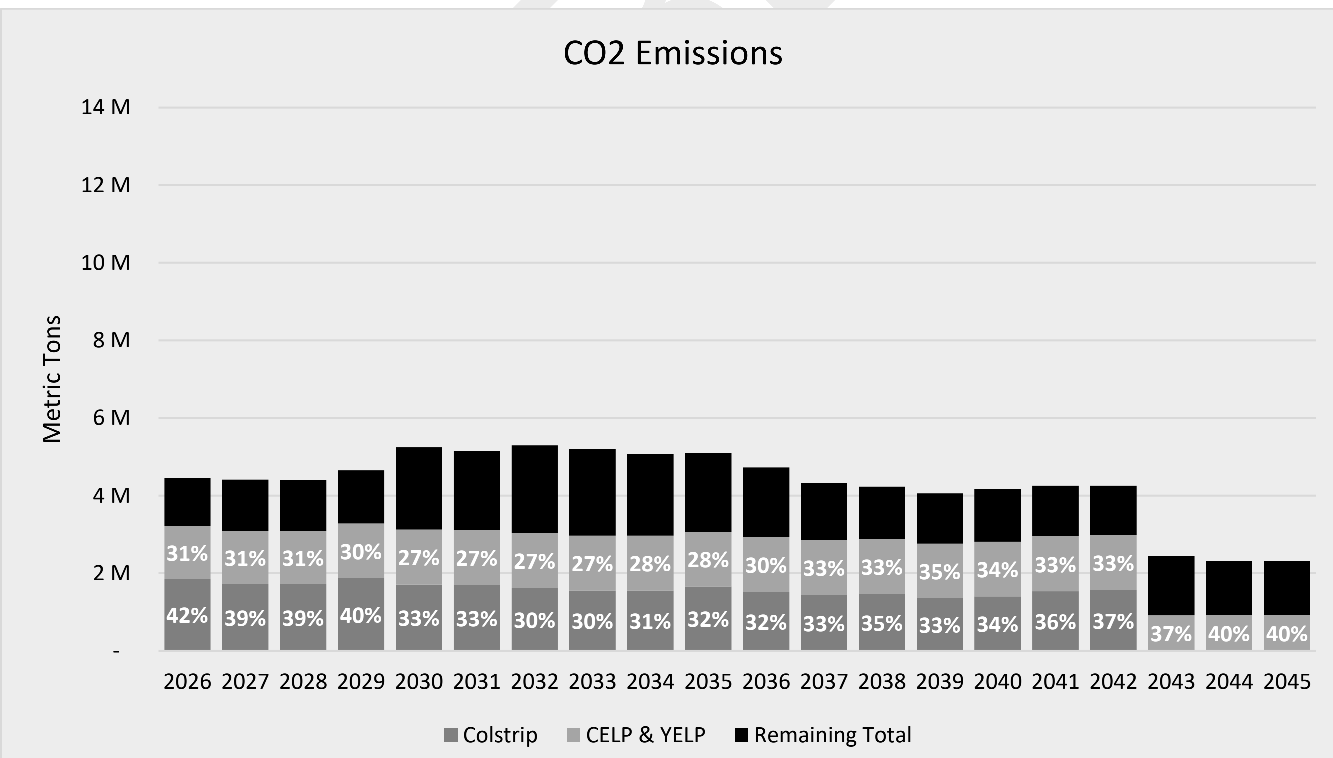

FIGURE 234: EMISSIONS FOR PCM RESULTS OF SCENARIO P.

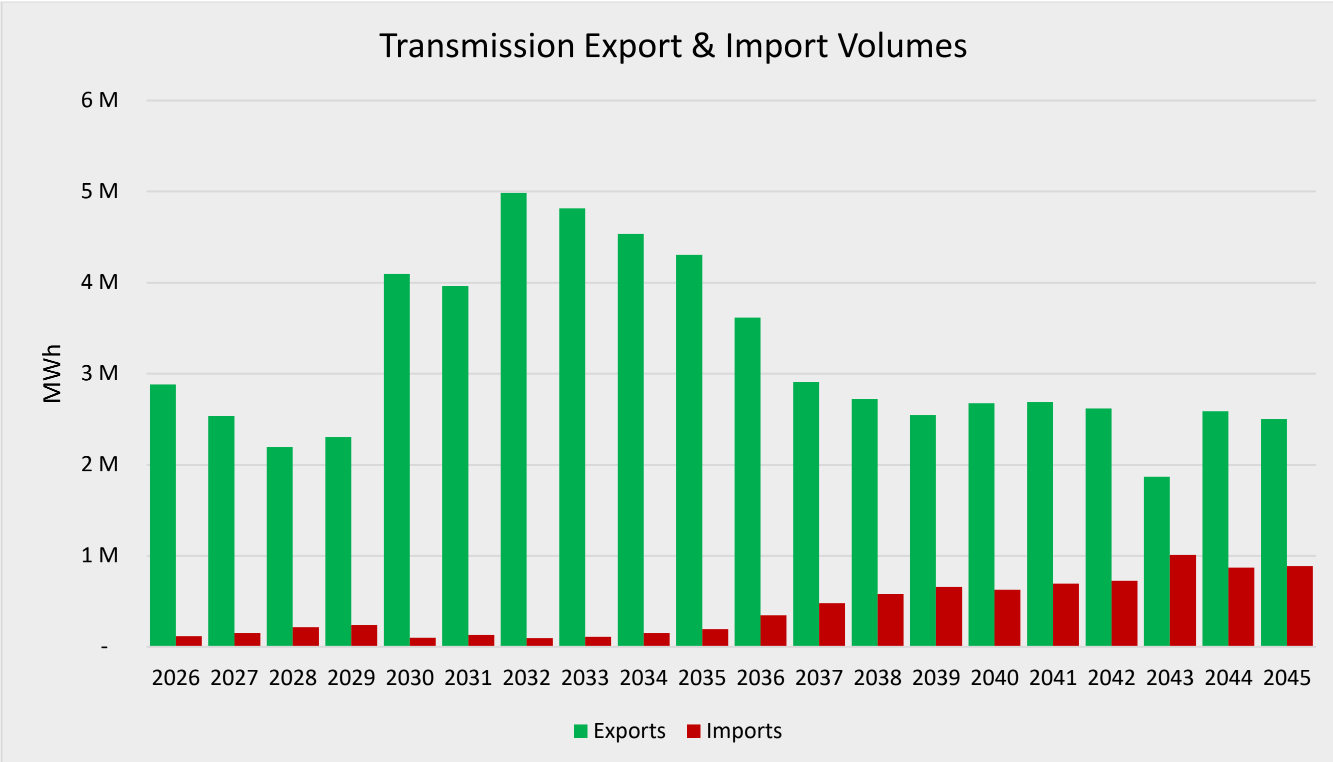

FIGURE 235: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO P.

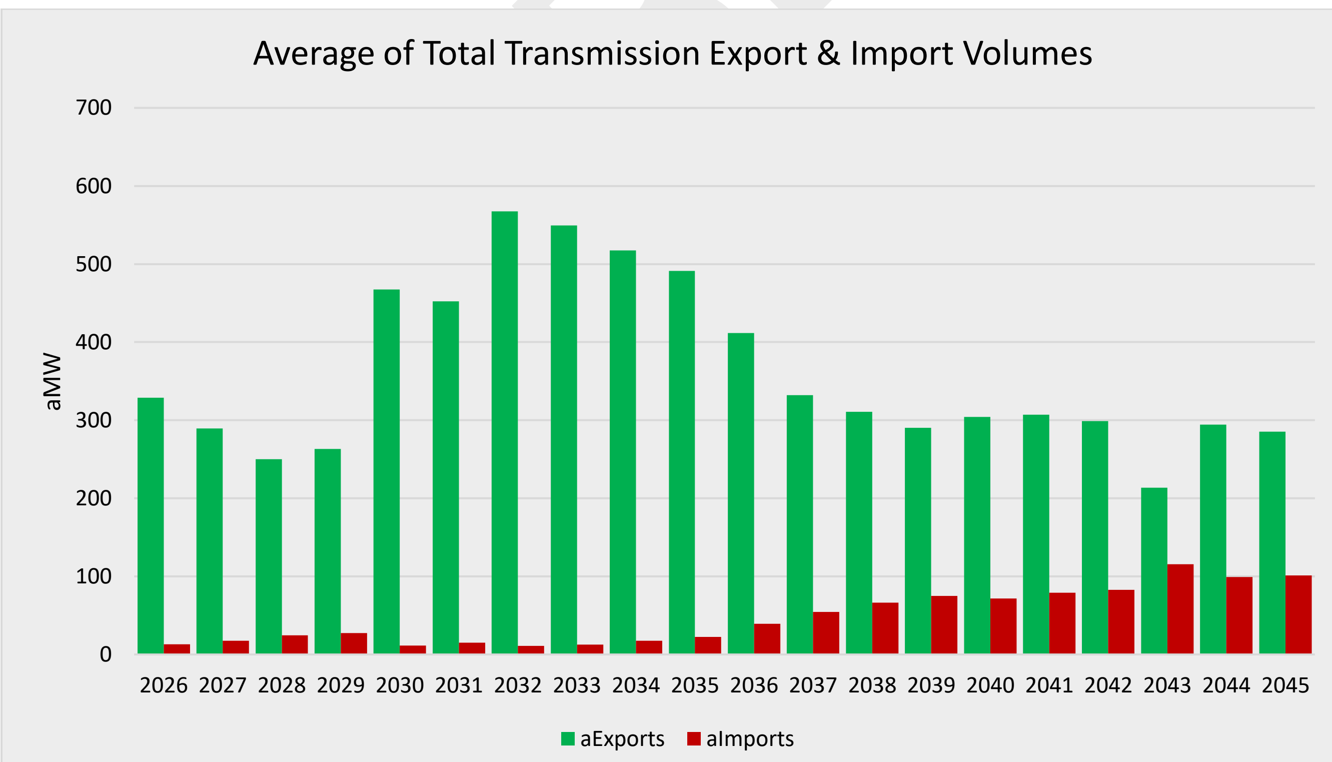

FIGURE 236: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO P.

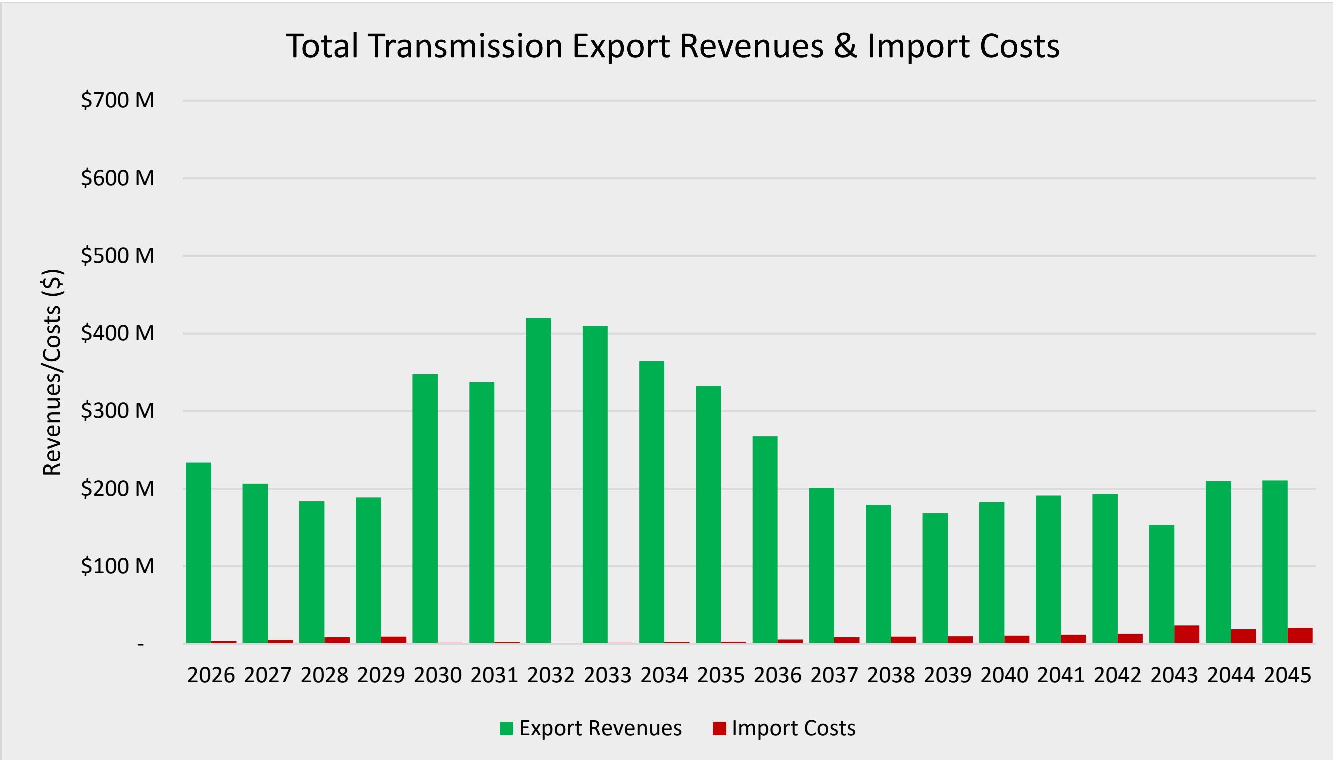

FIGURE 237: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO P.

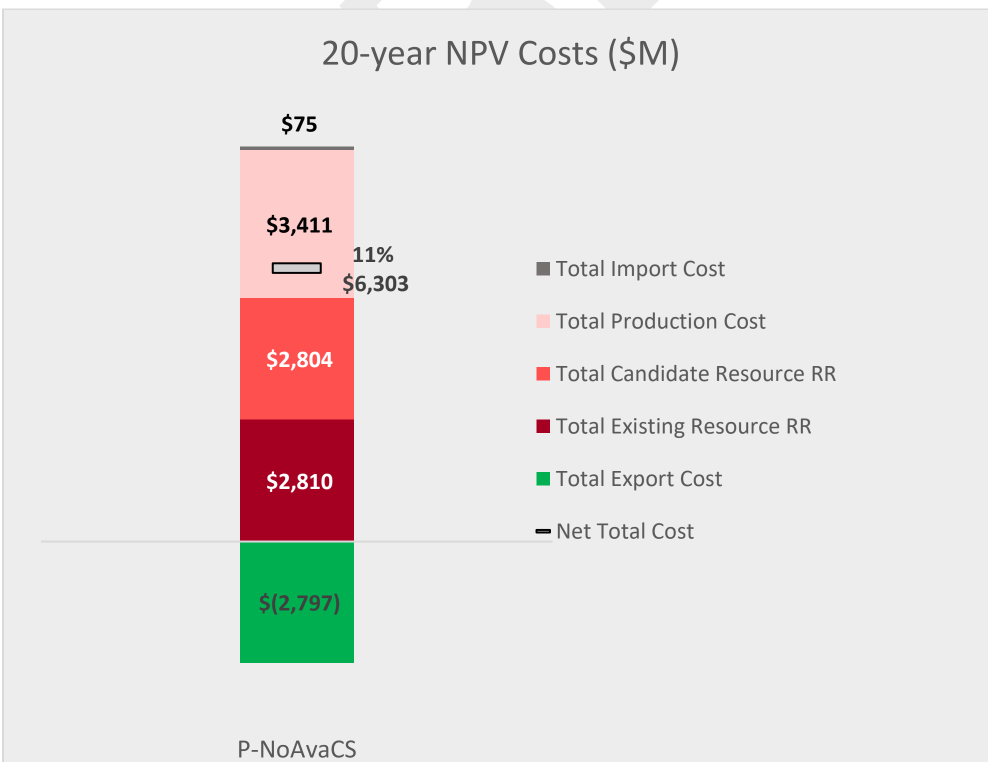

FIGURE 238: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO P.

16 PCM RESULTS: SCENARIO Q – ADD 300 MW OF NPC CAPACITY

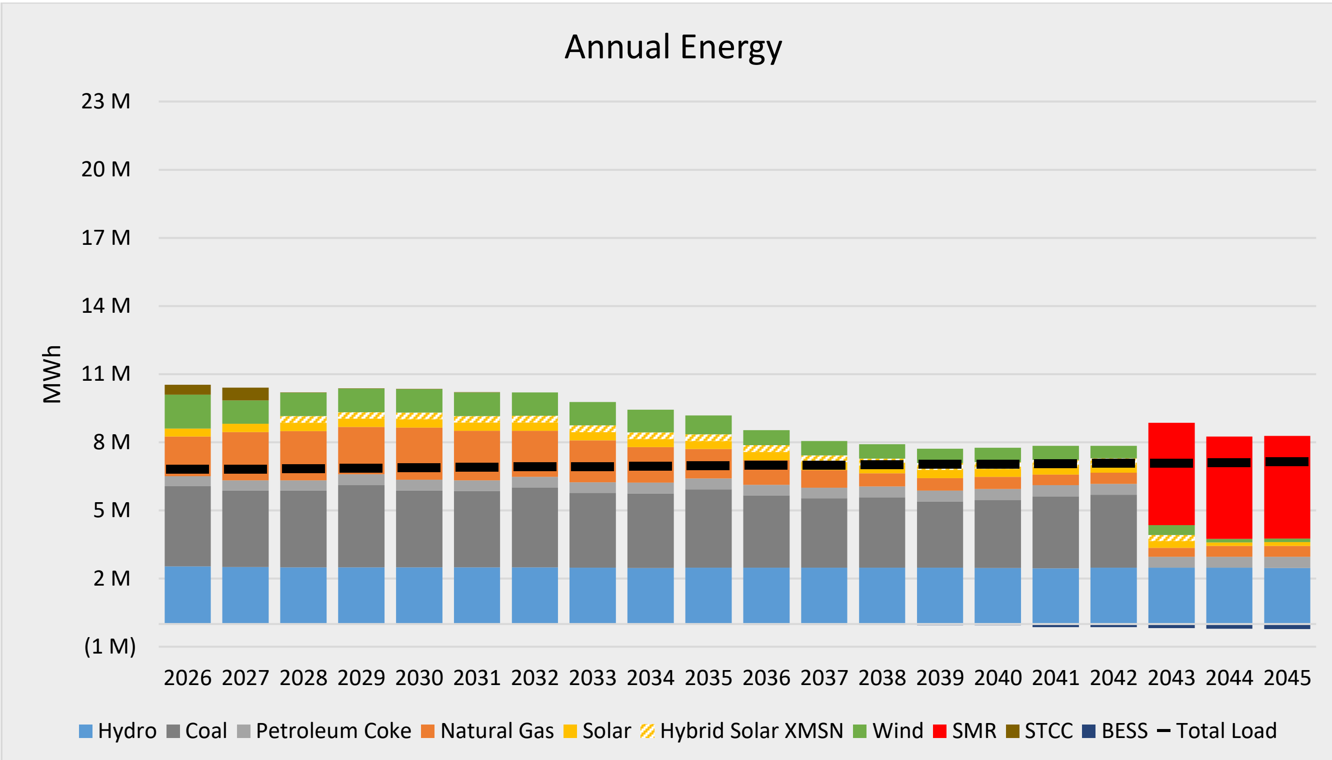

FIGURE 239: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO Q.

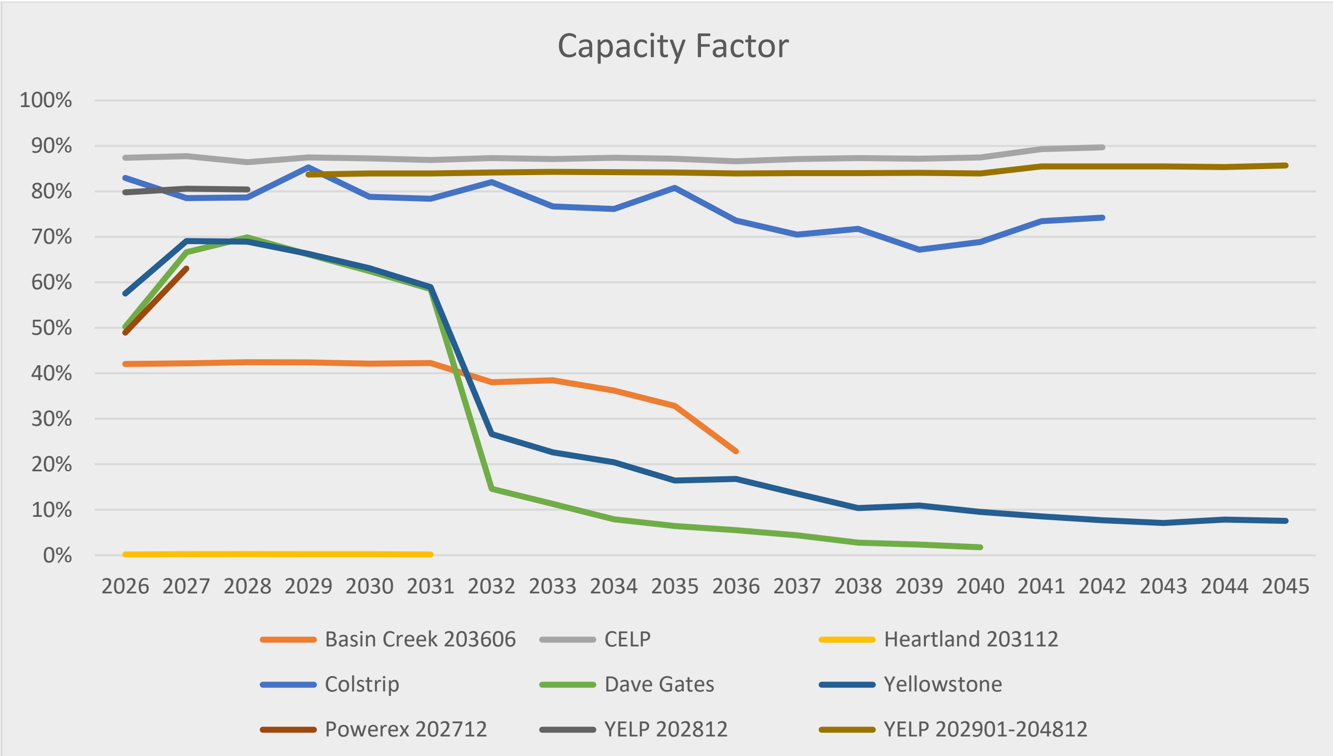

FIGURE 240: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO Q.

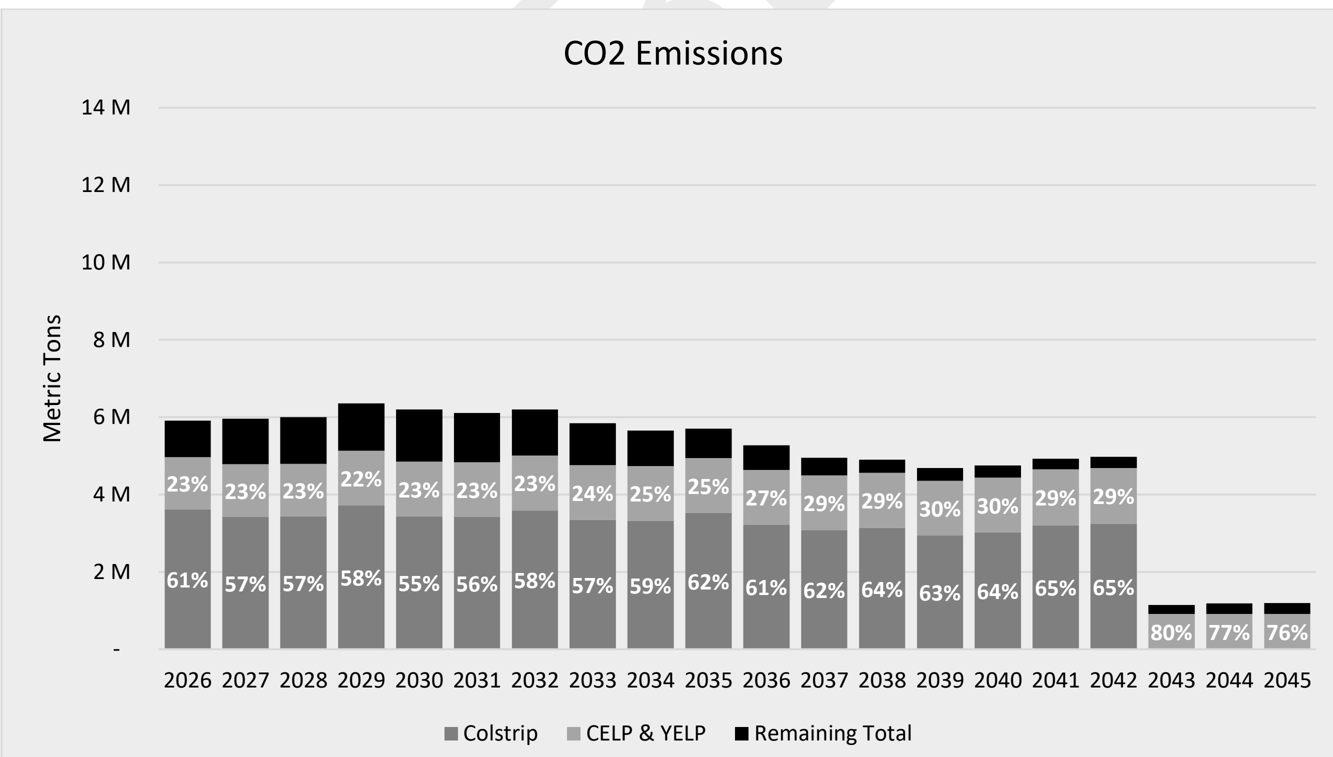

FIGURE 241: EMISSIONS FOR PCM RESULTS OF SCENARIO Q.

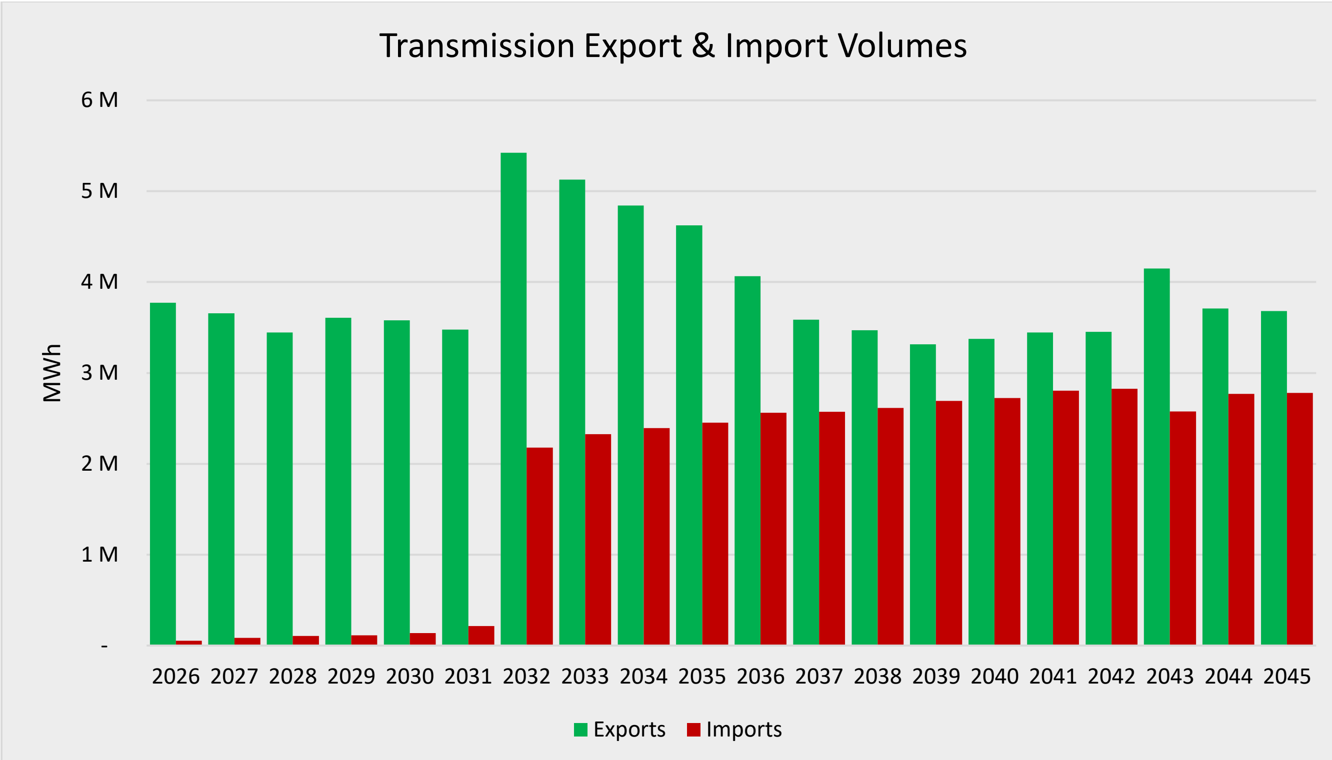

FIGURE 242: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO Q.

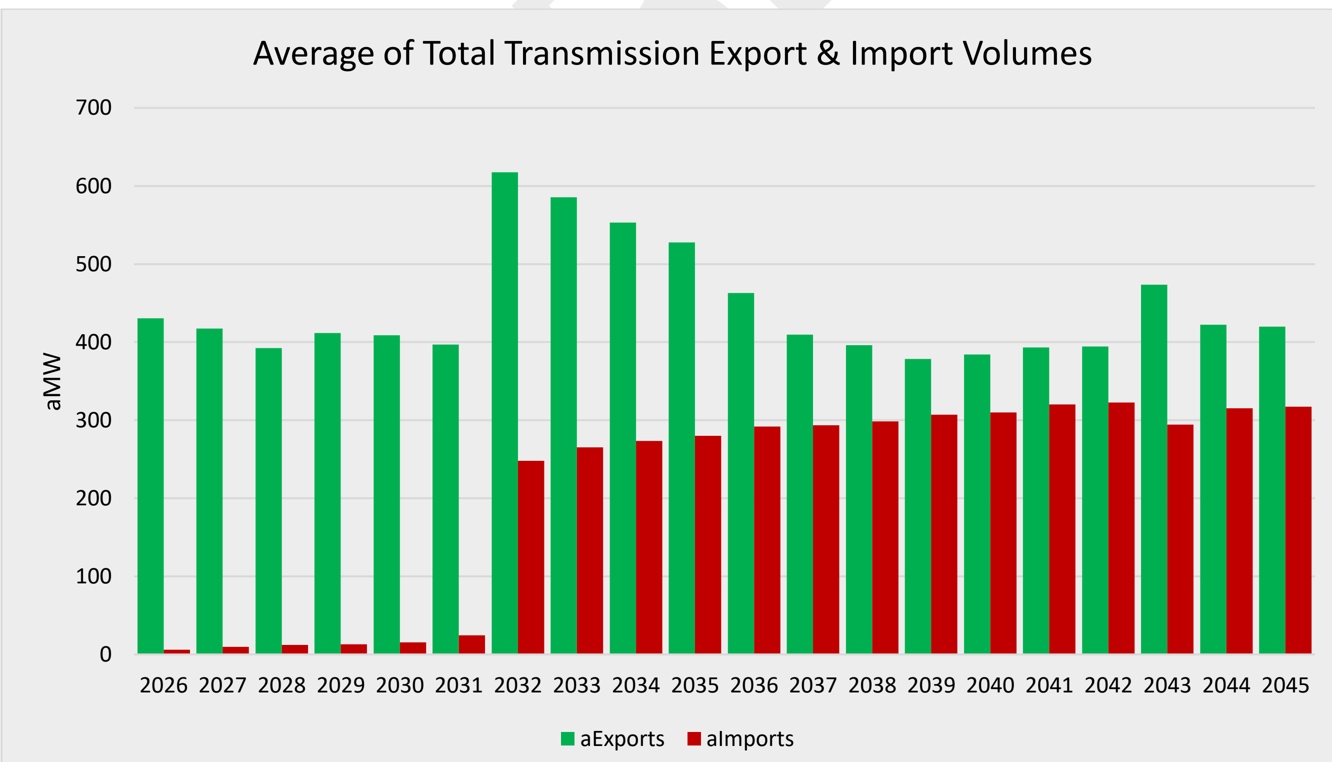

FIGURE 243: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO Q.

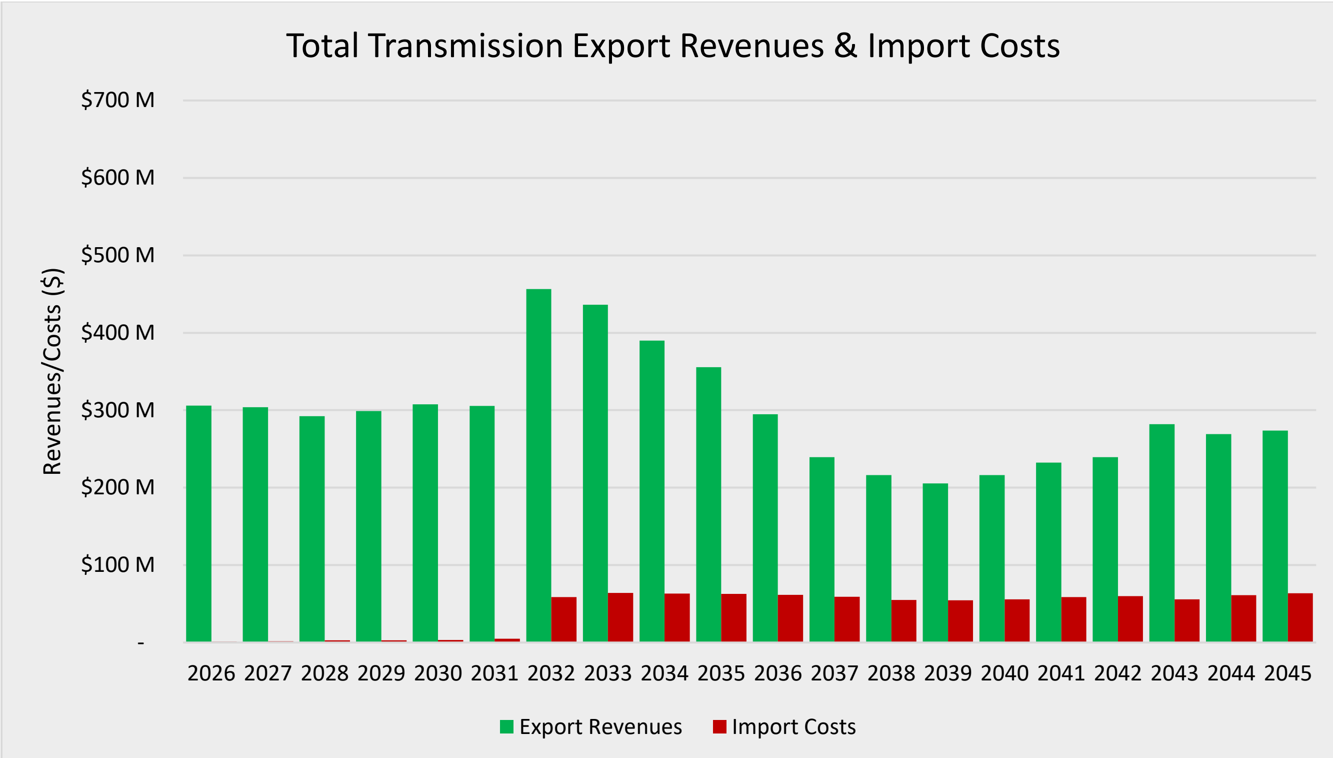

FIGURE 244: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO Q.

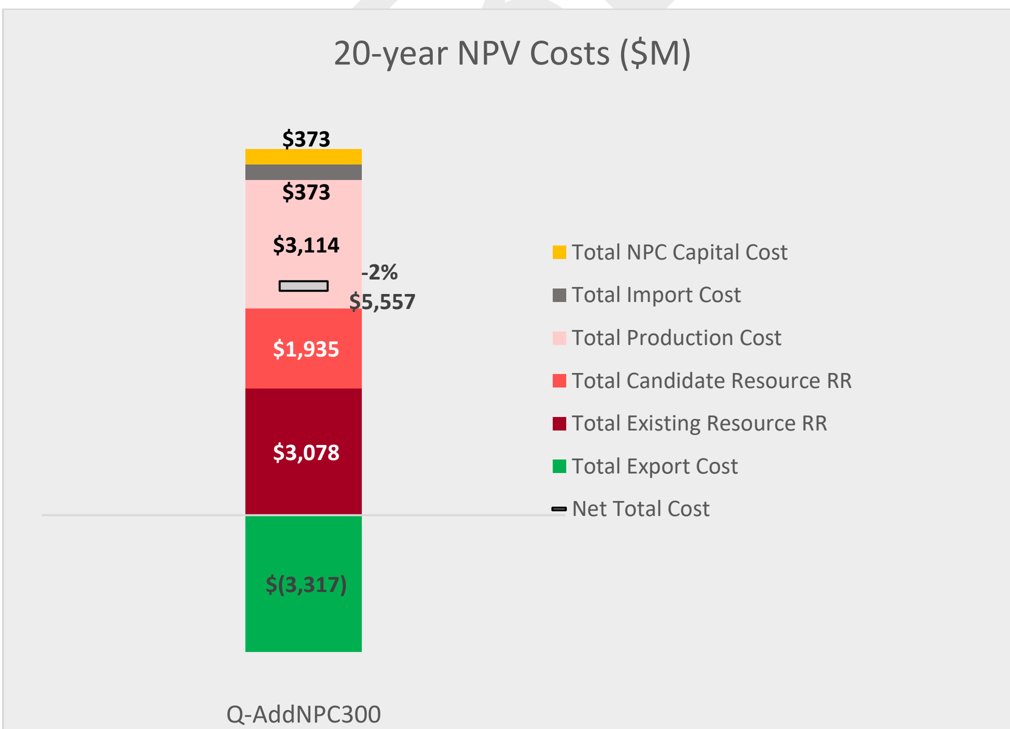

FIGURE 245: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO Q.

17 PCM RESULTS: SCENARIO R – INCREASE DSM AND NEM FORECASTS

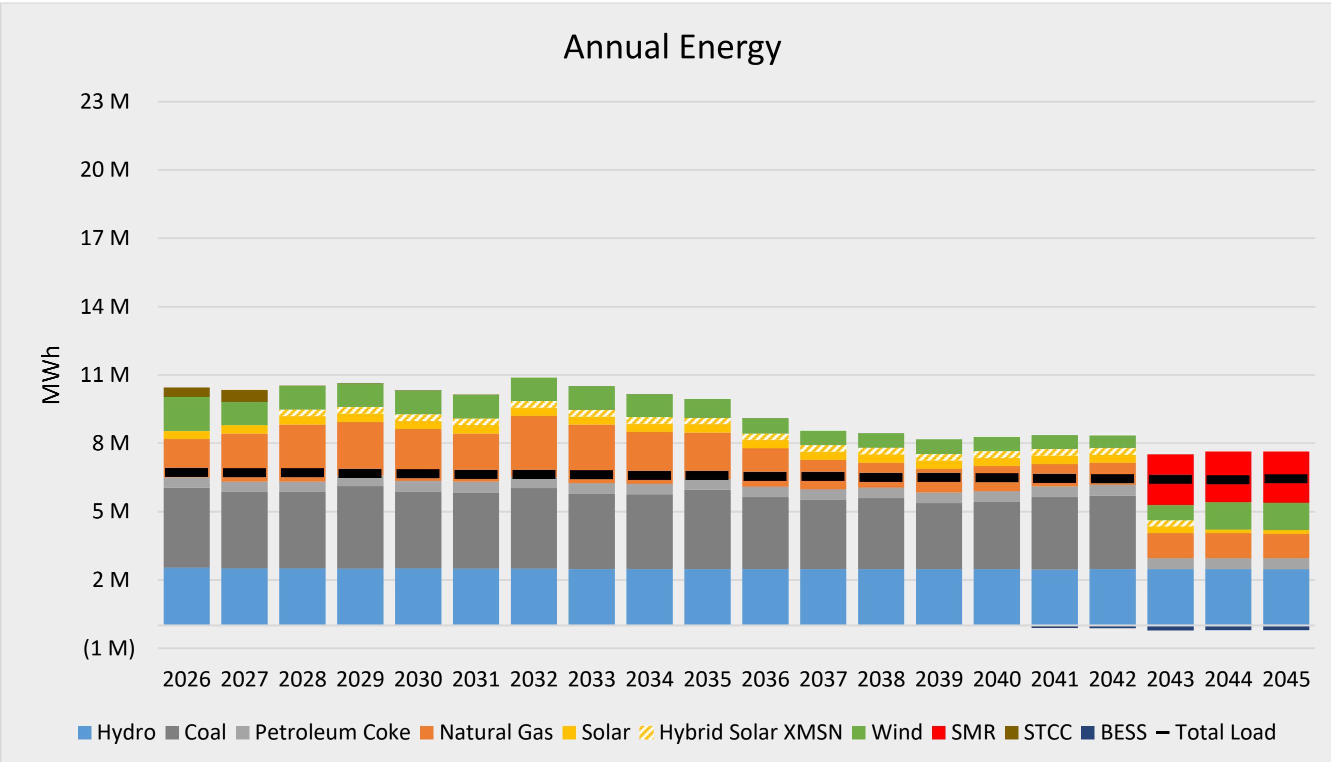

FIGURE 246: ENERGY PRODUCTION FOR PCM RESULTS OF SCENARIO R.

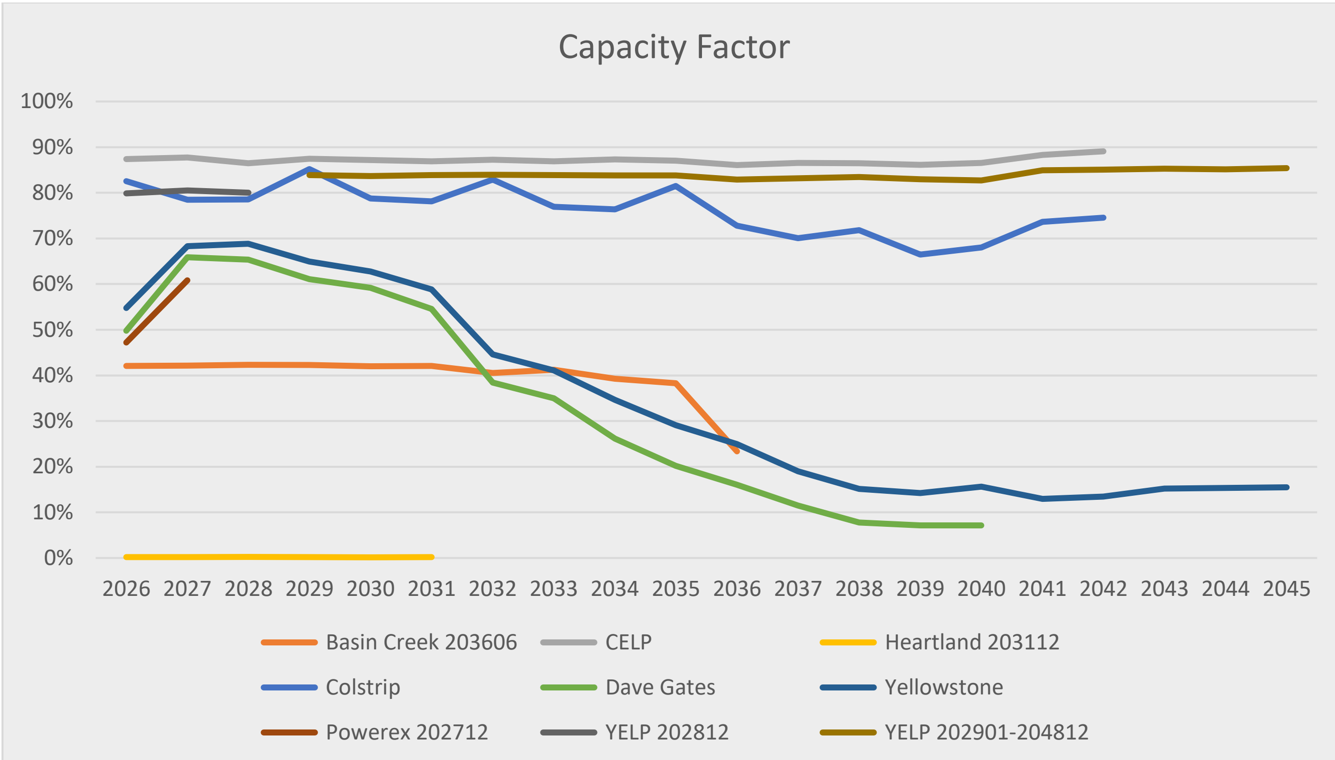

FIGURE 247: CAPACITY FACTOR FOR PCM RESULTS OF SCENARIO R.

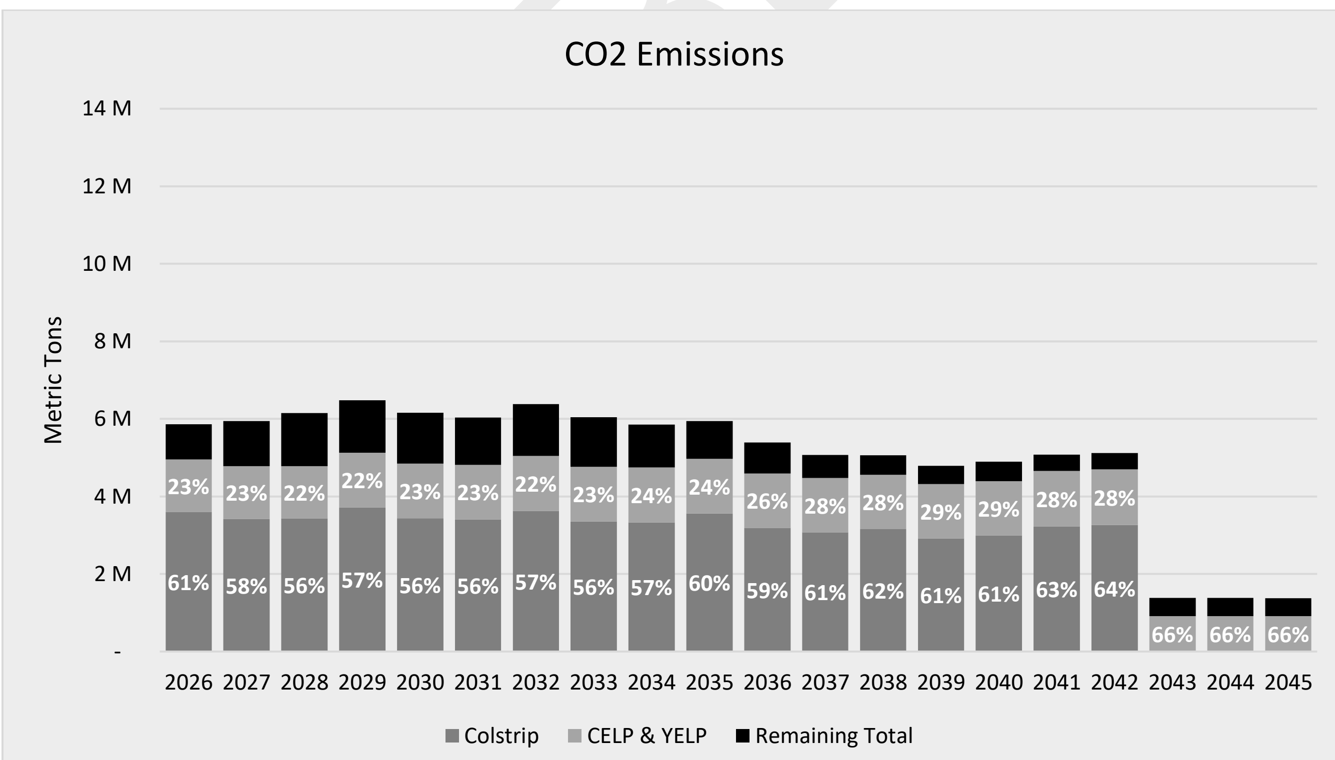

FIGURE 248: EMISSIONS FOR PCM RESULTS OF SCENARIO R.

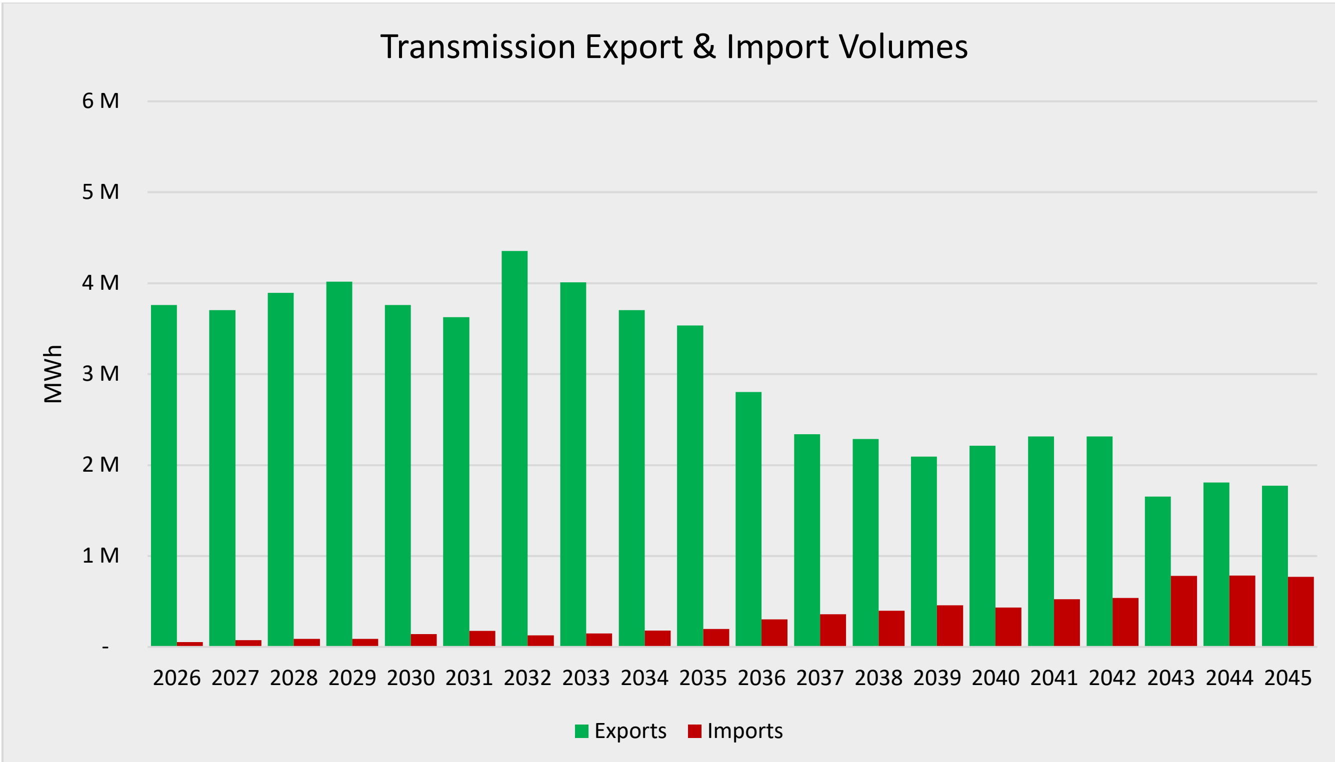

FIGURE 249: TRANSMISSION VOLUMES FOR PCM RESULTS OF SCENARIO R.

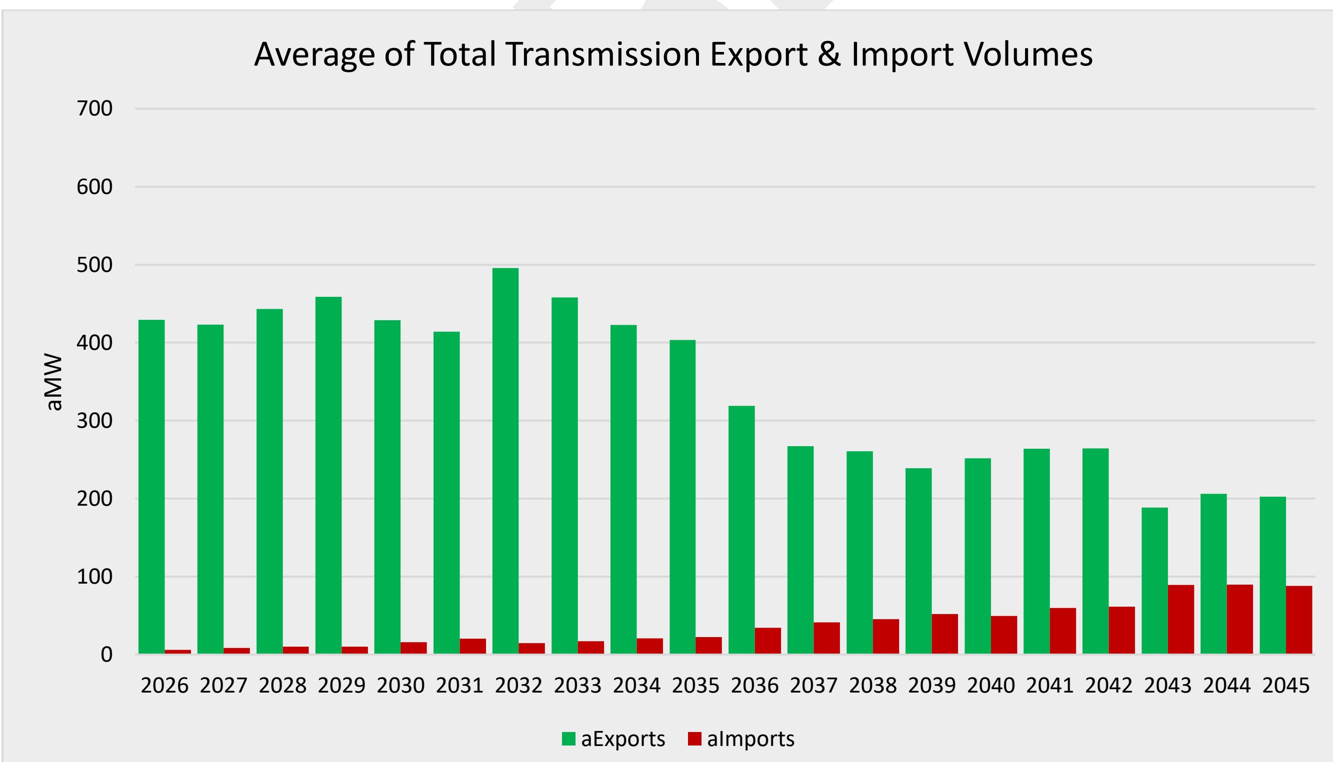

FIGURE 250: AVERAGE TRANSMISSION USAGE FOR PCM RESULTS OF SCENARIO R.

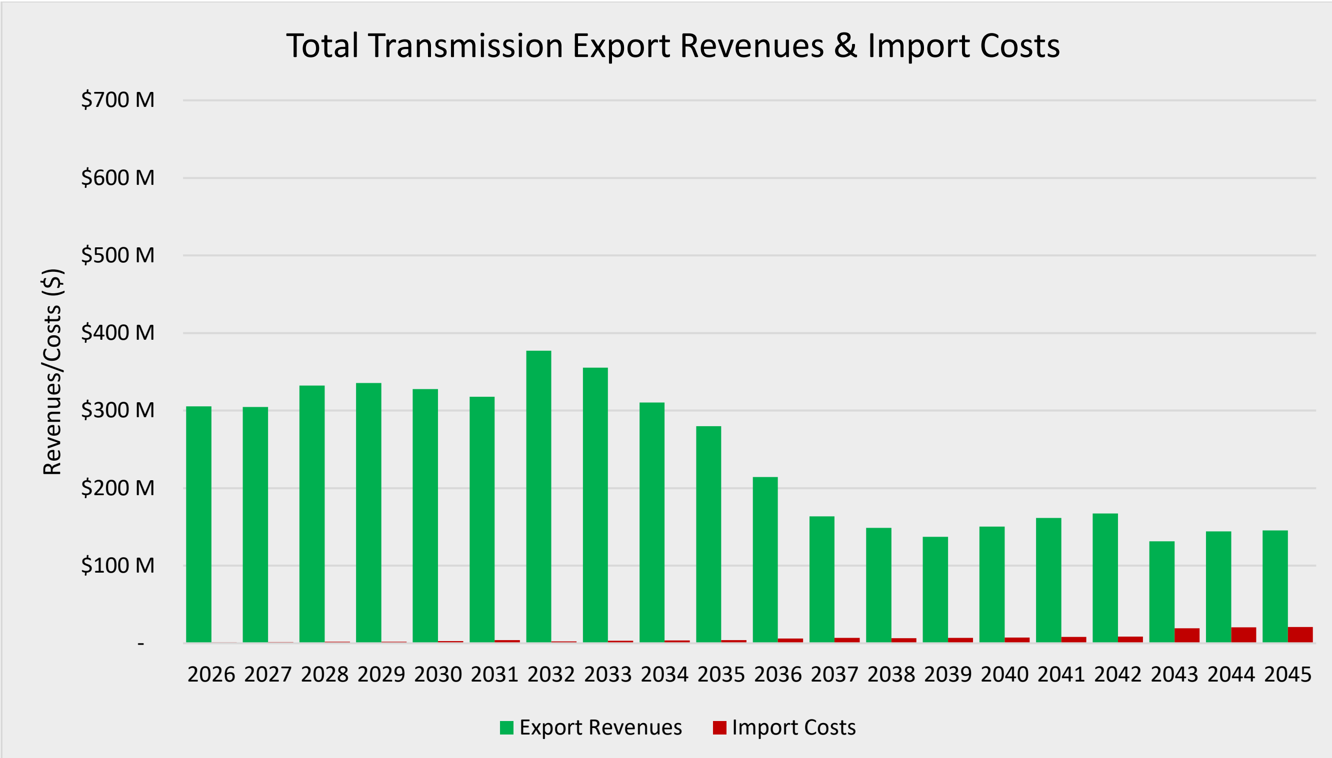

FIGURE 251: TRANSMISSION REVENUES FOR PCM RESULTS OF SCENARIO R.

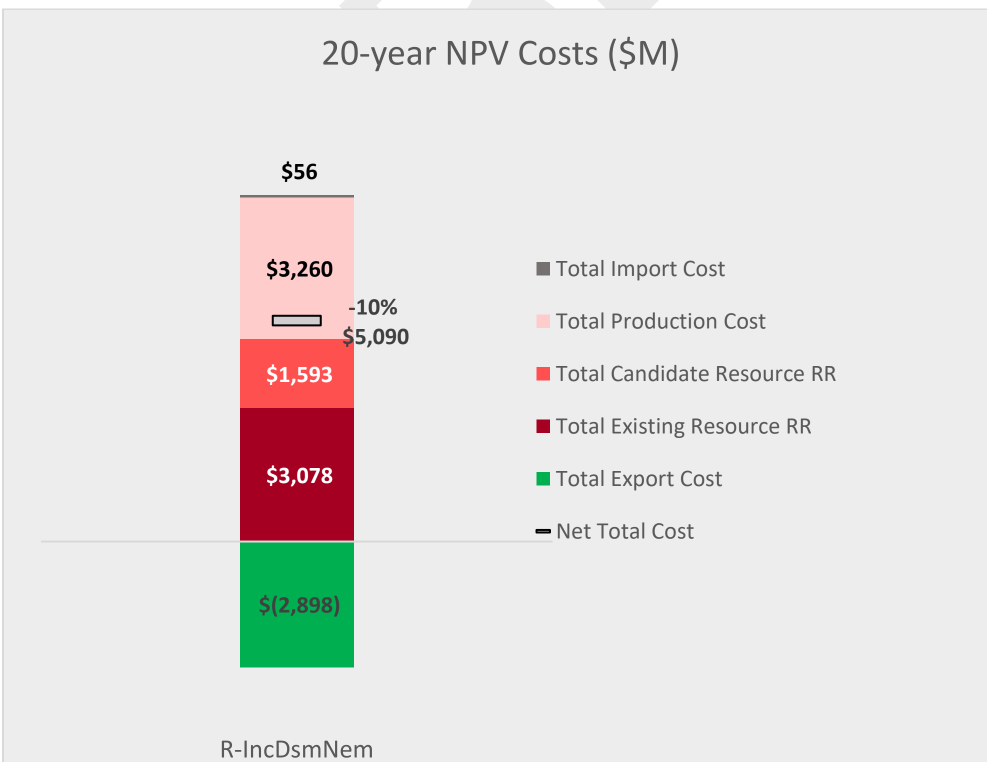

FIGURE 252: TOTAL PORTFOLIO COSTS FOR PCM RESULTS OF SCENARIO R.

APPENDIX F – ELECTRIC VEHICLE LOADING ANALYSIS

1 INTRODUCTORY STATEMENT

NorthWestern has continued to monitor EV adoption to understand and plan for, the system and supply impacts of EVs and EVSE. Due to differences in EV charging equipment and the utilization of this equipment, it is helpful to examine these current and potential system and supply impacts in terms of two distinct domains – private and public charging.

Private charging accounts for approximately 80-90% of all EV charging and is generally performed during the afternoon and nighttime hours at homes, garages, parking lots, and businesses. This charging infrastructure typically uses L1 or L2 chargers which range from 1 to 20 kW.[83] Public charging infrastructure is primarily used during daytime hours by travelers and/or visitors travelling large distances who prefer to charge quickly near highway or interstate corridors. This infrastructure is largely comprised of L3 or DCFC equipment which ranges from 50 to 350 kW.[84]

In the context of NorthWestern's Montana service territory, the growth of L1 and L2 charging is tied, in large part, to EV adoption rates within Montana whereas the utilization of public DCFC is more directly coupled with Montana's travel and tourism trends and with national EV adoption rates. Due to these differences in utilization, growth, and electrical demands, NWE has conducted separate analyses for private and public charging to evaluate the current and future impacts of EVs and EVSE on NorthWestern's system.

1.1 Private Charging:

In order to assess the impacts of private charging infrastructure, it is necessary to first understand the current and projected adoption of EVs within Montana. Since NorthWestern does not have its own data on the number of EVs driven by its customers, NorthWestern has utilized statewide EV registration data from the Montana DEQ and Atlas EV Hub.[85] This data indicates that, as of May 26th, 2025, there were 8,555 EVs registered in the state of Montana shown in Figure 253 and Table 64 as well as a steady increase in the historical number of EVs registered to the present date.

	Number of EVs Registered in Montana		
Year	BEVs	PHEVs	TOTAL
2025	5,803	2,752	8,555
2024	*No Data Provided		
2023	3,294	1,439	4,733
2022	1,893	1,002	2,895
2021	1,071	722	1,793
2020	517	426	943

TABLE 64: TABLE SHOWING THE NUMBER OF ELECTRIC VEHICLES REGISTERED IN MONTANA SINCE 2020.

[83] https://www.energy.gov/eere/evgrid-assist-charts-and-figures
[84] https://www.transportation.gov/rural/ev/toolkit/ev-basics/charging-speeds
[85] State EV Registration Data – Atlas EV Hub

**NOTE – 2024 data was unable to be obtained.*

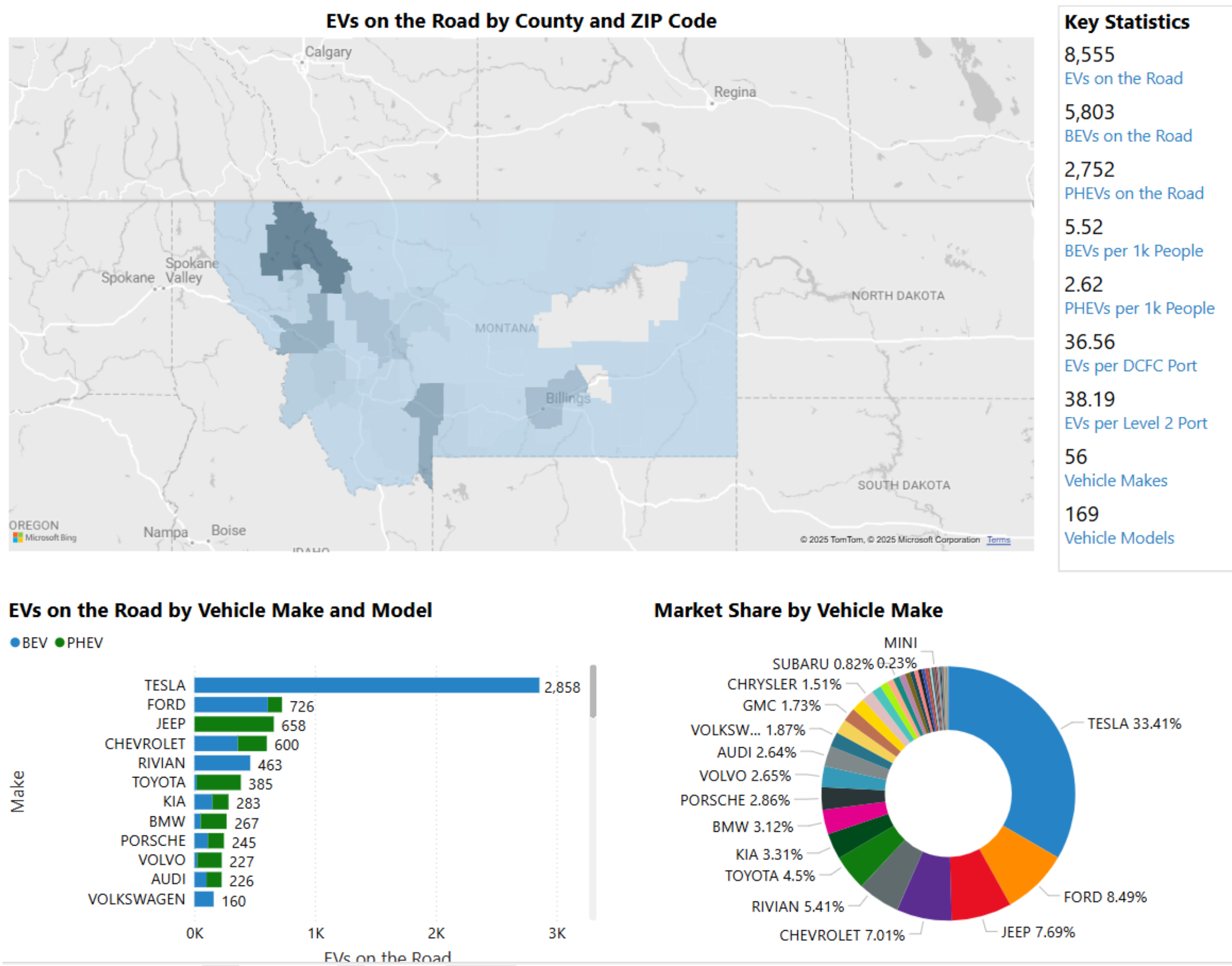

FIGURE 253: SCREENSHOT OF ATLAS EV HUB'S REGISTRATION DASHBOARD SHOWING THE TOTAL NUMBER OF EVS IN THE STATE OF MONTANA.

In addition to understanding the current and historical adoption of EVs in Montana it is also crucial to forecast the future adoption of EVs to understand what near-term and long-term impacts may result. In its 2023 IRP, NorthWestern developed its own growth models based on the historical adoption as well as utilized existing models developed for the Montana DEQ by its contractor AECOM.[86] Collectively, these models covered six different scenarios ranging from a low-adoption to a high-adoption future as shown in Figure 254. Before simply reusing these models for its 2025 analysis, NorthWestern first assessed the accuracy of these models in predicting numbers of EVs registered by 2025. Since the 2025 EV registration total did not significantly deviate from the previously forecasted models, NorthWestern elected to continue utilizing these models in its current assessment of private charging impacts.

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[86] https://deq.mt.gov/files/Energy/Transportation/MDEQ_EV_InfastructurePrioritizationStudy_Final.pdf

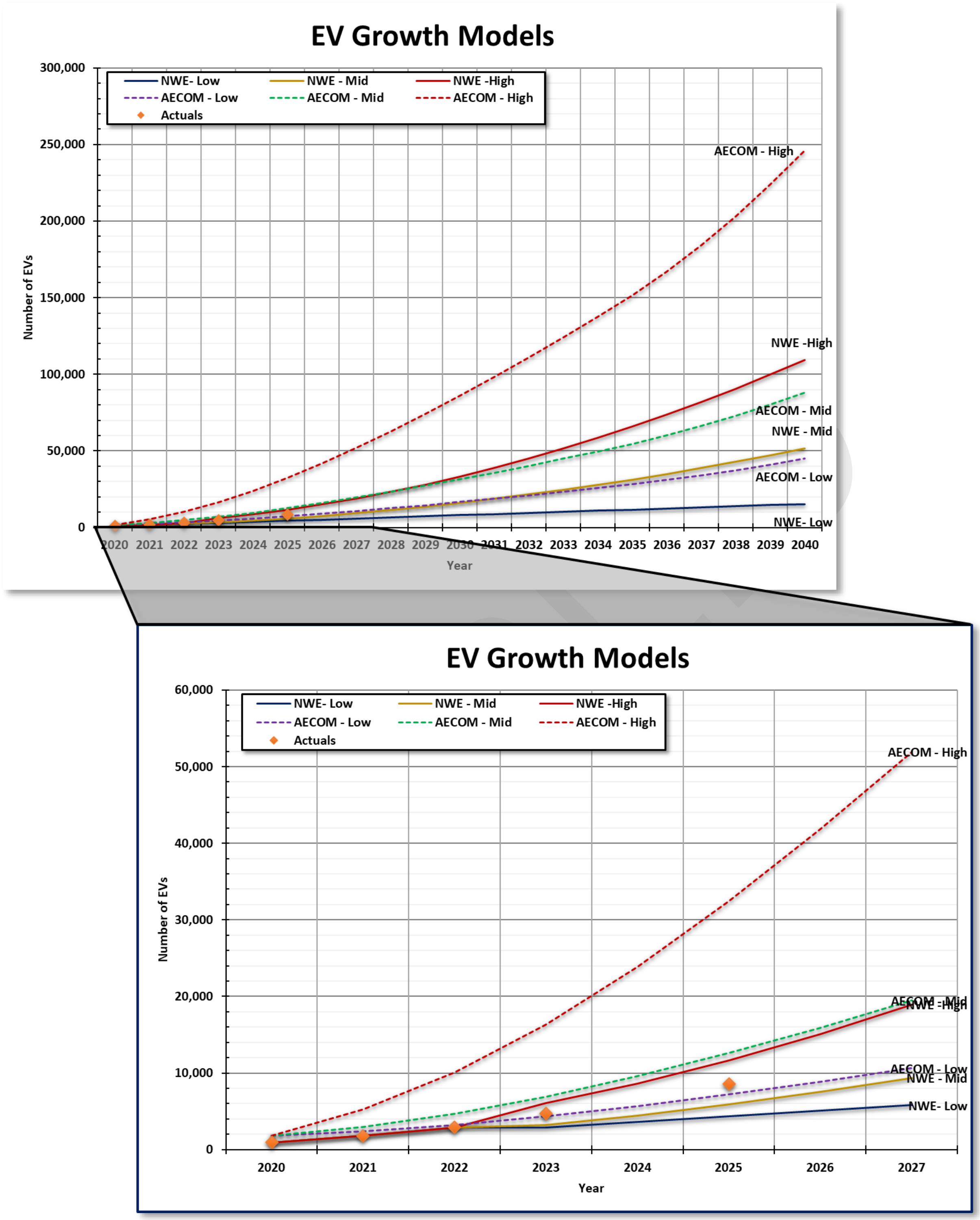
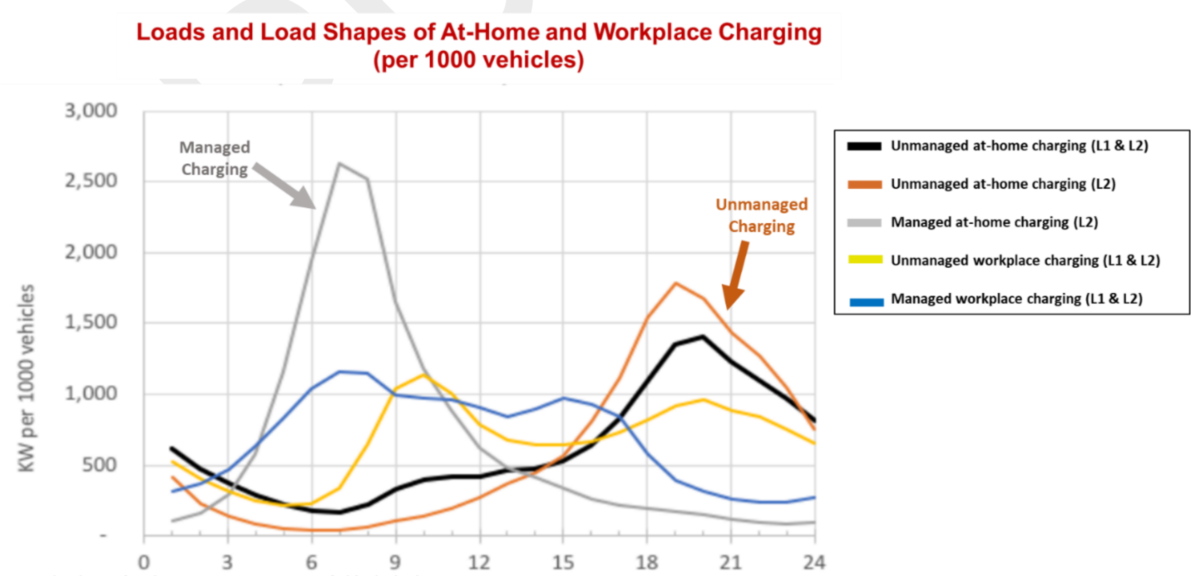


FIGURE 254: NORTHWESTERN ENERGY AND AECOM EV ADOPTION FORECASTS AND 2020-2025 ACTUALS.

NorthWestern then needed to identify a loading model to understand how past, present, and future EV adoption rates could translate into electrical loads. The selected model was developed by Pacific Northwest National Laboratory (PNNL) and describes the magnitude and shape of the load profiles of private charging across a variety of potential charging preferences.[87] The 5 scenarios identified in PNNL's study included:

1. a scenario in which most EV drivers charge at home using a combination of L1 and L2 charging equipment and the timing of that charging is not managed by either direct (e.g., active control of the EV or EVSE) or indirect means (e.g., time-of-use rates),
2. a scenario in which most EV drivers charge at home using primarily L2 charging equipment and the timing of that charging is not managed by either direct or indirect means,
3. a scenario in which most EV drivers charge at home using primarily L2 charging equipment, but the timing of that charging is managed by either direct or indirect means,
4. a scenario in which most EV drivers charge at work using a combination of L1 and L2 charging equipment and the timing of that charging is not managed by either direct or indirect means,
5. and a scenario in which most EV drivers charge at work using a combination of L1 and L2 charging equipment, but the timing of that charging is managed by either direct or indirect means.

As was done in 2023, NorthWestern's selected scenarios 2 and 3 for its analysis. Scenario 2 was selected because L2 charging equipment continues to be the preferred charging equipment for private charging, and at-home charging remains more common than workplace charging.[88,89] Scenario 3 was also selected to understand and quantify the potential system and supply benefits of an EV charging management program as other peer utilities offer today. As can be seen from Figure 255, the unmanaged L2 charging behavior results in an afternoon peak of approximately 1.75 MW per 1,000 EVs whereas the managed L2 charging behavior results in an afternoon peak of only about 0.25 MW per 1,000 EVs and an overnight/morning peak of approximately 2.5 MW per 1,000 EVs. In other words, these results indicate that managing private EV charging through mechanisms such as time-of-use rates and/or active EV/EVSE management could represent approximately 1.5 MW of flexible load per 1,000 EVs.



87 https://www.pnnl.gov/sites/default/files/media/file/EV-AT-SCALE_1_IMPACTS_final.pdf
88 https://afdc.energy.gov/fuels/electricity-infrastructure-trends
89 https://www.iea.org/reports/global-ev-outlook-2024/trends-in-electric-vehicle-charging?utm_source=web&utm_medium=article&utm_campaign=did_you_know

FIGURE 255: PACIFIC NORTHWEST NATIONAL LABORATORY'S AGGREGATED EV CHARGING PROFILES.

After defining both an EV growth model and a loading model for EV charging, NorthWestern was then able to summarize the findings in terms of anticipated load during afternoon peak hours due to private charging of EVs for both managed and unmanaged charging behavior, which is shown below in Table 65.

Estimated Afternoon Peak Loads Due to At-Home EV Charging[90]			
	2025	***2030***	***2035***
Number of EVs (*NWE mid-adoption forecast)*	**8,555**	***16,069***	***31,287***
Unmanaged At-Home L2 Charging Load	15 MW	*28.1 MW*	*54.8 MW*
Managed At-Home L2 Charging Load	N/A	*4 MW*	*7.8 MW*
Number of EVs (*AECOM mid-adoption forecast)*		***31,480***	***54,620***
Unmanaged At-Home L2 Charging Load		*55.1 MW*	*95.6 MW*
Managed At-Home L2 Charging Load		*7.9 MW*	*13.7 MW*

TABLE 65: SUMMARY OF POTENTIAL LOAD DURING AFTERNOON PEAK HOURS DUE TO AT-HOME CHARGING OF ELECTRIC VEHICLES FOR BOTH MANAGED AND UNMANAGED CHARGING BEHAVIOR.

The results of this analysis suggest that NorthWestern may be experiencing up to 15 MW of afternoon loads from existing private EV charging in Montana today. However, it is important to note that the past, present, and future EV adoption values show above include all of Montana rather than just NorthWestern electric service territory. For instance, Flathead County which NorthWestern does not provide electricity to, accounts for 27% of the EVs currently registered in Montana. Accordingly, NorthWestern actual electric loads resulting from private charging today may be closer to 11 MW.

NorthWestern's analysis also suggests that 28-55 MW of unmanaged private charging load may be present in Montana by 2030 and 55-96 MW of load may be present by 2035. Or, looking within NorthWestern's service territory, this translates to approximately 20-40 MW by 2030 and 40-70 MW by 2035. If, however, NorthWestern were to implement an EV charging management program, the resulting loads are anticipated to be closer to 3-6 MW by 2030 or 6-10 MW by 2035.

1.2 Public Charging

NorthWestern also recognized the need to understand the impacts and growth of public charging across Montana. As mentioned above, the utilization of public charging is not only tied to EV adoption within Montana, but it is also (and perhaps to a greater extent) tied to tourism and travel trends within the state as well as national EV adoption since much of this infrastructure is used by travelers or by people who may be unable to use private/L2 charging. As a result, it is challenging to forecast public/DCFC load growth in the same manner as was done for private charging – especially because the actual load growth is largely dependent upon the installation of DCFC infrastructure rather than the general adoption rates of EVs. Instead, NorthWestern chose to evaluate the historical demands of currently-installed DCFC infrastructure as well as consider both the near-term/planned buildout of a

[90] Load estimates are based on the EV forecast model specified in the table and on Pacific Northwest National Laboratory's, *Electric Vehicles at Scale – Phase 1: High EV Adoption Impacts on the Wester U.S. Power Grid* research paper. PNNL's "at-home" charging scenarios are utilized which assume 91% of private EV charging is done at home.

DCFC network (as proposed in MDEQ's Montana Electric Vehicle Infrastructure Deployment Plan)[91] and the longer-term potential buildout of a more extensive DCFC network.

For its assessment of currently installed DCFC infrastructure, NorthWestern utilized data provided by the U.S. DOE.[92] As of this analysis, in Montana there are currently 47 operational DCFC stations and 241 DCFC ports – totaling 51.97 MW of nameplate capacity, shown in Figure 256. Since 2022, there has been a significant increase in the frequency of new DCFC station installations. This uptick has resulted in a notable increase to the quantity of DCFC ports available and the total installed DCFC nameplate capacity – suggesting that these newer stations are larger and higher-powered than those of the past. Figure 257 shows increase in DCFC stations, ports, and total installed nameplate capacity.

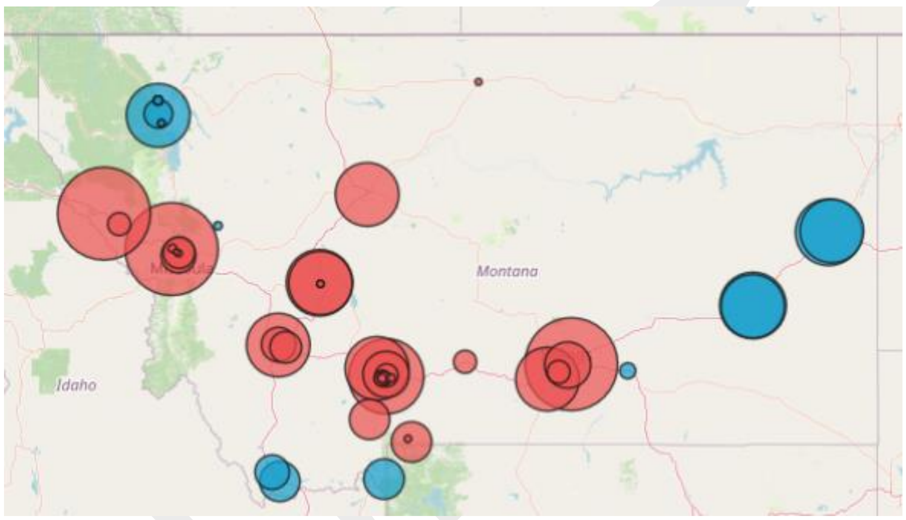


FIGURE 256: INSTALLED DCFC STATIONS ACROSS MONTANA (RED INDICATES STATIONS SERVED BY NORTHWESTERN ENERGY AND THE SIZE DENOTES THE RELATIVE NAMEPLATE CAPACITY OF EACH STATION).

[91] State Plan Template for Electric Vehicle Infrastructure Deployment (mt.gov)
[92] https://afdc.energy.gov/stations#/find/nearest

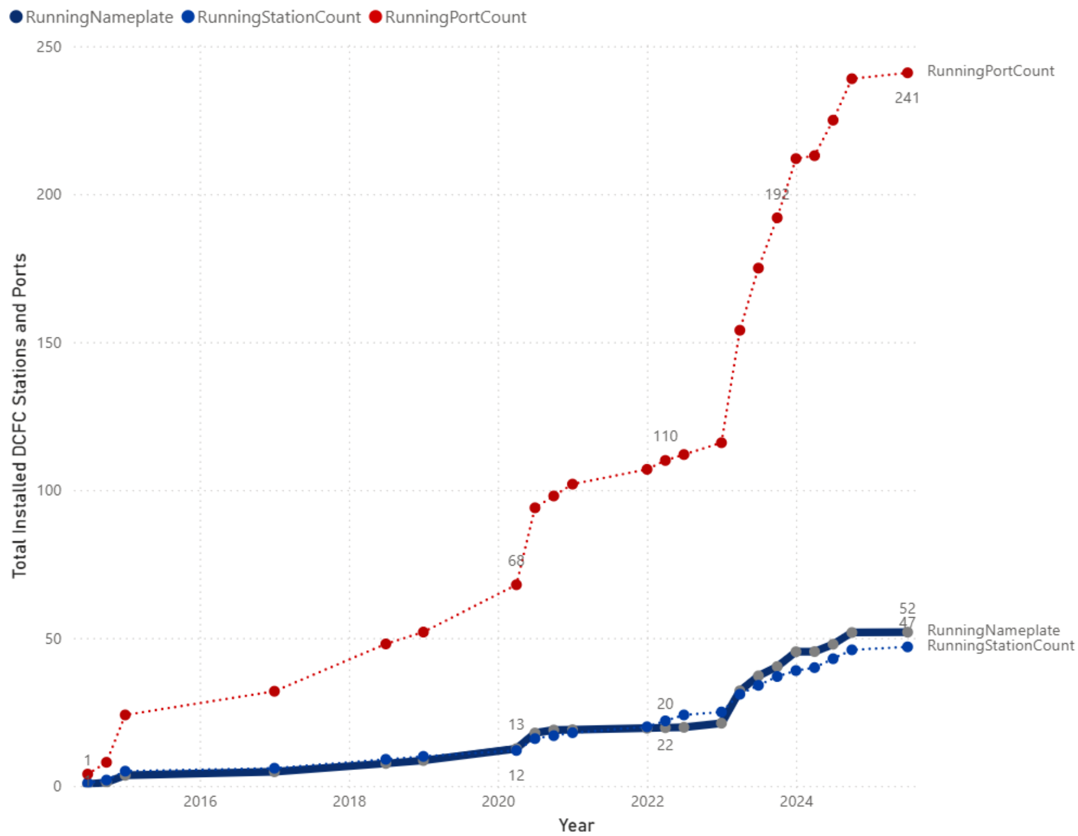


FIGURE 257: INSTALLED DCFC STATIONS, PORTS, AND TOTAL CAPACITY ACROSS MONTANA.

Of the 47 DCFC stations in Montana, NorthWestern currently serves 33 – totaling 168 ports and a combined capacity of 36.49 MW. Of these 33 stations, 27 (with a combined nameplate of 35.55 MW) are separately metered using AMI meters which provide NorthWestern with the ability to analyze the historical hourly combined loads of these 27 stations. By looking at the historical hourly usage of these stations, NorthWestern can better understand how, when, and where these stations are being most heavily utilized, and if any broad usage trends exist over time. One of the first clear trends that emerges from this data is the daily and seasonal usage of these stations shown in Table 66 and Table 67. In short, these stations tend to be most heavily utilized during midday and afternoon hours, on Fridays and weekends, and during the summer months.

interval_hour	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	**Total**
0	6.04	5.64	4.53	4.91	5.21	6.36	6.80	**5.64**
1	4.38	4.38	3.94	4.00	3.68	5.16	5.26	**4.40**
2	3.37	3.29	3.07	3.15	2.95	3.56	4.03	**3.35**
3	3.40	2.87	2.75	2.74	2.84	3.45	3.36	**3.06**
4	2.69	2.76	2.80	2.72	2.63	3.42	3.09	**2.87**
5	3.62	4.04	3.53	3.02	3.17	3.85	3.57	**3.54**
6	6.12	6.08	5.31	5.30	5.96	7.23	6.85	**6.12**
7	10.91	10.54	9.65	10.15	9.78	11.31	12.15	**10.65**
8	18.63	16.55	15.21	14.97	15.32	18.54	18.90	**16.88**
9	25.23	22.90	20.47	21.40	21.23	25.45	27.88	**23.52**
10	36.50	29.11	25.57	25.86	28.67	33.15	35.28	**30.62**
11	42.52	34.42	29.29	30.46	33.49	37.66	40.34	**35.48**
12	49.19	37.83	32.36	33.73	36.03	43.54	42.93	**39.40**
13	48.63	37.72	33.39	33.95	37.79	44.82	45.31	**40.26**
14	46.76	35.91	32.84	33.62	37.58	43.81	44.02	**39.25**
15	45.20	35.97	32.36	34.30	38.29	43.89	43.58	**39.11**
16	42.50	34.08	31.91	32.66	36.91	44.46	40.49	**37.60**
17	38.60	32.84	29.23	33.18	34.81	40.49	36.71	**35.13**
18	31.94	27.37	26.89	28.38	30.10	34.88	31.33	**30.14**
19	25.68	23.18	22.00	23.18	25.31	29.25	26.81	**25.07**
20	21.37	17.63	17.63	18.43	20.97	25.51	22.49	**20.59**
21	16.11	13.90	13.64	13.70	15.65	20.48	17.43	**15.86**
22	10.94	9.45	10.02	10.94	11.83	13.68	12.79	**11.39**
23	7.50	6.25	6.98	7.43	7.86	9.43	8.63	**7.73**
Total	**22.84**	**18.95**	**17.31**	**18.01**	**19.54**	**23.09**	**22.50**	**20.33**

TABLE 66: AVERAGE USAGE OF NWE-SERVED DCFC STATIONS BY HOUR OF DAY AND WEEKDAY.

interval_hour	1	2	3	4	5	6	7	8	9	10	11	12	**Total**
0	3.91	3.35	4.23	4.82	5.42	6.64	9.18	9.28	7.38	5.72	3.47	4.58	**5.64**
1	3.04	2.77	3.50	3.89	4.16	5.58	6.73	6.30	5.73	4.66	3.08	3.50	**4.40**
2	2.60	2.24	2.84	2.45	3.12	3.95	4.91	4.67	4.72	3.90	2.26	2.87	**3.35**
3	2.07	2.23	2.57	2.58	2.90	3.59	4.39	4.64	3.56	3.84	2.15	2.50	**3.06**
4	2.28	1.94	2.38	2.45	3.06	3.43	3.68	4.40	3.31	2.99	2.42	2.41	**2.87**
5	2.34	2.19	2.75	2.88	3.83	4.71	5.01	5.27	4.35	4.04	2.51	2.78	**3.54**
6	3.09	3.61	4.08	4.94	7.02	8.28	10.79	10.13	6.99	6.17	3.98	4.01	**6.12**
7	5.42	5.73	7.39	8.50	11.44	15.64	18.62	16.48	13.06	10.38	6.97	7.27	**10.65**
8	7.68	9.49	11.10	14.86	17.88	23.62	29.47	27.17	20.94	17.32	12.02	11.00	**16.88**
9	10.84	12.57	15.32	18.03	24.11	33.56	42.38	39.99	31.07	23.39	16.89	15.20	**23.52**
10	14.28	16.22	19.75	23.75	31.05	44.02	52.96	50.69	41.99	30.89	24.24	20.70	**30.62**
11	18.34	19.89	21.99	28.55	34.24	50.44	62.17	59.70	45.54	35.29	26.00	25.72	**35.48**
12	20.87	20.52	25.16	30.72	38.92	56.38	70.42	64.52	52.86	36.91	28.69	28.15	**39.40**
13	23.50	21.43	25.01	32.21	38.82	57.33	70.74	68.59	53.33	39.39	29.03	26.46	**40.26**
14	20.59	22.19	24.75	32.17	37.76	55.18	70.42	65.72	51.91	36.90	26.84	27.49	**39.25**
15	20.55	22.23	23.77	32.21	39.05	55.29	68.52	66.72	51.81	38.54	26.80	25.86	**39.11**
16	20.80	21.81	25.87	30.13	37.19	53.01	67.44	60.51	48.61	34.44	24.23	25.39	**37.60**
17	20.02	20.02	23.26	27.87	34.66	50.84	60.42	58.30	44.26	35.02	23.89	23.45	**35.13**
18	16.12	17.05	18.66	23.94	29.49	43.71	51.99	50.15	40.24	31.19	22.95	19.09	**30.14**
19	13.46	13.99	16.47	20.83	25.91	35.44	42.06	43.01	32.96	24.69	17.92	15.61	**25.07**
20	11.28	11.28	13.33	17.30	21.39	30.60	36.17	33.93	25.60	18.52	13.88	12.63	**20.59**
21	8.81	8.82	10.67	12.59	17.82	24.59	26.15	26.94	17.70	15.09	9.60	9.81	**15.86**
22	5.90	6.06	7.12	9.86	11.81	17.29	19.16	18.64	14.56	10.76	6.87	7.97	**11.39**
23	4.27	4.38	5.12	6.28	7.01	10.92	13.63	13.08	9.93	7.12	5.44	5.84	**7.73**
Total	**10.92**	**11.34**	**13.23**	**16.47**	**20.34**	**28.92**	**35.32**	**33.71**	**26.35**	**19.88**	**14.25**	**13.77**	**20.33**

TABLE 67: AVERAGE USAGE OF NWE-SERVED DCFC STATIONS BY HOUR OF DAY AND MONTH.

It is also possible to observe geographical differences in the utilization of these stations. Looking at each of the cities these stations are located in, it becomes clear that the average usage of certain cities are higher than others, yet the general load shape of each station remains similar – with most usage occurring during midday and afternoon hours as seen in Figure 258.

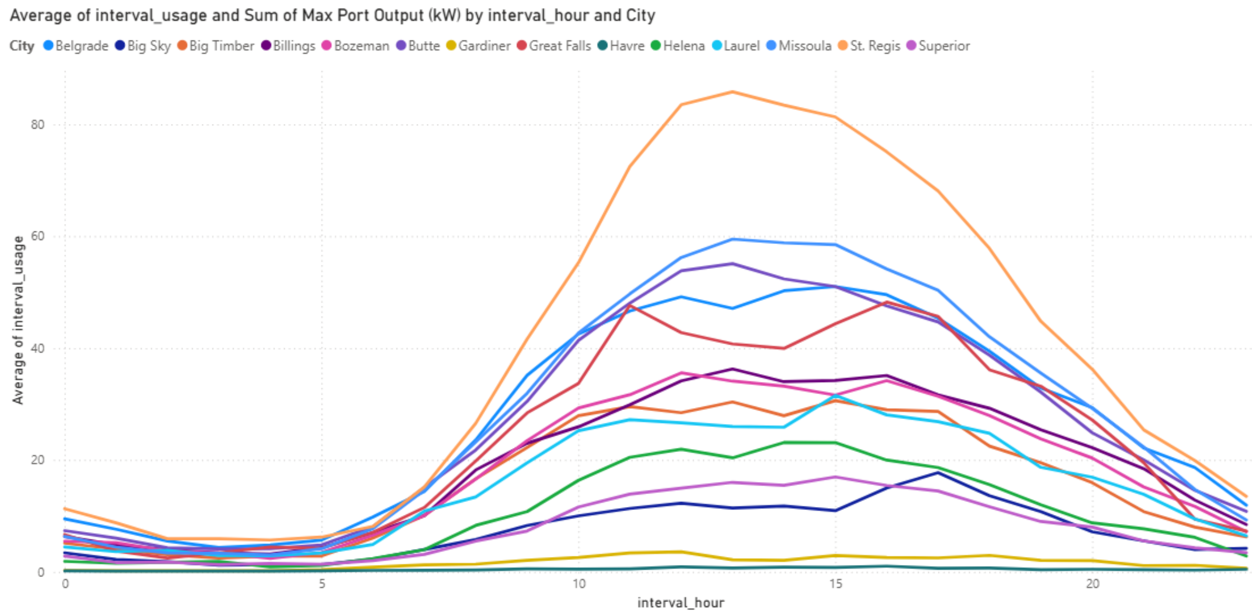


FIGURE 258: AVERAGE USAGE OF DCFC STATIONS BY CITY AND HOUR OF DAY.

Lastly, by looking back over historical usage NorthWestern can also assess trends that may be helpful in understanding future load impacts of DCFC infrastructure. For instance, it can be observed that, both the DCFC installed nameplate capacity and actual peak usages of installed stations have grown over time which is seen in Figure 259. In particular, nameplate capacity has grown from 11.5 MW in 2022 to 36 MW in 2025 (approximately a 300% increase), the maximum peak hourly load observed has also grown from 1 MW in 2022 to 3.1 MW in 2025 (also a 300% increase). While it cannot be certain that this trend will continue indefinitely, it does provide a meaningful guideline for estimating the anticipated actual peak loads resulting from planned DCFC infrastructure development.

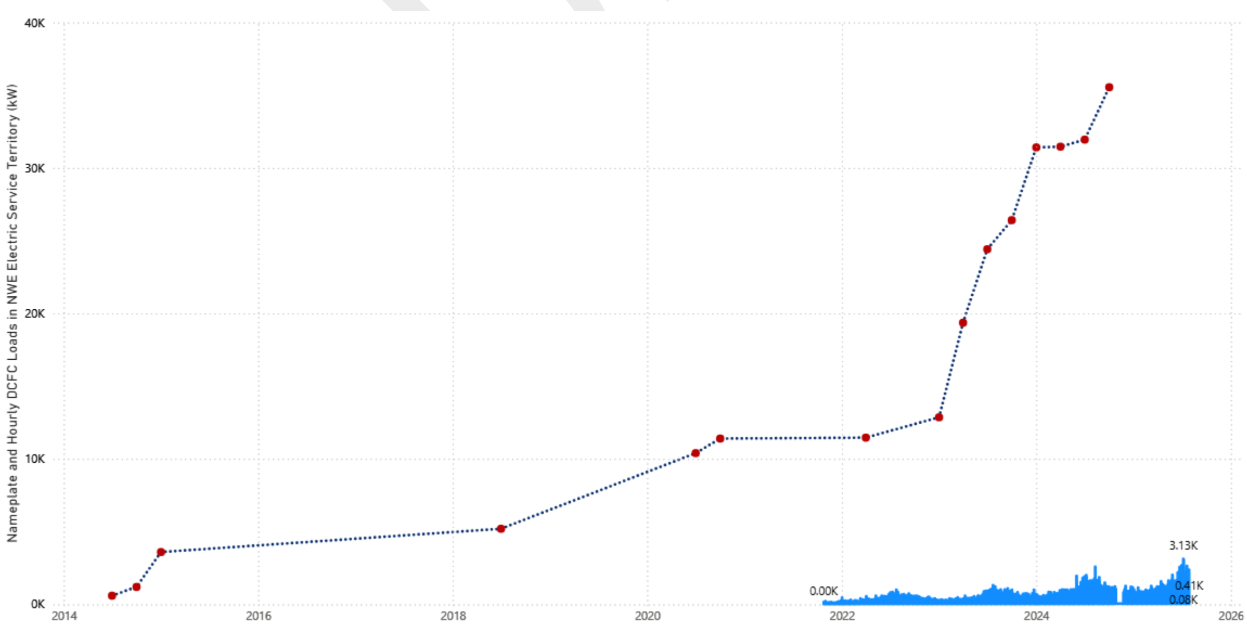


FIGURE 259:INSTALLED DCFC NAMEPLATE CAPACITY IN NWE'S SERVICE TERRITORY (RED) VS. OBSERVED COINCIDENT HOURLY PEAK LOADS (BLUE).

To understand this potential DCFC load NorthWestern also reevaluated the known and anticipated buildout of DCFC stations across Montana. As in 2023, NorthWestern referenced the Montana Electric Vehicle Infrastructure Deployment Plan developed by MDEQ in response to the National Electric Vehicle Infrastructure program. Although the funding and future of this program is presently uncertain, the plan still provides valuable insight into prioritized DCFC station locations. This plan details the 5-year phased installation of 36 DCFC stations, each with a minimum installed capacity of 600 kW. Of these 36 stations, NorthWestern would likely serve 16 – with a total nameplate of about 9.6 MW. This 9.6 MW nameplate growth represents a 27% increase to the existing nameplate capacity, as seen in Table 68. As mentioned above, the load growth of DCFC is largely a function of travel, tourism, and national EV adoption rates – making it challenging to predict without direct knowledge of planned infrastructure. As such, NorthWestern intends to continue monitoring the planned construction of DCFC infrastructure and the resulting load growth to better understand DCFC trends in Montana. By considering the current, planned, and potential DCFC infrastructure across Montana and NorthWestern's service territory, NorthWestern can more effectively plan for this load growth and develop tools to manage it.

Estimated Current, Planned, and Potential DCFC Load		
	2025	***2030***
NWE-Served DCFC Nameplate Capacity Load	**36 MW**	***46 MW***

TABLE 68: SUMMARY OF THE ESTIMATED CURRENT, PLANNED, AND POTENTIAL DCFC LOAD IN NWE'S SERVICE TERRITORY.

1.3 Tools for Managing Growing EV Loads

Though there are a wide range of possible EV futures in Montana, it is crucial that NorthWestern continue to monitor and understand the current system and supply impacts of EVs and EVSE while also planning for the future growth of EV charging load across all EV charging sectors. Analyses, such as those described above, are helpful for estimating and quantifying the potential impacts to NorthWestern's electrical supply. These efforts also help to recognize the potential value and urgency of developing effective tools for managing this new and growing load. Based on these analyses, NorthWestern y is already working to develop a range of tools that could be used to manage growing EV load for both private and public charging. Some of the tools being evaluated include developing program(s) to support both active and passive management of private/L2 charging loads and installing battery storage alongside private or public charging installations to enable load shifting.

APPENDIX G – NUCLEAR RESOURCE OPTIONS

1 REACTOR GENERATIONS OVERVIEW

1.1 Generation I

These were early prototype and demonstration reactors built primarily in the 1950s and 1960s, such as Shipping Port (USA) and Calder Hall (UK). They were experimental, small-scale units with low thermal efficiency (~20–30%) and limited safety systems, establishing foundational nuclear power technologies like pressurized water reactors (PWR), boiling water reactors (BWR), and gas-cooled reactors (GCR).

1.2 Generation II

Spanning the late 1960s to the 1990s, Generation II reactors matured into standardized commercial power plants forming the backbone of today's nuclear fleet. They featured medium to large unit sizes (500–1000+ MWe), improved thermal efficiency (~30–35%), and enhanced safety with multiple active engineered systems. Examples include Westinghouse PWRs, GE BWRs, CANDU heavy water reactors, and advanced gas-cooled reactors (AGR).

1.3 Generation III / III+

Evolving from the 1990s to the present, these designs offer incremental improvements focusing on passive safety, simplified systems, economic efficiency, and licensability. They include advanced LWRs like Westinghouse AP1000 and GE-Hitachi ESBWR, and small modular derivatives such as NuScale SMR. Features include passive emergency cooling, higher thermal efficiency (~35–40%), longer lifetimes (~60 years), and modular construction.

1.4 Generation IV

These are advanced reactors under research and development with expected deployment in the 2030s and beyond. They depart from conventional light-water designs aiming to enhance sustainability, safety, economics, proliferation resistance, and thermal efficiency. Technologies include sodium-cooled fast reactors (SFR), lead-cooled fast reactors (LFR), gas-cooled fast reactors (GCR/VHTR), molten salt reactors (MSR), and supercritical water-cooled reactors (SCWR). Several SMR finalists employ Gen IV technologies such as X-Energy's Xe-100 (GCR) and Oklo's Aurora (LMR).

1.5 Generation Classification of Top Five SMR Vendors

The top five evaluated by NorthWestern, shown in Table 69, out of more than twenty reactor designs are classified as Gen IV:

Vendor	Reactor	Generation
X-Energy	Xe-100	IV
Oklo	Aurora	IV
Kairos Power	KP-FHR	IV
TerraPower	Natrium	IV
Terrestrial Energy	IMSR	IV

TABLE 69: FIVE OEMS EVALUATED.

2 OVERVIEW OF SMALL MODULAR REACTOR DESIGNS

Twenty SMR designs passed an initial screening, reflecting a broad diversity in technology, scale, and commercial timelines. They range from micro reactors less than 20 MWe to larger units up to 500 MWe, employing various reactor and coolant technologies including PWR, BWR, SFR, LFR, MSR, GCR, and Liquid Metal Fast Reactor (LMR). Fuel types vary from conventional uranium dioxide pellets to TRISO particle fuel and molten salt fuels, with enrichment levels from low-enriched uranium (LEU) to high-assay low-enriched uranium (HALEU). Table 70 illustrates the wide range of SMR technologies under development, with various coolant types and power outputs tailored for diverse applications and siting needs.

Organization	Design	Net Power (MWe)	Technology	Country	Timeline
ARC Clean Tech	ARC-100	100	SFR	Canada	2029
Blykalla	SEALER-55	55	LFR	Sweden	2031
EDF	NUWARD	400	PWR	France	2033
GE-Hitachi	BWRX-300	300	BWR	USA	2029
Holtec International	SMR-300	300	PWR	USA	2030
KHNP	i-SMR	170	PWR	South Korea	2035
KAERI	SMART100	110	PWR	South Korea	2032
Kairos Power	KP-FHR	75	MSR	USA	2030
Moltex Energy	SSR-W	300	MSR	Canada	2030
newcleo	LFR-AS-200	200	LFR	UK	2033
NuScale Power LLC	NuScale Power Module	77	PWR	USA	2029
Rolls-Royce SMR	Rolls-Royce SMR	470	PWR	UK	2030
TerraPower	Natrium	345	SFR	USA	2030
Terrestrial Energy	IMSR400	390	MSR	USA	2031
Thorcon International	Thorcon 500	250	MSR	USA	2032
Westinghouse	AP300	330	PWR	USA	2032
X-Energy	Xe-100	82.5	GCR	USA	2030
Aalo Atomics	Aalo	10	MSR	USA	2029
Last Energy	PWR-20	20	PWR	USA	2027
Oklo	Powerhouse	15.5	LMR	USA	2027

TABLE 70: TWENTY OEMS THROUGH INITIAL SCREENING.

3 KEY DIFFERENCES AMONG SMR DESIGNS

- **Reactor and coolant technology:** From conventional water-cooled reactors (PWR, BWR) to advanced fast reactors (SFR, LFR), MSRs, and gas-cooled reactors (GCR). Fast and exotic coolants enable higher outlet temperatures, passive safety including walk-away technology, and potential fuel cycle advantages.
- **Scale and modularity:** Ranges from micro units (<20 MWe) for niche uses to larger SMRs (300–500 MWe) suitable for replacing retiring thermal plants.
- **Fuel types and enrichment:** Includes TRISO particle fuel, metallic uranium-zirconium alloys, conventional UO2 pellets, and molten salt fuels with enrichment levels spanning LEU to HALEU and some micro-reactors licensed for HEU.
- **Operational characteristics:** Emphasis on inherent/passive safety, walk-away capability, integration with thermal storage or batteries for load-following, and high-temperature outputs for increased efficiency.

- **Maturity and timeline:** Commercial deployment targets range from near-term (2027) to the mid-2030s, with conventional LWR-based designs closer to licensing readiness than advanced fast or MSRs.

4 PROFILES OF TOP FIVE SMR ORIGINAL EQUIPMENT MANUFACTURERS

4.1 X-Energy (Xe-100)

- Location: Rockville, MD; Established 2009
- Reactor: Gas-cooled high-temperature reactor (GCR)
- Output: 82.5 MWe at 750°C; Target COD: 2029
- Fuel: TRISO particles with HALEU (15.5%)
- Funding: USD 2.4 billion total
- Status: Construction permit submitted to NRC in 2025
- Benefits: High outlet temperature, inherent walk-away safety, modular design for scalable deployment
- Challenges: Engineering scale-up, HALEU supply, licensing and cost.

4.2 Oklo (Aurora / Powerhouse)

- Location: Santa Clara, CA; Established 2013
- Reactor: LMR, micro-reactor
- Output: 15.5 MWe at 420°C; Target COD: 2027
- Fuel: Metallic U–Zr enriched to HALEU; Sodium coolant
- Funding: USD 3.2 billion valuation after SPAC
- Status: NRC application re-engaged in 2025 after prior rejection
- Benefits: Compact size for data centers and remote sites, inherent fast-spectrum safety, grid-scale battery integration
- Challenges: Licensing setbacks, financial model requirements, establishing market contracts.

4.3 Kairos Power (KP-FHR)

- Location: Alameda, CA; Established 2016
- Reactor: Fluoride salt-cooled high-temperature reactor (FHR)
- Output: 75 MWe at 650°C; Target COD: 2030
- Fuel: TRISO with HALEU (19.75%)
- Funding: USD 303 million public support
- Status: NRC construction permit approved for Hermes test reactor; first unit targeted 2030
- Benefits: High-temperature output, iterative demonstration strategy
- Challenges: Regulatory treatment of iterative builds, supplier standardization, expanding commercial interest.

4.4 TerraPower (Natrium)

- Location: Bellevue, WA; Established 2008
- Reactor: SFR with integrated molten salt energy storage

- Output: 345 MWe at 540°C; Peaking capacity up to 500 MWe; Target COD: 2030
- Fuel: Metallic U–Zr enriched to HALEU (19.8%)
- Funding: USD 2.6 billion total
- Status: NRC construction permit submitted in 2024; construction to start in 2026
- Benefits: Large scale approximates coal replacement, integrated thermal storage for dispatchable peaking, strong utility partnerships
- Challenges: Long build schedules, HALEU sourcing, cost escalation.

4.5 Terrestrial Energy (IMSR)

- Location: Canada; Established 2012
- Reactor: Integral MSR
- Output: 195 MWe at 700°C; Target COD: 2030
- Fuel: UF4 dissolved in molten salt (LEU)
- Funding: USD 90 million total
- Status: Completed Canadian vendor design review; NRC process underway; pilot targeted early 2030s
- Benefits: Simplified integration and maintenance, passive safety, high-temperature output
- Challenges: Attracting North American offtake, harmonizing licensing, updating cost estimates.

The summary of the comprehensive review highlights the technological diversity, maturity, and commercial potential of advanced nuclear reactor designs, with a particular focus on SMRs that could contribute to future energy portfolios emphasizing safety, while achieving NorthWestern's affordable, reliable, and sustainable objectives.

APPENDIX H – SUPPORTING DATA

Appendix H lists attachments and/or supporting data by chapter where the reference was made.

Attachment ID	Attachment Title	Type	IRP Section Reference(s)	Description	Key Use in IRP	Confidentiality
H-01	Comprehensive Existing Resource Table	Data Table	Chapter 5, 7	Inventory of Montana existing generation resources and characteristics	Establishes baseline system representation	Confidential
H-02	NorthWestern Energy End-Use Study - Final (March 2024)	Technical Study	Chapter 2, 4	Historical and baseline end-use consumption characteristics	Supports load forecast development and calibration	Public
H-03	NorthWestern Electric EE and DR Market Potential Study Final (May 2024 - Revised October 2025)	Technical Study	Chapter 1,2,4,9	Assessment of DSM and energy efficiency potential	Supports demand-side resource evaluation	Public
H-04	2025-2026 DSM Acquisition Plan	Technical Study	Chapter 4	DSM Program Planned Acquisition with Associated Savings	Establishes energy and demand reduction as a component of the load forecast and used in DSM forecasting.	Public
H-05	ARS & PCM Inputs	Modeling Inputs	Chapter 7	Input assumptions, scenario definitions, and modeling configurations used in ARS and PCM analysis	Establishes analytical foundation for portfolio modeling and scenario evaluation	Confidential

Attachment ID	Attachment Title	Type	IRP Section Reference(s)	Description	Key Use in IRP	Confidentiality
H-06	ARS Results	Modeling Outputs	Chapter 7	Results of ARS portfolio development and screening analysis	Supports identification of candidate portfolios	Confidential
H-07	PCM Results	Modeling Outputs	Chapter 7	Production cost modeling outputs including dispatch, system costs, and import/export activity	Supports evaluation of system performance and cost outcomes	Confidential
H-08	Montana Capacity Forecast	Forecast / Analysis	Chapter 7	Forecast of system capacity needs under applicable reliability constructs	Supports resource adequacy and capacity need determination	Public
H-09	Aion's Candidate Resource Report	Technical Study	Chapter 7	Evaluation of candidate generation Costs, ATB Curves, ATB Comparisons and Configurations	Supports development of candidate resource set	Public