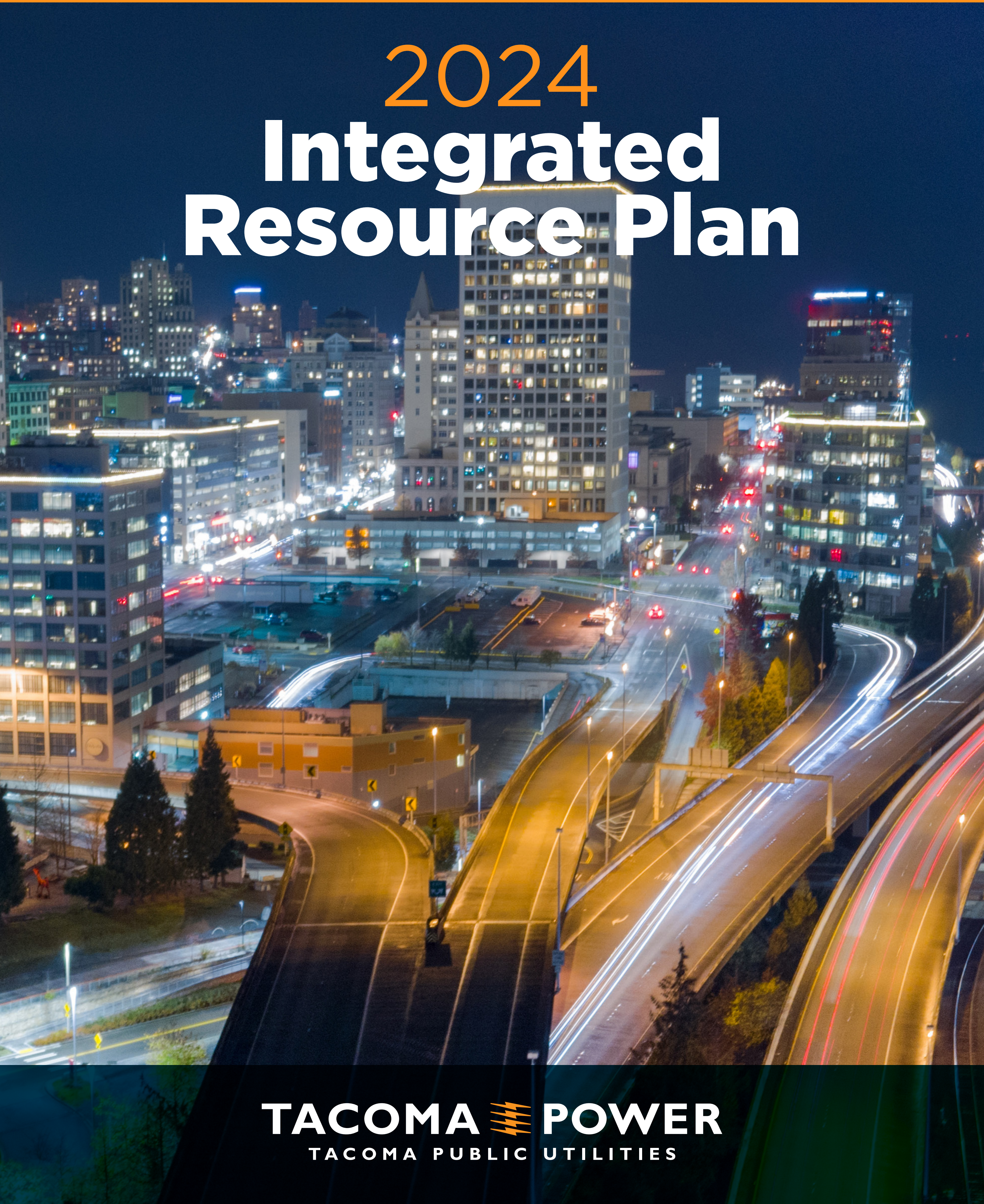
2024 Integrated Resource Plan



TACOMA POWER
TACOMA PUBLIC UTILITIES

RESOLUTION NO. U-11468

A RESOLUTION relating to Tacoma Power; approving and adopting Tacoma Power's 2024 Integrated Resource Plan.

WHEREAS Chapter 19.280 of the Revised Code of Washington (RCW") requires the Department of Public Utilities, Light Division (d/b/a. "Tacoma Power"), at a minimum to develop progress reports reflecting the changing conditions and the progress of its integrated resource plan ("IRP") every two years and develop an updated IRP every four years, and

WHEREAS RCW 19.280.050 states "the governing body of a consumer-owned utility that develops a plan under this chapter shall encourage participation of its consumers in development of the plans and progress reports and approve the plans and progress reports after it has provided public notice and hearing", and

WHEREAS conducting integrated resource planning at regular intervals is not only a state requirement but is also consistent with the Public Utility Board's Guiding Principle Fourteen ("GP 14"), and

WHEREAS updates to Tacoma Power's last IRP were completed in 2022, and

WHEREAS the 2024 IRP is an update to the 2022 IRP, and to remain compliant with Chapter 19.280 of the RCW, the 2024 IRP must be submitted to the Department of Commerce by September 2, 2024, and

WHEREAS the recommended resource strategy and action plan for which this resolution seeks approval are:

1) **BPA contract renewal:** Based on the information available at the time this document was completed, the IRP recommends renewing our BPA contract with the Slice/Block product if it is offered. Slice/Block remains our preferred BPA product because it leaves us energy adequate in the summer and reduces the risk of a peaking capacity shortfall. However, BPA is still contemplating whether Slice/Block will be an option in the next contract. If Slice/Block is not available, our alternative product choice will depend greatly on design choices BPA makes for its other product options.
    a. **Two-year actions:**
        i. Update our analysis of BPA product choice once we learn which products BPA will offer and precisely what they will look like.
        ii. Sign a new contract with BPA by December of 2025.

2) **Make incremental investments in existing resource infrastructure where cost-effective:** The IRP finds that we do not have an immediate need for a large supply-side resource so long as we continue to invest heavily in conservation. To mitigate the potential risks that could emerge in the second half of the 2030s, the IRP recommends that we seek out smaller, incremental investment opportunities on both the supply side and the demand side to bolster our energy and capacity position. On the supply side, this means exploring potential opportunities to enhance the capabilities of our existing hydropower projects when cost-effective to do so. On the demand side, this means continuing to invest heavily in conservation and scaling up investments in demand response. The IRP recommends acquiring all the programmatic conservation identified as cost-effective in our 2024-2043 Conservation Potential Assessment and acquiring at least 10 MW of cost-effective demand response over the next 10 years.
    a. **Two-year actions:**
        i. Continue to seek FERC authorization to restore Riffe Lake elevation.
        ii. Conduct Cowlitz pumped storage feasibility and cost assessment provided the Climate Commitment Act (CCA) and the associated funding for the study is not repealed in November 2024.
        iii. Evaluate opportunities to add incremental capacity to existing generators during scheduled rebuilds.
        iv. Acquire 2-year conservation target of 55,992 MWh set in 2024-2043 conservation potential assessment (CPA).
        v. Acquire 2 MW of demand response, continue piloting demand response opportunities, and begin to scale up those found to be successful and cost-effective in pilots.

b. **Ten-year actions:**
   i. Restore Riffe Lake elevation if authorized by FERC.
   ii. Seek authorization to add pumped storage or additional generator at Cowlitz as part of FERC re-licensing process if feasible and cost-effective.
   iii. Add incremental capacity to existing generators during scheduled rebuilds whenever cost-effective.
   iv. Regularly update CPA and continue to acquire 2-year targets set in subsequent CPAs.
   v. Scale up demand response opportunities and acquire at least 10 MW of DR opportunities found to be successful and cost-effective in pilots.

3) **Other ways to mitigate risks:** Several follow-up analyses are recommended by this IRP. First, it is critical to track the load trends that could put our adequacy position at risk, namely the progression of electrification and data center load growth. Second, it is critical to track market trends (i.e., power prices) in conjunction with our energy position. This IRP indicates that climate change will degrade our summer energy position, a risk that can be cost-effectively managed over the next 5 to 10 years through midday power purchases from the wholesale market. It is important to evaluate whether that will be a durable strategy in the future. Finally, there may be operational adjustments we can make to operate our hydro resources more conservatively to preserve winter capacity. Further investigation is needed to understand the extent to which those operational adjustments will be capable of managing future sustained capacity risks in a time of need without the procurement of an additional supply resource.
   a. **Two-year actions:**
      i. Actively engage with large retail customers to explore mutually beneficial collaborations to add low or zero-carbon resources when potential opportunities arise.
      ii. Develop a plan to track progress of electrification and data center load growth and begin tracking.
      iii. Evaluate feasibility of continuing to rely on wholesale market for occasional summer energy needs in long-run.
      iv. Explore opportunities to make operational adjustments to maximize winter capacity.
   b. **Ten-year actions:**
      i. Actively engage with large retail customers to explore mutually beneficial collaborations to add low or zero-carbon resources when potential opportunities arise.
      ii. Track progress of electrification and data center load growth and regularly update projections.

WHEREAS the background materials provided to the Clerk of the Board includes the draft 2024 IRP document that describes Tacoma Power's recommended resource strategy and 2-year and 10-year action plans for which Tacoma Power is seeking approval, and

WHEREAS although the resource strategy recommendations and action plan will not change from what has been presented to the Public Utility Board, the Public Utility Board acknowledges that some of the language describing the analyses may change slightly as the document is finalized because the 2024 IRP document is still in draft form, and

WHEREAS the 2024 IRP analysis conforms to the requirements set forth in RCW 19.280.030, and

WHEREAS the Public Utility Board conducted a public hearing on the plan on August 14, 2024, and

WHEREAS Tacoma Power requests approval and adoption of the 2024 Integrated Resource Plan by the Public Utility Board; Now, therefore,

BE IT RESOLVED BY THE PUBLIC UTILITY BOARD OF THE CITY OF TACOMA:

That following notice and a public hearing, Tacoma Power's 2024 Integrated Resource Plan is approved, and the appropriate officers of the City are directed to timely file such plan with the state of Washington in accordance with Chapter 19.280 of the Revised Code of Washington.

Approved as to form:

/s/
Chief Deputy City Attorney

Charleen Jacobs
Clerk

Chair

Secretary

Adopted 8-14-24

2024\Resolutions\Power\U-11468 2024 Integrated Resource Plan

Tacoma Power 2024 Integrated Resource Plan

1 Executive Summary

1.1 About Tacoma Power and our Integrated Resource Plan

Tacoma Power is a national leader in providing renewable, reliable, and affordable energy. Virtually all the electricity we deliver to our retail customers comes from hydroelectric sources. A little more than half comes from our long-term contract with the Bonneville Power Administration (BPA). We produce most of the rest ourselves at the four hydropower projects we own and operate. We also contract with hydroelectric projects in central Washington for a small amount of our power. Our portfolio is generally "carbon-negative", meaning that, on average, we generate more carbon-free energy than our retail customers use, and we export the surplus to other customers in the region.

The Integrated Resource Plan (IRP) is a tool to help us plan for an uncertain future so that we can continue to meet our customers' needs for decades to come. The recommended resource strategy and action plan in the IRP represent our resource plan based on the best information available at the time of its creation. However, the plan may change as new information becomes available. We update our IRP every two years to incorporate new information and adjust our plan as needed.

The 2024 IRP includes a scenario consistent with the Tacoma Community Building Decarbonization Strategy[1] and accomplishes Action #46 identified in the City of Tacoma's 2030 Climate Action Plan.[2]

1.2 Key findings and recommendations

We find that our current portfolio is usually adequate along each of our resource adequacy metrics and that we don't face an acute or imminent need for a new supply-side resource. However, we do face several risks in the future that we need to actively track, namely (a) some risks to our summer energy position that can be managed over the next 5 to 10 years through midday light load hour purchases from the market when plenty of solar is available, (b) some risks to our sustained capacity position and, in the most extreme cases, our short-term peaking capacity position that emerge in the second half of the 2030s at the earliest and (c) the risk of failing our adequacy standard along all of our metrics if we see significant load growth from the industrial sector (e.g. from data centers).

The 2024 IRP recommends the following resource strategy to ensure we continue to be able to meet customer needs into the future at the lowest reasonable cost and identifies the associated action plan summarized in Table 1:

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[1] Available for download from the City of Tacoma: https://www.cityoftacoma.org/government/city_departments/environmentalservices/office_of_environmental_policy_and_sustainability/climate_action

[2] For a description of Action #46, see the Buildings and Energy sub-section of Section 2 of the City's 2030 Climate Action Plan.

1. **BPA contract renewal:** Based on the information we have available at the time this document was complete, the IRP recommends renewing our BPA contract with the Slice/Block product if it is offered. Slice/Block remains our preferred BPA product because it leaves us energy adequate in the summer and reduces the risk of a peaking capacity shortfall. However, BPA is still contemplating whether Slice/Block will be an option in the next contract. If Slice/Block is not available, our alternative product choice will depend greatly on design choices BPA makes for its other product options.
2. **Make incremental investments in existing resource infrastructure where cost-effective:** The IRP finds that we do not have an immediate need for a large supply-side resource so long as we continue to invest heavily in conservation. To mitigate the potential risks that could emerge in the second half of the 2030s, the IRP recommends that we seek out smaller, incremental investment opportunities on both the supply side and the demand side to bolster our energy and capacity position. On the supply side, this means exploring potential opportunities to enhance the capabilities of our existing hydropower projects when cost-effective to do so. On the demand side, this means continuing to invest heavily in conservation and scaling up investments in demand response. The IRP recommends acquiring all the programmatic conservation identified as cost-effective in our 2024-2043 Conservation Potential Assessment and acquiring at least 10 MW of cost-effective demand response over the next 10 years.
3. **Other ways to mitigate risks:** Several follow-up analyses are recommended by this IRP. First, it is critical to track the load trends that could put our adequacy position at risk, namely the progression of electrification and data center load growth. Second, it is critical to track market trends (i.e., power prices) in conjunction with our energy position. This IRP indicates that climate change will degrade our summer energy position, a risk that can be cost-effectively managed over the next 5 to 10 years through midday power purchases from the wholesale market. It is important to evaluate whether that will be a durable strategy ten or more years from now and what risks might threaten our ability to rely on this strategy in the future. Finally, there may be operational adjustments we can make to operate our hydro resources more conservatively to preserve winter capacity. Further investigation is needed to understand the extent to which those operational adjustments will be capable of managing future sustained capacity risks in a time of need without the procurement of an additional supply resource.

The recommended resource strategy prepares us to meet a wide range of potential future demands, including a future consistent with the Tacoma Community Building Decarbonization Strategy[3].

[3] Available for download from: https://www.cityoftacoma.org/government/city_departments/environmentalservices/office_of_environmental_policy_and_sustainability/climate_action

Table 1: 2024 IRP action plan

Action Type	Two-year action plan	Ten-year Clean Energy Action Plan
Supply-side resources: BPA	Update BPA analysis and sign new contract	
Supply-side resources: Riffe Lake	Continue to seek FERC authorization to restore Riffe Lake elevation	Restore Riffe Lake elevation if authorized by FERC
Supply-side resources: Cowlitz pumped storage hydro	Conduct Cowlitz pumped storage feasibility and cost assessment provided the Climate Commitment Act (CCA) and the associated funding for the study is not repealed in November 2024	Seek authorization to add pumped storage or additional generator at Cowlitz as part of FERC re-licensing process if feasible and cost-effective
Supply-side resources: Existing generators	Evaluate opportunities to add incremental capacity to existing generators during scheduled rebuilds	Add incremental capacity to existing generators during scheduled rebuilds whenever cost-effective
Collaboration with customers: Conservation	Acquire 2-year conservation target of 55,992 MWh set in 2024-2043 conservation potential assessment (CPA)	Regularly update CPA and continue to acquire 2-year targets set in subsequent CPAs
Collaboration with customers: Demand response	Acquire 2 MW of demand response. Continue piloting demand response opportunities & begin to scale up those found to be successful and cost-effective in pilots	Scale up demand response opportunities and acquire at least 10 MW of DR opportunities found to be successful and cost-effective in pilots
Collaboration with customers: Other opportunities	Actively engage with large retail customers to explore mutually beneficial collaborations to add low or zero-carbon resources when potential opportunities arise	Actively engage with large retail customers to explore mutually beneficial collaborations to add low or zero-carbon resources when potential opportunities arise
Other important actions: Demand-side factors	Develop a plan to track progress of electrification and data center load growth and begin tracking	Track progress of electrification and data center load growth and regularly update projections
Other important actions: Market risk factors	Evaluate feasibility of continuing to rely on wholesale market for occasional summer energy needs in long-run	
Other important actions: Operations analysis	Explore opportunities to make operational adjustments to maximize winter capacity	

Contents

2 Introduction

2.1 About Tacoma Power

Tacoma Power has been publicly owned since 1893. We are a division of Tacoma Public Utilities, which is governed by a five-member Public Utility Board. We were established when the citizens of Tacoma voted to buy the privately-owned Tacoma Light & Water Company. Local citizens believed that public ownership and local control would give them a higher caliber of services and the ability to maintain control over them. That decision paved the way for us to build one of the finest and most reliable electric systems in the United States.

Today, we generate, transmit, and distribute electricity in an increasingly competitive marketplace. We provide electric service to over 180,000 customers across 180 square miles of service area in the cities of Tacoma, Fircrest, University Place, Fife, parts of Steilacoom, Lakewood, Joint Base Lewis-McChord, and unincorporated Pierce County as far south as Roy.

2.1.1 Current resource portfolio

We are a national leader in providing renewable, reliable, and affordable energy to electricity customers. Virtually all the electricity delivered to retail customers comes from hydroelectric sources. We produce a little less than half at four hydroelectric generation projects that we own and operate: the Cowlitz River Project, Cushman Hydro Project, Nisqually River Project, and Wynoochee River Project[4]. We contract with other entities for the remainder.

The Cowlitz River Project is the largest Tacoma Power-owned resource. In 2017, we reduced the maximum level of Riffe Lake from 778.5 to 749 feet due to updated seismic loading concerns on the Mossyrock Dam spillway piers (not to the dam itself). We worked with our regulators to make this decision, and they approved our plan to voluntarily lower the level. Our objective is to bring Riffe Lake back to full pool as soon as safely possible. We are working hard to make progress on identifying potential seismic risks to any other parts of the dam, as well as possible seismic retrofits, but this is a long and complex process. We assembled a team to determine what projects need to be done to mitigate risk and allow us to bring the lake back up. We received an updated seismic hazard analysis at the end of 2022 and are awaiting regulatory acceptance of the analysis.

Our largest contract power purchase is with BPA. As a Washington State customer-owned utility, we are one of BPA's "preference customers" and have been a customer of BPA since 1940. We receive energy through a hybrid Slice/Block product under our current contract. Under the "Slice" portion of the contract, we receive approximately 3% of the wholesale power that BPA produces, an amount that varies by year and by season depending on streamflow conditions. Under the "Block" portion of the contract, we are guaranteed a certain amount of energy every month that does not change with streamflow conditions. About half of the firm power (i.e., power we can rely on under any water

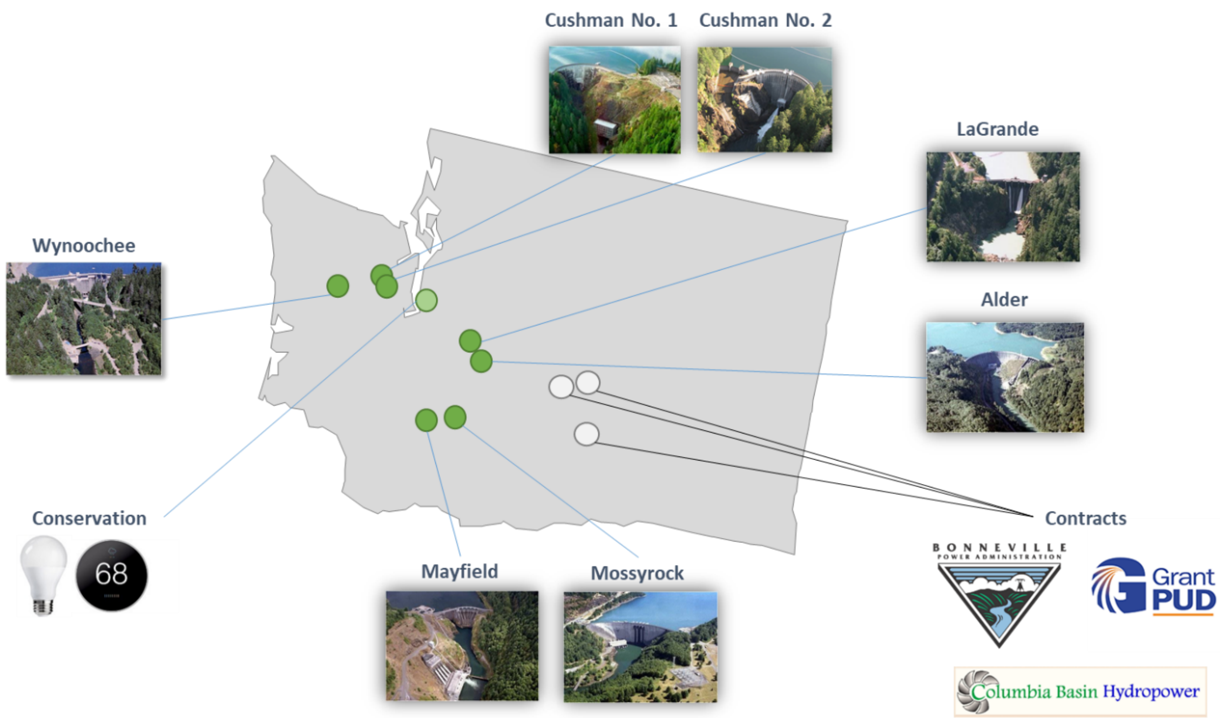
[4] At Wynoochee River Project, Tacoma Power owns the generation components of the project (e.g., intake, penstock, powerhouse). The City of Aberdeen owns the rest, including the dam, and is a co-licensee of the project.

conditions) we receive from BPA comes from the Slice portion of the contract. Half comes from the Block portion.

We currently also receive a small amount of power from Columbia Basin Hydropower (CBH) through contracts for 50% of the output of five hydroelectric projects on irrigation canals, which produce power primarily in the summer months. Those contracts began to expire in 2022 and fully terminate in 2027.

For years conservation has been the only resource that we have acquired, and we remain committed to helping our customers reduce their energy use and defer the need to invest in costly generation. We are a leader in energy conservation and have a long history of working with our customers to identify and acquire cost-effective conservation measures. Thanks to our investments in conservation, our utility and customers have accumulated enough savings since 2007 that each year we save an amount equivalent to the power we generate at Mayfield Dam.

Figure 1: Tacoma Power's resource portfolio



2.2 About the Integrated Resource Plan

The Integrated Resource Plan (IRP) is a tool to help us plan for an uncertain future so that we can continue to meet our customers' needs for decades to come. Our IRP looks out over 20 years. Findings in the IRP represent our resource plan based on the best information available at the time of its creation. However, the plan may change as new information becomes available. We update our IRP every two years. We completed our last IRP in 2022.

2.2.1 Community input

Community input is an integral part of the development of the IRP. Each IRP cycle, we look for ways to improve on our process to make it more engaging and meaningful to community members and interested stakeholders. In response to feedback on our past public process, we increased the number of ways community members could participate and reduced the complexity and duration of public IRP workshops. Feedback on these changes has been overwhelmingly positive.

Our outreach efforts to invite community participation included online announcements both on the TPU website and TPU social media accounts, announcements in residential and business newsletters, tabling at community events, and working with our internal community liaisons to directly invite tribal, youth, and community-based organization to provide input.

All stakeholders identified through the above outreach efforts were offered four different opportunities to provide input:

1. Attend public (virtual) workshops with Tacoma Power
2. Attend public (in person) meetings/events held in the community
3. Complete an online “community priorities” survey
4. Submit comments online via email

In terms of participation, we had between 7 and 9 external stakeholders attend the two public virtual workshops and presented in-person to the Mayor’s Youth Commission. We also received over 30 responses to the community priorities survey as well as several questions/comments submitted through email. We addressed and considered all comments provided by our stakeholders.

3 Review of the last IRP

In our 2022 IRP, we found that our preferred resource strategy was to: (1) renew our Bonneville Power Administration (BPA) contract with the same Slice/Block product as we have today, (2) continue to acquire all economic achievable conservation identified in our 2022 Conservation Potential Assessment and (3) acquire 10 MW of demand response. Table 2 provides a summary of key two-year action items that we identified related to resource acquisition and follow-up analyses.

Table 2. Progress on the 2022 IRP Action Item Plan

Two-year Action Item	Status
Acquire 53,114 MWh of energy conservation	We are on track to achieve this target.
Continue active participation in BPA post-2028 contract discussions	Tacoma Power has been an active and vocal participant in BPA's "Provider of Choice" stakeholder process.
Pursue additional opportunities for demand response (DR)	We have conducted a residential water heater DR pilot and have continued to engage in conversations with one of our industrial customers to provide an industrial DR product offering. We have also identified the next most promising DR opportunities to pilot and plan to expand our pilot activities over the next two years.
Update DR potential assessment	The DR potential assessment was updated in 2023 and is available on the IRP webpage[5].
Explore short-term contracts to shore up potential resource adequacy risks	Earlier in 2024, we hired consulting firm Energy West to assess the likely availability and cost of short-term contracts that meet our carbon requirements and comply with regional resource adequacy requirements. The report finds that supply of these contracts is limited and that the cost is high.
Final decision on joining WRAP	Tacoma Power officially joined WRAP in the fall of 2022. We began participating in the non-binding program, both forward showing and operational, in the fall of 2023. The WRAP program becomes binding for all participants, including Tacoma Power, in Summer 2027.
Electrification study	Our electrification study was completed in December 2023 and is available on the IRP webpage. Projections from the study are incorporated into this IRP.
Enhance climate change modeling	We have made significant improvements in our approach to incorporating climate change into our modeling and plan to continue to refine how we use climate change projections in future IRPs.

[5] https://www.mytpu.org/about-tpu/services/power/integrated-resource-plan/

4 What's new since the last IRP?

4.1 Changes to the planning environment

4.1.1 BPA Provider of Choice process

Our current contract with BPA ends on September 30, 2028. We are currently participating in BPA's Provider of Choice process, which will establish the long-term power sales policy and contracts for the next contract cycle. This process will not be complete by the time we finalize this IRP.

We have evaluated BPA product options in every IRP since 2015, and each time we find that our current Slice/Block product is our best and lowest cost option. We address the same question again in this IRP, but we do not yet have complete information on exactly what each product offering will look like in the Provider of Choice contracts or even whether the Slice/Block product will be offered. As a result, our analysis of BPA product options in this IRP is preliminary and will need to be updated later in 2024 once we have complete information from BPA.

4.1.2 Western Resource Adequacy Program (WRAP)

Widespread changes in demand for grid services, retirement of carbon emitting resources, and integration of variable energy resources (i.e., wind and solar) represent a major transition for the power system. While individual utilities have standards to ensure adequacy in isolation, the patchwork of individual planning among interconnected entities may leave a region inadequate. Part of this risk comes from potentially unrealistic regional assumptions and an over-reliance on shared market resources. Additionally, market prices may not always provide an adequate signal to build power resources in time to meet market needs.

The goal of WRAP is to ensure adequate resources exist among load serving entities in the Western Interconnection. The WRAP includes two major programs: a Forward Showing Program and an Operational Program. The Forward Showing Program involves the analysis of supply and demand to identify capacity requirements for each entity in future seasons. The program design takes advantage of diversity benefits to ensure that each individual entity must carry less capacity than they would if they were meeting their capacity requirements without the WRAP. The Operational Program is a structure for pre-arranging access to resources across participants during times of need.

Tacoma Power has been involved in the design of the WRAP program since 2019 and officially joined WRAP in the fall of 2022. We began participating in the non-binding program, both Forward Showing and Operational, in the fall of 2023. The WRAP program becomes binding for all participants, including Tacoma Power, in Summer 2027. The binding program will include financial consequences related to program requirements. This IRP evaluates our compliance position with respect to our WRAP Forward Showing position.

4.1.3 Climate Commitment Act

In the 2021 legislative session, the State Legislature passed, and the State Governor signed, the Washington Climate Commitment Act (SB 5126). The Climate Commitment Act (CCA) establishes a comprehensive, market-based program, including in the electric sector, to reduce carbon pollution and achieve greenhouse gas limits. The CCA requires the Department of Ecology (Ecology) to adopt rules to implement a cap-and-invest program to achieve Washington's goal of net zero greenhouse gas emissions by 2050. The cap-and-invest program set a cap (limit) on overall carbon emissions in the State and requires businesses, including electric utilities, to obtain allowances equal to their covered greenhouse gas emissions. These allowances can be obtained through quarterly auctions hosted by Ecology or bought and sold on a secondary market. The cap will be reduced over time, and Ecology will issue fewer emissions allowances each year, reducing overall greenhouse gas emissions.

While the Climate Commitment Act Program Rule (chapter 173-466 WAC) has been adopted and the program went into effect on October 30, 2022, ancillary rulemakings are in progress. These rulemakings address changes to the CCA Program Rule, the reporting of greenhouse gas emissions, incorporation of centralized electricity markets, linkage with California and Quebec's markets, GHG assessment for offset projects, CCA funds reporting and the allowance price containment reserve.

Tacoma Power submitted its first GHG emissions report in August 2023 for calendar year 2022. In April 2023 Ecology released the number of no-cost allowances that Tacoma Power would receive each year for the first compliance period (calendar years 2023-2026) and shortly thereafter Tacoma Power received the 2023 allocation of no-cost allowances. These are meant to mitigate the compliance cost burden of electric utilities who are also subject to Clean Energy Transformation Act (CETA) compliance.

There is currently an initiative on the November 2024 ballot (I-2117) to repeal the Climate Commitment Act and prohibit state agencies from "implementing any type of carbon tax credit trading, also known as 'cap and trade' or 'cap and tax' scheme."

4.1.4 Markets

Two competing centralized market options may become available to electric utilities in the West. Both markets, the Extended Day-Ahead Market (EDAM) offered by the California Independent System Operator (CAISO) and Markets+ provided by the Southwest Power Pool (SPP) would provide the economic co-optimization of loads and resources in both the day-ahead and real-time horizons across the respective market footprints. CAISO's EDAM would enable entities outside of California's current Independent System Operator (ISO) region to participate along with loads and resources already in CAISO's day-ahead market, like the model CAISO has used to expand the footprint of its real-time Western Energy Imbalance Market (WEIM). By contrast, Markets+ would represent a new day-ahead market that is entirely separate from SPP's Regional Transmission Operator (RTO) system that operates in the Central U.S. Tacoma Power has engaged in the stakeholder initiatives responsible for the development of both market options and will likely face a future decision as to whether and which market it should join. While important for Tacoma Power's future, this decision is outside the purview of the IRP and so is not addressed in our IRP analyses.

4.1.5 Electrification

Electrification (converting from using a carbon emitting fuel source like gasoline or natural gas to electricity) is a critical piece of policy efforts to move toward a decarbonized future and could yield large and potentially unprecedented changes to customer demand. We have addressed the potential impacts of electrification in several past IRPs, but the 2024 IRP incorporates much more detailed projections. In 2023, Tacoma Power conducted a comprehensive Electrification Assessment[6] to addresses the question, "How might electrification contribute to changes in the future trajectory of Tacoma Power customers' demand for electricity?" The study aims to create a set of thoughtful and internally consistent projections of how electrification will change customer demand in the Tacoma Power service area over the next 20 years to inform internal planning processes.

The study is expansive in its treatment of electrification. It addresses electrification in nearly every end use and sector, projects impact for every hour of the year over 20 years and provides substation-level projections. Recognizing that there is substantial uncertainty around how electrification will unfold, the study also provides projections for a range of plausible scenarios using different assumptions about future policy and market developments.

Tacoma Power staff have started incorporating projections from the study into our corporate load forecast and into various internal planning processes, including this IRP. The 2024 IRP considers the following scenarios from the study:

1. **Anticipated Electrification:** This scenario represents a possible high level of electrification. It reflects what we believe to be the likely trajectory of policy expansion and market trends.
2. **Policy Regression:** This scenario represents an unlikely low level of electrification. It reflects a policy backslide and lower market adoption.
3. **Expansive Policy:** This scenario represents an unlikely high level of electrification. It reflects an acceleration of both electrification policy and market adoption and is consistent with the Tacoma Community Building Decarbonization Strategy.

4.1.6 Data centers

Data center power demand is expected to grow at an unprecedented pace, driven by the expansion of cloud computing, cryptocurrency mining, and data processing requirements of artificial intelligence (AI) workloads. Many utilities in the region have adjusted their forecasts to account for this increased growth in consumption. The Northwest Regional Forecast[7], produced by the Pacific Northwest Utilities Conference Committee, highlights a growing demand for electricity in the region, with data center development being a significant contributor. The 2023 Northwest Regional Forecast projected demand could rise by 24% over the next decade, while the 2024 Forecast anticipates an increase in demand in the region of over 30% in the same timeframe. While it is likely that data centers will continue to demand more power in the Northwest and beyond, whether and when Tacoma Power specifically might experience significant demand growth from data centers is less certain.

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[6] https://www.mytpu.org/wp-content/uploads/Tacoma-Electrification-Study_Final-Report-withTPWRintro.pdf
[7] https://www.pnucc.org/system-planning/northwest-regional-forecast/

4.2 Updates to our tools and metrics

We have made several major updates and improvements to our tools and metrics since our last IRP, including (1) creating a new modeling framework and (2) updating our resource adequacy standard.

4.2.1 Modeling framework

The IRP modeling framework builds upon other internally developed Tacoma Power models, including the SAM model used in the 2020 and 2022 IRPs. The current set of IRP modeling tools makes extensive use of open-source data science software packages (the Python data science ecosystem) and open-source software development workflows (GitHub for collaboration and versioning). To the extent possible, the IRP modeling suite uses best practices from data science software development, with the goal that the IRP modeling framework is reliable, transparent, and adaptable for future needs. The modeling suite is built on open-source software tools, but the code is private to Tacoma Power. Our IRP model contains the following main components:

- **Hydropower Dispatch**: A major component of the IRP model is the approximation of Tacoma Power's hydropower generation under different operating conditions. To develop this component of the model, the IRP team reviewed existing Tacoma Power models, reviewed operational information for Tacoma Power hydro generation projects (such as generator characteristics and permit conditions) and discussed practical hydro generating operations with the Tacoma Power Resource Operations team. The hydropower dispatch algorithm is a heuristic model, based on a series of algorithmic decisions that simulate the decisions of an operations team under various inflow and load conditions. The heuristic model aims to: a) maintain reservoir elevations at prudent levels, b) generate additional power during high load conditions, and c) comply with permit conditions. While this model provides a reasonable approximation of Tacoma Power's hydro dispatch, it cannot capture every consideration involved in operating hydropower projects and should be considered a planning estimate only.
    - As discussed in Section 2.1.1, Riffe Lake currently operates at elevations below the original design elevations to mitigate seismic risk. However, our objective is to bring Riffe Lake back to full pool. Therefore, two hydropower dispatch algorithms were modeled in this IRP. The first was based on current operations with a maximum elevation for Riffe Lake set to 749 ft. The second was based on the expected operations following the restoration of Riffe Lake (full pool lake elevation of 778.5 ft). Riffe Lake is assumed to be restored in 2030 unless otherwise noted in the model runs.
- **Bonneville Power Administration Contracted Power:** A second major component of the IRP modeling effort is to approximate the amount of power we expect to receive from BPA at an hourly level under current and future BPA contracts. As discussed in Section 2.1.1, the Slice/Block product that we currently receive from BPA includes a Slice component, which represents a partially dispatchable portion of the federal system, and a Block component, which is constant over the month. In the IRP model, the amount of Slice we receive in each hour (called our Slice Right to Power) is estimated from historical Right to Power using a regression model that considers stream flows in the BPA system and Tacoma Power loads. The amount of Block we receive is calculated using formulas set in our contract combined with load projections

consistent with the specific scenario in question. As noted in Section 4.1.1, details regarding our post-2028 contract options are under regional discussion. This IRP evaluates and compares several preliminary contract options given information currently available. Following the publication of this IRP, our BPA simulations will be updated to reflect the final contract options provided by BPA.

- **Loads:** Loads within the Tacoma Power service area are estimated in a two-step process. First, hourly loads are calculated with a machine learning model using historical factors such as temperature, day of the week, and time of day. These initial load simulations are representative of 2023 loads within the TPU service area. Second, a series of adders are used to capture projections of how loads will change over time. We adjust our base simulations to match our corporate load forecast's projections of general load trends. Both our corporate forecast and our load simulations incorporate our 2024-2043 Conservation Potential Assessment's projections of reductions in usage over time from our conservation programs, codes, and standards. Data from three of the scenarios in our 2023 Electrification Assessment (Section 4.1.5) were used to account for the range of increases in usage we expect to see from electrification. In one scenario, we also add a series of flat industrial loads.
- **Portfolio Expansion:** Our modeling framework currently handles new generating resources and new storage resources differently.
    - For generating resources, an optimization algorithm is used to select the least cost resource from a set of potential resources. The portfolio expansion model uses the results of a particular model run to calculate monthly energy needs and then selects the least-cost resource to meet those needs. Once the algorithm selects the least-cost portfolio to meet energy needs, the new resources are added to the system model to recalculate system performance. The costs of the resources are estimated based on industry data, discussions with developers, and discussions with other utilities. Generation profiles for renewables were based on data from the National Renewable Energy Laboratory (NREL).
    - For storage resources, an optimization algorithm dispatches a specified resource with the objective of reducing peak loads. The storage resources evaluated in this IRP are lithium-ion batteries and pumped storage hydro.
- **Weather Simulations:** River inflows and temperatures are critical inputs to hydro operations and load predictions. The 2024 IRP modeling effort includes several weather simulations for comparison: 1) the recent historical record back to 1981, 2) the historical record adjusted to account for long-term climate trends, and 3) simulated temperature and inflows based on global climate models combined with hydrological models. The latter were produced for the University of Washington (UW) Hydro Columbia River Climate Change project.[8] In each case, our model incorporates inflow data at each of our hydroelectric projects and outdoor air temperature data from the SeaTac weather station.
- **Power Prices:** Tacoma Power buys and sells power to the market to balance generation and load. Therefore, power prices are important for assessing the potential financial benefits and

[8] https://www.hydro.washington.edu/CRCC/

risks of alternative resource strategies we might take. Our long-term price simulations draw from data produced by the Northwest Power and Conservation Council using a fundamentals-based model of the grid (using Aurora software simulations) for their 2028 resource adequacy assessment[9] as well as power price data from the Intercontinental Exchange futures trading platform. Our long-term price simulations are blended with near-term power price simulations that reflect current market conditions. All our price simulations consider seasonality, volatility, and regional hydro conditions.

4.2.2 Resource adequacy standard

A resource adequacy (RA) standard is used to measure whether a utility has enough power resources to meet loads based on a consistent criterion. As the grid evolves, so do utilities' approaches to assessing their resource adequacy. Traditionally, power utilities would compare their maximum power generating capacity with their expected peak load plus a planning reserve margin to account for uncertainties. Hydropower generators would identify a worst-case "critical water" year, and then compare expected loads to that worst-case scenario. While these practices are still relevant and commonly used, many industry groups have developed updated guidelines for what a resource adequacy standard should entail as the grid has evolved to include many more renewable resources and storage solutions like batteries.[10] Some common themes include many features already incorporated into Tacoma Power's modeling approach and resource adequacy standard, including (1) the importance of energy resource adequacy in addition to capacity adequacy, (2) modeling chronological operations (especially important for energy-limited resources like hydropower), (3) taking into account correlated weather events, (4) analyses that look at all hours of the year rather than only looking at annual peak hours, (5) multi-metric adequacy standards to measure different dimensions of risk and (6) metrics measuring tail-end risks.

As part of a process of continuous improvement, we frequently review and update our resource adequacy standard to ensure we continue to "measure what matters" as our needs change, the grid changes and industry best practices change. After evaluating many different potential metrics, we ultimately selected a standard that includes three components to measure different aspects of our system's capabilities: (1) monthly energy, (2) sustained capacity, (3) short-term peaking capacity.

4.2.2.1 Monthly energy

Energy adequacy is important for hydropower utilities because the amount energy (from precipitation/ runoff) can vary drastically from year to year and month to month. In an update to some of our older approaches of looking at a specific "Critical Water" year to assess resource adequacy, we assess resource adequacy based on the 10th percentile of our load-resource balance (LRB), which is total monthly generation minus total monthly load, across our simulations for each month separately. This approach is conceptually similar to BPA's current critical water planning approach.

For the seasons of most concern to us (winter and summer), we define an advisory threshold of 0 average megawatts (aMW) (i.e., the monthly 10th percentile LRB must be greater than or equal to zero)

[9] https://www.nwcouncil.org/reports/2023-1/ accessed 7/24/2024

[10] See, for example, the Energy Systems Integration Group's recent report entitled "Redefining Resource Adequacy for Modern Power Systems": https://www.esig.energy/resource-adequacy-for-modern-power-systems/

as fully adequate, between 0 and -10 aMW as marginally adequate, and lower than -10 aMW as inadequate. In shoulder seasons (spring and fall), the standard is more lenient, and we consider ourselves fully adequate if the monthly 10th percentile LRB is greater than -25 aMW, marginally adequate if it is between -25 aMW and -50 aMW inadequate when it is below -50 aMW. While we look at outcomes for each month of the year, the months that drive our findings are February in the winter and August in the summer, as these are the months when our reservoirs will tend to be most depleted in a poor water season.

Our 2024 IRP reports and considers our energy position as an advisory metric, meaning that our model's failure to meet the RA standard from time to time does not necessarily imply the need to acquire additional resources. Rather, we use this metric to flag consistent problem areas or potential degradations in our energy position over time.

4.2.2.2 Sustained capacity

Sustained capacity measures the maximum amount of power that can be generated by the Tacoma Power system while also considering water levels (i.e., energy) for subsequent needs. For this calculation, low water conditions will have less sustained capacity compared to high water conditions due to operational considerations. We use an industry-standard metric to measure our sustained capacity position: loss of load hours (LOLH). LOLH measures the number of hours when the load plus the required reserves of the system is less than potential generation, resulting in a capacity shortfall:

$$LOLH\left(\frac{hours}{year}\right) = \frac{\sum_{s=1}^{S}\sum_{h=1}^{H} L_{s,h}}{S}$$

Where:

- S is the number of simulations,
- H is the number of hours in the year, and
- $L_{s,h}$ = 1 for each hour that Capacity – (Required Reserves + Load) < 0 and = 0 otherwise.

We consider a portfolio to be fully adequate from a sustained capacity perspective when LOLH is 1.0 hours/year or lower, marginally adequate when it is between 1.0 hours/year and 2.4 hours/year and inadequate when it is higher than 2.4 hours/year.

4.2.2.3 Short-term peaking capacity

Short-term peaking capacity measures the maximum amount of power that can be generated in a given hour and represents the physical capacity of the system. Reservoir elevation levels affect short-term peaking capacity by increasing or decreasing the head pressure on the generator, thereby impacting physical generating capability. However, in low water conditions, short-term peaking capacity is not degraded beyond these physical impacts. In contrast, sustained capacity is degraded in low water conditions due to assumed operational considerations.

Short-term peaking capacity is evaluated in this IRP in two ways. The first way is similar to sustained capacity above. LOLH is calculated with the same formula above but using short-term peaking capacity rather than sustained capacity. The thresholds are also the same (fully adequate when LOLH is 1.0

hours/year or lower, marginally adequate when it is between 1.0 hours/year and 2.4 hours/year, and inadequate when it is higher than 2.4 hours/year).

In addition to our short-term peaking adequacy standard, we also assess potential worst-case outcomes. For this evaluation, we compare the lowest peaking capacity outcome across all our runs within a scenario to the highest loads across runs within the scenario. This effectively means that we analyze what would happen if we faced the coldest temperatures we have seen in 43 years on the tail end of a winter drought. This is not a situation we have seen in our historical records, but it is possible. This analysis is referred to as the Extreme Event analysis. We use the Extreme Event analysis to understand how our short-term peaking capacity risk differs under different scenarios or resource choices we might make.

5 Resource position analysis

5.1 Summary of model runs

The following section presents our resource position prior to adding any new power resources. We begin by examining our position under a "base case" set of resources, in which we assume renewal of our BPA contract with the Slice/Block product and Riffe Lake elevation restoration in 2030. We then conduct several sensitivity analyses around our weather assumptions under climate change, Riffe Lake restoration, alternative BPA product offerings, and alternative load growth assumptions.

1. **Base case runs:** We start with a look at our resource position under our "base case" set of resources (our current BPA Slice/Block product and assuming Riffe Lake elevation is restored in 2030). We run our base case analysis through three load growth scenarios: (1) our corporate load forecast, which includes Anticipated Electrification projections from our recently completed electrification study, (2) Expansive Policy projections of electrification and (3) Policy Regression projections of electrification. The "base case" runs use a 43-year historical weather record (1981 through 2023).
2. **Impacts of climate change:** In our base case analyses, we use a relatively short historical weather record (1981-2023) to reflect climate conditions representative of what we expect to see today. In our climate change analysis, we perform additional model runs with different weather inputs to analyze how the continuation of climate change trends would impact our position.
3. **Riffe Lake restoration delay:** Tacoma Power's intention is to restore Riffe Lake to full pool as soon as possible. However, it is possible that our base assumption of restoration by 2030 is too optimistic. We run a simple sensitivity analysis using the alternative assumption that Riffe Lake elevation is not restored over the course of the twenty-year study period. This sensitivity analysis in no way implies an intention on the part of Tacoma Power to not restore lake levels.
4. **BPA product choice:** Tacoma Power's decision around which BPA product to select in our next contract with BPA is the most critical decisions we will make in the coming years. While we do not have all the information needed to model future BPA product options accurately, we do

analyze the potential impact of different product choices we could make given the information we have available today.

5. **Risk trifecta:** Most of our runs look at changing one parameter at a time. The risk trifecta scenario compounds potential impacts of increased electrification, Riffe lake restoration delay, and BPA product choice.
6. **Other load projection sensitivities:** To evaluate the impact of uncertain load projections, we perform several additional analyses:
    a. **Data center sensitivity:** We run a sensitivity in which an additional 10 aMW of new industrial load is added per year between 2025 and 2035 to understand how many of these new loads our system might be able to handle before it is no longer adequate.
    b. **Rooftop solar sensitivity**: We evaluate the sensitivity of our results to projections of rooftop solar growth we have built into our load scenarios.
    c. **Load decline sensitivity**: We evaluate the sensitivity of model results to alternative projections of load decline.

5.2 Summary of findings

We find that our resource portfolio is usually adequate along each of our resource adequacy metrics if we continue to purchase Slice/Block from BPA and restore Riffe Lake elevation. If we can do both, we do not face an acute or imminent need for a new supply-side resource. However, we do face several risks in the future that we need to actively track, namely:

1. **Risks to our summer energy position:** We expect climate change to worsen our summer energy position, and it eventually may leave us approximately 40 to 50 aMW short in a summer drought year. Switching to a BPA Block product would also leave us short by a similar amount in the summer, a shortfall that would be exacerbated by climate change. Over the next 5 to 10 years, we will be able to manage these risks through midday light load hour purchases from the market when plenty of solar is available. However, additional analysis will determine whether relying on the market is a viable long-term strategy.
2. **Risks to our sustained and peaking capacity positions:** We find that high electrification loads, an inability to restore of Riffe Lake elevation, and having to switch to a BPA block product all present risks to our resource adequacy in different ways. When we examine our resource position under a “risk trifecta” scenario in which these three key risk factors are combined into a single pessimistic but plausible scenario, we find that our resource adequacy position is compromised to the point that we would likely need to acquire an additional supply-side resource. In all scenarios, we begin to fail our adequacy standard only in the second half of the 2030s. This gives us some time to prepare and track how each risk factor trends over the next 5 years.
3. **Industrial (e.g., data center) load growth:** We run a sensitivity in which 10 aMW per year of new flat industrial load is added to our system between 2025 and 2035. We find that our energy position and sustained capacity position both degrade quickly after the first few loads are added. While restoration of Riffe elevation in 2030 helps stabilize our

position temporarily, but our resource adequacy metrics suffer as we experience the combined effects of new data center load and progressively higher peak demand from electrification.

Table 9 and Table 10 at the end of Section 5 summarize outcomes for our resource adequacy metrics across all the different scenarios considered for 2035 and 2043, respectively.

5.3 Position under base case set of resources

We start by examining our resource adequacy position under our "base case" set of resources—our current BPA Slice/Block product and assuming Riffe Lake is restored in 2030. We run our base case analysis through our three load growth scenarios: (a) our corporate load forecast, which includes Anticipated Electrification projections from our recently completed electrification study, (b) Expansive Policy projections for electrification and (c) Policy Regression projections. The base case runs use a 43-year historical weather record (1981 through 2023).

5.3.1 Monthly energy position

Before restoration of Riffe elevation, the monthly 10th percentile outcome of our load-resource balance (LRB) hovers around -15 aMW in the winter and declines from a 40 aMW summer surplus in 2024 to around -5 aMW once our Columbia Basin Hydro contracts have all expired.[11] Once Riffe is restored to full elevation, our position hovers around -5 aMW in the winter and summer. These results suggest that we are fully energy adequate (10th percentile LRB>-10 aMW) in both the summer and winter under our Anticipated Electrification scenario once Riffe Lake elevation is restored (Figure 2, panel a). Results are nearly identical for our Policy Regression scenario of electrification (Figure 2, panel c). We meet our energy resource adequacy standard even under the more aggressive Expansive Policy electrification scenario if Riffe elevation is restored, though with a less comfortable margin in the winter and a more comfortable margin in the summer due to the higher levels of rooftop solar penetration projected in the Expansive Policy scenario (Figure 2, panel b). Our position in the fall and spring is adequate in all cases.

Our ability to absorb the increases in consumption from electrification is due primarily to reductions in consumption we project from building codes, standards (e.g., for appliances, lighting, etc.) and past and future conservation investments made by the utility.

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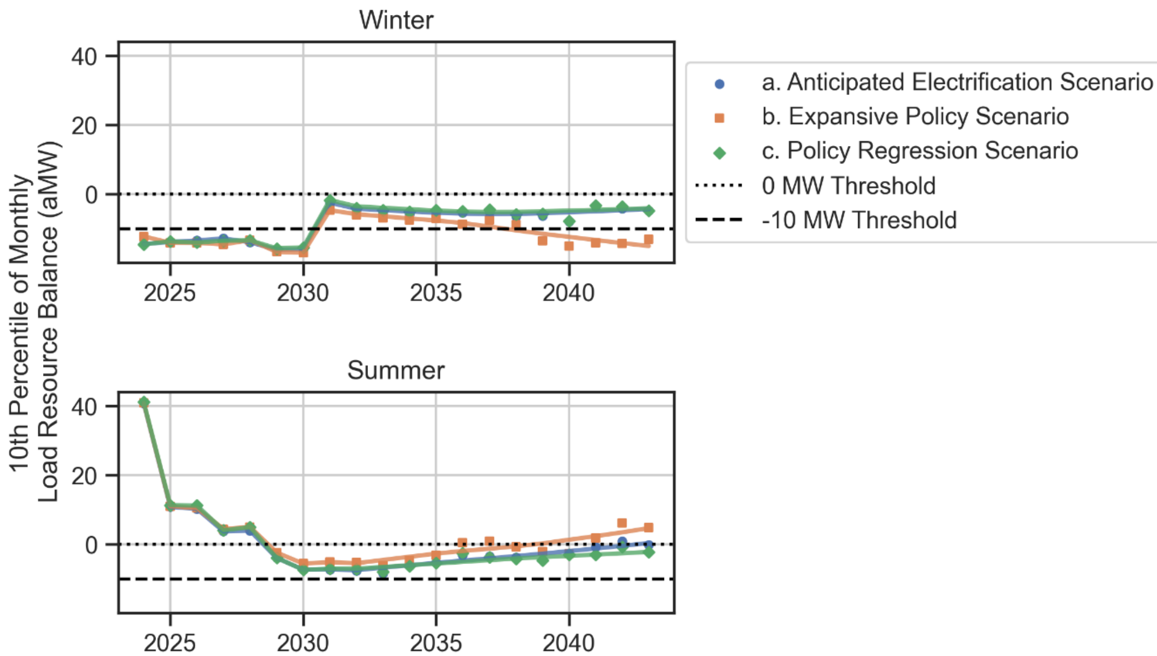
[11] Tacoma Power elected not to renew Columbia Basin Hydropower (CBH) Contracts beyond their latest termination dates. The contracts began to roll off in 2022, and the last contract expires at the end of 2026. The contracts combined represented roughly 3% of our generation in an average year. Because the generation is driven by the irrigation summer, the power came primarily in the summer. The decision not to renew these contracts primarily affects our summer energy surplus within our current BPA contract period. Had we renewed our contracts with CBH, the generation would have counted against the amount of power allocated to us by BPA. As a result, the decision not to renew the contracts has a negligible impact on our resource adequacy position beginning in October 2028, when the new BPA contract is in effect.

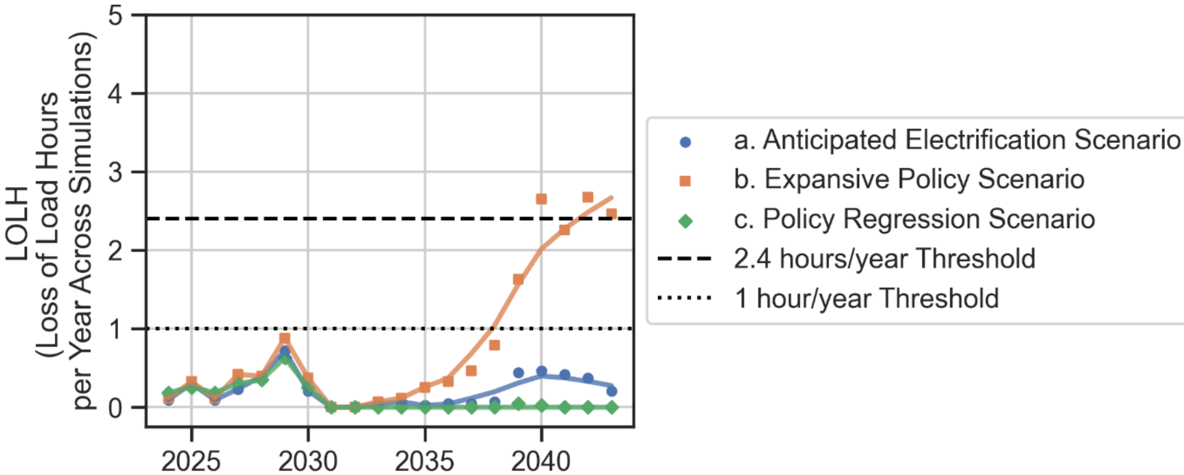
Figure 2: Energy Position (Base Case Resources)



5.3.2 Sustained capacity position

Model runs with our base case set of resources indicate that we will continue to meet our sustained capacity adequacy standard under both the Anticipated Electrification scenario and the Policy Regression scenario but that we will begin to just barely fail our adequacy standard in 2040 (Figure 3).

Figure 3: Sustained Capacity position (Base Case Resources)



5.3.3 Short-term peaking capacity position

While a short-term peaking capacity shortfall does not occur in our base case runs, our Extreme Event analysis indicates that capacity shortfalls are possible (Table 3) if we were to experience a severe cold snap on the tails of some of a bad winter drought. Under such conditions, a peaking capacity shortfall of around 59 MW is possible by 2035 in the Anticipated Policy scenario. The magnitude of the potential shortfall rises as peak demand from electrification rises.

Table 3: Short-term Peaking Capacity Position in 2035

	Loss of Load Hours (hours/year)		Extreme Event Capacity Balance (MW)	
Scenario	**2035**	**2043**	**2035**	**2043**
a. Anticipated Electrification Scenario	0.0	0.0	−59	−105
b. Expansive Policy Scenario	0.0	0.0	−76	−135
c. Policy Regression Scenario	0.0	0.0	−35	−81

Notes

Loss of load hours represents the average annual hours during which the load plus reserves exceed the physical generating capacity. The thresholds for loss of load hours for physical capacity are 1.0 and 2.4 hours/year.

Extreme event capacity balance is the difference between the minimum physical generating capacity and the maximum load plus reserves during the winter across all model runs. A negative value indicates that maximum load plus reserves exceeds the minimum physical generating capacity on model simulations. This measure does not maintain the hour-by-hour linkage in the simulations.

5.4 Impacts of climate change

We have progressively improved our approach to understanding how climate change will affect our resources over recent IRP cycles. The 2024 IRP modeling effort includes several weather simulations for comparison: a) the recent historical record back to 1981, b) the historical record adjusted to account for long-term climate trends, and c) simulated global climate model temperature and river inflows. The third data source is the same dataset used in regional studies by the University of Washington Climate

Impacts Group (UW CIG)[12], Bonneville Power Administration[13], and the Northwest Power and Conservation Council[14].

The general trends from climate change in the Puget Sound region are warmer temperatures (both summer and winter), drier summers, wetter winters, and earlier spring snowmelt. Trends in the historical record were compared with trends from climate model simulations and were generally in agreement. The trend toward lower river flows in the summer was consistent across datasets. However, the trend toward higher river flows in the winter was stronger in the climate model simulations compared to the historical record, where inflows had little to no trend across the winter months.

The impact of climate change on the monthly energy position for Tacoma Power is shown in Figure 4. We consistently find that our summer energy position is likely to degrade as a result of climate change and that it could cause us to fall 40 to 50 aMW below our threshold for energy adequacy in the summer. Our analysis does not, however, identify any emerging summer capacity inadequacies. In the winter, we find that our energy position would stay similar to our position today or could even improve.

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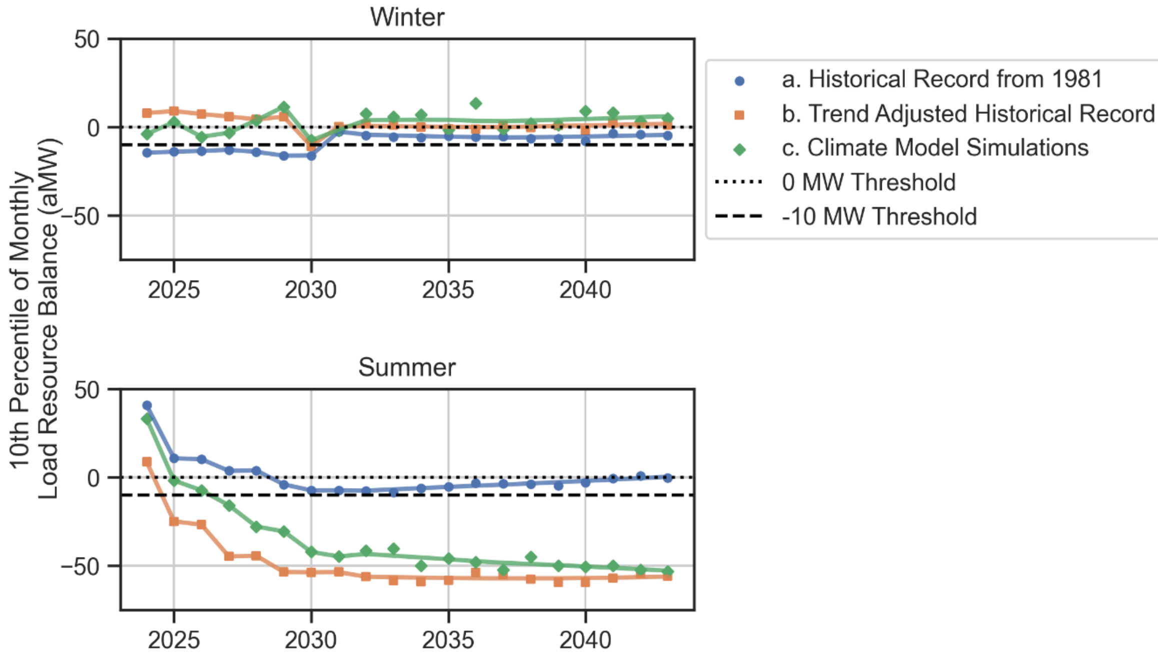
[12] Chegwidden, O. S., Nijssen, B., Rupp, D. E., Arnold, J. R., Clark, M. P., Hamman, J. J., et al. (2019). How do modeling decisions affect the spread among hydrologic climate change projections? Exploring a large ensemble of simulations across a diversity of hydroclimates. Earth's Future, 7, 623–637. https://doi.org/10.1029/2018EF001047
[13] Bonneville Power Administration. (2021). Climate change impacts and adaptation in the Pacific Northwest. Retrieved from https://www.bpa.gov/Projects/Climate/Documents/Climate-Change-Impacts-and-Adaptation.pdf
[14] Northwest Power and Conservation Council. (2022). The 2021 North West Power Plan (Document No. 2022-3). https://www.nwcouncil.org/fs/17680/2021powerplan_2022-3.pdf

Figure 4: Energy Position under Climate Change Scenarios (Base Case Resources and Anticipated Electrification)



As shown in Figure 5, our model runs indicate a possible degradation of our sustained capacity position due to climate trends, though we continue to pass our adequacy standard. Sustained capacity shortfalls in the climate-adjusted historical runs are due to generally lower water conditions in certain years, driven by lower summer flows combined with lack of a trend in the winter. Note that the climate model simulation runs are not shown in Figure 5 because the results are dominated by spurious low-temperature impacts that are more likely a modelling artefact rather than a reflection of a true change to the severity of cold snaps. Figure 5 also shows that, if climate change were to worsen our sustained capacity, restoring Riffe Lake to full pool would significantly improve our position by allowing us to store more water for winter. This is evident by the notable drop in our LOLH right after Riffe elevation is restored in 2030.

Figure 5: Sustained Capacity Position under Climate Change (Base Case Resources and Anticipated Electrification)

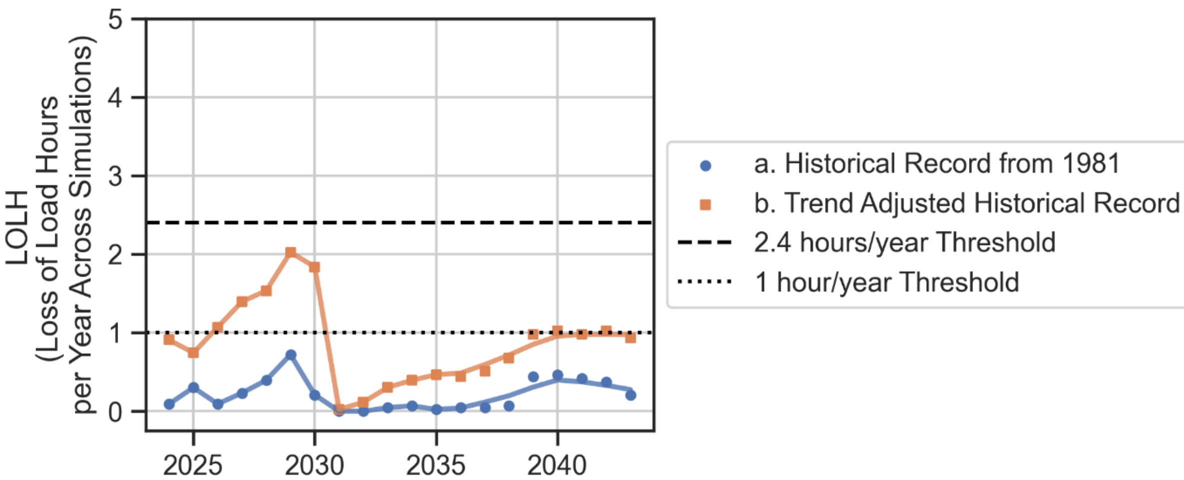


Table 4 shows the short-term peaking capacity position in 2035 and 2043 for the climate change scenarios. Our LOLH metric is not impacted by climate trends. However, our results indicate that climate trends may reduce the size of a potential peaking capacity shortfall in our Extreme Event analysis because of a small reduction in load (due to warming) compared with what we find using the historical record. The data we have available today are not able to address potential changes in the likelihood of extreme weather events.

Table 4: Short-term Peaking Capacity Position in 2035 under Climate Change (Base Case Resources and Anticipated Electrification)

	Loss of Load Hours (hours/year)		Extreme Event Capacity Balance (MW)	
Scenario	**2035**	**2043**	**2035**	**2043**
a. Historical Record from 1981	0.0	0.0	−59	−105
b. Trend Adjusted Historical Record	0.0	0.0	−27	−72

Notes

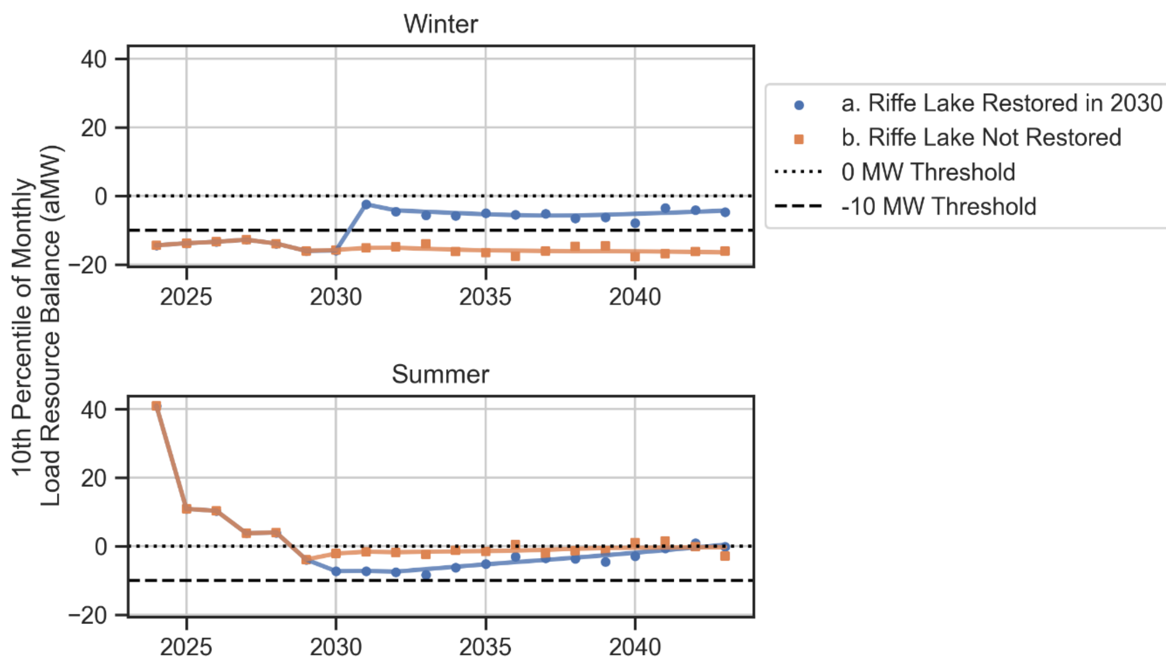
Loss of load hours represents the average annual hours during which the load plus reserves exceed the physical generating capacity. The thresholds for loss of load hours for physical capacity are 1.0 and 2.4 hours/year.

Extreme event capacity balance is the difference between the minimum physical generating capacity and the maximum load plus reserves during the winter across all model runs. A negative value indicates that maximum load plus reserves exceeds the minimum physical generating capacity on model simulations. This measure does not maintain the hour-by-hour linkage in the simulations.

5.5 Riffe Lake restoration sensitivity

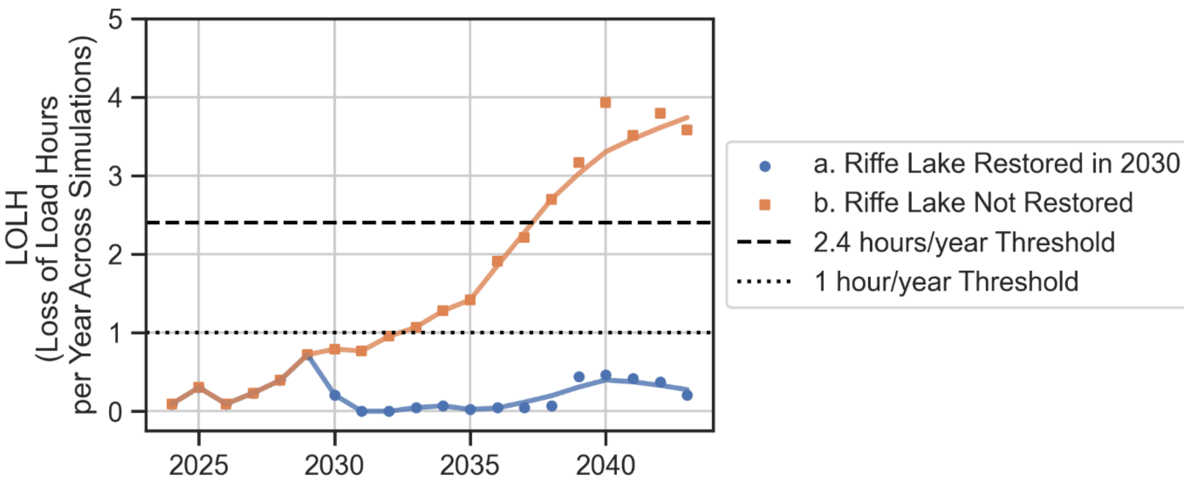
As discussed in Section 4.2.1, Tacoma Power's intention is to restore Riffe Lake to full pool as soon as possible. However, it is possible that our base assumption of restoration by 2030 is too optimistic. To analyze this potential source of risk, we run a simple sensitivity analysis using the alternative assumption that Riffe Lake is not fully restored over the course of the twenty-year study period. We find that, without restoration of Riffe Lake levels and with our Anticipated Electrification scenario, our winter energy position remains just below (-5 aMW) our adequacy standard (Figure 6).

Figure 6: Energy position under Riffe Lake restoration sensitivity (Base Case Resources with Anticipated Electrification)



More importantly, reduced storage capabilities from staying at the lower elevation at Riffe Lake result in a significant degradation of our sustained capacity position over the 20-year study period. We enter our “yellow zone” for sustained capacity (LOLH between 1.0 and 2.4 hours/year) by the early 2030s and begin to fail our adequacy standard in the late 2030s (Figure 7). The degradation of our sustained capacity position is driven by winter (primarily February) shortfalls.

Figure 7: Sustained capacity position under Riffe Lake restoration sensitivity (Slice/Block with Anticipated Electrification)



There are no short-term peaking capacity shortfalls for either Riffe Lake scenario. However, our Extreme Event analysis indicates that short-term peaking capacity shortfalls could be around 40 MW larger without restoration of Riffe elevation (Table 5).

Table 5: Short-term peaking capacity position in 2035 under Riffe Lake restoration sensitivity (Base Case resources with Anticipated Electrification demand)

	Loss of Load Hours (hours/year)		Extreme Event Capacity Balance (MW)	
Scenario	**2035**	**2043**	**2035**	**2043**
a. Riffe Lake Restored in 2030	0.0	0.0	−59	−105
b. Riffe Lake Not Restored	0.0	0.0	−97	−144

Notes

Loss of load hours represents the average annual hours during which the load plus reserves exceed the physical generating capacity. The thresholds for loss of load hours for physical capacity are 1.0 and 2.4 hours/year.

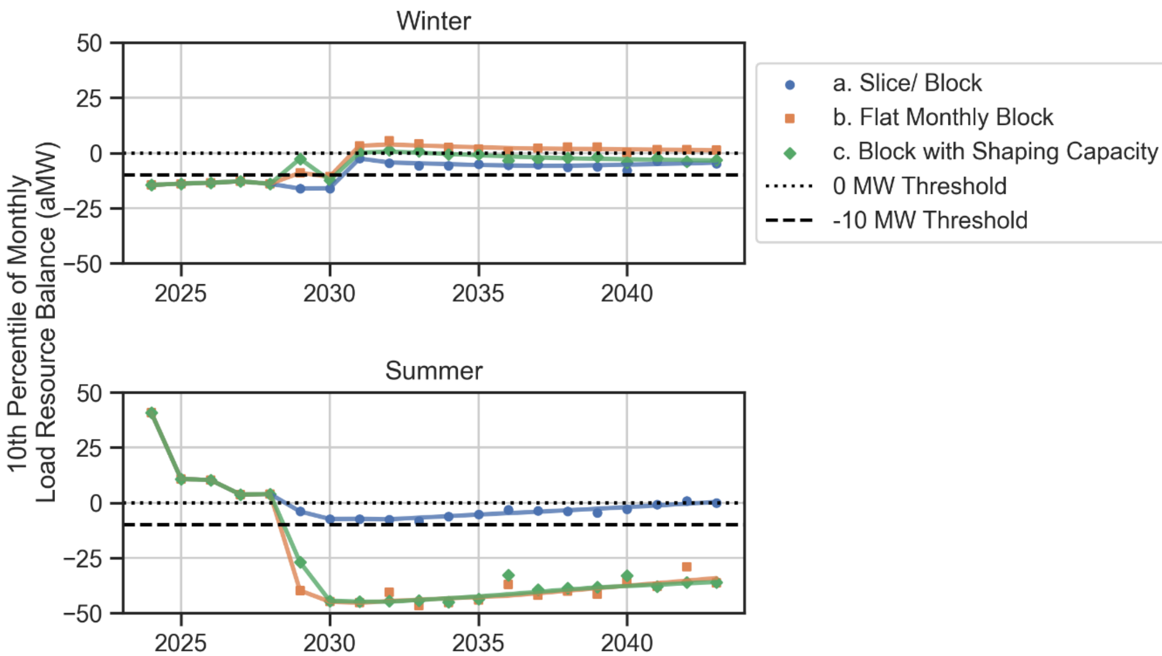
Extreme event capacity balance is the difference between the minimum physical generating capacity and the maximum load plus reserves during the winter across all model runs. A negative value indicates that maximum load plus reserves exceeds the minimum physical generating capacity on model simulations. This measure does not maintain the hour-by-hour linkage in the simulations.

5.6 BPA product choice

Tacoma Power's product selection for the next BPA contract is perhaps the most critical decision we will make in the coming years. As explained in Section 4.1.1, we do not have all the information we need to model BPA product options accurately. Our analysis incorporates the best information available as of the completion of the IRP. We expect to update our analysis of BPA product options once we have complete information on each product offering. In this section, we compare our position under three BPA product offerings: (a) Slice/Block (our current product), incorporating some of the product design changes we expect to see based on information available as of the writing of this IRP, (b) a Flat Monthly Block product, and (c) a Block with Shaping Capacity product.

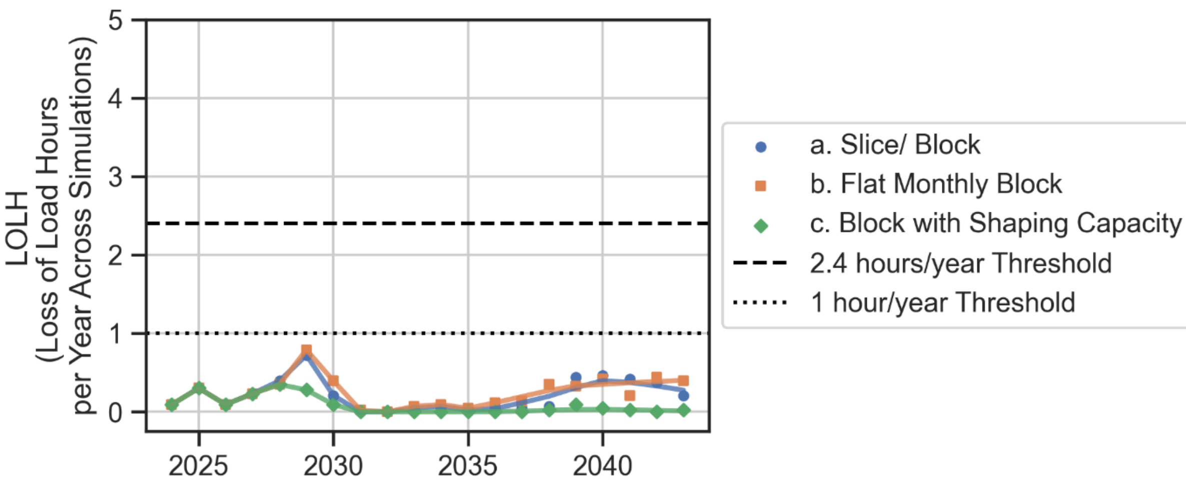
Switching to a Block product affects many aspects of our resource adequacy position. For winter energy, Flat Monthly Block and Block with Shaping Capacity perform marginally better than Slice/Block because they offer a guaranteed amount of monthly energy regardless of inflow conditions (in contrast to Slice/Block which partially varies across water conditions and offers slightly less energy than the Block products under the lowest water conditions). In the summer, Slice/Block provides us with substantially more energy under all water conditions. Switching to any Block product would degrade our summer energy position by about 30 to 40 aMW in a poor water year immediately upon switching products (Figure 8).

Figure 8: Energy position under alternative BPA products (Anticipated Electrification)



We do not find that switching would cause us to fail our resource adequacy standard for sustained capacity (Figure 9). This is because sustained capacity considers both energy and capacity, and the additional winter energy provided by Block in low water years makes up for the reduction in peaking capacity. Block with shaping capacity performs slightly better than the other two products because it has the higher winter energy of Block in low water years plus some additional capacity, but the differences across products do not change whether we pass our sustained capacity adequacy standard.

Figure 9: Sustained capacity position under alternative BPA products (Anticipated Electrification demand)



Switching to a Block product does, however, significantly increase our risk exposure in an extreme weather event. Our Extreme Event analysis suggests that it is possible that we could see a short-term peaking capacity shortfall of up to nearly 144 MW under a Flat Monthly Block product versus 59 MW under Slice/Block (Table 6). While the Block with Shaping Capacity product would improve our peaking capacity position relative to a Flat Monthly Block product, it will still leave us in a worse position than Slice/Block. How much worse our peaking capacity position is under Block with Shaping Capacity will depend on the specific product design choices BPA adopts.

Table 6: Short-term peaking capacity position in 2035 under alternative BPA products (Anticipated Electrification demand)

	Loss of Load Hours (hours/year)		Extreme Event Capacity Balance (MW)	
Scenario	**2035**	**2043**	**2035**	**2043**
a. Slice/ Block	0.0	0.0	−59	−105
b. Flat Monthly Block	0.0	0.0	−144	−192
c. Block with Shaping Capacity	0.0	0.0	−103	−153

Notes

Loss of load hours represents the average annual hours during which the load plus reserves exceed the physical generating capacity. The thresholds for loss of load hours for physical capacity are 1.0 and 2.4 hours/year.

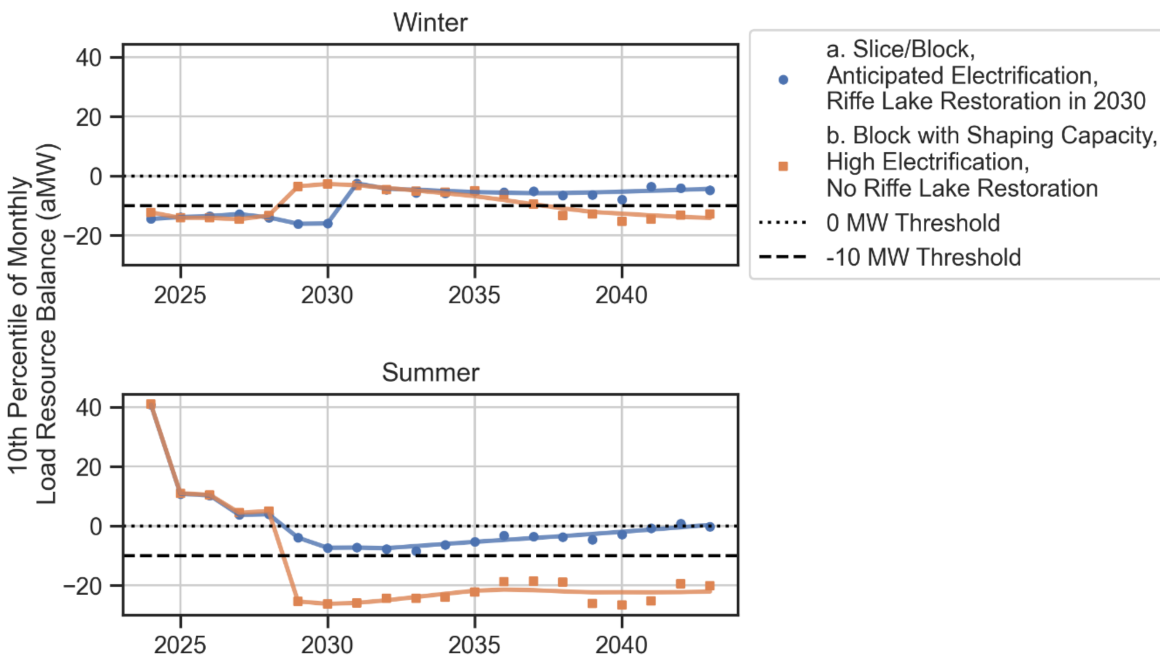
Extreme event capacity balance is the difference between the minimum physical generating capacity and the maximum load plus reserves during the winter across all model runs. A negative value indicates that maximum load plus reserves exceeds the minimum physical generating capacity on model simulations. This measure does not maintain the hour-by-hour linkage in the simulations.

5.7 “Risk trifecta” scenario

In the previous sections, we consider sensitivities around one risk factor at a time. In this section, we consider a scenario in which multiple risk factors compound to challenge our resource adequacy position. In this scenario, we combine the high levels of electrification seen in our Expansive Policy scenario, an assumption that we are not able to restore Riffe Lake elevation to full pool and an assumption that the BPA Slice/Block product is not available and that we instead must choose a Block with Shaping Capacity (BWSC) product. While pessimistic from a resource adequacy perspective, it is a plausible and realistic set of future outcomes for Tacoma Power.

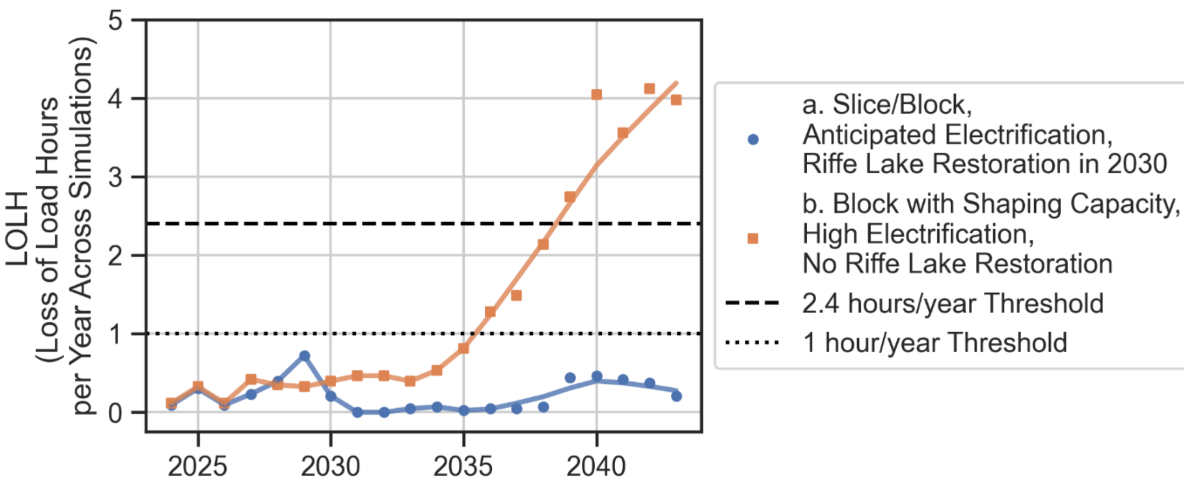
The combined impacts of our three key risk factors compromise our resource adequacy position and would likely necessitate the acquisition of an additional supply-side resource. Consistent with results presented in Section 5.6, we find that our summer energy position quickly falls below our adequacy threshold as we switch from Slice/Block to Block with Shaping Capacity (Figure 10). While it improves over the study period as additional rooftop solar is added to our system, we remain below our adequacy standard throughout most of the study period. We expect the impact of climate change to further degrade our summer energy position. Our winter energy position fares better and stays right at our adequacy limit until the late 2030s. Over the late 2030s and early 2040s, however, our winter energy position degrades to approximately 10 aMW below our adequacy threshold.

Figure 10: Energy position under "Risk Trifecta" scenario



As a result of the combination of aggressively increasing peak loads from expansive electrification and weakened capacity from lower Riffe Lake elevations, we also see a steady degradation of our sustained capacity and fail our adequacy standard by the late 2030s (Figure 11).

Figure 11: Sustained capacity position under Risk Trifecta scenario



This is the only scenario under which we see a degradation in our peaking capacity adequacy metric as well. Our degraded peaking capacity shows up in our Extreme Event analysis as well. Relative to our base case resource scenario (Slice/Block product and restoration of Riffe Lake by 2030) with the more moderate Anticipated Electrification load growth assumptions, we find that a peaking capacity shortfall during an extreme event could be more than 100 MW larger (Table 7).

Table 7: Short-term peaking capacity in 2035 and in 2040s under Risk Trifecta scenario

	Loss of Load Hours (hours/year)		Extreme Event Capacity Balance (MW)	
Scenario	**2035**	**2043**	**2035**	**2043**
a. Slice/Block, Anticipated Electrification, Riffe Lake Restoration in 2030	0.0	0.0	−59	−105
b. Block with Shaping Capacity, High Electrification, No Riffe Lake Restoration	0.0	0.1	−148	−227

Notes

Loss of load hours represents the average annual hours during which the load plus reserves exceed the physical generating capacity. The thresholds for loss of load hours for physical capacity are 1.0 and 2.4 hours/year.

Extreme event capacity balance is the difference between the minimum physical generating capacity and the maximum load plus reserves during the winter across all model runs. A negative value indicates that maximum load plus reserves exceeds the minimum physical generating capacity on model simulations. This measure does not maintain the hour-by-hour linkage in the simulations.

5.8 Other load projection sensitivities

This section presents additional analyses we use to understand the sensitivity of our results to different components of our load projections. The first sensitivity addresses the potential impact additional industrial loads like data centers might have on our resource adequacy. The second addresses how our projections for rooftop solar buildout within the service area affect our resource adequacy findings. The third addresses uncertainty in our projections of the underlying declining load trends.

5.8.1 Data center sensitivity

As discussed in Section 4.1.6, load growth from new data centers locating in our service is an important source of load uncertainty for power utilities. We run a sensitivity in which an additional 10 aMW per year of new flat load is added between 2025 and 2035. The goal of this sensitivity is to understand how much of this new load our system might be able to handle before it is no longer adequate rather than try to predict when and how much new data center load might locate our service area. We focus this sensitivity on load additions of just under 10 aMW because these loads would be eligible for our New Large Load rate schedule, which sets power rates based on Tacoma Power's system portfolio. Larger new loads will require a resource acquisition and fall under our Very Large Load rate class, in which the load is charged a rate based on the cost of acquiring new resources to serve it.

We find that our energy position quickly degrades after the first few loads are added. While restoration of Riffe elevation in 2030 helps stabilize our winter energy position temporarily, our position remains inadequate throughout the 2030s and into the 2040s (Figure 12). Our sustained capacity position exhibits a pattern similar to our winter energy position. Restoration of Riffe Lake in 2030 helps defer the decline in our position temporarily, but our sustained capacity suffers as we experience the combined effects of new data center load and progressively higher peak demand from electrification (Figure 13). Our short-term peaking capacity metrics fare better, but we see an increased risk in the magnitude of a peaking capacity shortfall in our extreme event analysis (Table 8)

Figure 12: Energy position under other load projection sensitivities

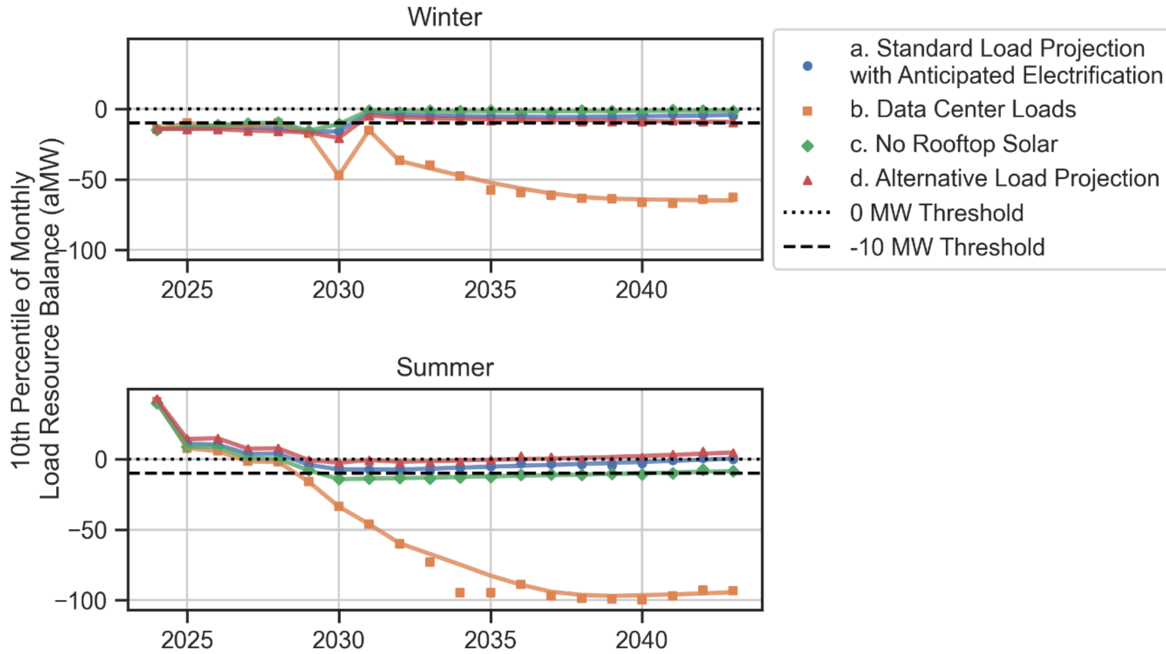


Figure 13: Sustained capacity under other load projections

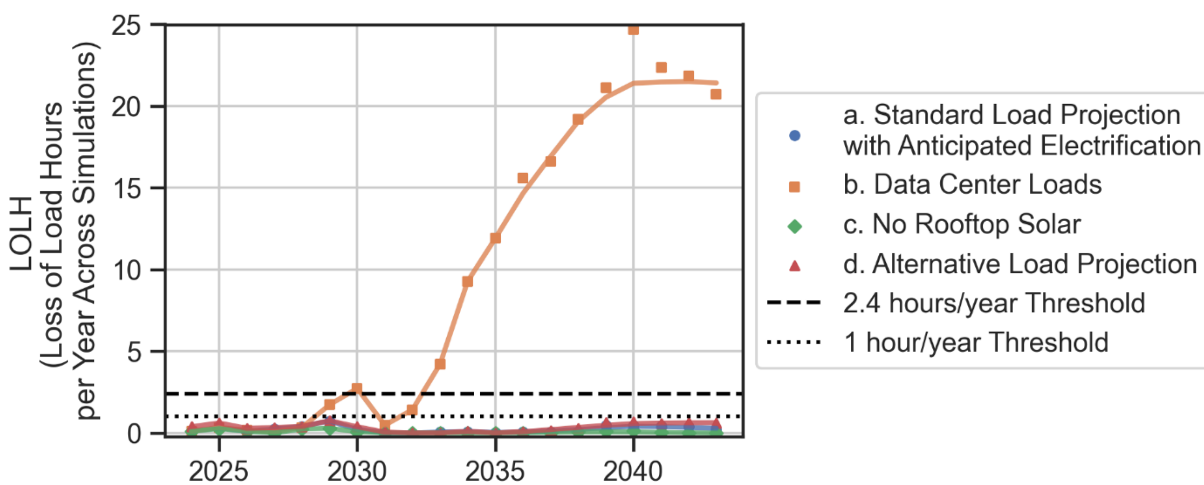


Table 8: Short-term peaking capacity position in 2035 under other load projections

	Loss of Load Hours (hours/year)		Extreme Event Capacity Balance (MW)	
Scenario	**2035**	**2043**	**2035**	**2043**
a. Standard Load Projection with Anticipated Electrification	0.0	0.0	−59	−105
b. Data Center Loads	0.0	0.0	−126	−181
c. No Rooftop Solar	0.0	0.0	−41	−84
d. Alternative Load Projection	0.0	0.0	−70	−102

Notes

Loss of load hours represents the average annual hours during which the load plus reserves exceed the physical generating capacity. The thresholds for loss of load hours for physical capacity are 1.0 and 2.4 hours/year.

Extreme event capacity balance is the difference between the minimum physical generating capacity and the maximum load plus reserves during the winter across all model runs. A negative value indicates that maximum load plus reserves exceeds the minimum physical generating capacity on model simulations. This measure does not maintain the hour-by-hour linkage in the simulations.

5.8.2 Rooftop solar sensitivity

Each of our three core load scenarios (Anticipated Electrification, Expansive Policy and Policy Regression) includes a projection of rooftop solar growth that is consistent with the policy environment described by the scenario. This sensitivity considers an extreme case in which no additional rooftop solar is added to our system beyond what is currently installed. While not realistic, this sensitivity is helpful to understand the extent to which our position depends on our assumptions regarding the growth of rooftop solar. The rooftop solar in our projections sightly improves our summer energy position and slightly degrade our winter energy position as a result of interactions with our BPA contract but does not substantively change our energy position (Figure 12), sustained capacity position (Figure 13) or short-term peaking capacity position (Table 8).

5.8.3 Alternative load decline projections

Our third sensitivity considers what our position would look like with a slightly less aggressive underlying load decline estimate. In this sensitivity, we assume load decline is limited to that projected in our conservation potential assessment (CPA) rather than the more aggressive decline projected in our corporate load forecast. We find that the results are qualitatively similar to those using our base assumptions (Figure 12, Figure 13 and Table 8).

Table 9: Summary of resource position analysis (2035)

Summary of Resource Position Analysis (2035)

	Energy		Sustained Capacity	Peaking Capacity	
	Summer LRB (aMW)	Winter LRB (aMW)	LOLH (hours/ year)	LOLH (hours/ year)	Extreme Event Capacity Balance (MW)
1. Base Case Scenarios (Electrification Assumptions)					
a. Anticipated Electrification, Historical Weather, Riffe Lake Restoration in 2030, Slice/ Block BPA Contract	−5	−5	0.02	0.00	−56
b. Expansive Policy Scenario	−3	−7	0.26	0.00	−67
c. Policy Regression Scenario	−5	−5	0.00	0.00	−35
2. Climate Scenarios					
b. Trend Adjusted Historical Record	−58	−1	0.47	0.00	−27
c. Climate Model Simulations	−46	−1	1.34	0.01	
3. Riffe Lake Restoration					
b. Riffe Lake Not Restored	−2	−17	1.42	0.00	−97
4. BPA Contract Scenarios					
b. Flat Monthly Block	−44	2	0.05	0.00	−134
c. Block with Shaping Capacity	−44	−1	0.00	0.00	−98
5. Risk Trifecta Scenario					
b. Block with Shaping Capacity, High Electrification, No Riffe Lake Restoration	−22	−5	0.81	0.00	−140
6. Alternative Load Assumption Scenarios					
b. Data Center Loads	−95	−58	11.91	0.00	−116
c. No Rooftop Solar	−13	−1	0.00	0.00	−41
d. Alternative Load Projection	−0	−8	0.00	0.00	−62

Notes

Red = fails adequacy threshold

Yellow = adequacy warning

Green = adequate

Black = no established adequacy standard

Blank cell = unreliable modeling result not presented. Climate model temperatures lead to spurious results in some hours.

- Run 1a is the benchmark scenario for comparing to other runs. In IRP figures, run 1a is repeatedly presented as run "a" (2a, 3a, etc.) for comparison purposes.
- **Energy.** The seasonal load resource balance (LRB) is based on the following: the load resource balance (average generation minus average load) is calculated for each month and each model simulation; then, the 10th percentile is calculated across model simulations for each month; finally, the seasonal LRB is the minimum of those monthly percentiles. The thresholds for seasonal LRB are 0 aMW and -10 aMW for both summer and winter.
- **Sustained Capacity.** The loss of load hours (LOLH) are calculated based on the number of hours that load plus reserves exceed sustained generating capacity. Sustained generating capacity is calculated based on the physical capacity of the Tacoma Power system with adjustments made for operational considerations such as low water conditions. The thresholds for sustained capacity are 1.0 hours/ year and 2.4 hours/ year.
- **Peaking Capacity.** The loss of load hours (LOLH) are calculated similar to sustained capacity but without adjusting for operational considerations. The thresholds for peaking capacity LOLH are 1.0 hours/ year and 2.4 hours/ year. The extreme event capacity balance is the difference between the maximum load plus reserves minus the minimum peaking capacity across all model simulations and winter hours. This measure does not maintain the hour-by-hour linkage in the simulations.

Table 10: Summary of resource position analysis (2043)

Summary of Resource Position Analysis (2043)

	Energy		Sustained Capacity	Peaking Capacity	
	Summer LRB (aMW)	Winter LRB (aMW)	LOLH (hours/ year)	LOLH (hours/ year)	Extreme Event Capacity Balance (MW)
1. Base Case Scenarios (Electrification Assumptions)					
a. Anticipated Electrification, Historical Weather, Riffe Lake Restoration in 2030, Slice/ Block BPA Contract	−0	−5	0.21	0.00	−104
b. Expansive Policy Scenario	5	−13	2.47	0.00	−124
c. Policy Regression Scenario	−2	−5	0.00	0.00	−81
2. Climate Scenarios					
b. Trend Adjusted Historical Record	−56	1	0.93	0.00	−58
c. Climate Model Simulations	−53	5	6.12	0.34	
3. Riffe Lake Restoration					
b. Riffe Lake Not Restored	−3	−16	3.58	0.00	−144
4. BPA Contract Scenarios					
b. Flat Monthly Block	−36	1	0.40	0.02	−183
c. Block with Shaping Capacity	−36	−3	0.02	0.00	−133
5. Risk Trifecta Scenario					
b. Block with Shaping Capacity, High Electrification, No Riffe Lake Restoration	−20	−13	3.98	0.12	−213
6. Alternative Load Assumption Scenarios					
b. Data Center Loads	−93	−63	20.72	0.05	−169
c. No Rooftop Solar	−9	−1	0.00	0.00	−84
d. Alternative Load Projection	4	−10	0.60	0.00	−92

Notes

Red = fails adequacy threshold

Yellow = adequacy warning

Green = adequate

Black = no established adequacy standard

Blank cell = unreliable modeling result not presented. Climate model temperatures lead to spurious results in some hours.

- Run 1a is the benchmark scenario for comparing to other runs. In IRP figures, run 1a is repeatedly presented as run "a" (2a, 3a, etc.) for comparison purposes.
- **Energy.** The seasonal load resource balance (LRB) is based on the following: the load resource balance (average generation minus average load) is calculated for each month and each model simulation; then, the 10th percentile is calculated across model simulations for each month; finally, the seasonal LRB is the minimum of those monthly percentiles. The thresholds for seasonal LRB are 0 aMW and -10 aMW for both summer and winter.
- **Sustained Capacity.** The loss of load hours (LOLH) are calculated based on the number of hours that load plus reserves exceed sustained generating capacity. Sustained generating capacity is calculated based on the physical capacity of the Tacoma Power system with adjustments made for operational considerations such as low water conditions. The thresholds for sustained capacity are 1.0 hours/ year and 2.4 hours/ year.
- **Peaking Capacity.** The loss of load hours (LOLH) are calculated similar to sustained capacity but without adjusting for operational considerations. The thresholds for peaking capacity LOLH are 1.0 hours/ year and 2.4 hours/ year. The extreme event capacity balance is the difference between the maximum load plus reserves minus the minimum peaking capacity across all model simulations and winter hours. This measure does not maintain the hour-by-hour linkage in the simulations.

6 Strategies to fill potential gaps

While our analyses do not identify an imminent need for a new supply-side resource, we do identify some potential risks to our future resource adequacy position. In this section we discuss what our future options for mitigating the risks identified in Section 5 might be. In Section 7, we analyze how effectively they might be able to mitigate each risk and analyze the cost of each option.

6.1 New supply-side generation or storage resource alternatives

We limit our analysis of potential new supply-side resources to those that are currently commercially available today or appear to be on the cusp of being commercially available. For the 2024 IRP, that list includes:

1. Wind power from several possible locations within Washington and along the Columbia River Gorge (Gorge)
2. Solar power from several possible locations within Washington and along the Gorge in Oregon
3. Small modular nuclear reactors
4. Short-duration battery storage
5. Incremental investments at existing hydropower assets

6.1.1 Generation and storage capability assumptions

We use wind and solar generation profiles from the National Renewable Energy Laboratory's System Advisor Model.[15] We allow our model to select from several possible locations within Washington and along the Gorge in Oregon.

Our small modular nuclear reactor profile assumes a 95% capacity factor with a flat generation profile across all hours.

For IRP purposes, energy storage resources are dispatched with the objective of reducing daily peak loads. The following storage resources are evaluated:

- Lithium-ion battery, 6 hours, 100 MW with round trip efficiency of 85% and no standing loss rate.[16]
- Pumped storage hydro, 9 hours, 250 MW with round trip efficiency of 78% and no standing loss rate.

6.1.2 Cost assumptions

We rely on the NREL Annual Technology Baseline (ATB) data[17] to develop our cost assumptions whenever possible. For all our runs, we use the 'moderate' ATB costs for the 30-year capital recovery

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[15] We use NREL's SAM model, turbine data, and simulated weather data which can be found here: https://sam.nrel.gov/

[16] We tested other battery configurations of smaller sizes and shorter duration and found that they had little impact on our sustained capacity position.

[17] NREL (National Renewable Energy Laboratory). 2024. "2024 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/

period, under the R&D-only conditions, which do not account for future benefits from the Inflation Reduction Act and other credits. Operation and maintenance (O&M) costs are assumed to remain constant at the annualized level presented in the ATB, with an annual inflation rate of 2.4%[18] applied to these costs.

To estimate integration costs for variable energy resources (i.e., wind and solar), we use publicly available external sources. To approximate our integration costs, we take a weighted average of Lazard's LCOE+[19] estimates for the cost of firming intermittency for various ISOs. The weights are based on the similarity of an ISO's overall variable energy resource (VER) penetration to local levels. To create resource-specific integration costs, we then adjust these VER integration costs using BPA's resource-level VERBS rates to derive relative firming costs.

Table 11: Cost assumptions by resource

	CapEx ($/kw)	O&M ($/kw-year)	Grid Connection ($/kw)	Variable Cost ($/MWh)	Lifetime (years)	Integration Cost ($/kwh)
Utility-Scale PV	1447	20.38	116	0	30	18.23
Land-Based Wind Power	1600	31.88	116	0	30	30.17
Utility-Scale lithium-ion battery (4-hour)	1938	44.25	116	*[20]	15	0
Commercial lithium-ion battery (4-hour)	2040	49.16	116	*	15	0
Utility-Scale lithium-ion battery (6-hour)	2676	62.03	116	*	30	0
Nuclear - SMR	9650	136.00	116	2.60	60	0

For short duration battery storage, we take a slightly more detailed approach to estimating O&M to enable incorporation of variable costs directly, and account for returns to scale. We mix ATB-estimates for commercial and utility-scale batteries which are sized to one and sixty megawatts respectively to approximate the cost of a 4-hour, 20 MW battery resource and use utility-scale estimates for the cost of a 6-hour, 100 MW battery.

[18] Taken from the Cleveland Federal Reserve 20-year expected inflation value: https://www.clevelandfed.org/indicators-and-data/inflation-expectations
[19] Document can be found here: https://www.lazard.com/research-insights/levelized-cost-of-energyplus/
[20] Battery variable costs primarily arise from charging the battery, and thus are extremely dependent on power market conditions and resulting usage patterns

We include in our set of portfolio options a small nuclear resource (SMR). However, the estimated cost for the SMR is considerably higher than other alternatives. It is thus an inefficient choice for our needs in every scenario tested and never selected by our portfolio expansion model. Our cost assumptions are from the earliest-available projections from NREL (2030).

For modeling purposes, we assume that we would secure BPA point-to-point transmission rights for any resources located outside of our service area (i.e. wind, solar, nuclear, and closed loop pumped storage) and cost transmission at BPA's most recently published tariff ($1.648/kW-month).[21] We assume that we would secure rights equal to the maximum generation of the resources' power curve. For example, a 100 MW wind plant, with a maximum hourly capacity factor of .8 would require 80 MW of transmission capacity.

6.2 Incremental investments at existing hydropower assets

Another option is to make incremental investments to build upon the capabilities of our existing generating resource fleet. This entails two distinct options. The first is to incrementally add a little bit of capacity or other capabilities to generators as they're taken offline to be rebuilt. We estimate that we might be able to add around 5% more capacity at each generator, but the potential upgrade opportunity and cost of making those upgrades will be specific to each generator and cannot be known definitively until each generator's rebuild needs and opportunities are assessed. We do not model these opportunities in our IRP but do plan to evaluate them on an on-going basis over the coming decades as each specific generator is assessed and a rebuild plan is created.

The second opportunity to consider is adding pumped storage hydro at our Cowlitz River Project. Cowlitz offers a unique opportunity to consider installing pumped storage. The powerhouse at Mossyrock Dam has infrastructure already in place for a third large pump storage unit to be installed. Additionally, the site may offer the possibility of adding a third reservoir, increasing the efficiency and energy storage potential of the project. We have looked at the possibility of adding pumped storage at Cowlitz in the past, but a major barrier to serious consideration of this resource option has been the risk of reopening our FERC license. Now we are beginning to approach the end of our Cowlitz license and are preparing for the relicensing effort, so this is the right time to seriously evaluate this question again. In our 2020 IRP, we estimated that it could cost between $150 million and $250 million to add pumped storage. However, pumped storage costs are highly site-specific. We have received funding through the Climate Commitment Act (CCA) to conduct an in-depth study of the feasibility and cost of pumped storage at Cowlitz and will be able to conduct that study in 2025 provided the Climate Commitment Act (CCA) is not repealed in November 2024.

6.3 Demand-side resource alternatives

On the customer-side of the meter, we have three key resource options: (1) encourage or incentivize customers to generate their own power through rooftop solar, (2) incentivize customers to use less

[21] Tariffs are published on BPA's Transmission Rates webpage: https://www.bpa.gov/energy-and-services/rate-and-tariff-proceedings/transmission-rates

energy through our conservation programs, or (3) encourage customers to shift when they use energy through demand response offerings.

6.3.1 Rooftop solar

Our base case runs already include an assumption that we will see continued growth of rooftop solar and so we do not model additional rooftop solar beyond what is already assumed to be installed as a resource option in the IRP. We do, however, run a sensitivity analysis in Section 5.8.2 to understand how the rooftop solar projections embedded into our load projections contributes to resource adequacy. We find that rooftop solar does not substantively change our energy, sustained capacity, or short-term peaking capacity position. We also include a Western Washington solar resource as an option for our portfolio expansion model to choose, but it is never selected by the model.

6.3.2 Conservation

Our base case runs also already include an assumption of continued conservation progress. The energy savings projections in our IRP are grounded in our most recent (2024-2043) Conservation Potential Assessment and are consistent with our corporate load forecast. Projections include energy savings from building codes, efficiency standards (e.g., for appliances, lighting, etc.) and energy savings we expect to acquire through our conservation programs. Our projected investments in conservation are a critical component of our future resource strategy. Without those investments, we would be at risk of failing our resource adequacy standard along all dimensions and require a new supply-side resource. In our Expansive Policy scenario, we are especially at risk of significant energy, sustained capacity, and peaking capacity shortfalls if we do not make these projected investments.

Our IRP model does not currently include additional conservation as a resource that can be selected. However, we update our CPA every two years. Our next CPA will be the first to incorporate projections from our 2023 electrification study, and we may find that there are additional conservation opportunities on the horizon as customers switch to using electricity. We generally prefer to invest in conservation to meet a resource adequacy need rather than purchasing a new supply-side resource so long as it (a) is available and able to meet our need, (b) is a similar cost or less costly than whatever supply-side resource we might otherwise need to acquire and (c) provides a positive customer touchpoint. Any new conservation opportunities that meet these criteria would be selected before a supply-side resource to meet growing needs from electrification.

6.3.3 Demand response

Under scenarios in which we find ourselves inadequate under our peaking or short-term peaking capacity standard, we test demand response as a potential resource option in our models. Tacoma Power has conducted several studies to understand the potential availability and cost of demand response resources. Our 2024 IRP considered generic demand response resources of two types: (1) one that consistently shifts customer usage patterns and (2) one that is called upon only when it is needed. For the former, we assume a peak load reduction of 1.25% and a corresponding load increase spread across off-peak hours. For the latter, we assume an additional 2% reduction in load during peak events but limit the number of demand response events each year to seven in the winter and seven in the summer.[22] This is equivalent to approximately 20 to 30 MW of demand response by the late 2030s.

6.4 Other alternatives

In the case of sustained capacity, our key alternative approaches to acquiring a new resource involve different interactions with the market: (1) rely on short-term (five-year or less) contracts for power or (2) adjust our operations to preserve more winter capacity to manage sustained capacity risks. Cost assumptions were based on Intercontinental Exchange futures for power, with a premium included for a guarantee of low carbon content and qualification of capacity under the Western Resource Adequacy Program (WRAP). This option was more expensive than our modeled supply-side resource options and was not selected by our portfolio expansion model.

The latter option would certainly be available, as it relies only on our existing resource fleet. We do not include this strategy as a resource option in this IRP but plan to conduct additional modeling and analysis to assess the extent to which this strategy could address sustained capacity risks and the potential cost of this strategy.

7 Analysis of resource alternatives

In this section we analyze the alternatives identified in Section 6 and assess their ability to mitigate key risks we face. We also compare the cost of each alternative. This objective of this analysis is to understand which future investments might be promising if we find we need additional resources in the future.

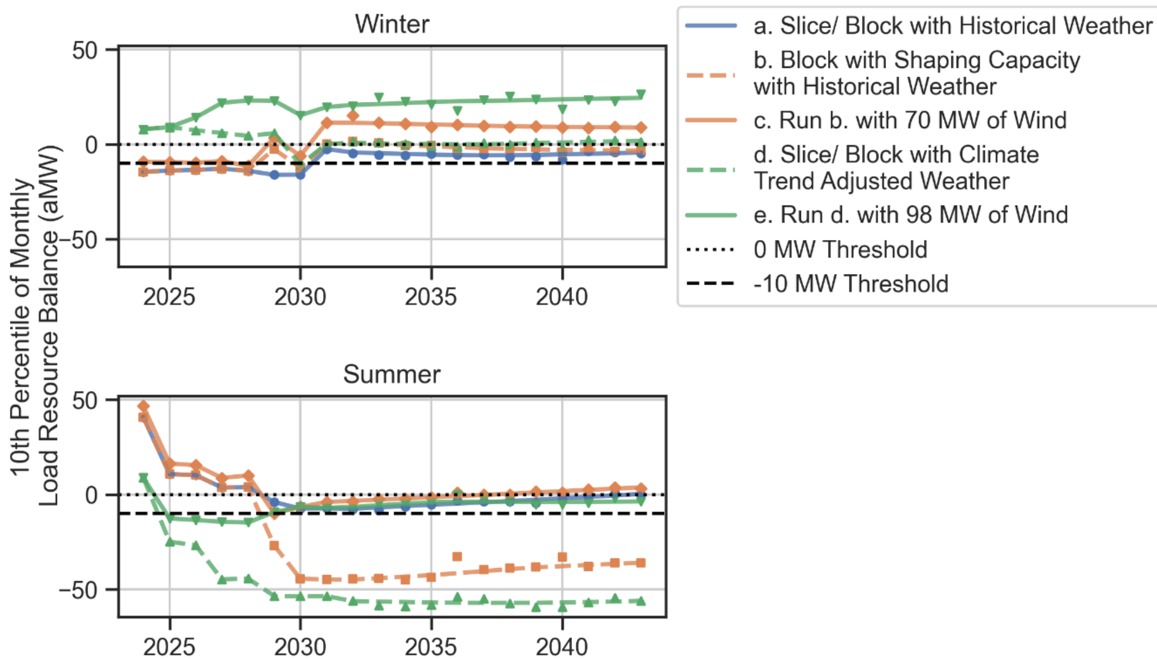
7.1 Resources to mitigate potential summer energy risks

Sections 5.4 and 5.6 identify potential summer energy shortfalls from switching to a Block product from BPA or, eventually, from climate change. Our portfolio expansion model identifies approximately 100 MW of Gorge wind to be the lowest cost supply-side resource acquisition needed to fully mitigate the potential summer energy shortfalls we might face from climate change and 70 MW of Gorge wind to fully mitigate the potential summer energy shortfalls resulting from having to select a Block product instead of Slice/Block.

Figure 14 compares our 10th percentile energy position before and after the hypothetical resource additions are made. Line b of Figure 14 uses our standard climate assumptions but assumes we switch to a BPA Block product. Line d of Figure 14 assumes we remain on Slice/Block but uses weather data adjusted for the historical trend we've seen in weather over time. In each case, Figure 14 confirms that the resources selected by our model improve our summer energy position and ensure that we are energy adequate in the summer.

[22] Assumptions based on findings from a Portland General Electric evaluation of their Residential Pricing Pilot (known as Flex).

Figure 14: Energy position with buildout of supply-side generating resources (Anticipated Electrification demand)



7.2 Resources to mitigate sustained capacity risks under certain scenarios

We next evaluate the options we might consider in the future to mitigate potential sustained capacity shortfalls that appear in the second half of the 2030s in certain scenarios (namely, high electrification growth or an inability to restore Riffe elevation during the study period). In each scenario, we compare the adequacy improvement of four alternative resource acquisitions to fill the future potential gaps: (1) an energy resource, (2) demand response, (3) a 100 MW, 6-hour battery resource or (4) 250 MW of pumped storage.

We use our portfolio expansion model to identify the optimal energy resource addition. Our model finds approximately 16 MW of Western Washington wind to be the lowest cost generating resource acquisition needed to fully mitigate the potential sustained capacity shortfalls in both risk scenarios.

Figure 16 (line c) confirms that the 16 MW of Western Washington wind would be more than sufficient to mitigate sustained capacity risks under our Expansive Electrification scenario and nearly sufficient under our Riffe Lake restoration sensitivity. The 20 to 30 MW of demand response resource modeled in our IRP would also fully mitigate our sustained capacity risks in the Expansive Scenario. It would help our position in the Riffe Lake sensitivity, but it would not fully mitigate the issue alone. The large capacity additions of a 100 MW, 6-hour lithium-ion battery or pumped storage resource both succeed in improving our position and allow us to pass our resource adequacy standard (Figure 15 and Figure 16, lines e and f).

Figure 15: Sustained capacity position with resource additions under Expansive Policy electrification demand

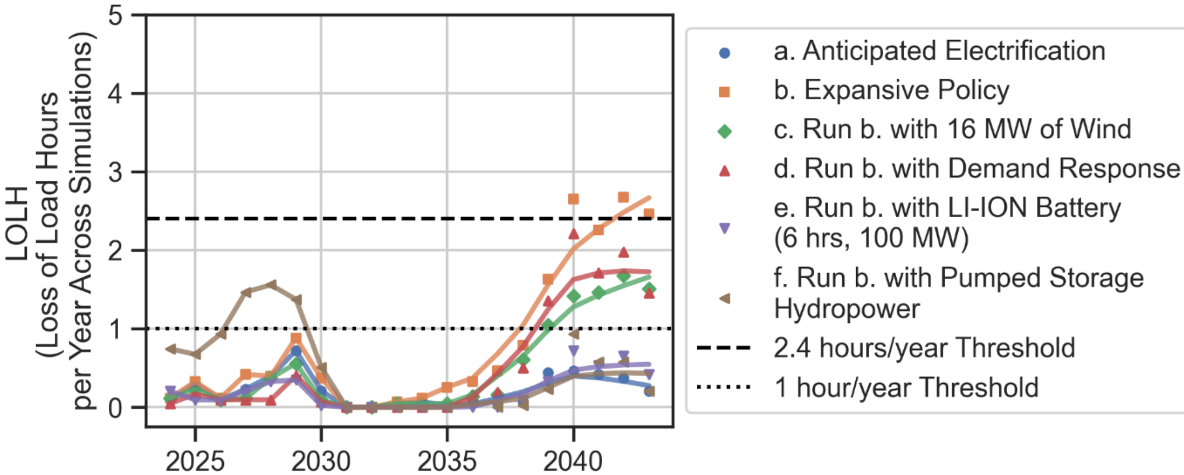
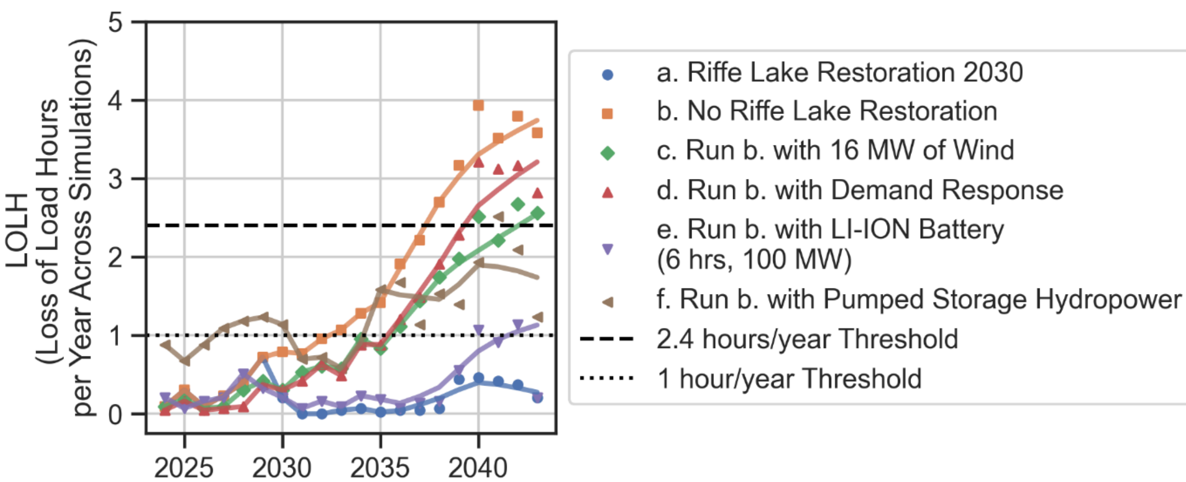


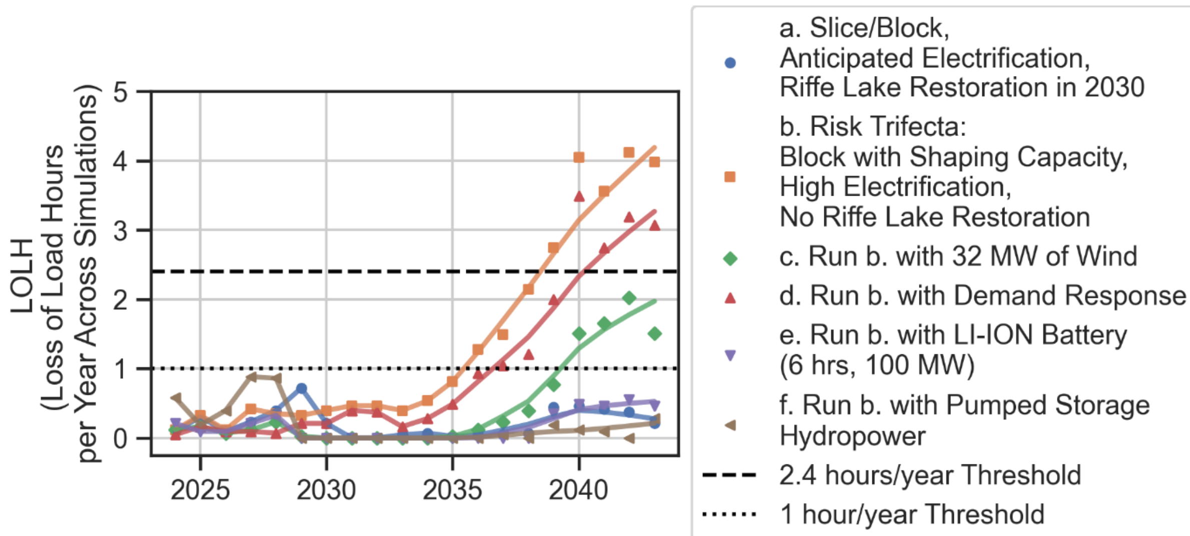
Figure 16: Sustained capacity position with resource additions under Riffe Lake sensitivity scenario (Anticipated Electrification)



7.3 Resources to mitigate potential shortfalls under risk trifecta scenario

In Section 5.7, we find that a combination of risk factors (switching to a Block with Shaping Capacity product, a delay in restoring Riffe elevation and high electrification load growth) can compromise all aspects of resource adequacy. Our portfolio expansion model identifies 32 MW of Gorge wind to be the lowest cost supply-side resource acquisition needed to fully mitigate the potential sustained capacity shortfalls we might see in the winter in this scenario. Figure 17 (line c) confirms that this addition would be sufficient to meet our sustained capacity adequacy standard. The 20 to 30 MW of demand response in our model improve our sustained capacity position but does not bring us fully back to sustained capacity adequacy (Figure 17, line d). We find that adding a 100 MW, 6-hour battery or 250 MW of pumped storage hydro at our Cowlitz River Project both improve our position to a level similar to what we would see under Anticipated Electrification with Slice/Block and restoration of Riffe Lake elevation in 2030 runs (Figure 17, lines e and f versus line a).

Figure 17: Sustained capacity position with resource additions under Risk Trifecta scenario



7.4 Cost analysis

In this section, we estimate the costs of alternative resource investments we might need to make in the future if certain risk factors emerge.

7.4.1 Cost of alternatives to mitigate summer energy risks

Section 7.1 identifies approximately 70 MW to 100 MW of Gorge wind would be needed if we were to acquire a supply-side resource to fill the gap in summer energy identified in our climate change analysis or if we are not able to purchase Slice/Block. We estimate that the cost of doing so would be approximately $245 million to $350 million over a 20-year period ($12.2 to $17.5 million on average per year). This is equivalent to approximately a 3.5% to 5% increase in our total portfolio costs of over $200 million per year. It is, however, important to recognize that the costs of the wind resource would be partially offset by wholesale revenues in years when we had more energy than needed to serve our own load. We estimate that the net cost of these resources after accounting for offsetting wholesale revenues ranges from $123 to $170 million over a 20-year horizon ($6.2 to $8.5 million on average per year), depending on the price scenario. These estimates do not account for the revenue benefits and costs of having wind as part of our portfolio in the Western Energy Imbalance Market or within day-ahead markets.

Relying on the wholesale market to fill those gaps in years when we might have summer energy shortfalls instead is likely to be a significantly lower cost alternative to acquiring the wind resource. We estimate that it would typically cost us around $1.5 to $2.5 million in the years when those purchases are needed, depending on the price scenario, and up to around $4 million under some of the worst-case outcomes. In most years, we would not see these shortfalls and would not need to pay those wholesale market costs to shore up our resource adequacy position.

7.4.2 Cost of alternatives to mitigate sustained capacity risks

Sections 7.2 and 7.3 collectively identify wind resources of between 16 MW to 32 MW to be the lowest-cost supply-side energy resource to address potential sustained capacity risks under most of our more challenging scenarios of the future so long as we also continue to acquire conservation at the levels projected in our CPA. If we were to find we are heading toward a situation in which we needed a wind resource within that size range, we estimate that the cost would be approximately $73 million to $116 million over a 20-year period ($3.6 million to $5.8 million on average per year). This is equivalent to approximately a 1.8% to 2.9% increase in our total portfolio costs of over $200 million per year. Net of wholesale revenues, we project this acquisition would cost between $43 million and $76 million over the entire timespan.

We find that the cost of relying on the wholesale market to solve those issues is likely to be more expensive in years when we run into sustained capacity challenges but that those issues only arise once every 20 years or so. Another approach to solving this potential future challenge is to adjust our operations to preserve more of our capacity to mitigate the risk of a sustained capacity shortfall. We expect that strategy to be lower cost than acquiring a new supply-side energy resource. We plan to conduct a more thorough analysis of the feasibility and cost of using operational adjustments to mitigate sustained capacity risks.

We find that the 20 to 30 MW of demand response modeled in this IRP is also effective at mitigating sustained capacity risk and restores adequacy in our Expansive Policy scenario. The capabilities and cost of demand response will vary significantly depending on the specific demand response offering, but opportunities that are likely to be equivalent to or lower cost than supply-side resource options are promising options to pursue.

Other larger capacity additions (a 100 MW, 6-hour battery or 250 MW of pumped storage at our Cowlitz River Project) would be sufficient to fully mitigate our adequacy risks. Acquiring the 100 MW, 6-hour battery would cost approximately $319 million over the battery's 15-year expected lifespan ($21.3 million on average per year). We estimate that it might cost around $346 million to add 250 MW of pumped storage, but this estimate is approximate at best. Our current pumped storage model is not able to accurately estimate the potential revenues we might make to offset this large up-front cost, but the more detailed analysis of pumped storage that we will conduct in 2025 will address this question.

8 Recommended resource strategy

The 2024 IRP recommends several the following resource strategy to ensure we continue to be able to meet customer needs into the future at the lowest reasonable cost:

1. **BPA contract:** Based on the information we have available at the time of writing this IRP, the IRP recommends renewing our BPA contract with the Slice/Block product, if it is offered. The

Slice/Block product design remains our preferred BPA product because it leaves us energy adequate in the summer and substantially reduces the risk of a peaking capacity shortfall. However, BPA is still contemplating whether Slice/Block will be an option in the next contract. If Slice/Block is not available, our alternative product choice will depend greatly on product design choices BPA makes for some of its other product options.

2. **Make Incremental investments in existing resource infrastructure where cost-effective:** The IRP finds that we do not have an immediate need for a large supply-side resource so long as we continue to invest heavily in conservation but that we do face some resource adequacy risk in the future under certain scenarios. To mitigate that risk, the IRP recommends that we seek out smaller, incremental investment opportunities on both the supply side and the demand side to bolster our energy and capacity position. On the supply side, this means exploring potential opportunities to enhance the capabilities of our existing hydropower projects through either (1) incremental capacity additions in conjunction with planned generator rebuilds or (2) a large capacity addition (either in the form of third generator or pumped storage) at Mossyrock. On the demand side, this means continuing to invest heavily in conservation as well as identifying new opportunities in both conservation (for example, encouraging customers to pick more efficient equipment as they switch from gas to electric) and demand response.
3. **Other ways to mitigate risks:** There are several other approaches to explore as well. First, it is critical to track the load trends that could put our adequacy position at risk, namely the progression of electrification and data center load growth. Second, while the IRP finds that a degradation of our summer energy position as a result of climate change can be managed most cost-effectively through midday purchases from the wholesale market, it is important to evaluate whether that will be a durable strategy ten or more years from now and what risks might threaten our ability to rely on this strategy in the future. Finally, there may be operational adjustments we can make to forego lucrative wholesale market opportunities and preserve more winter capacity. Further exploration is needed to understand the extent to which those operational adjustments will be capable of managing future sustained capacity risks without the purchase of an additional resource.

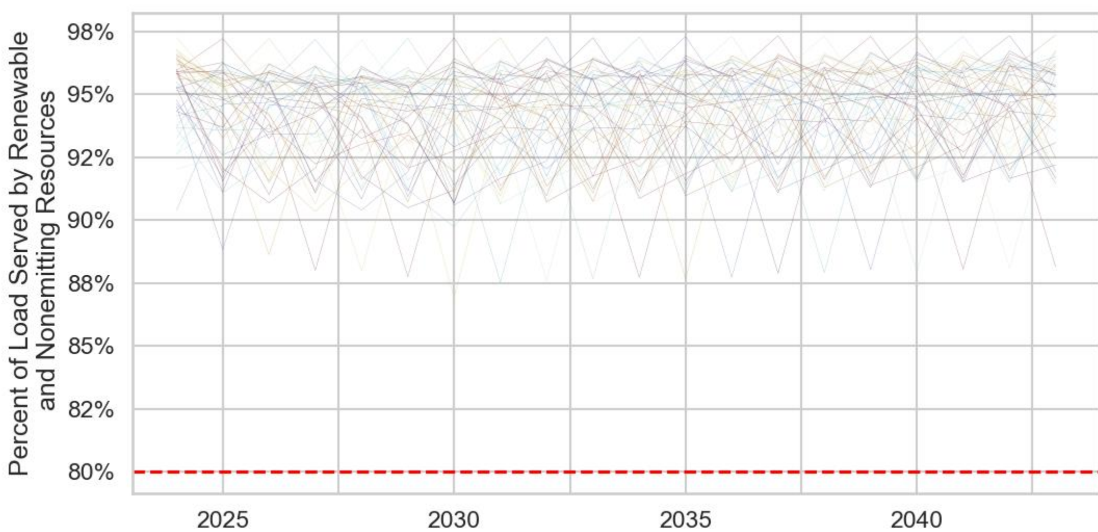
8.1 Compliance position under recommended strategy

8.1.1 CETA compliance

To comply with the Clean Energy Transformation Act's greenhouse gas neutral standard, consumer-owned utilities must, among other things, demonstrate through an hourly analysis that the expected renewable or non-emitting output of their resource portfolio could be generated and delivered to serve at least 80 percent of expected retail electric load over each compliance period using inputs and assumptions consistent with the integrated resource plan.

For each weather-year simulation and each scenario, we take the total amount of renewable and non-emitting energy generated by our portfolio (which in our case is hydropower from our own resources or from BPA) within each hour up to a maximum of load in that hour and sum up all those megawatt-hours across the year. That total is divided to the total megawatt hours of energy demanded by customers within that simulation-year to approximate the share of retail electric load served by renewable and non-emitting output. Figure 18 presents results for each simulation year across the 20-year period for our Anticipated Electrification scenario under base case resource assumptions. From 2030 on, the very worst outcome we see in any single weather year stays stable at just below 90% while every other simulation year is at 90% or above. Our ability to exceed the 80% standard in every singly simulation demonstrates that our generating portfolio is easily capable of serving at least 80% of our retail load over each four-year compliance period. Results are nearly identical for our Expansive Policy and Policy Regression scenarios and qualitatively similar under alternative BPA products and when Riffe Lake elevation is not restored. The only scenario in which our CETA compliance position is significantly degraded is our data center sensitivity. Even in that scenario, the calculated share of retail electric load served by renewable and non-emitting output stays above 80% in every weather year throughout the twenty-year study period.

Figure 18: Annual compliance with 80% renewable and non-emitting standard under Slice/Block (Anticipated Electrification scenario)



8.1.2 WRAP forward showing position under recommended strategy

It is critical that we meet our resource adequacy obligation under WRAP in addition to our internally determined resource adequacy standard. To determine each participant's resource adequacy position under the program, the WRAP uses a planning reserve margin framework that calculates the difference between a participant's available capacity and capacity requirement in each month. Available capacity is akin to our internal measure of short-term peaking capacity. The amount of available capacity credited to each resource is determined using a standard set of protocols, though operators of hydropower with storage may adjust their resources' capabilities downward from what the standard methodology produces if they feel that the standard methodology overstates their capacity. The capacity requirement aims to represent a normal 1 in 2 peak load plus a planning reserve margin. Both the forecast 1 in 2 peak load and the planning reserve margin are determined by the WRAP. Each participant must demonstrate in each forward showing period that they have sufficient capacity available to meet their identified capacity requirement in each month of the winter (November through March) and summer (June through September). We analyze our WRAP compliance position using our current WRAP QCC values for each of our resources and several alternative approaches to calculating our likely capacity requirement in each month of the winter and summer binding seasons. We find results that are consistent with our short-term peaking capacity analyses in Section 5. We expect to be able to pass our winter forward showing requirements under most scenarios so long as we purchase Slice/Block from BPA, though our position becomes tighter over time as electrification increases our peak loads. Our winter WRAP position becomes especially tight in the second half of the 2030s if (1) we experience high levels of electrification, (2) we are not able to restore Riffe Lake or (3) Slice/Block is not available and we must purchase a Block with Shaping Capacity product instead.

9 Transmission assessment

We own and operate a transmission system comprised of 115 and 230 kV facilities in select portions of Western Washington. The system interconnects our retail distribution network with the BPA regional transmission system, adjacent utility systems, and three of our major hydroelectric generation projects. It provides essential capabilities to serving Tacoma Power customers but also requires additional purchases of transmission service from BPA to supplement this capability.

BPA owns and operates a majority of the high voltage transmission facilities in the Pacific Northwest region. Through its Open Access Transmission Tariff (OATT), we purchase long-term, point-to-point (PTP) transmission service from BPA. Much of the transmission capability that we purchase is used to support the delivery of energy from energy resources marketed by BPA, from Wynoochee Dam, from the Priest Rapids Project from which Tacoma Power currently receives a small amount of output, and from other sources of energy that can be delivered to our customers. In addition to transmission service purchased from BPA under its OATT, Tacoma Power is also able to move energy across portions of the BPA transmission system under agreements executed prior to BPA implementing its OATT. These agreements enable Tacoma Power to deliver the output of the Cowlitz River Project to Tacoma as well as to schedule energy across the Pacific Northwest AC intertie with California.

Tacoma Power periodically reviews the adequacy of its transmission system and transmission service rights for meeting customer demand. At present, renewal of existing rights leaves us with sufficient access to transmission to continue to meet customer demand. Given that our resource strategy does not include acquisition of additional supply-side resources, that strategy will continue to be sufficient to accommodate our recommended resource portfolio.

It is not a given that we can secure transmission rights to deliver the power from any new resource addition to our customers. We periodically evaluate whether different configurations of service might make sense and help address future contingencies for load growth or new resource acquisition. The potential future resources identified in this IRP will inform those analyses. Conversely, our transmission evaluations will serve to inform future resource strategies if we find that our need for a resource is growing.

10 Action plan

Table 12 summarizes our two-year action plan and our ten-year Clean Energy Action Plan. The table divides actions into three distinct types: (1) supply-side actions, (2) actions we will take in collaboration with our customers and (3) other important actions.

10.1 Two-year action plan

On the supply-side, our most immediate action will be to update our analysis of BPA product choice once we learn which products BPA will offer and precisely what they will look like. We expect to have the information we need from BPA later in 2024 and sign a new contract with BPA by December of 2025.

At our own hydroelectric projects we will continue to seek FERC authorization to restore Riffe Lake elevation to full pool (778.5). We will also analyze opportunities to add new capacity, large and small, to build upon our existing resources. As discussed in Section 6.2, we have received funding through the Climate Commitment Act (CCA) to conduct an in-depth study of the feasibility and cost of pumped storage at Cowlitz. We plan to conduct that study in 2025 using CCA funding allocated to the study, provided the CCA is not repealed in November 2024. Finally, we plan to begin evaluating opportunities to incrementally add a small amount of capacity to some of our generators. Tacoma Power's Generation group is developing a fifteen-year Unit Modernization Plan, which will assess the condition of and determine the need for investment in unit modernization for 9 of our 22 generating units. If significant work on a unit is needed to modernize it, that would also be the best and most cost-effective time to make additional investments. We will assess the value of adding incremental capacity or other capabilities in conjunction with each unit modernization effort. Evaluation of these opportunities will begin in late 2024 and will continue on an on-going basis over the coming decade as each specific generator is assessed and a modernization plan is created.

On the customer side, we plan to acquire the 2-year conservation target of 55,992 MWh (approximately 6.4 aMW) set in our 2024-2043 conservation potential assessment (CPA). The IRP sets a ten-year target of at least 10 MW of demand response and a 2-year target of 2 MW to ensure we are progressively building the capability to offer demand response in the future when we need it. To achieve our demand response targets, our two-year action plan includes continuing to pilot promising demand response opportunities and scaling those found to be successful and cost-effective. Third, we plan to engage with larger retail customers when potential mutually beneficial opportunities arise to collaborate to add low or zero-carbon resources at a low cost. We are currently exploring one opportunity with one of our large customers interested in adding supply-side resources to meet resiliency goals.

In Section 8, we identify the need for several other analyses relevant to our long-term resource position and strategy. The first is to identify and use available sources of data to track the progression of electrification and assess how closely electrification demand growth is tracking with projections from our electrification study. This will help us understand which scenario (Anticipated Electrification, Expansive Policy, or Policy Regression) most closely reflects our load growth and adjust our projections accordingly. Another component of tracking the progression of electrification is continuing to track laws that may change the expected pace of electrification. Similarly, we will continue to track data center load growth outside and inside of our service area. We further identify the need to evaluate the feasibility of continuing to rely on the wholesale market for occasional summer energy needs over the long-term. We plan to conduct this analysis before our 2026 IRP. Finally, we also plan to explore the extent to which operational adjustments aimed at preserving more winter capacity could manage future sustained capacity risks without the purchase of a new supply-side resource.

10.2 Ten-year Clean Energy Action Plan (CEAP)

RCW 19.280.030 requires that utilities with more than 25,000 customers develop a Clean Energy Action Plan (CEAP) as part of each Integrated Resource Plan. Like our two-year action plan, our ten-year CEAP includes a combination of different types of actions. Those actions are summarized in Table 12 and are described in more detail in this section.

First and foremost on the supply-side, we plan to restore Riffe Lake to full pool as soon as we receive FERC authorization. Second, we will seek authorization to add pumped storage or an additional generator at our Cowlitz River Project as part of our 2037 FERC relicensing efforts if our 2025 feasibility and cost assessment finds it is feasible and cost-effective to do so. Third, we will continue efforts described in Section 10.1 to analyze opportunities to incrementally add capacity to existing generating units as they undergo modernization work and make those investments when it is cost-effective to do so.

Over the next ten years, we will continue to engage with our customers to find mutually beneficial opportunities to maintain a solid resource position. First, in accordance with RCW 19.285.040, we will update our CPA and establish a new 2-year target every two years, and we will continue acquiring the two-year target set in each subsequent CPA we conduct. Our next (2026-2045) CPA will be the first to incorporate growth projections from our 2023 Electrification Study. Second, we will continue to scale up demand response opportunities that are found to be successful and cost-effective to meet the 2024 IRP ten-year target of 10 MW of demand response. Third, we will continue to explore opportunities to partner with larger retail customers interested in adding low or zero-carbon resources to identify mutually beneficial opportunities to add supply-side resources at a low cost. Finally, we plan to continue efforts begun in our two-year action plan to track the progression of demand growth from electrification and data centers.

Per RCW 19.280.030, our Clean Energy Action Plan must include an assessment of “energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities (HICs); long-term and short-term public health and environmental benefits, costs, and risks; and energy security and risk.” Our 2021 Clean Energy Implementation Plan (CEIP) established both how we define vulnerable populations and the indicators we use to track and forecast the distribution of costs and benefits. Using the City of Tacoma’s Equity Index, we define vulnerable populations as Census block groups classified as “Very Low” and “Low” opportunity areas within Tacoma Power’s service area. In accordance with CETA requirements, we use the Washington State Department of Health (DOH) cumulative impact analysis[23] to identify Highly Impacted Communities. The indicators identified in our

[23] The DOH cumulative impact analysis is available here: https://doh.wa.gov/data-statistical-reports/washington-tracking-network-wtn/climate-projections/clean-energy-transformation-act

2021 CEIP and an assessment of how this plan will affect the distribution of those indicators are described below. In our next CEIP process in 2025, we will review our indicators and revise them as appropriate.

- **Energy Benefits:** To track energy benefits, we currently measure the share of electrically heated homes built before 1989 that have received a high-touch conservation measure (weatherization or HVAC). Based on the best information we have from our 2024-2043 CPA, we estimate our conservation potential to be distributed evenly across HICs and non-HICs and across vulnerable populations versus other groups. However, we know from our conservation program data that programs have been more successful in areas of higher opportunity. Specifically, our programs are most suitable to residential customers who own their homes, have the authority to renovate their homes, will likely reap the long-term benefits of conservation investments, and can leverage their savings, financing, or home equity for higher-cost energy conservation, such as whole-home heat pumps and windows. While we need to maintain these programs to help achieve our legally mandated energy conservation target, we must also tailor our offerings for areas with lower opportunity. Our 2024-2025 Conservation Plan[24] describes our plans to continue to improve our support for marginalized customers who struggle to access our programs, including expansion of our income-qualified offerings and changing the level of incentive we offer for this segment. We expect this to improve participation within HICs and vulnerable populations.
- **Reduction of burdens:** To track reduction of burdens, we currently measure the share of households who are energy burdened using the US Department of Energy's Low-Income Energy Affordability Data (LEAD). Our resource strategy aims to minimize additional costs needed to continue meeting our resource adequacy requirements into the future and, in turn, minimize any cost impacts to households already burdened by their energy expenses. However, it is important to note that there are potential future developments (namely climate change, rapid and expansive growth of electrification and possibly having to switch BPA products) that will degrade our resource adequacy position over time. Whether through the purchase of a resource or through reliance on the market to fill gaps, we can expect our costs to increase if these resource adequacy risks materialize. We plan to continue to rely on a combination of bill assistance programs and residential energy conservation program offerings targeted at income-qualified customers (discussed above) to help mitigate risks to HICs and vulnerable populations.
- **Resiliency:** To track resiliency, we measure the average number of service interruptions and the average number of minutes of service interruption per year using feeder-level reliability data. We expect our CEAP to maintain resource adequacy at current levels and do not expect these actions to change our resiliency indicators for any of our customers, including HICs or vulnerable populations.

[24] The Conservation Plan is available on our IRP webpage under "Other Resources": https://www.mytpu.org/about-tpu/services/power/integrated-resource-plan/

Table 12: 2024 IRP action plan

Action Type	Two-year action plan	Ten-year Clean Energy Action Plan
Supply-side resources: BPA	Update BPA analysis and sign new contract	
Supply-side resources: Riffe Lake	Continue to seek FERC authorization to restore Riffe Lake elevation	Restore Riffe Lake elevation if authorized by FERC
Supply-side resources: Cowlitz pumped storage hydro	Conduct Cowlitz pumped storage feasibility and cost assessment provided the Climate Commitment Act (CCA) and the associated funding for the study is not repealed in November 2024	Seek authorization to add pumped storage or additional generator at Cowlitz as part of FERC re-licensing process if feasible and cost-effective
Supply-side resources: Existing generators	Evaluate opportunities to add incremental capacity to existing generators during scheduled rebuilds	Add incremental capacity to existing generators during scheduled rebuilds whenever cost-effective
Collaboration with customers: Conservation	Acquire 2-year conservation target of 55,992 MWh set in 2024-2043 conservation potential assessment (CPA)	Regularly update CPA and continue to acquire 2-year targets set in subsequent CPAs
Collaboration with customers: Demand response	Acquire 2 MW of demand response. Continue piloting demand response opportunities & begin to scale up those found to be successful and cost-effective in pilots	Scale up demand response opportunities and acquire at least 10 MW of DR opportunities found to be successful and cost-effective in pilots
Collaboration with customers: Other opportunities	Actively engage with large retail customers to explore mutually beneficial collaborations to add low or zero-carbon resources when potential opportunities arise	Actively engage with large retail customers to explore mutually beneficial collaborations to add low or zero-carbon resources when potential opportunities arise
Other important actions: Demand-side factors	Develop a plan to track progress of electrification and data center load growth and begin tracking	Track progress of electrification and data center load growth and regularly update projections
Other important actions: Market risk factors	Evaluate feasibility of continuing to rely on wholesale market for occasional summer energy needs in long-run	
Other important actions: Operations analysis	Explore opportunities to make operational adjustments to maximize winter capacity	