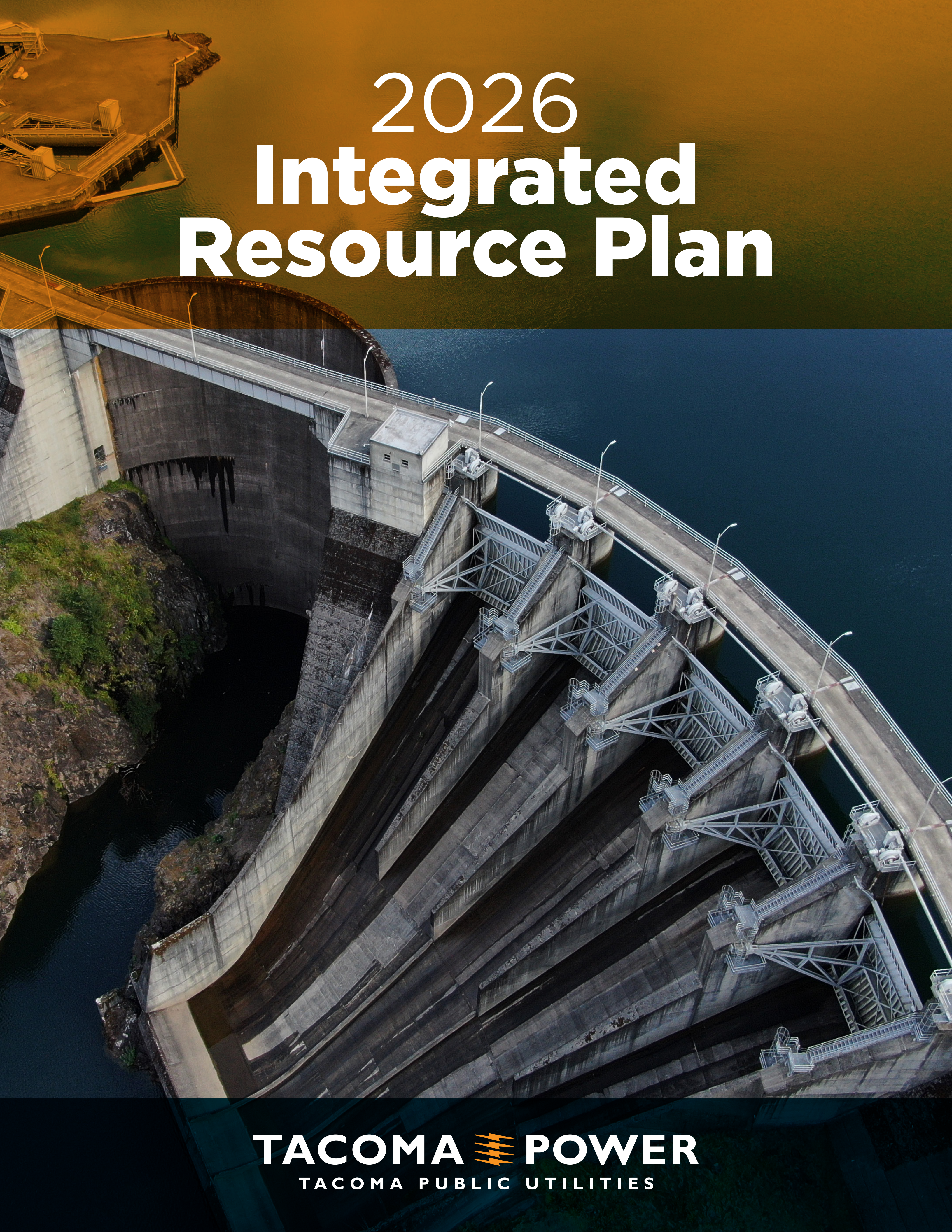
2026
Integrated Resource Plan



TACOMA POWER
TACOMA PUBLIC UTILITIES

Tacoma Power 2026 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 is carbon-free. A little more than half comes from our long-term contract with the Bonneville Power Administration (BPA), which provides us with low-cost power primarily from hydroelectric projects on the Columbia River. 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. 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 help Tacoma Power defer the need to invest in costly generation.

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 over time as needed.

1.2 Key findings

We find that our energy position is expected to remain stable over the IRP study horizon, but our capacity position tightens due to a combination of projected growth in peak demand and changes to the structure of our next BPA contract, which result in a smaller amount of capacity from our Slice/Block product. While we expect to continue to meet our resource adequacy standard in most years, we project intermittent capacity risks in some years at the end of our 20-year study period when generators are expected to be out of service for extensive rebuild work. We could face small but systematic risks at the end of the study period if demand grows more quickly than projected. These capacity risks are present under extended winter drought conditions combined with a cold snap. Our climate change sensitivity runs suggest some changes to our resource adequacy position relative to historical climate conditions but do not identify an emerging summer resource adequacy risk.

At the Cowlitz River Project, we have been holding the upper reservoir (Riffe Lake) to a lower maximum level (778.5 to 749 feet) since 2017 as a response to updated seismic loading concerns on the Mossyrock Dam spillway piers (not to the dam itself). Our objective is to bring Riffe Lake back to full pool as soon and safely as possible, and work is progressing through analysis and design phases. Our IRP analysis confirms the important role that restoring Riffe Lake elevation plays for our resource position.

We find that demand response is a promising resource to mitigate the capacity risks identified under our base case scenario, as it directly mitigates the rising peak demand that is driving our capacity risk. Our analyses suggest that many cost-effective opportunities are available. These opportunities could provide significant relief from the capacity risks identified in our analysis, but cost-effective opportunities may not to be enough on their own to fully mitigate those risks.

Of the supply-side resource options examined in this IRP, we find that adding hydro capacity at Mossyrock Dam at the Cowlitz River Project could be the lowest-cost option to mitigate growing peaking capacity risks on a per kilowatt basis. Significant additional analysis would be needed to fully understand what the limitations of its use would be and what the full set of costs and benefits would be, but we find that this opportunity is promising enough to warrant further investigation. Our current FERC license at the Cowlitz River Project expires in 2037. If Tacoma Power were to seek permission to make this kind of enhancement there, it would be most prudent to do so in conjunction with relicensing efforts.

The next lowest-cost resource option on both a per kilowatt basis and a total portfolio cost basis is natural gas peaking generation, but this option would not be compliant with CETA's 100% renewable and non-emitting requirements starting in 2045. Utility-scale battery storage is the next lowest-cost supply-side capacity resource that does comply with CETA's 2045 clean energy requirements.

Our load growth sensitivity runs suggest that our capacity position could be at risk even with mildly higher growth in peak demand. If peak loads begin to rise somewhat more quickly than anticipated, we may face consistent capacity deficits starting around 2040. Adequacy would be significantly compromised if we see a significant acceleration in load growth from electrification or industrial demand. If we were to experience electrification load growth consistent with deep economy-wide decarbonization, we would likely need a new supply-side resource as soon as 2035.

Under our higher load growth scenarios we find that, apart from a natural gas generator, no single resource we model would be sufficient to solve both the energy and capacity adequacy challenges we might face. Portfolios combining energy and capacity resources are successful at mitigating resource adequacy risks under these high load growth scenarios but do so at a higher cost than the natural gas generator.

1.3 Resource strategy and action plan

Our 2026 IRP identifies conservation and demand response as our preferred resource investments for now. The IRP does not recommend acquiring any new supply-side resources at this time but does identify a need for further investigation into supply-side opportunities to mitigate potential future capacity risks that begin to emerge in the early 2040s. The 2026 IRP resource strategy is described below, and the associated action plan is summarized in Table 1-1.

1. **Continue to invest in cost-effective conservation:** We have a long history of partnering with our customers to invest in cost-effective conservation measures, and we must continue this work. We plan to continue to invest in all conservation when it is feasible and cost-effective to do so. Our most recent Conservation Potential Assessment (CPA) set a target of 26,214 MWh (approximately 3 average megawatts, or aMW) over 2026 and 2027 and identifies 131,068 MWh (approximately 15 aMW) of cost-effective conservation potential over the next ten years. The two and ten-year potentials are equivalent to approximately 0.6% and 2.9% of expected 2026 load, respectively. We will continue to update our assessment every two years and re-evaluate existing and new conservation opportunities.
2. **Ramp up demand response programs:** As our capacity position tightens over time, we will need to expand our work with customers into demand response to help manage projected growth in peak demand. Our Demand Response Potential Assessment (DRPA) suggests that approximately 8 to 14 MW of winter demand response opportunities may be available by 2035 at a relatively low cost when compared to other capacity resources. To ensure we are progressively building the capability to offer demand response in the future when we need it, we plan to initiate at least 2 new demand response pilots and acquire 0.6 MW over the next two years and 12 MW of demand response over the next ten years.
3. **Continue our work to restore Riffe Lake elevation by 2031:** On the supply-side, we will continue to seek authorization from the Federal Energy Regulatory Commission (FERC) to restore Riffe Lake elevation to full pool (778.5 feet), which will restore approximately 35 MW of capacity to our system.
4. **Develop a strategy for mitigating intermittent capacity risks during generator rebuilds:** We find that long-duration outages required for the rebuild projects under the modernization program schedule are likely to create peaking capacity risks for our system when coupled with an already tight

peaking capacity position toward the end of the IRP study period. Our IRP identifies resource opportunities to mitigate these risks, but a new power supply resource is not the only option for addressing small, intermittent capacity risks of the nature we identify. Our two-year action plan includes work to analyze non-resource alternatives (for example, single-year contracts for a small amount of capacity) to cover these intermittent capacity risks during generator rebuilds. This work will inform a longer-term effort to develop and refine our strategy for mitigating these risks.

5. **Continue to explore opportunities to build upon existing hydro system:** Based on information from a 2025 study[1] we commissioned evaluating pumped storage and other hydrogeneration possibilities at Mossyrock Dam, we find that adding a conventional generator at Mossyrock Dam has the potential to be a promising resource to help meet the growing future capacity needs of our customers and the region. More detailed analysis will be needed to fully understand the full range of benefits and costs of this resource option. We plan to conduct further analysis into the potential feasibility, costs and benefits of this resource option before our next IRP and, if this option continues to look promising, determine what additional studies are necessary and appropriate to inform a decision. Any effort to make this kind of enhancement at the Cowlitz River Project would necessarily be tied to our work to relicense the project. We also plan to evaluate opportunities to incrementally add capacity or other capabilities to generators when they're taken offline to be rebuilt. 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.

Renewal of existing transmission rights leaves us with sufficient access to transmission to meet customer demand currently and will continue to be sufficient to accommodate our recommended resource portfolio.

---

[1] The Pumped Storage Feasibility Study at Tacoma Power's Mossyrock Dam is supported with funding from Washington's Climate Commitment Act. The CCA supports Washington's climate action efforts by putting cap-and-invest dollars to work reducing climate pollution, creating jobs, and improving public health. Information about the CCA is available at www.climate.wa.gov/.

Table 1-1: 2026 IRP action plan

Strategy	Two-year action plan	Ten-year Clean Energy Action Plan
Continue to invest in cost-effective conservation	Acquire 2-year conservation target of 26,214 MWh (3 aMW) set in 2026-2045 conservation potential assessment (CPA)	Regularly update CPA and continue to acquire 2-year targets set in subsequent CPAs
Ramp up demand response programs	Implement 2 pilots and acquire 0.6 MW of demand response	Acquire 12 MW of demand response
Continue work to restore Riffe Lake elevation by 2031	Continue to seek FERC authorization to restore Riffe Lake elevation	Restore Riffe Lake elevation by 2031 if authorized by FERC
Develop a strategy for mitigating intermittent capacity risks during generator rebuilds	Analyze non-resource alternatives to prepare for intermittent capacity risks during generator rebuilds	Develop long-term strategy to prepare for intermittent capacity risks during generator rebuilds
Continue to explore opportunities to build upon existing hydro system	Conduct further analysis of costs and benefits of adding a conventional hydro generator at Mossyrock Dam	Evaluate opportunities to add incremental capacity to existing generators during planning stage of scheduled rebuilds

Contents

This document strives to follow Americans with Disabilities Act (ADA) Web Content Accessibility Guidelines (WCAG). All figures use scientific colour maps[2] and include alternative text.

---

[2] https://zenodo.org/records/8409685

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 approximately 190,000 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.

2.2 Our 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 carbon-free sources, most of which is hydroelectric. We produce a little less than half of our power at four hydroelectric generation projects that we own and operate: the Cowlitz River Project, Cushman Hydro Project, Nisqually River Project, and Wynoochee River Project[3]. 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 (the upper reservoir) 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 and safely as possible. We assembled a team to identify the projects needed to mitigate risk and support returning Riffe Lake to full pool. Those projects have now been identified, and work is progressing through analysis and design phases. Tacoma Power continues to work closely with FERC and our technical consultants to advance the regulatory and engineering efforts necessary to support a safe return to full pool operations.

Many of the turbine-generators within Tacoma Power's hydro fleet will be nearing the end of their lives over the 2026 IRP study period and will need extensive work to rebuild them. During these planned rebuilds, each turbine-generator is expected to be out of service for a minimum of one full year while being rebuilt. Tacoma Power has a long-term plan for staging this work. Our 2026 IRP is the first time this long-term rebuild schedule was incorporated into our modeling. While the exact year of each rebuild is subject to change, our results are indicative of the potential impacts that rebuilds can have on our capacity position.

Our largest contract power purchase is with Bonneville Power Administration (BPA). As a customer-owned utility in the Northwest, we are one of BPA's "preference customers" and have been a customer since 1940. We receive energy through a hybrid Slice/Block product. Under the "Slice" portion of the contract, we receive a share 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.,

---

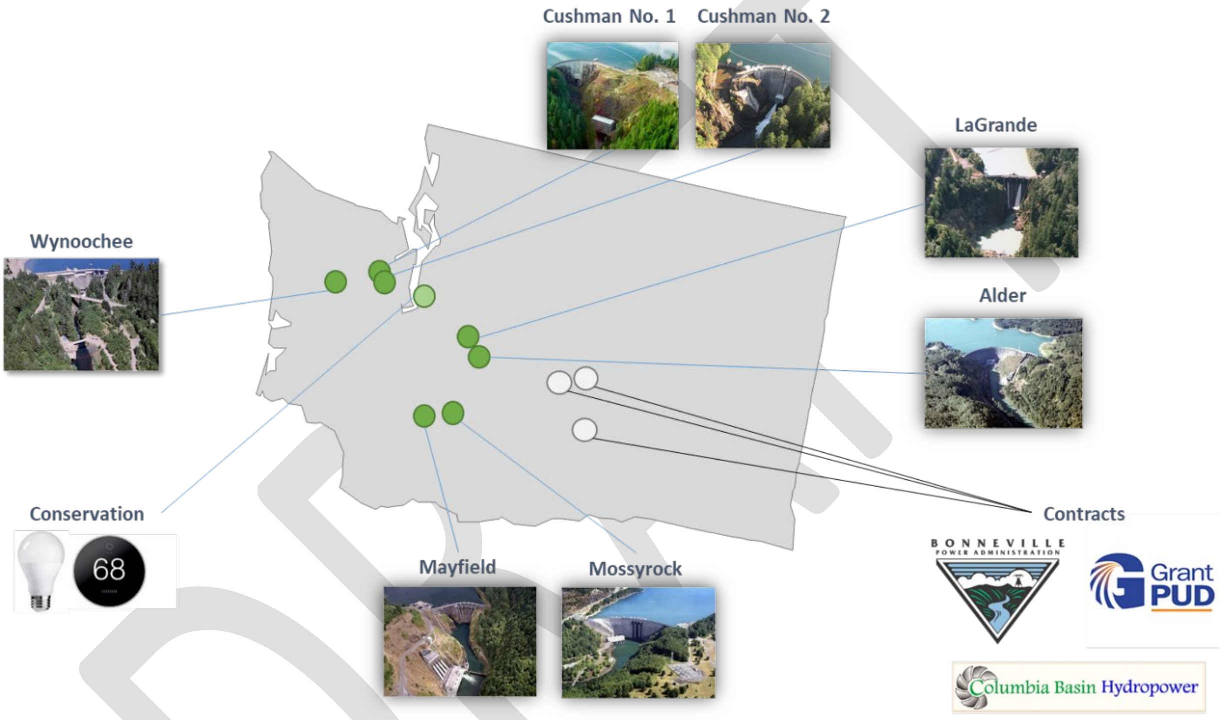
[3] At Wynoochee River Project, Tacoma Power owns the generation components of the project (e.g., intake, penstock, powerhouse). The City of Aberdeen owns the rest, including the dam, and is a co-licensee of the project.

power we can rely on under any water conditions) we receive from BPA comes from the Slice portion of the contract. Half comes from the Block portion.

We currently 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.

We also 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 from Mayfield Dam.

Figure 2-1: Tacoma Power's resource portfolio



2.3 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 2024.

2.3.1 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 continue to maintain a diverse number of ways community members could participate. We also continue to minimize the complexity and duration of public IRP workshops, while allowing options for deeper dives into the planning process for interested individuals. We are also incorporating an incentive payment for participants who are not paid to attend through their employers. This incentive payment is intended to encourage greater participation from residential customers who are often not able to participate. 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 (hybrid) workshops with Tacoma Power
2. Complete an online “community priorities” survey
3. Submit comments online via email
4. Provide comments on the draft IRP

We had 7 participants choose to attend the hybrid workshop – 4 online and 3 in-person. These participants included 2 of our largest customers, our BPA account executive, 2 city of Tacoma employees, and one of our residential customers. Nine members of the public completed the online survey. Most of the survey respondents were residential customers expressing interest in affordability topics. No participants have elected to submit comments online.

3 Review of the last IRP

In our 2024 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. We discuss key action items for our 2-year plan in detail below. Table 3-1 provides a summary of all two-year action items.

3.1 BPA Contract

Our current contract with BPA ends on September 30, 2028. While we were certain that it was in the best interest of our customers to renew our contract with BPA, we did consider which product would best meet customer needs in the next contract. We have evaluated BPA product options in every IRP since 2015, and each time we have found that our current Slice/Block product is our best and lowest-cost option. We addressed the same question again in our 2024 IRP but did not yet have complete information on exactly what each product offering will look like in new contracts or even whether the product would be offered. As a result, our 2024 IRP analysis of BPA product options was preliminary. We updated our analysis again once we had complete information from BPA. Our analyses continued to find that the Slice/Block product was the best option for Tacoma Power.

In October 2025, Tacoma Power signed a contract with BPA to continue purchasing the Slice/Block product when the current contract ends. This long-term contract secures approximately 60% of our power supply through September 30, 2044.

3.2 Conservation

As in past IRPs, our 2024 IRP action plan included acquiring all cost-effective conservation identified in our Conservation Potential Assessment (CPA). Our 2024-2025 target was 55,992 MWh. We reported 81,374

MWhs of conservation savings acquisitions[4] to the Washington State Department of Commerce for the 2024-2025 biennium.

In accordance with RCW 19.285.040, we update our Conservation Potential Assessment (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 most recent (2026-2045) CPA identified 131,068 MWh (approximately 15 aMW) of cost-effective conservation potential over the next ten years and established a two-year acquisition target of 26,214 MWh (approximately 3 aMW) over the next two years. This target was approved by the Tacoma Public Utilities Board on August 13, 2025. The CPA's projections of reductions in usage over time from our conservation program targets, codes, and standards are incorporated into the load projections used in our analysis. The 2026-2027 target was approximately 50% lower than our target in the previous cycle. Most of the reductions in our acquisition potential are attributable to improvements to codes and standards.

3.3 Demand response

Our 2024 IRP action plan also included demand response acquisition. Our demand response action plan included acquisition of 2 MW of demand response within two years and 10 MW within ten years, continued piloting demand response opportunities and scaling up of opportunities found to be successful and cost-effective in pilots. While we did not acquire 2 MW of demand response within the two-year period since our last IRP, we successfully completed a water heater demand response pilot but determined it was not ready to be scaled up. We are in the planning stages for additional pilots.

We also completed a Demand Response Potential Assessment (DRPA) in 2025 in conjunction with and using assumptions consistent with our CPA. Our 2026-2045 DRPA identified nearly 18 MW of winter potential by 2030, 34 MW by 2035, and 59 MW by 2045.[5] In contrast to the CPA, the DRPA does not evaluate the cost-effectiveness of demand response opportunities or identify a specific demand response acquisition target. Rather, demand response resources are evaluated in the IRP using savings potential and cost results produced in the DRPA.

3.4 Electrification projections

Over the past few IRP cycles, the speed and breadth of electrification has emerged as a major source of uncertainty for our future resource adequacy position. 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.

In 2023, Tacoma Power conducted a comprehensive Electrification Assessment[6] to address the question, "How might electrification contribute to changes in the future trajectory of Tacoma Power customers' demand for electricity?" The study aimed 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 was expansive in its treatment of electrification. It addressed electrification in nearly every end use and sector, projected 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 provided projections for a range of plausible scenarios using different assumptions about future policy and market developments.

---

[4] This figure has not been audited and should be considered preliminary. Savings include planned rollover, a compliance mechanism that allows utilities to count excess conservation achieved in the previous biennium towards a portion of current acquisition targets.

[5] Results for summer were similar but slightly lower.

[6] https://www.mytpu.org/wp-content/uploads/Tacoma-Electrification-Study_Final-Report-withTPWRintro.pdf

Tacoma Power staff started incorporating projections from the study into our corporate load forecast and into various internal planning processes, including in our 2024 IRP. Because of the uncertainty around how extensive and quickly loads may grow due to electrification, our 2024 two-year action plan included creating a plan to track progress of electrification load growth. Our initial work in this area served to inform our most recent corporate load forecast and our base case assumptions in the IRP. We continue to work on improving our processes for tracking and projecting electrification growth.

3.5 Data centers

Our 2024 IRP also identified continued tracking of data center growth as an action item in our two-year plan. Data centers are large facilities filled with computer servers that store, process, and transmit the digital information we rely on every day — from streaming video and online banking to health records and cloud services. As artificial intelligence, connected devices, and digital services continue to expand, data centers have become one of the fastest-growing sources of electricity demand in the country.

This growth is being felt by utilities across the country, which are navigating interconnection queues, infrastructure investment decisions, and rate design questions they have never faced at this scale before. This growth is already straining regional infrastructure. Utilities in central Washington —where low-cost hydropower has historically been a major draw — are receiving interconnection requests that dwarf their existing capacity, with much of the interest coming from data center developers. Backbone transmission capacity has become a significant bottleneck, and utilities across the region are working to distinguish serious development proposals from speculative ones. The competitive landscape has also shifted: as established data center markets in places like Northern Virginia and Silicon Valley become saturated, developers are actively exploring alternative markets.

Data centers can bring meaningful benefits to a community. They represent significant capital investment, generate tax revenue, and create construction and technology jobs. For a public utility like Tacoma Power, large, stable electricity loads can also contribute positively to the rate base — helping to spread fixed infrastructure costs across more customers. At the same time, data centers present planning challenges. They require highly reliable power around the clock, and large new loads can strain existing transmission and distribution infrastructure, potentially requiring costly upgrades. Tacoma Power is committed to ensuring that any new large load does not create undue risk or cost burden for existing residential and business customers. Responsible planning means understanding this potential demand before it arrives, so the utility can make informed decisions about infrastructure investment, rate design, and resource adequacy.

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. Tacoma Power undertook an initiative to better understand the likelihood, risks, and opportunities of data center load appearing within our service area. Tacoma Power assessed its service area against the key factors that data center developers consider when selecting a location: access to reliable and affordable clean energy, land availability, fiber connectivity, water supply, and speed to market. The utility identified meaningful strengths alongside real constraints. Our assessment concluded that smaller-footprint data center types are the most realistic near-term candidates, while large cloud and hyperscale facilities are unlikely.

Tacoma Power will continue to monitor regional data center trends as part of our Integrated Resource Plan process, ensuring that any future load growth from this sector is planned for in a way that maintains reliability and keeps rates fair for all customers. In the meantime, we continue to work proactively across the utility to understand how we might be able to serve new large loads like data centers and ensure that existing customers are insulated from the additional cost and risk of doing so.

3.6 Cowlitz pumped storage feasibility and cost assessment

Our 2024 IRP also identified the need to further explore options to make incremental investments to build upon the capabilities of our existing generating resource fleet, and our two-year action plan included conducting an in-depth study of the feasibility and cost of pumped storage at Cowlitz River Project.

The powerhouse at Mossyrock Dam has infrastructure already in place for a third large generator or 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 an additional generator or 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, which expires in 2037. Now we are preparing for relicensing, so it is an appropriate time to seriously evaluate this question again.

In 2025, Tacoma Power engaged HDR Engineering, Inc. (HDR) to evaluate the potential of adding PHES capabilities and other hydro-generation possibilities at Mossyrock Dam. The Pumped Storage Feasibility Study at Tacoma Power's Mossyrock Dam was supported with funding from Washington's Climate Commitment Act. The CCA supports Washington's climate action efforts by putting cap-and-invest dollars to work reducing climate pollution, creating jobs, and improving public health. Information about the CCA is available at www.climate.wa.gov/.

The initial alternatives identified included different pumped storage options, a pump-only option, a conventional turbine/generator unit option, and various battery options at the site. The non-pumped storage alternatives were included in this assessment to allow for a comparison of PHES to alternative enhancements at the existing facility.

HDR conducted a screening process and analysis to narrow down the list of alternatives at the site and produced Association for the Advancement of Cost Engineering (AACE) International Class 5 opinions of probable construction cost for select alternatives as well as conceptual schematics for selected alternatives.

Information from the study was used to inform our IRP modeling of future potential resources. It is important to note that information from the study can be used to assess which alternatives may be considered reasonable for continued evaluation but does not reflect the more rigorous requirements, analyses, and deliverables associated with such future studies that are required to advance an engineering project. More in-depth analyses would be required to produce an investment-grade study.

3.7 Summary review of all 2024 IRP action items

Table 3-1 below provides a summary of progress all two-year action items identified in our 2024 IRP.

Table 3-1. Progress on 2024 IRP Action Plan

Action Type	Two-year action plan	Status
Supply-side resources: BPA	Update BPA analysis and sign new contract	Complete. Contract for Slice/Block was signed in October 2025.
Supply-side resources: Riffe Lake	Continue to seek FERC authorization to restore Riffe Lake elevation	On-going. Official letter to be sent to FERC end of 2026. We expect a response in early 2027.
Supply-side resources: Cowlitz pumped storage hydro	Conduct Cowlitz pumped storage feasibility and cost assessment	Completed in 2025.
Supply-side resources: Existing generators	Evaluate opportunities to add incremental capacity to existing generators during scheduled rebuilds	On-going as generator rebuilds are planned.

Collaboration with customers: Conservation	Acquire 2-year conservation target of 55,992 MWh set in 2024-2043 conservation potential assessment (CPA)	Complete. 81,374 MWh of savings acquisitions reported for 2024-2025 biennium.
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	In progress. Successfully completed one pilot but determined it was not cost-effective to scale up. In planning stage for additional 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	On-going. Some opportunities explored with customers, but no concrete opportunities identified to date. New opportunities will be explored if and when they arise.
Other important actions: Demand-side factors	Develop a plan to track progress of electrification and data center load growth and begin tracking	On-going. Initial effort complete and was used to inform updates to our forecasts. Work to improve processes and data sources will continue.
Other important actions: Market risk factors	Evaluate feasibility of continuing to rely on wholesale market for occasional summer energy needs in long-run	On-going. We have updated thresholds for energy adequacy to reflect reliance on market for summer and winter energy needs based on extensive internal discussions. Assessments will continue to be updated over time.
Other important actions: Operations analysis	Explore opportunities to make operational adjustments to maximize winter capacity	On-going. We have updated our modeling to better reflect our current efforts to maximize winter capacity and continue to explore the extent to which additional changes are needed.

4 Changes to the planning environment

4.1 Regional resource adequacy

In the Northwest, resource adequacy (having enough power resources to reliably meet customer demand) is challenged by accelerating load growth, retirement of aging and carbon emitting resources, permitting and supply chain obstacles, and integration challenges for variable energy resources like wind and solar. Resource adequacy studies of the Northwest have increasingly identified growing risks, and multiple recent studies suggest that the Northwest will not be resource adequate within the next 5 years. The North American Electric Reliability Corporation (NERC) assessed reliability risk in the Northwest as "high" beginning in 2029 in the most recent long-term reliability assessment[7]. The Pacific Northwest Utilities Conference Committee (PNUCC) 2026 Northwest Regional Forecast[8] identifies a growing gap between its members load projections and their existing and planned resource builds throughout the next ten years. A study recently completed by Energy + Environmental Economics (E3) and commissioned by a broad coalition of utilities and independent power producers in the Pacific Northwest similarly concludes that the Northwest faces an elevated risk of

---

[7] https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf

[8] https://www.pnucc.org/system-planning/northwest-regional-forecast/

power supply shortfalls with a significant need for new effective capacity by 2030[9]. Early findings from the Northwest Power and Conservation Council's 9th Northwest Regional Power Plan[10] also indicate that the Northwest has significant resource needs in both the near and long-term.

While study methodologies differ and many identify growing summer resource adequacy risks as well, a multi-day winter cold snap during a low hydro year is typically the situation that puts Northwest adequacy at most risk.

4.2 Western Resource Adequacy Program (WRAP)

Tacoma Power's commitment to resource adequacy requires awareness of resources and load within our system as well as regional trends that impact our trading partners and opportunities for coordination. While individual utilities, including Tacoma Power, have standards to plan for resource adequacy, regional coordination creates additional value including common planning standards and heightened ability of electric utilities to assist each other during unexpected peak demand events or supply disruptions. Regional coordination also can mitigate risks to resource adequacy that derive from potentially unrealistic regional assumptions about excess capacity and an over-reliance on shared market resources while providing more transparent data about where and when new resources will be needed across the larger region.

The goal of WRAP is to ensure adequate generation and transmission resources exist among load serving entities in the Western Interconnection. WRAP includes two major programs: a Forward Showing Program and an Operational Program. The Forward Showing Program requires each participant to demonstrate that it has sufficient resources to serve its load for the upcoming summer or winter season. The program design takes advantage of regional modeling and diversity benefits to establish common planning reserve margins for participants that recognize and incorporate the value of regional coordination. The Operational Program provides a mechanism for a participant that has met its Forward Showing obligations to call on assistance from the program by purchasing energy from another WRAP participant during an unexpected time of need.

Tacoma Power has been involved in the design of WRAP since 2019 and joined WRAP in the fall of 2022. We began participating in the non-binding program in the fall of 2023. The WRAP program becomes binding for all participants, including Tacoma Power, during the Winter 2027-28 season. The binding program will impose financial consequences when a participant fails to demonstrate its Forward Showing obligation or does not sell energy to another participant when called on to do so by the Operational Program.

4.3 Organized Energy Markets

Tacoma Power is mindful of opportunities to increase value for its customers by optimizing the way it buys and sells energy. In an organized market, participants bid in their load and resources while the program operator uses a software optimization tool to determine what generation can serve load at the lowest cost. This structure contrasts with a bilateral market, in which no central operator is optimizing purchases and sales. Since 2022, Tacoma Power has participated in the Western Energy Imbalance Market, an organized real-time energy market that is operated by the California Independent System Operator (CAISO). An organized energy market that operates on a day-ahead basis will provide more economic transparency for decisions about planning and operating generating resources, increase the efficiency of the transmission system, and improve the regional integration of variable generation resources like wind and solar.

Tacoma Power has committed to begin participating in Markets+, an organized market that will be operated by the Southwest Power Pool (SPP) and will operate on both a real-time and day-ahead basis. Markets+ is scheduled to begin operations in October 2027 while Tacoma Power and other entities in the Pacific

---

[9] https://www.ethree.com/ra-pnw/

[10] https://www.nwcouncil.org/energy/ninthpowerplan/

Northwest will begin their participation in October 2028. The utilities that have committed to Markets+ so far include utilities in the Pacific Northwest, Desert Southwest, and Rocky Mountain regions.

Participating in Markets+ will give Tacoma access to diversity both in terms of generation resource types and load peak times in the winter or summer. Markets+ will also support existing regional resource adequacy efforts because Markets+ participants must participate in WRAP. Tacoma Power is contributing financial and personnel resources to ensure Markets+, and Tacoma Power's participation in it, remain on schedule.

4.4 Climate Commitment Act

The Climate Commitment Act (CCA), which took effect in 2022, establishes a comprehensive, market-based cap-and-invest program to reduce carbon pollution and achieve greenhouse gas limits. The cap-and-invest program sets 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.

Although the CCA is already in effect, changes to how the program works are being contemplated. These changes include but are not limited to the incorporation of centralized energy markets and linkage with California's and Quebec's carbon markets. Currently a draft linkage agreement is undergoing a public review process. In addition to the Washington review of the linkage agreement, additional regulatory changes to ensure compatibility between the markets need to be analyzed, and an Environmental Justice assessment must be performed. Linkage with California and Quebec could occur as early as 2026. However California and Quebec will need to complete their own analyses on the potential benefits of linkage before any final decision is made.

Tacoma Power submitted its first GHG emissions report in August 2023 for calendar year 2022. In 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). These are meant to mitigate the compliance cost burden of electric utilities that are also subject to Clean Energy Transformation Act (CETA) compliance. Ecology has released periodic updates to the allowances allocated to utilities. There has not been any significant change to the number of allowances that have been allocated to Tacoma Power during the first compliance period.

Our forecast of our no-cost allowance need for the 2027-2030 compliance period is provided in Appendix A.

5 Modeling and analysis framework

Our basic analytical process consists of the following steps:

1. We assess our resource adequacy position under a range of different future scenarios.
2. We identify possible resource additions to fill any resource adequacy gaps.
3. We re-run our system model with the additional possible future resources and re-assess our resource adequacy under each possible resource.
4. We compare the cost and financial risk associated with each resource addition.
5. We use these results to develop our resource strategy and action plan.

5.1 Modeling suite

The IRP modeling suite 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 modeling framework is reliable, transparent, and adaptable for future needs. The codebase is private to Tacoma Power. Our IRP model contains the following main components:

1. Hydropower dispatch
2. Weather simulations
3. Load simulations
4. Power prices
5. BPA product
6. Portfolio expansion
7. Dispatch algorithms for potential new resources

5.1.1 Hydropower dispatch

A major component of the IRP model is the approximation of Tacoma Power's hydropower generation under different operating conditions. This component of the model uses operational information for Tacoma Power hydro generation projects (such as generator characteristics and permit conditions). 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) comply with license requirements, b) maintain reservoir elevations at prudent levels, and c) generate additional power during high load 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.

5.1.2 Weather simulations

River inflows and temperatures are critical inputs to hydro operations and load predictions. The 2026 IRP modeling effort includes several weather simulations for comparison: a) the recent historical record back to 1981 (our base case runs) and b) the recent historical record back to 1981 adjusted to account for projected long-term climate trends[11] using two alternative approaches to making the adjustments (one in which adjustments are made via an additive term and one in which adjustments are made via a multiplier), and c) a longer historical record back to 1950 adjusted to account for long-term climate trends using the same two alternative approaches. We also conduct simulations with a longer unadjusted historical record back to 1950 for comparison purposes.

5.1.3 Loads

Tacoma Power’s customer demand (or load) is 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 2025 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. We consider several different future load scenarios (described in more detail in Section 5.3).

5.1.4 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 risks of alternative resource strategies we might take. Our long-term price simulations draw from data produced by the Northwest Power and

---

[11] Long-term trends are projected based on a publicly available dataset produced by researchers in the UW Hydro | Computational Hydrology research group at the University of Washington and the Oregon Climate Change Research Institute at Oregon State University (https://www.hydro.washington.edu/CRCC/)

Conservation Council using a fundamentals-based model of the grid (using Aurora software simulations) for their 2028 resource adequacy assessment[12] 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, regional hydro conditions, and natural gas prices.

5.1.5 Portfolio expansion

Our modeling framework currently handles new energy resources and new capacity 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.

For storage resources, we identify potential resource investments without an optimization tool and, depending on the resource, identify either what is reasonably expected to mitigate capacity resource shortfalls in our model output or what is likely to be available based on other studies we have conducted. Once resources have been selected, they are tested in our model. The storage optimization algorithm dispatches a specified resource with the objective of reducing peak loads.

5.2 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. 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. Our current standard includes three components to measure different aspects of our system's capabilities: (1) monthly energy, (2) sustained capacity, (3) short-term peaking capacity.

5.2.1.1 Monthly energy

Energy adequacy is important for hydropower utilities because the amount of "fuel" we have (which comes from precipitation or 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 -25 average megawatts (aMW) (i.e., the monthly 10th percentile LRB must be greater than or equal to -25 aMW) as fully adequate, between -25 aMW and -50 aMW as marginally adequate, and lower than -50 aMW as inadequate. While we look at outcomes for each month of the year, the months that drive our findings are February in the winter and August or September in the summer, as these are the months when our reservoirs will tend to be most depleted in a poor water season.

Our 2026 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.

---

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

5.2.1.2 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.

5.2.1.3 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 LOLH analysis, we also assess whether we have sufficient short-term peaking capacity to meet high demand under drought conditions. For this component of resource adequacy, we compare our lowest short-term peaking capacity to capacity requirements (i.e. peak demand + required reserves[13]) needed to meet a 1 in 10 peak load[14]. We consider our system adequate if this worst-case peaking capacity is greater than or equal to our 1 in 10 peak capacity requirements. We also report results for a 1 in 20 peak but do not currently apply an adequacy threshold to this more extreme metric.

---

[13] Typically, our reserve requirement is calculated as 3% of load plus 3% of generation. For the purposes of this extreme event analysis, we assume that the reserve requirement is 6% of load. The rationale for this assumption is that, under very low water conditions and very high loads, we would generate enough to meet load and no more.

[14] The 1-in-10 peak load is the forecasted customer demand for electricity with a 10% probability of being exceeded for at least one hour in a given season. This metric provides a pragmatic balance between ensuring system reliability during foreseeable extremes and the high cost of over-engineering solutions for rare, outlier events.

5.3 2026 IRP scenarios

Our IRP analysis begins by examining a “base case” set of assumptions. We then conduct several sensitivity analyses around our weather assumptions under climate change, Riffe Lake restoration, and alternative load growth assumptions. All scenarios include conservation projections consistent with our most recent (2026-2050) Conservation Potential Assessment. 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. All scenarios also include distributed solar generation projections consistent with those used in our corporate load forecast.

1. **Base case:** We run our base case analysis through a load growth scenario consistent with building and vehicle electrification projections used in our corporate load forecast. The “base case” runs use a 45-year historical weather record (1981 through 2025) and assume conservatively that Riffe Lake is restored to full pool before the end of 2033[15].
2. **Impacts of climate change:** In our climate change analysis, we perform additional model runs with different weather inputs to analyze how the continuation of climate change trends could impact our position.
3. **Alternative load growth assumptions:** To evaluate the impact of uncertain load projections, we perform several additional analyses:
    a. **Electrification growth sensitivities**: Projected future customer growth is highly dependent on how quickly and extensively electrification (i.e., conversion from carbon emitting energy sources like natural gas or gasoline to fuel heating, vehicles, etc.) progresses. Because there is significant uncertainty in these projections, we evaluate three higher electrification sensitivities beyond those included in our base case. The highest growth scenario in this sensitivity analysis is consistent with a deeply decarbonized economy. These scenarios are also consistent with the range of additional load growth we might expect to see through Home in Tacoma[16].
    b. **Industrial load growth sensitivity:** We run a sensitivity in which an additional 10 aMW of new industrial load is added each year over ten years.
4. **Delays in restoration of Riffe Lake:** To analyze the impact of potential delays in the timing of Riffe Lake restoration, 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.

6 Resource position analysis

6.1 Summary of findings

Our base case runs suggest that our energy position is expected to remain stable over the IRP study horizon. Our capacity position remains adequate in most years but increasingly tight due to three major factors: (1) changes to the structure of our next BPA contract, which effectively reduces the amount of capacity we receive through our Slice/Block product, (2) projected peak demand growth that outpaces growth in average energy consumption and (3) planned generator rebuilds that require long outages. While we expect to continue to meet our resource adequacy standard in most years, we see these factors combine to produce intermittent capacity risks in the early 2040s. These capacity risks are present under extended winter drought conditions combined with a cold snap.

---

[15] This is a conservative assumption. Our goal is to have Riffe Lake restored to full pool in 2031.

[16] https://tacoma.gov/government/departments/planning-and-development-services/home-in-tacoma/#summary-sheets

Our climate change sensitivity runs suggest some changes to our resource adequacy position relative to historical climate conditions, but the changes are moderate. Our model results suggest that we may experience mild improvements in our winter energy and capacity position and some degradation to our summer position. While the changes to our summer position may change some aspects of how we operate, our modeling results do not identify an emerging summer resource adequacy risk.

Our load growth sensitivity runs suggest that our current portfolio could absorb moderately higher growth from electrification and maintain resource adequacy, but adequacy would be compromised if we see a significant acceleration in load growth from electrification or industrial growth. If we were to experience electrification load growth consistent with deep economy-wide decarbonization, we would likely need a new supply-side resource as soon as 2035.

Additional sensitivity runs around delays to restoration of Riffe Lake elevation confirm the important role that restoring Riffe Lake elevation plays in helping to mitigate future risks to our capacity position.

6.2 Base case position

We start by examining our resource adequacy position under our base case set of resources and loads. We run our base case analysis through a load growth scenario consistent with the building and vehicle electrification projections used in our corporate load forecast[17]. The base case run uses a 44-year historical weather record (1981 through 2025) and assumes that Riffe Lake is restored to full pool before the end of 2033. The base case IRP outage schedule includes all planned outages greater than 4 weeks. Shorter outages (e.g., for routine annual maintenance) are not included in the IRP outage schedule because there is more flexibility in their timing in practice. Although the exact timing of longer-duration outages will change as project conditions change, the schedule provides valuable information for planning purposes.

Figure 6-1 provides a summary of the increases in energy consumption and winter and summer peak demand in our base case. Load growth in average energy is moderate under the base case scenario: from 524 aMW in 2027 to 534 aMW in 2037. Increased electrification loads are projected to add to peak load more than average load. For example, the 1-in-10 year winter peak is expected to increase from 983 MW in 2027 to 1,018 MW in 2037.

---

[17] The electrification projections in our corporate load forecast use a combination of scenario projections from our 2023 Electrification Study (Scenario 1 for building electrification, Scenario 4 for vehicles electrification, and a mix of no incremental electrification and Scenario 4 for most industrial processes).

Figure 6-1: Load trend in base case scenario

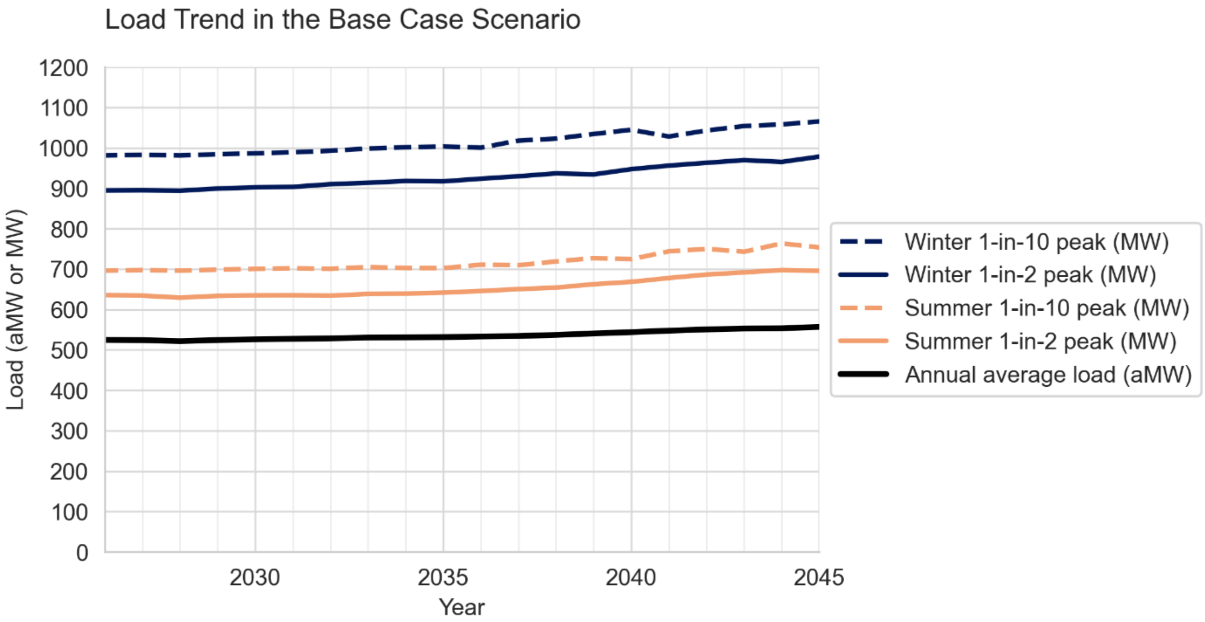


Figure 6-2 shows the resource adequacy position for energy based on the seasonal load resource balance metric. Our modeling results indicate that we do face some risks but are generally in an adequate resource position given our base case load projection. Under the winter drought conditions, we may need to rely on some energy from wholesale power markets to meet load across the course of the month. However, that reliance stays within our resource adequacy threshold of -50 aMW across the study period and is expected to lessen slightly under our new BPA contract when we receive a little more Block energy and a little less inflow-dependent Slice energy.

Figure 6-2: Energy resource adequacy metric under base case scenario

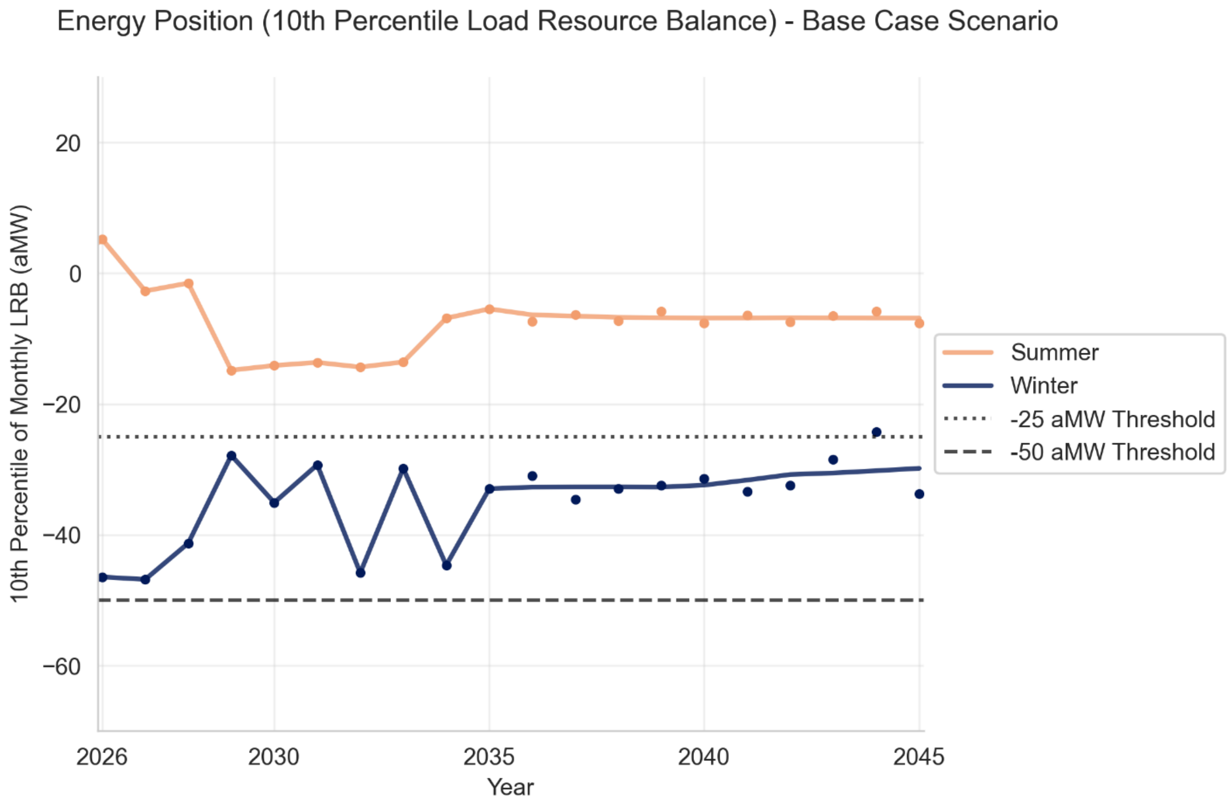


Figure 6-3 shows the sustained capacity risk for the modeling period. We pass our sustained capacity standard in all but one year of the study period (2034). The shortfalls in that year are due to overlapping scheduled generator outages for generator rebuild work as well as other longer-duration maintenance work. The shortfalls caused by overlapping outages are concentrated in the spring, when regional reliability concerns are lower. While our modeling shows a sustained capacity shortfall, it is important to note that the outage schedule used in our model is preliminary and can be adjusted to avoid the degree of overlap causing this heightened sustained capacity risk.

Figure 6-3: Sustained capacity resource adequacy metric under base case scenario

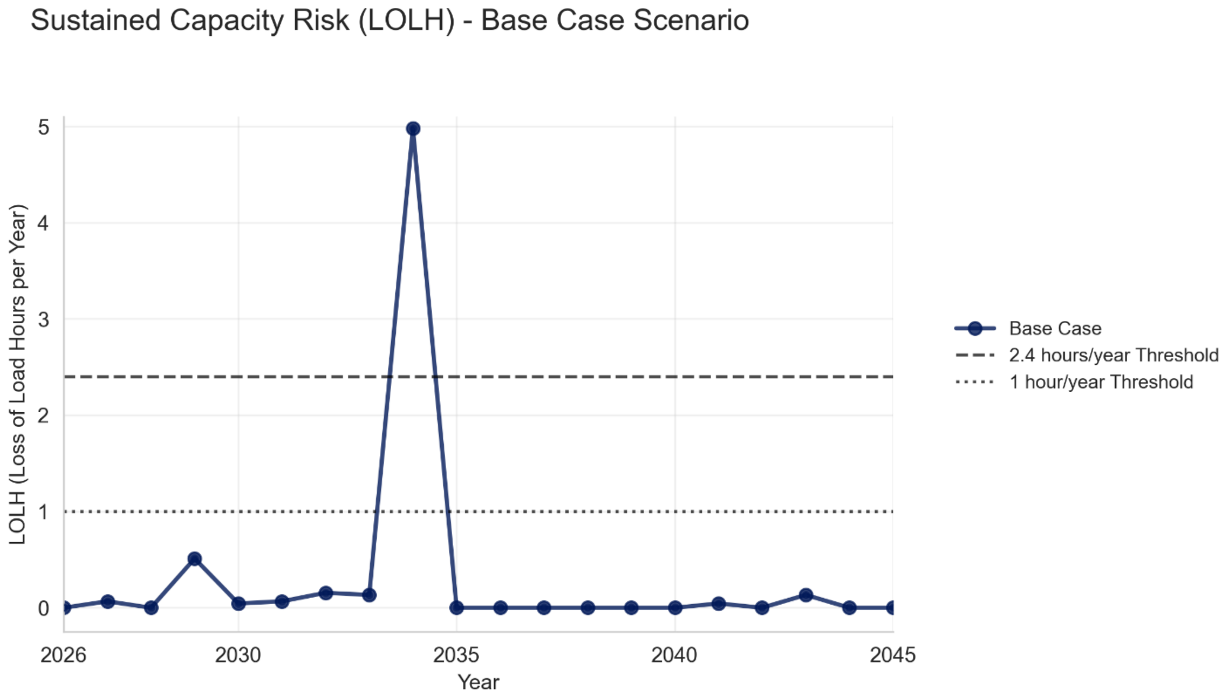
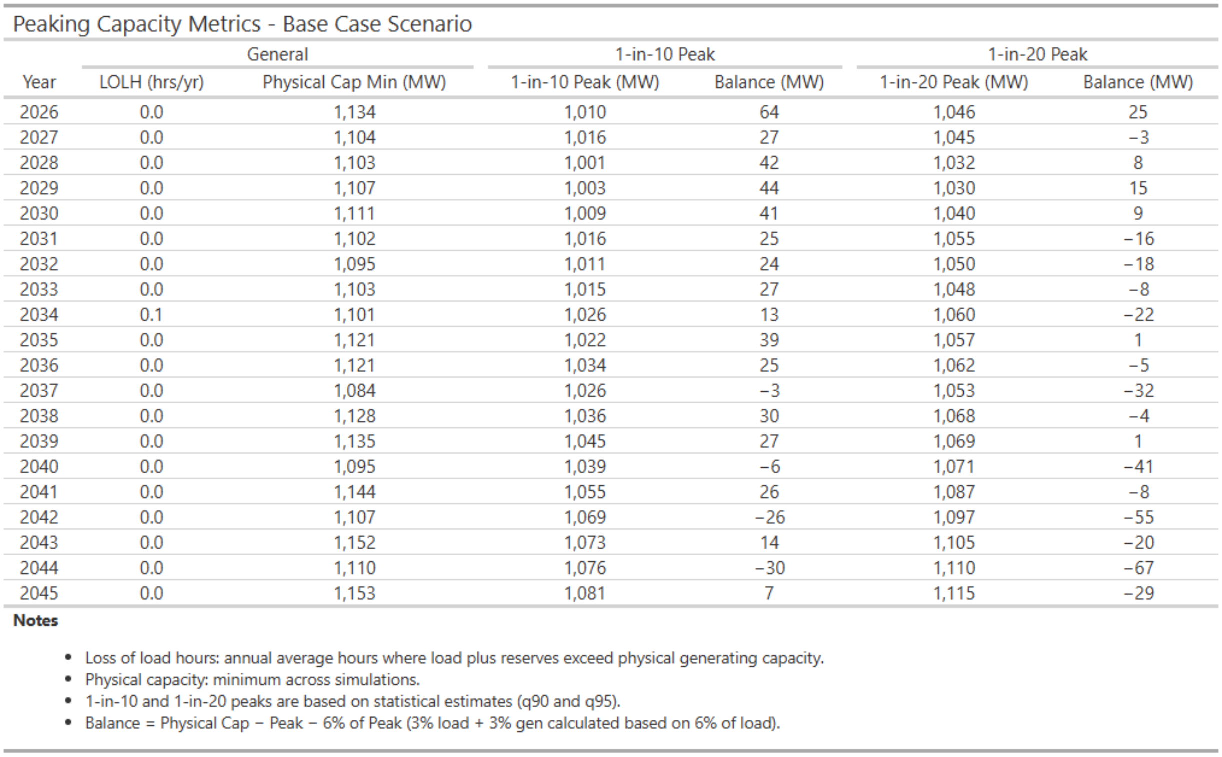


Table 6-1 shows the peaking capacity results, and Figure 6-4 provides a more detailed look at our extreme event capacity position for 1 in 10 peak loads. While our LOLH metric remains adequate throughout the study period, our modeling projects a degradation of our extreme event capacity balance over time. This is due primarily to a combination of changes to our BPA contract and peak demand growth from electrification. Extreme event risk is more pronounced in years when generators are projected to be offline for rebuilds during the second half of the study period. Towards the end of the study period, we have very little room to accommodate these rebuilds and start seeing temporary shortfalls during those years.

Table 6-1: Peaking capacity metric under base case scenario



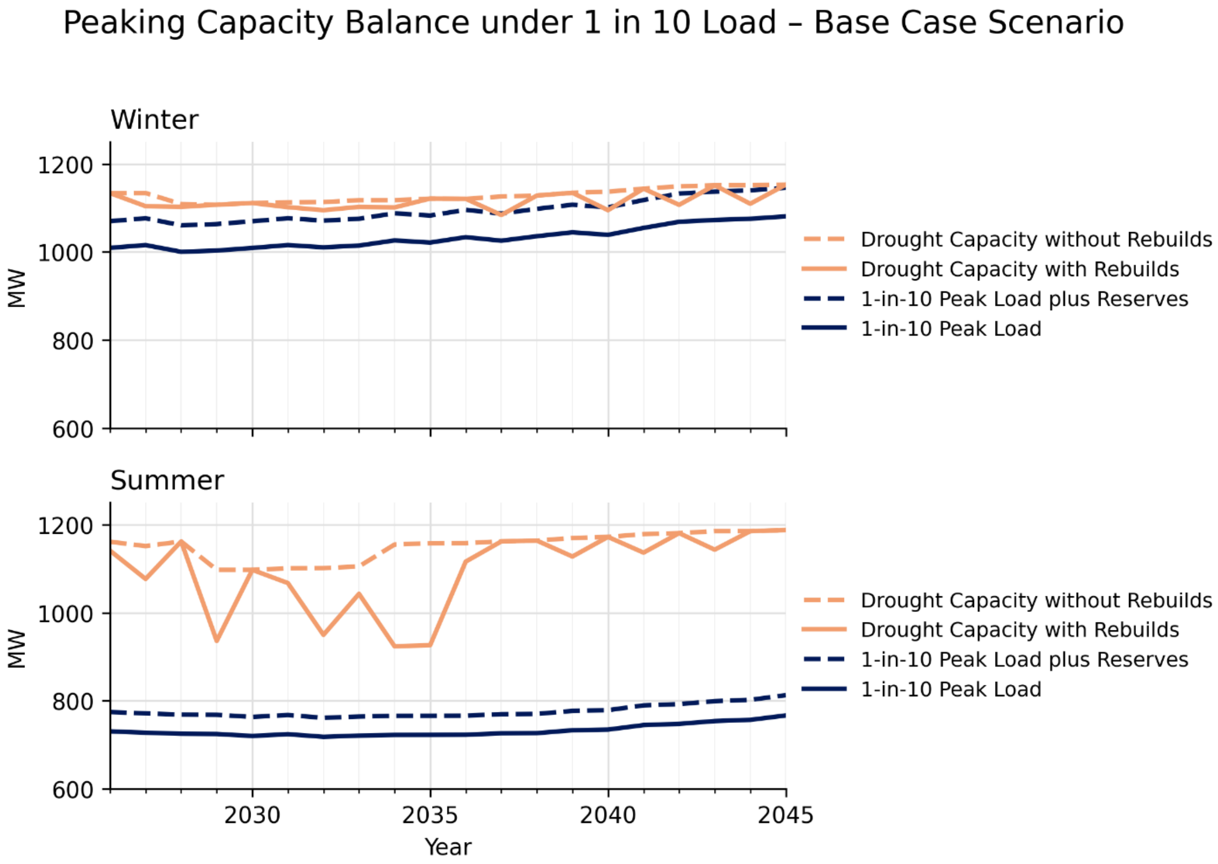
Peaking Capacity Metrics - Base Case Scenario

	General		1-in-10 Peak		1-in-20 Peak	
Year	LOLH (hrs/yr)	Physical Cap Min (MW)	1-in-10 Peak (MW)	Balance (MW)	1-in-20 Peak (MW)	Balance (MW)
2026	0.0	1,134	1,010	64	1,046	25
2027	0.0	1,104	1,016	27	1,045	−3
2028	0.0	1,103	1,001	42	1,032	8
2029	0.0	1,107	1,003	44	1,030	15
2030	0.0	1,111	1,009	41	1,040	9
2031	0.0	1,102	1,016	25	1,055	−16
2032	0.0	1,095	1,011	24	1,050	−18
2033	0.0	1,103	1,015	27	1,048	−8
2034	0.1	1,101	1,026	13	1,060	−22
2035	0.0	1,121	1,022	39	1,057	1
2036	0.0	1,121	1,034	25	1,062	−5
2037	0.0	1,084	1,026	−3	1,053	−32
2038	0.0	1,128	1,036	30	1,068	−4
2039	0.0	1,135	1,045	27	1,069	1
2040	0.0	1,095	1,039	−6	1,071	−41
2041	0.0	1,144	1,055	26	1,087	−8
2042	0.0	1,107	1,069	−26	1,097	−55
2043	0.0	1,152	1,073	14	1,105	−20
2044	0.0	1,110	1,076	−30	1,110	−67
2045	0.0	1,153	1,081	7	1,115	−29

Notes

- Loss of load hours: annual average hours where load plus reserves exceed physical generating capacity.
- Physical capacity: minimum across simulations.
- 1-in-10 and 1-in-20 peaks are based on statistical estimates (q90 and q95).
- Balance = Physical Cap − Peak − 6% of Peak (3% load + 3% gen calculated based on 6% of load).

Figure 6-4: Peaking capacity balance under 1 in 10 load - base case scenario



6.3 Impacts of climate change

We have progressively improved our approach to understanding how climate change will affect our resources over recent IRP cycles. Similar to the 2024 IRP, the 2026 IRP modeling effort includes several weather simulations for comparison: a) the recent historical record back to 1981 (our base case runs), b) the recent historical record back to 1981 adjusted to account for projected long-term climate trends[18] using two alternative approaches to making the adjustments (one in which adjustments are made via an additive term and one in which adjustments are made via a multiplier), and c) a longer historical record back to 1950 adjusted to account for long-term climate trends using the same two alternative approaches. Climate change projections are uncertain, and performing the evaluation in multiple ways helps to build up an ensemble of potential outcomes.

The general trends from climate change in the Puget Sound region are warmer temperatures in both summer and winter, drier summers, wetter winters, less accumulation of snowpack, and earlier spring snowmelt. The projected impacts of these changes on our monthly energy position, sustained capacity position and peaking capacity position are shown in Figure 6-5, Figure 6-6 and Table 6-2. Regardless of our approach to modeling climate change, we find that our summer energy position becomes slightly tighter as the climate warms and that our winter energy position may improve marginally. The combined results suggest the need to continue

---

[18] Long-term trends are projected based on publicly available datasets produced by researchers in the UW Hydro | Computational Hydrology research group at the University of Washington and the Oregon Climate Change Research Institute at Oregon State University (https://www.hydro.washington.edu/CRCC/)

to manage summer water conservatively and rely on the market for energy in the summer more than we used to, but they do not suggest emerging resource adequacy issues caused by climate change.

We also conduct simulations with a longer unadjusted historical record back to 1950 for comparison purposes to understand how climate trends have shown up in our system so far. A comparison of our base case historical record to the longer record is largely consistent with our projections of future trends. We find that the shortened historical record suggests a lower summer energy position relative to what it might be with the longer historical record unadjusted for climate change. The results do not suggest a clear directional change to our winter energy position or sustained capacity position.

Figure 6-5: Energy resource adequacy metric under climate scenarios

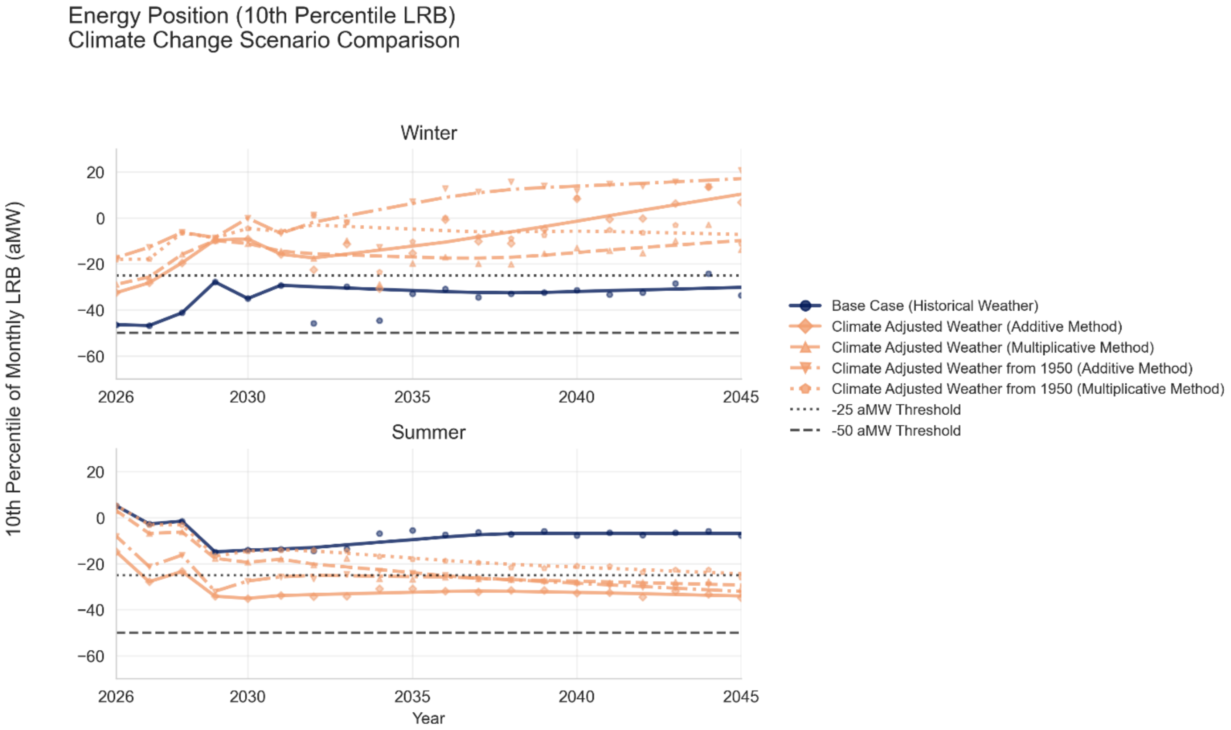


Figure 6-6: Sustained capacity adequacy metric under climate scenarios

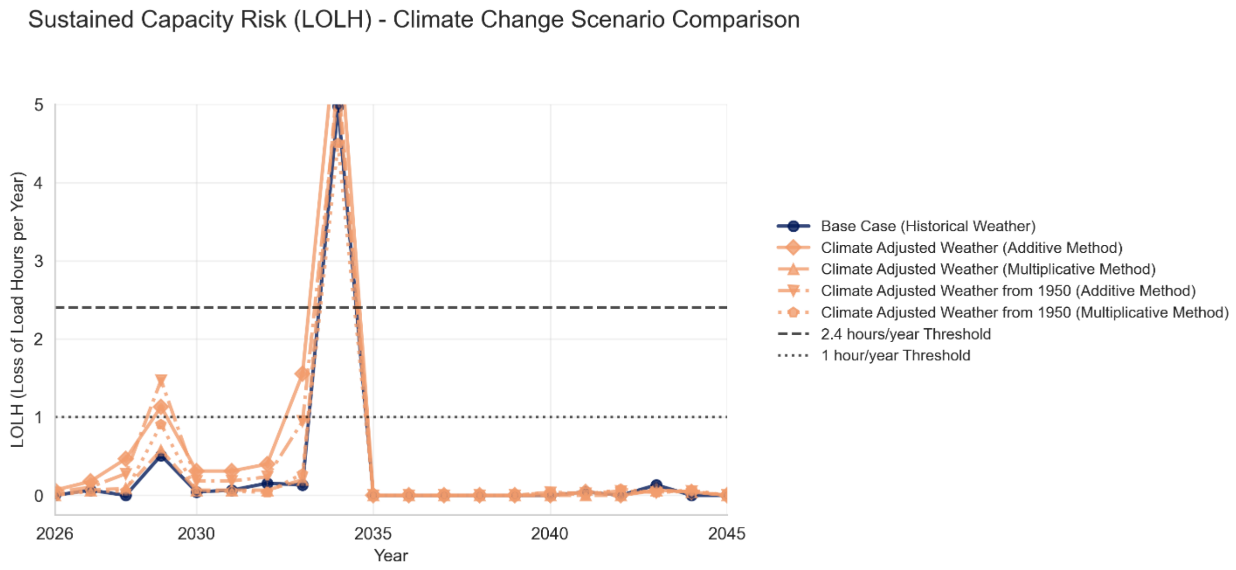
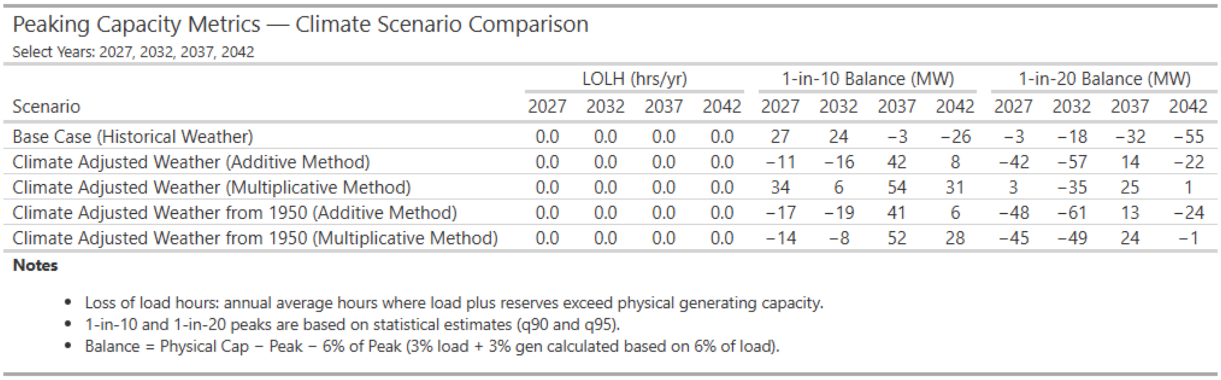


Table 6-2: Peaking capacity resource adequacy metrics under climate scenarios



Peaking Capacity Metrics — Climate Scenario Comparison

Select Years: 2027, 2032, 2037, 2042

	LOLH (hrs/yr)				1-in-10 Balance (MW)				1-in-20 Balance (MW)			
Scenario	2027	2032	2037	2042	2027	2032	2037	2042	2027	2032	2037	2042
Base Case (Historical Weather)	0.0	0.0	0.0	0.0	27	24	−3	−26	−3	−18	−32	−55
Climate Adjusted Weather (Additive Method)	0.0	0.0	0.0	0.0	−11	−16	42	8	−42	−57	14	−22
Climate Adjusted Weather (Multiplicative Method)	0.0	0.0	0.0	0.0	34	6	54	31	3	−35	25	1
Climate Adjusted Weather from 1950 (Additive Method)	0.0	0.0	0.0	0.0	−17	−19	41	6	−48	−61	13	−24
Climate Adjusted Weather from 1950 (Multiplicative Method)	0.0	0.0	0.0	0.0	−14	−8	52	28	−45	−49	24	−1

Notes

- Loss of load hours: annual average hours where load plus reserves exceed physical generating capacity.
- 1-in-10 and 1-in-20 peaks are based on statistical estimates (q90 and q95).
- Balance = Physical Cap − Peak − 6% of Peak (3% load + 3% gen calculated based on 6% of load).

6.4 Alternative load scenarios

Like other utilities, Tacoma Power faces significant uncertainty regarding future load growth. While we expect to see increased adoption of electric vehicles and increased reliance on electricity for space, water and other heating needs, the extent and speed of that transition is highly uncertain. Potential growth from industrial loads presents additional uncertainty. We test the robustness of our adequacy position across several alternative scenarios with higher load growth driven by electrification and one scenario of industrial load growth. The alternative electrification scenarios[19] are consistent with scenarios developed in our 2024 Electrification Forecast[20]:

---

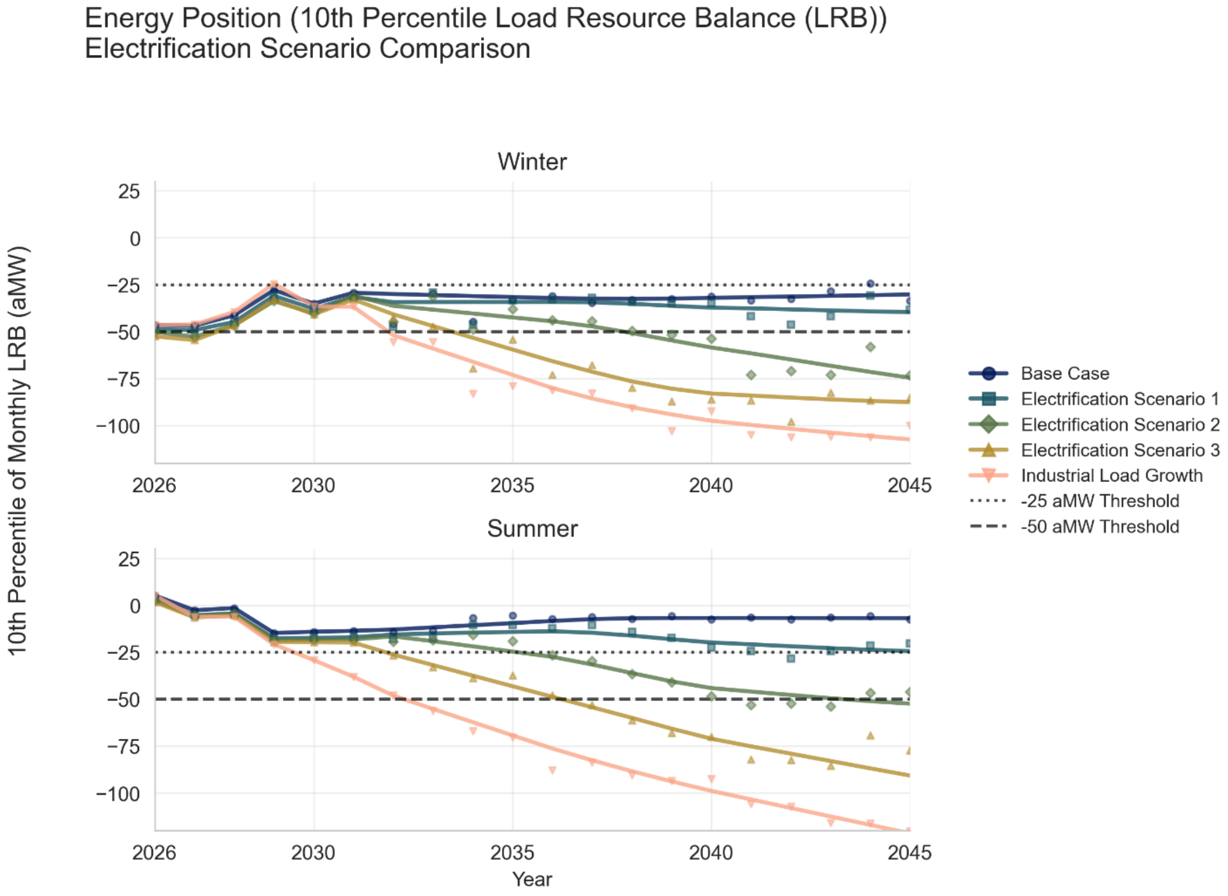
[19] The electrification projections against which these alternative scenarios are compared is consistent with assumptions used in our corporate load forecast and is based on a combination of scenario projections from our 2023 Electrification Study (Scenario 1 for building electrification, Scenario 4 for vehicles electrification, and no electrification or Scenario 4 for most industrial processes).

[20] The study is available on our IRP webpage: https://www.mytpu.org/about-tpu/services/power/integrated-resource-plan/

- **Scenario 1** represents moderately higher growth and is consistent with the "Current Landscape" scenario from the electrification study
- **Scenario 2** represents significantly higher growth and is consistent with the "Anticipated Electrification" scenario from the electrification study
- **Scenario 3** is representative of deep economy-wide decarbonization and is consistent with the "Expansive Policy" scenario from the electrification study.

Figure 6-7 compares our energy position across load scenarios, Figure 6-8 examines our sustained capacity position and Table 6-3 examines our peaking capacity position. Together the results indicate that some additional growth from electrification degrades our resource position over time but does not compromise our resource adequacy. However, our current resource portfolio would not be sufficient to meet demand if growth were to accelerate significantly due to either rapid electrification or large increases in demand from industrial loads. Under an accelerated growth scenario, we would need additional power supply resources by the late 2030s. We would need additional power supply resources as soon as 2035 under our most expansive electrification growth scenario and even sooner under our industrial load growth scenario[21].

Figure 6-7: Energy resource adequacy metric under alternative load scenarios



---

[21] The specific timing, size and makeup of the resource need for new industrial loads will depend on the specifics of the load. As a result, our is not necessarily representative of the timing, size or need profile of any specific industrial load addition. They simply indicate that we expect the need for a new resource if a large industrial load or multiple smaller industrial loads were to locate in our service area.

Figure 6-8: Sustained capacity resource adequacy metrics under alternative load scenarios

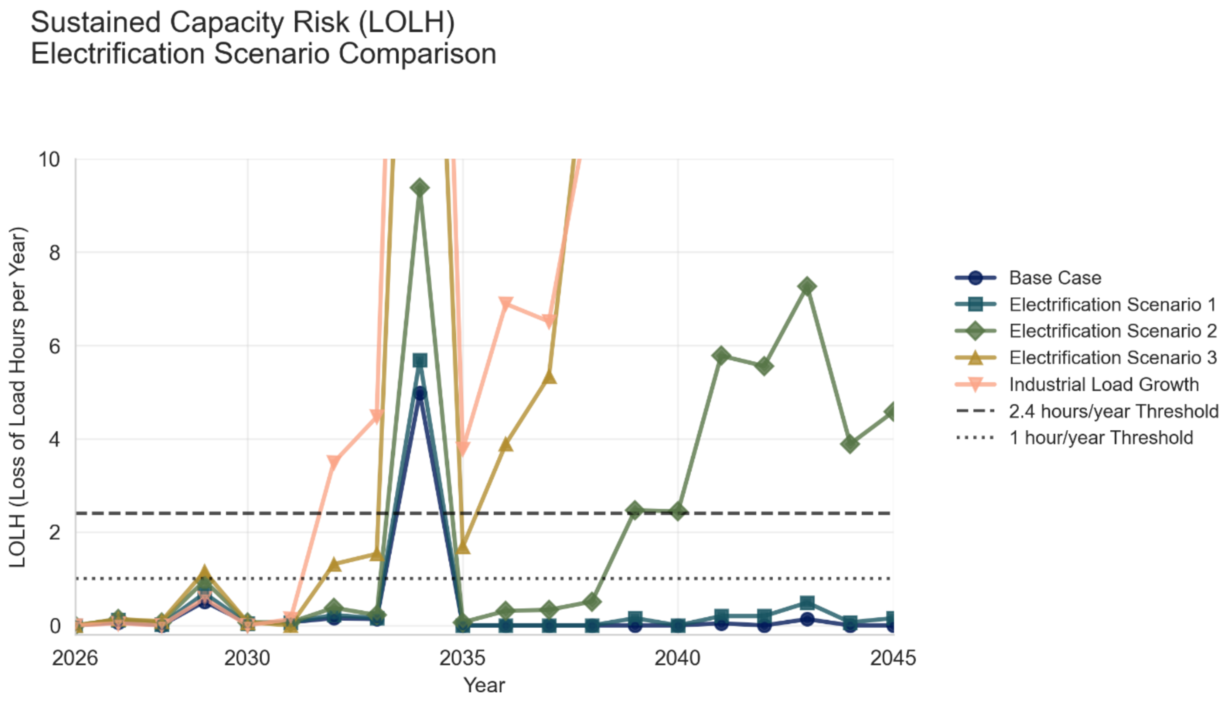
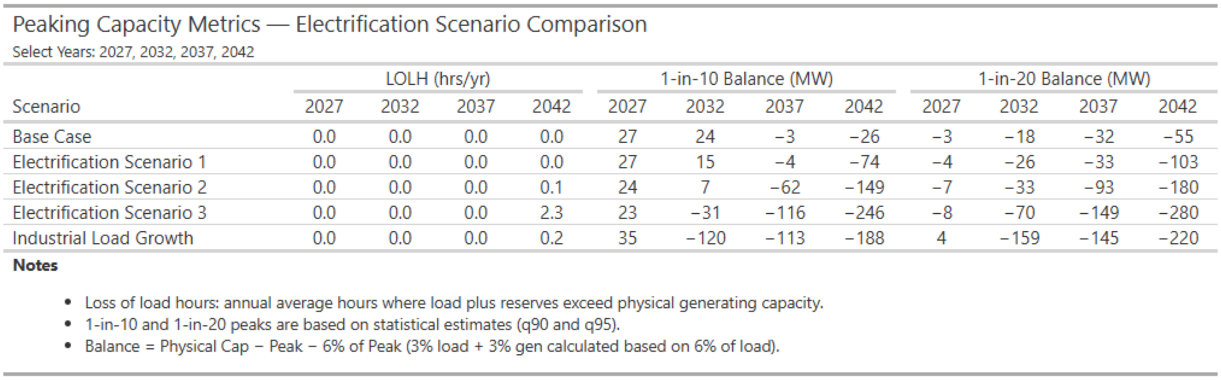


Table 6-3: Peaking capacity metrics under alternative load scenarios



Peaking Capacity Metrics — Electrification Scenario Comparison

Select Years: 2027, 2032, 2037, 2042

	LOLH (hrs/yr)				1-in-10 Balance (MW)				1-in-20 Balance (MW)			
Scenario	2027	2032	2037	2042	2027	2032	2037	2042	2027	2032	2037	2042
Base Case	0.0	0.0	0.0	0.0	27	24	−3	−26	−3	−18	−32	−55
Electrification Scenario 1	0.0	0.0	0.0	0.0	27	15	−4	−74	−4	−26	−33	−103
Electrification Scenario 2	0.0	0.0	0.0	0.1	24	7	−62	−149	−7	−33	−93	−180
Electrification Scenario 3	0.0	0.0	0.0	2.3	23	−31	−116	−246	−8	−70	−149	−280
Industrial Load Growth	0.0	0.0	0.0	0.2	35	−120	−113	−188	4	−159	−145	−220

Notes

- Loss of load hours: annual average hours where load plus reserves exceed physical generating capacity.
- 1-in-10 and 1-in-20 peaks are based on statistical estimates (q90 and q95).
- Balance = Physical Cap − Peak − 6% of Peak (3% load + 3% gen calculated based on 6% of load).

6.5 Risk scenario: Delay in restoration of Riffe Lake elevation

Tacoma Power's intention is to restore Riffe Lake to full pool by 2031. However, it is possible that unforeseen barriers to restoration mean that even our conservative IRP assumption of restoration in late 2033 is too optimistic. 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. Figure 6-9, Figure 6-10 and Table 6-4 present results for energy, sustained capacity, and peaking capacity, respectively. Because the peaking capacity impact of this scenario is different in years with and without extended outages from rebuilds, we also include Figure 6-11, which examines our 1 in 10 capacity balance under winter drought conditions with and without Riffe restoration for all study years.

Delays to restoration of Riffe are not expected to have meaningful impacts on our critical water energy position, but results confirm that restoration of Riffe Lake is important for our capacity position. While it does not always eliminate resource adequacy risk in all situations, it reduces the magnitude and duration of potential sustained capacity shortfalls and increases our system's short-term peaking capacity by approximately 35 MW in years when all generators at the Cowlitz River Project are online.

Figure 6-9: Energy resource adequacy metric under alternative Riffe assumption

Figure 6-10: Sustained capacity adequacy metric under alternative Riffe assumption

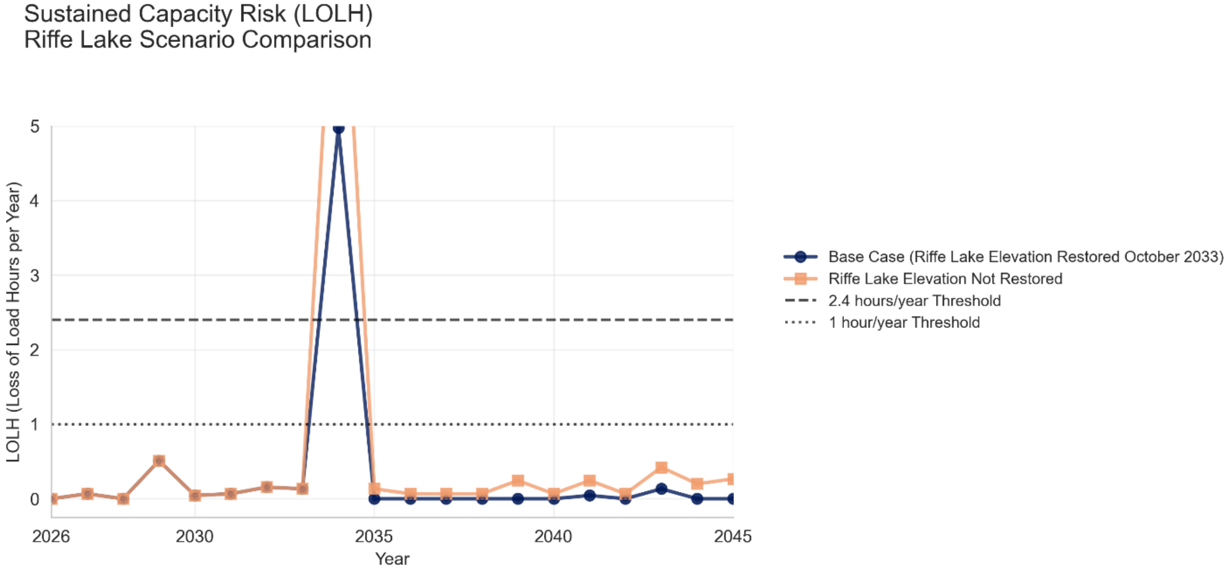
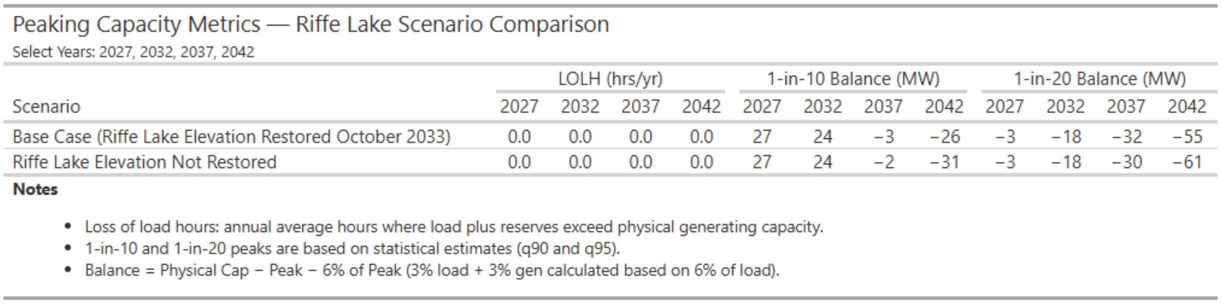


Table 6-4: Peaking capacity adequacy metrics under alternative Riffe assumption



Peaking Capacity Metrics — Riffe Lake Scenario Comparison

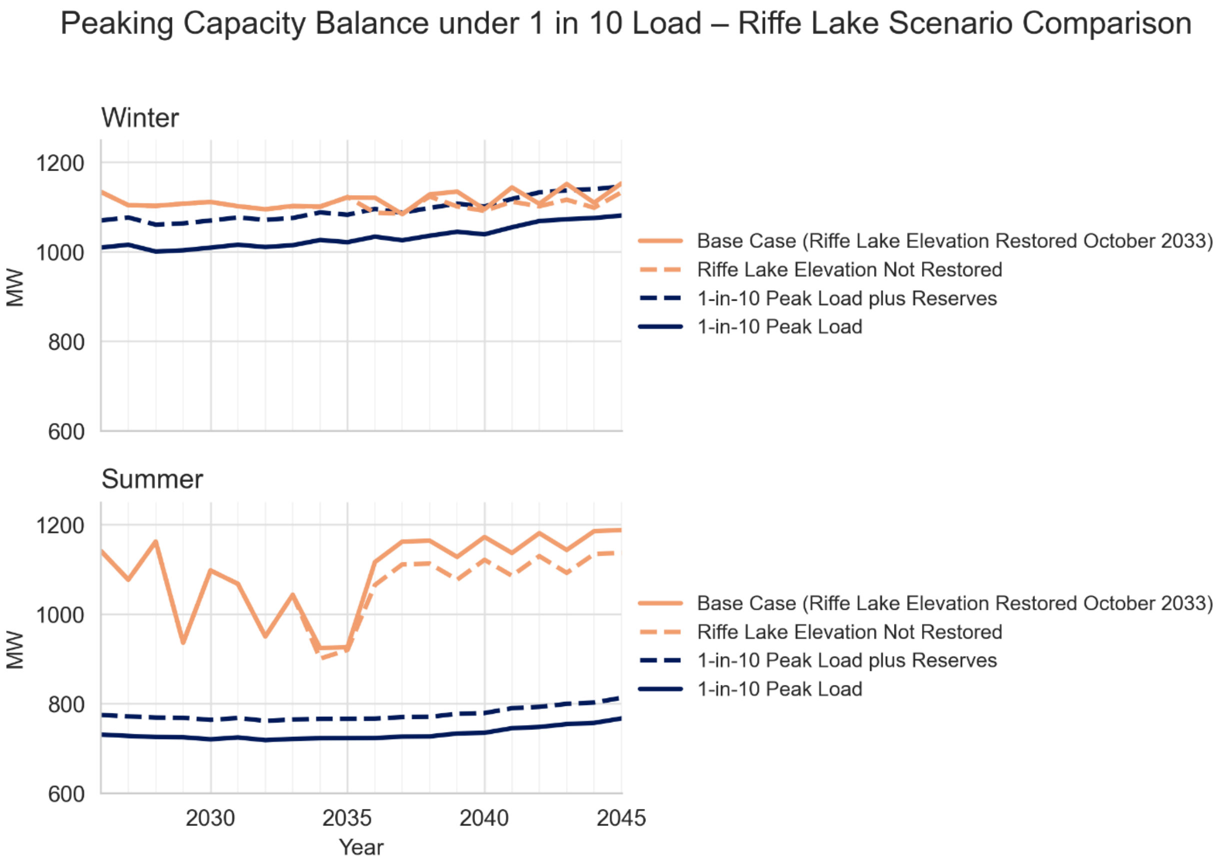
Select Years: 2027, 2032, 2037, 2042

	LOLH (hrs/yr)				1-in-10 Balance (MW)				1-in-20 Balance (MW)			
Scenario	2027	2032	2037	2042	2027	2032	2037	2042	2027	2032	2037	2042
Base Case (Riffe Lake Elevation Restored October 2033)	0.0	0.0	0.0	0.0	27	24	−3	−26	−3	−18	−32	−55
Riffe Lake Elevation Not Restored	0.0	0.0	0.0	0.0	27	24	−2	−31	−3	−18	−30	−61

Notes

- Loss of load hours: annual average hours where load plus reserves exceed physical generating capacity.
- 1-in-10 and 1-in-20 peaks are based on statistical estimates (q90 and q95).
- Balance = Physical Cap − Peak − 6% of Peak (3% load + 3% gen calculated based on 6% of load).

Figure 6-11: Peaking capacity balance under 1 in 10 load - Riffe Lake scenario comparison



7 Analysis of resource alternatives

In this section we analyze resource alternatives and assess their ability to mitigate risks identified in Section 6. We find that demand response is a promising resource to mitigate the capacity risks identified under our base case scenario, as it directly mitigates the rising peak demand that is driving our capacity risk. However, each demand response opportunity will need to be evaluated for cost-effectiveness. We find that the lowest-cost demand response opportunities identified in our DRPA can contribute significantly to reducing projected capacity risks and have a minimal impact on total portfolio costs, but they are not enough by themselves to fully mitigate our capacity risks. Our higher-cost bundle of demand response resources (DR Bundle 2) is sufficient to mitigate our capacity risks under the base case scenario but is significantly more expensive on a per kilowatt basis than a battery storage resource.

Of the supply-side resources examined in this IRP, we find that adding hydrogeneration capacity at Mossyrock Dam could be the lowest-cost option to mitigate growing peaking capacity risks. However, because it would be a larger resource than some other additions, it would likely increase total costs of our resource portfolio more than other resource options that are more scalable to our need. On the other hand, the advantage of this larger capacity addition is that it would also mitigate capacity risks even under higher peak load growth. This option may have some additional benefits for our system relative to some other supply-side resources. Significant additional analysis would be needed to fully understand how we might utilize the additional hydro capacity and what the limitations of its use would be, and more in-depth study would be required to improve our estimates of benefits and costs before pursuing this option.

The next lowest-cost resource option on both a per kilowatt basis and a total portfolio cost basis is a small natural gas peaking generator, but this option would not be compliant with CETA's 100% renewable and non-emitting requirements starting in 2045. Utility-scale battery storage is the next lowest-cost supply-side resource that does comply with CETA's 2045 clean energy requirements.

Under our higher load growth scenarios we find that, apart from a natural gas generator, no single resource we model would be sufficient to solve both the energy and capacity adequacy challenges we might face. We find that portfolios combining energy and capacity resources are more successful at mitigating energy, sustained capacity and peaking capacity shortfalls under these high load growth scenarios but at a significantly higher cost than the natural gas generator.

While our analyses do not identify an imminent need for a new resource beyond our planned investments in conservation, we do identify some capacity risks at the very end of our study period under our extreme event metric. We also identify some potential risks to our future resource adequacy position should customer demand grow significantly more quickly than anticipated. In this section we analyze our options for mitigating these potential future adequacy risks.

7.1 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 2026 IRP, that list includes:

1. **Demand response:** Tacoma Power has conducted several studies to understand the potential availability and cost of demand response (DR) resources and updates these studies regularly. Our 2026 IRP considers two demand response resource bundles based on the outputs of our 2025 Demand Response Potential Assessment: (1) one bundle that includes only the two lowest cost resources identified in the study (third party contracts with large industrial customers and a Critical Peak Pricing rate design) and (2) another bundle that includes all but the two highest-cost DR resource identified in the study.
2. **Wind generation:** We use wind generation profiles from the National Renewable Energy Laboratory's System Advisor Model.[22] We allow our model to select from several possible locations within Washington and along the Gorge in Oregon.
3. **Solar generation:** We use solar generation profiles from the National Renewable Energy Laboratory's System Advisor Model. We allow our model to select from several possible locations within Washington and along the Gorge in Oregon.

---

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

4. **Short-duration battery storage:** We consider a four-hour lithium-ion battery with round trip efficiency of 85% and no standing loss rate.[23] For IRP purposes, energy storage resources are dispatched with the objective of reducing daily peak loads.
5. **Small modular nuclear reactors (SMRs):** Our small modular nuclear reactor profile assumes a 95% capacity factor with a flat generation profile across all hours.
6. **Pumped storage at the Cowlitz River Project:** Our pumped storage study described in Section 3.6 identified several different versions of pumped storage that were potentially feasible. In the IRP, we model one of these alternatives. The alternative we model includes the construction of a separate reservoir, which seems geographically feasible but may ultimately not be practically feasible. The pumped storage resource is assumed to be a 100 MW resource with 8 hours of storage based on data from the study.
7. **Additional conventional hydro capacity at Mossyrock Dam:** Our pumped storage study also included high-level information on capabilities and costs of adding a conventional hydrogenator without pumping capabilities. This alternative is also analyzed. The hydrogenator is assumed to have a nameplate capacity of 100 MW.
8. **Natural gas generation:** For the IRP, we use the cost and operational characteristics of an 'NG Combustion Turbine (F-Frame)' from the NREL Annual Technology Baseline (ATB) dataset[24]. To enforce its role as a peak-load resource, the unit is economically dispatched based on simulated marginal costs and power prices, but its annual operation is limited to a 15% capacity factor. An additional value premium is applied during the top 5% of loads for both Tacoma Power and the WECC to reflect its role as a reliability asset.

Note that conservation and customer-owned solar are not analyzed in this section because they are already embedded into the load projections used in the IRP. We did run an alternative load scenario in which customer-owned solar penetration is significantly higher to test the potential resource adequacy contribution of customer-owned solar. However, customer-owned solar interacts with the power supply from our BPA contract in such a way that degrades rather than improves our capacity position overall. As such, it is not a viable resource to mitigate Tacoma Power's specific resource adequacy risks.

7.2 Other resource options not modeled in the IRP

7.2.1 Incremental capacity improvements during generator rebuilds

Another resource option available to us is to incrementally add a little bit of capacity or other capabilities to generators as they're taken offline to be rebuilt. Although any individual upgrade is unlikely to solve an emerging resource adequacy issue, each capacity increase would incrementally improve our position. 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.

7.2.2 Emerging technologies

While our IRP modeling and analyses focus on conventional technologies such as utility-scale solar, onshore wind, and lithium-ion battery storage, we recognize that there are many promising technologies that may become commercially available in the future. Emerging technologies that are typically projected to become

---

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

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

commercially available over the next 10 years include small modular reactors (SMRs), offshore wind, enhanced geothermal systems, long-duration energy storage and next-generation battery chemistries. Aside from SMRs, these technologies are not modeled in our analysis of resource alternatives. We will consider these resource opportunities in future IRPs as they become more widely available and future costs are more certain. Outside of the IRP, Tacoma Power continuously tracks emerging technology opportunities.

7.3 Resource cost assumptions

7.3.1 Direct resource costs

We rely on the NREL ATB data[25] to develop our cost assumptions whenever possible. For all our runs, we use the 'moderate' ATB costs for the 30-year capital recovery 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%[26] applied to these costs. Our cost assumptions for small modular reactors (SMRs) are from the earliest-available projections from NREL (2030).

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. For batteries less than 50 MW, 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 4-hour, 100 MW battery.

Table 7-1: Cost assumptions by resource

Resource	CapEx ($/kw)	O&M ($/kw-year)	Grid Connection ($/kw)	Variable Cost ($/MWh)	Lifetime (years)	Integration Cost ($/kw-month)	Requires additional Transmission?
Utility-scale wind (land-based)	1,536.87	30.85	100.00	0.00	30	0.63	Yes
Utility-scale solar	1,432.01	20.40	100.00	0.00	30	1.15	Yes
Utility-scale battery storage - 4-hour lithium-ion	1,869.71	45.05	100.00	*	20	0.00	Yes
Natural gas peaking generator - NG combustion turbine (F-Frame)	1,309.59	31.60	100.00	6.94	25	0.00	Yes
Nuclear – small modular reactors (SMRs)	12,681.13	216.00	100.00	2.80	40	0.00	Yes

---

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

[26] Taken from the Cleveland Federal Reserve 20-year expected inflation value: https://www.clevelandfed.org/indicators-and-data/inflation-expectations

Conventional hydro generator addition at Mossyrock Dam	1,221.05	7.72	0.00	0.00	40	0.00	No
Pumped storage addition at Cowlitz River Project	9,077.70	44.90	0.00	0.00	40	0.00	No

7.3.2 Integration costs

To estimate integration costs for variable energy resources (i.e., wind and solar), we use BPA's resource-level variable energy resource balancing service (VERBS) rates from BPA's BP-26 rate case[27].

7.3.3 Transmission costs

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, and nuclear) and cost transmission at BPA's most recently published tariff ($2.043/kW-month).[28] 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 80% would require 80 MW of transmission capacity. It is important to emphasize that this is a modeling assumption used for the IRP. It is not a given that we can secure transmission rights to deliver the power from any new resource addition to our customers at the costs assumed in our analysis. Certain resources, like battery storage, are less geographically constrained while others, like utility-scale wind and solar, tend to be located along transmission corridors that are already more constrained. The potential cost of adding the transmission capabilities needed to deliver a given resource to our customers may be significantly higher than our assumptions for some resources. Outside of the IRP, we periodically evaluate whether different configurations of transmission service might make sense and help address future contingencies for load growth or new resource acquisitions. The potential future resources identified in this IRP will inform those analyses.

7.3.4 Natural gas delivery costs

NREL ATB costs generally define the scope of cost as those that fall within 'the fence line', referring to costs that are directly attributable to construction/operation of the resource. This is reasonably broad to cover all expected costs borne by Tacoma power for most resources but is not sufficient to cover many of the additional costs from a new natural gas plant. We follow assumptions used by the Northwest Power and Conservation Council in the development of their 9th Northwest Regional Power Plan for firm natural gas access of six dollars per kilowatt-year plus a 1.5% of $/mmbtu hub price charge for compression.

7.3.5 Summary of levelized cost of energy and capacity

When evaluating new resources to cover potential deficits, we compare a range of candidates based on the capacity and energy they deliver. A natural starting point is levelized cost of energy (LCOE), which summarizes each resource's overall cost relative to the energy that the resource provides. Table 7-2 summarizes annual and a seasonal levelized cost of energy for each candidate resource[29]. Because Tacoma Power's risks are concentrated in the winter, a resource's winter LCOE is particularly relevant for us.

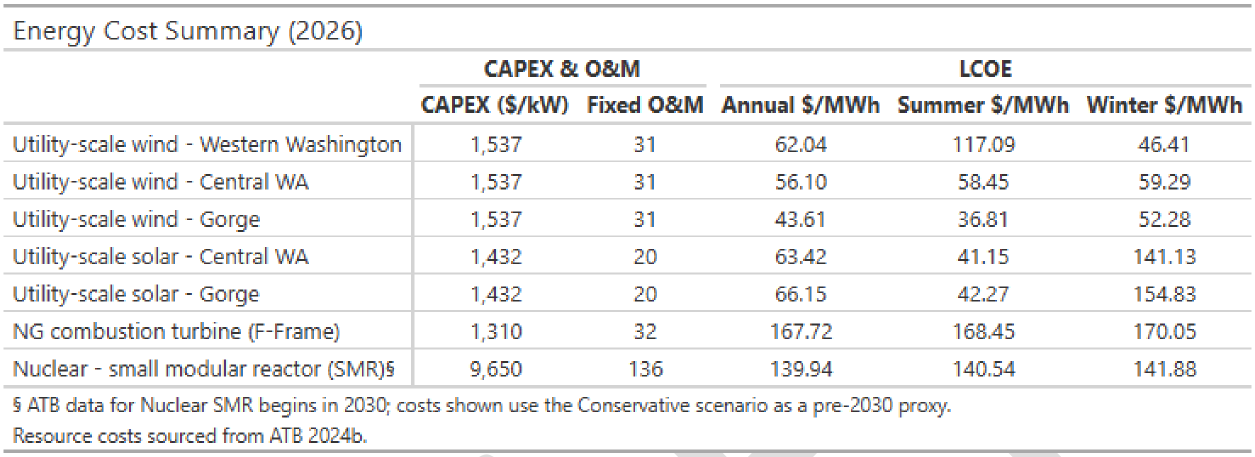
---

[27] See Appendix E: Transmission Rate Schedules and General Rate Schedule Provisions (BP-26-A-01-AP02). https://www.bpa.gov/energy-and-services/rate-and-tariff-proceedings/bp-26-rate-case

[28] Ibid.

[29] "Seasonal LCOE" is not a traditional metric for measuring cost effectiveness – this metric allocates only the season's proportional share of annual cost based on the ratio $\frac{days-in-season}{days-in-year}$ across the MWh generated in

Table 7-2: Levelized cost of energy (LCOE) for candidate resources



Energy Cost Summary (2026)

	CAPEX & O&M		LCOE		
	CAPEX ($/kW)	Fixed O&M	Annual $/MWh	Summer $/MWh	Winter $/MWh
Utility-scale wind - Western Washington	1,537	31	62.04	117.09	46.41
Utility-scale wind - Central WA	1,537	31	56.10	58.45	59.29
Utility-scale wind - Gorge	1,537	31	43.61	36.81	52.28
Utility-scale solar - Central WA	1,432	20	63.42	41.15	141.13
Utility-scale solar - Gorge	1,432	20	66.15	42.27	154.83
NG combustion turbine (F-Frame)	1,310	32	167.72	168.45	170.05
Nuclear - small modular reactor (SMR)§	9,650	136	139.94	140.54	141.88

§ ATB data for Nuclear SMR begins in 2030; costs shown use the Conservative scenario as a pre-2030 proxy.
Resource costs sourced from ATB 2024b.

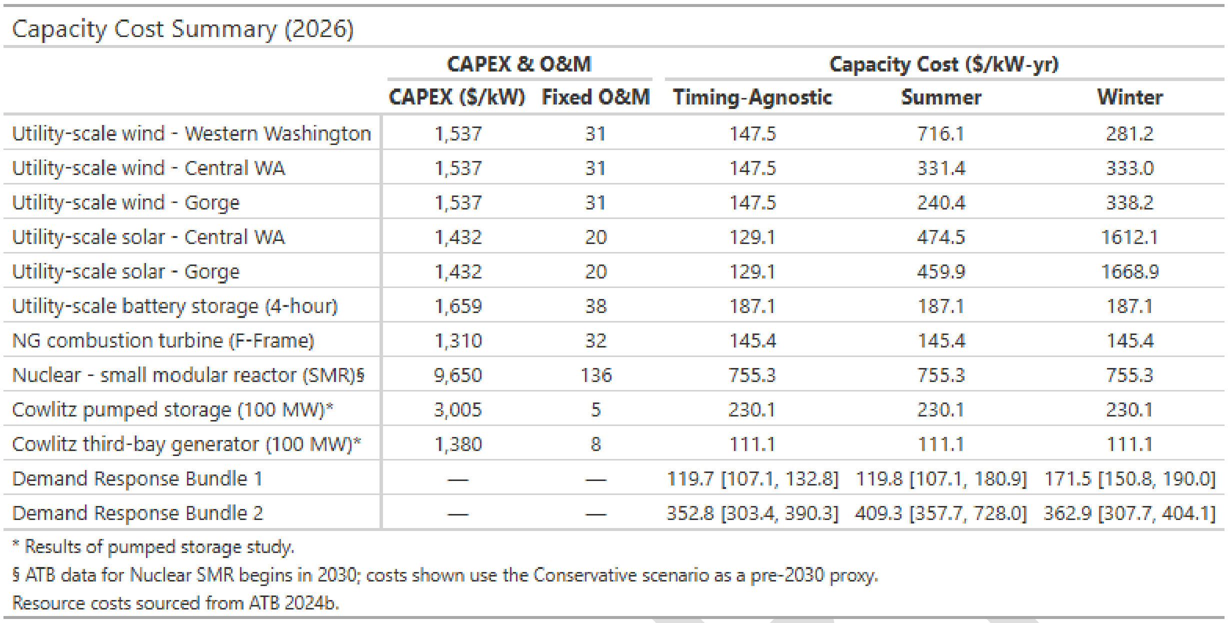
While a useful starting point, LCOE is not sufficient for identifying the optimal portfolio even when applied seasonally because it does not account for the capacity a resource provides or its dispatchability. Capacity costs reflect how much energy a resource can deliver during an hour of peak load. For variable resources like wind or solar, this means the energy they are expected to produce during that specific hour rather than their nameplate rating. Capacity costs can also be broken out by season. A timing-agnostic capacity cost simply reflects the maximum output a resource can deliver in any hour, regardless of when that hour falls. Summer and winter capacity costs, by contrast, reflect output during each season's peak loads.[30] Table 7-3 summarizes annual and a seasonal levelized cost of capacity for each candidate resource. Some evaluated resources (battery storage, pumped storage, additional hydro capacity, and demand response) provide capacity with no or even negative net energy, so Table 7-3 includes more resources than the energy cost comparison in Table 7-2.

---

that season. It answers: if you only charged this resource for its summer (or winter) cost share, what would each summer (or winter) MWh cost?"

[30] It is more challenging to estimate costs for natural gas peaking generation because some cost elements are not included in the ATB. Aside from construction, financing and variables costs, natural gas generators require firm gas delivery and some ability to store natural gas to be a firm capacity resources. Publicly available estimates of firm gas transmission vary widely from E3s published $43 to the NWPC power plan’s 2026 $6 with an additional storage capital expense. Furthermore, firm gas in the Pacific Northwest is described by regional utilities as ‘fully subscribed’ in the sense that it runs at max capacity during winter cold events, making acquiring such capacity more complicated or impossible without significant capital investment.

Table 7-3: Levelized cost of capacity for candidate resources



Capacity Cost Summary (2026)

	CAPEX & O&M		Capacity Cost ($/kW-yr)		
	CAPEX ($/kW)	**Fixed O&M**	**Timing-Agnostic**	**Summer**	**Winter**
Utility-scale wind - Western Washington	1,537	31	147.5	716.1	281.2
Utility-scale wind - Central WA	1,537	31	147.5	331.4	333.0
Utility-scale wind - Gorge	1,537	31	147.5	240.4	338.2
Utility-scale solar - Central WA	1,432	20	129.1	474.5	1612.1
Utility-scale solar - Gorge	1,432	20	129.1	459.9	1668.9
Utility-scale battery storage (4-hour)	1,659	38	187.1	187.1	187.1
NG combustion turbine (F-Frame)	1,310	32	145.4	145.4	145.4
Nuclear - small modular reactor (SMR)§	9,650	136	755.3	755.3	755.3
Cowlitz pumped storage (100 MW)*	3,005	5	230.1	230.1	230.1
Cowlitz third-bay generator (100 MW)*	1,380	8	111.1	111.1	111.1
Demand Response Bundle 1	—	—	119.7 [107.1, 132.8]	119.8 [107.1, 180.9]	171.5 [150.8, 190.0]
Demand Response Bundle 2	—	—	352.8 [303.4, 390.3]	409.3 [357.7, 728.0]	362.9 [307.7, 404.1]

* Results of pumped storage study.

§ ATB data for Nuclear SMR begins in 2030; costs shown use the Conservative scenario as a pre-2030 proxy.

Resource costs sourced from ATB 2024b.

7.4 Portfolio analysis results

To develop the set of potential resources, we first use our portfolio expansion model to select the least cost resource or set of resources from among the list described in Section 7.1. Our portfolio expansion model identifies wind generation as the lowest-cost resource needed to meet future energy needs under high electrification growth scenarios. The model tends to select more wind from Western Washington relative to other areas due to its strong winter generation patterns, but the model does also select some wind from other areas of the Pacific Northwest as well.

The portfolio expansion model identifies the least-cost set of energy resources but is not currently used to do the same for capacity resources. For capacity resources, we identify potential resource investments without an optimization tool. For some resources (for example, battery storage), we scale the size of the resource based on the size of the capacity shortfalls we see in our model output. For other resources, the relevant resource size was determined based on other studies conducted by Tacoma Power. Demand Response resource additions are determined based on our most recent Demand Response Potential Assessment (DRPA) described in Section 3.3. The size of hydro capacity additions (both conventional hydro and pumped storage hydro) is based on the Pumped Storage Feasibility Study at Tacoma Power’s Mossyrock Dam described in Section 3.6.

7.5 Portfolio analysis results

Once the set of portfolios has been identified, the new resources within each portfolio are added to the system model to recalculate system performance and analyze resource costs.

7.5.1 Resource adequacy results under base case scenario

Table 7-4 presents the final set of portfolios analyzed for the base case scenario. Although no energy adequacy shortfalls were identified in our base case scenario, we do consider an energy resource. We use the resource build from Electrification Scenario 2 as the energy resource build for the base case run.

Table 7-4: List of resource portfolios analyzed for base case scenario

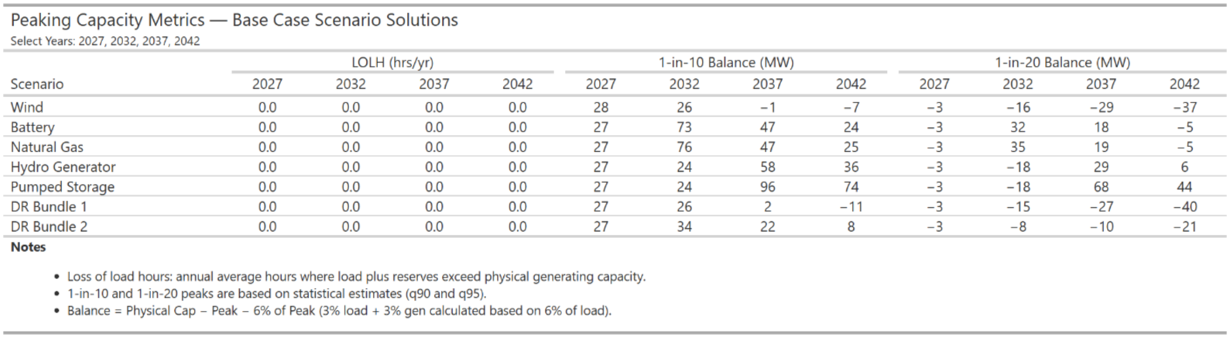
Portfolio Name	**Resource Additions**

Wind	Gradual build to 13 MW by 2037, 48 MW by 2040 and 58 mw by 2045 (build developed to fill Electrification Scenario 2 energy gaps)
Battery	50 MW battery storage by 2040
Natural Gas Peaker	50 MW natural gas peaking generation by 2040
Hydro Generator	100 MW Conventional Hydro Generator added at Cowlitz River Project in 2037
Pumped Storage	100 MW Pumped Storage Hydro Generation added at Cowlitz River Project in 2037
Demand Response (DR) Bundle 1	Bundle of demand response programs including only 2 lowest-cost resources from DRPA (gradual build over time)
Demand Response (DR) Bundle 2	Bundle of demand response programs including all but 2 highest-cost resources from DRPA (gradual build over time)

Table 7-5 presents capacity balance metrics from different potential resource additions for our base case scenario. We find that demand response is likely to be an effective component of our strategy to manage peak demand growth and the eventual intermittent shortfalls we see during years when generators are offline for rebuilds. The more limited and low-cost demand response bundle (Bundle 1) roughly halves projected 1 in 10 capacity balance deficits, and the more expansive and expensive bundle (Bundle 2) succeeds in fully covering projected shortfalls. By adding energy to the system and allowing us to hold on to more water, the wind resource provides some indirect capacity benefits, though it does not eliminate capacity gaps. The pumped storage and conventional hydro capacity additions both provide more than enough peaking capacity to cover projected gaps, as does the 50 MW battery.

It is important to note that a resource acquisition is just one potential solution to cover projected intermittent gaps. Other non-resource alternatives (for example, temporary contracts to purchase capacity from others for one season or potential strategies to reduce the duration of outages) must also be explored. Each of these strategies will have a cost and must be compared against the long-term costs and benefits of acquiring a new resource to cover the gaps. This broader set of alternative solutions is not analyzed in this IRP but will be analyzed outside of the IRP.

Table 7-5: Base case peaking capacity 1 in 10 peaking capacity balance under different resource options



Peaking Capacity Metrics — Base Case Scenario Solutions

Select Years: 2027, 2032, 2037, 2042

	LOLH (hrs/yr)				1-in-10 Balance (MW)				1-in-20 Balance (MW)			
Scenario	2027	2032	2037	2042	2027	2032	2037	2042	2027	2032	2037	2042
Wind	0.0	0.0	0.0	0.0	28	26	−1	−7	−3	−16	−29	−37
Battery	0.0	0.0	0.0	0.0	27	73	47	24	−3	32	18	−5
Natural Gas	0.0	0.0	0.0	0.0	27	76	47	25	−3	35	19	−5
Hydro Generator	0.0	0.0	0.0	0.0	27	24	58	36	−3	−18	29	6
Pumped Storage	0.0	0.0	0.0	0.0	27	24	96	74	−3	−18	68	44
DR Bundle 1	0.0	0.0	0.0	0.0	27	26	2	−11	−3	−15	−27	−40
DR Bundle 2	0.0	0.0	0.0	0.0	27	34	22	8	−3	−8	−10	−21

Notes

- Loss of load hours: annual average hours where load plus reserves exceed physical generating capacity.
- 1-in-10 and 1-in-20 peaks are based on statistical estimates (q90 and q95).
- Balance = Physical Cap − Peak − 6% of Peak (3% load + 3% gen calculated based on 6% of load).

7.5.2 Resource adequacy under high load risk scenarios

Table 7-6 and Table 7-7 present the final set of portfolios analyzed for Electrification Scenario 2 and 3, respectively. For these scenarios, we run some portfolios with a combination of resource additions along with individual resource additions because results from Section 6.4 suggest that these higher load growth scenarios will require adding both energy and capacity to the system to fill gaps. These combination portfolios include the relevant energy build identified through our portfolio expansion model, the addition of

100 MW of hydro capacity at Mossyrock Dam and demand response (DR Bundle 1 in Scenario 2 and the more expansive and expensive DR Bundle 2 in Scenario 3).

Table 7-6: Portfolio list for Electrification Scenario 2

Portfolio Name	Resource Additions
Wind	Gradual build, with 48 MW by 2040 and 58 mw by 2045
Battery	100 MW battery storage by 2040
Natural Gas Peaker	100 MW natural gas peaking generation by 2040
Hydro Generator	100 MW Conventional Hydro Generator added at Cowlitz River Project in 2037
Pumped Storage	100 MW Pumped Storage Hydro Generation added at Cowlitz River Project in 2037
Demand Response (DR) Bundle 1	Bundle of demand response programs including only 2 lowest-cost resources from DRPA (gradual build over time)
Demand Response (DR) Bundle 2	Bundle of demand response programs including all but 2 highest-cost resources from DRPA (gradual build over time)
Wind + DR Bundle 1 + Hydro Generator	Electrification Scenario 2 Energy + Demand Response Bundle 1 + 100 MW Pumped Storage Hydro Generation at Cowlitz River Project

Table 7-7: Portfolio list for Electrification Scenario 3

Portfolio Description	Resource Additions
Wind	Gradual build, with 27 MW by 2035, 84 MW by 2040 and 105 MW by 2045
Battery	60 MW by 2032, 120 MW by 2036, 200 MW by 2038
Natural Gas Peaker	60 MW by 2032, 120 MW by 2036, 200 MW by 2038
Hydro Generator	100 MW Conventional Hydro Generator added at Cowlitz River Project in 2037
Pumped Storage	100 MW Pumped Storage Hydro Generation added at Cowlitz River Project in 2037
Demand Response (DR) Bundle 1	Bundle of demand response programs including only 2 lowest-cost resources from DRPA (gradual build over time)
Demand Response (DR) Bundle 2	Bundle of demand response programs including all but 2 highest-cost resources from DRPA
Wind + DR Bundle 2 + Hydro Generator	Electrification Scenario 3 Energy + Demand Response Bundle 2 + 100 MW Conventional Hydro Generator (gradual build over time)

Figure 7-1, Figure 7-2, and Table 7-8 present the resource adequacy metrics for the solution runs for Electrification Scenario 2. Figure 7-3, Figure 7-4, and Table 7-9 present the resource adequacy metrics for the solution runs for Electrification Scenario 3.

Wind generation, the energy resource preferred by our model, succeeds in providing the energy needed across the month to mitigate winter and summer energy adequacy failures. Under Scenario 2 electrification, the additional winter energy provided to the system also helps stave off some sustained capacity risk and stabilizes our sustained capacity adequacy metric in all but the last year of the study period (2045). Under higher Scenario 3 electrification growth, the additional energy is not sufficient to mitigate sustained capacity adequacy risks as they continue to grow. While the wind resource helps our system by providing energy during times when water is limited, it does little to mitigate short-term peaking capacity balance risks in either scenario.

Demand response is helpful in reducing the magnitude and duration of sustained capacity risks under all scenarios. The more expansive portfolio of DR programs (Bundle 2) contributes enough capacity to stave off failure of our sustained capacity adequacy standard by two years under Scenario 2 electrification. It also improves our short-term peaking capacity balance in a drought year. However, our current DRPA does not identify enough resource potential to entirely mitigate capacity risks under high load growth scenarios. As a capacity-only resource, it does nothing by itself to improve our energy position.

Battery storage contributes significantly to reducing short-term peaking capacity risk and is expected to reduce peaking capacity risk by approximately the size of the battery. However, battery storage also has some limitations. While the large battery resources modeled reduce sustained capacity risks and mitigate short-term peaking capacity risks, they are less effective at mitigating sustained capacity shortfalls than the energy resource. Because it needs energy to charge, the battery further degrades our already-inadequate energy position by a little bit.

Initial modeling of **pumped storage hydro** at the Cowlitz River Project suggests that this resource is similar to battery storage in its contributions to our system. It provides short-term peaking capacity that is close to its nameplate capacity and helps mitigate sustained capacity risks. Because its duration is 10 hours, it is expected to be more effective than a four-hour battery at mitigating sustained capacity risks. However, it is not capable of fully mitigating these risks. It also requires energy from our system to charge and further degrades our winter energy position.

Initial modeling of **adding conventional hydro capacity** at Mossyrock Dam suggests that this resource could significantly improve our peaking and sustained capacity position but has different strengths and weaknesses relative to other capacity resources. The 100 MW hydro generator addition is expected to produce approximately 60 MW of peaking capacity under our extreme event analysis. The 100 MW hydro capacity addition is found to be less effective than battery storage or pumped storage hydro at mitigating peaking capacity risks because, like our other hydro generators, its capacity is dependent on lake elevations. Under winter drought conditions, elevation levels will be lower than normal, and hydro generator capacity is also lower than normal. However, it is more effective at mitigating sustained capacity risks under high load growth scenarios. Under Scenario 2 electrification a 100MW generator is enough to fully mitigate resource adequacy failures along these two dimensions. Under Scenario 3 electrification, it significantly reduces the number and duration of sustained capacity shortfalls but cannot fully mitigate shortfall risk by itself. Initial modeling does not suggest a change to our energy position. This contrasts with many other capacity-only resources like battery storage, which need energy from our system to charge.

The natural gas generator, which adds both capacity and energy to the system, fully mitigates adequacy shortfalls for peaking and sustained capacity. Our modeling assumption limiting its annual run time to no more than 15% of hours in the year and dispatching reduces its ability to also mitigate all energy shortfalls, though it is expected that it could do so in practice.[31]

---

[31] Because our model dispatches natural gas primarily based on market prices, and market prices are often higher during the summer in our price simulations, the natural gas generator over-produces in the summer relative to our energy needs and under-produces slightly in the winter. The result is that our summer LRB improves by more than necessary to meet our adequacy standard and our winter LRB does not improve by quite enough. Actual dispatch of the natural gas generator could look different in practice.

Taken together, these findings suggest that, apart from a natural gas generator, no single resource would be sufficient to solve both the energy and capacity adequacy challenges we might face under scenarios in which load grows significantly more quickly than anticipated. The portfolios combining energy resources and capacity resources are successful at mitigating energy, sustained capacity and peaking capacity shortfalls.

Figure 7-1: Scenario 2 energy resource adequacy metrics after modeled resource solutions

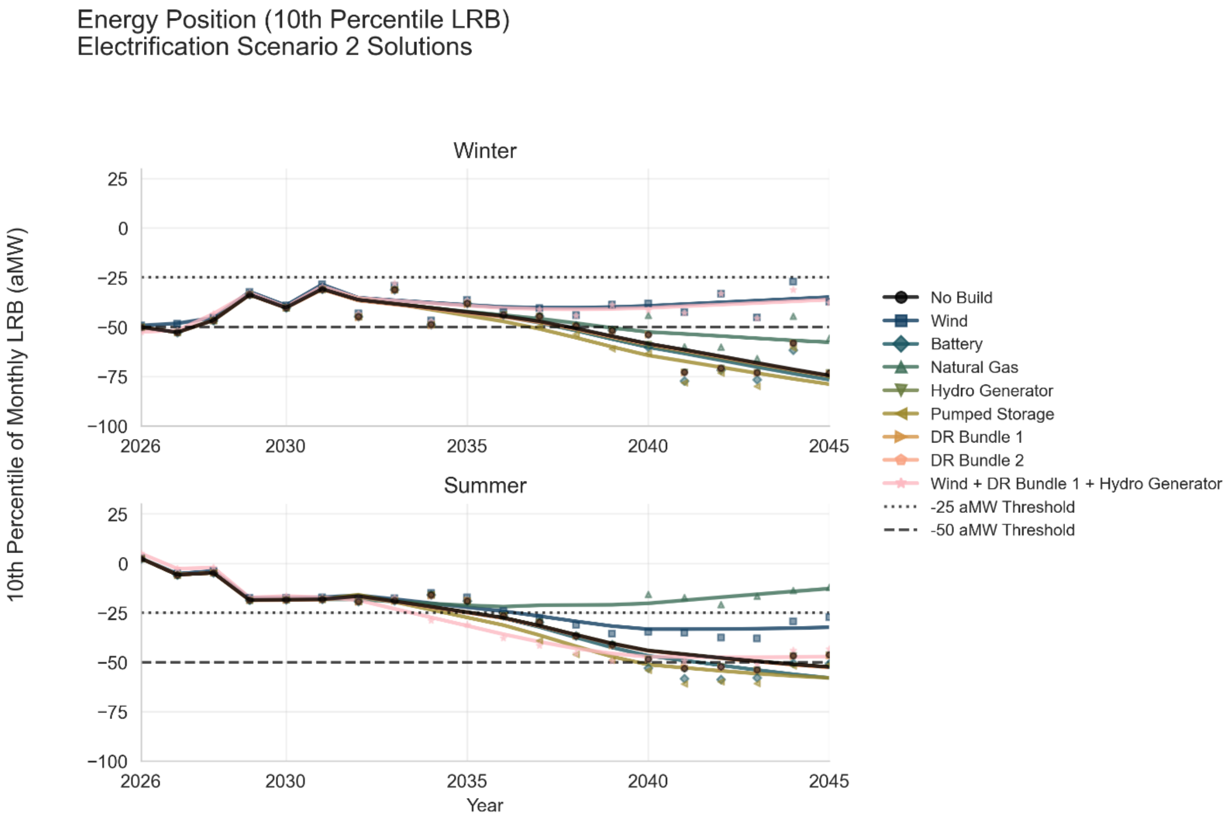


Figure 7-2: Scenario 2 sustained capacity resource adequacy metrics after modeled resource solutions

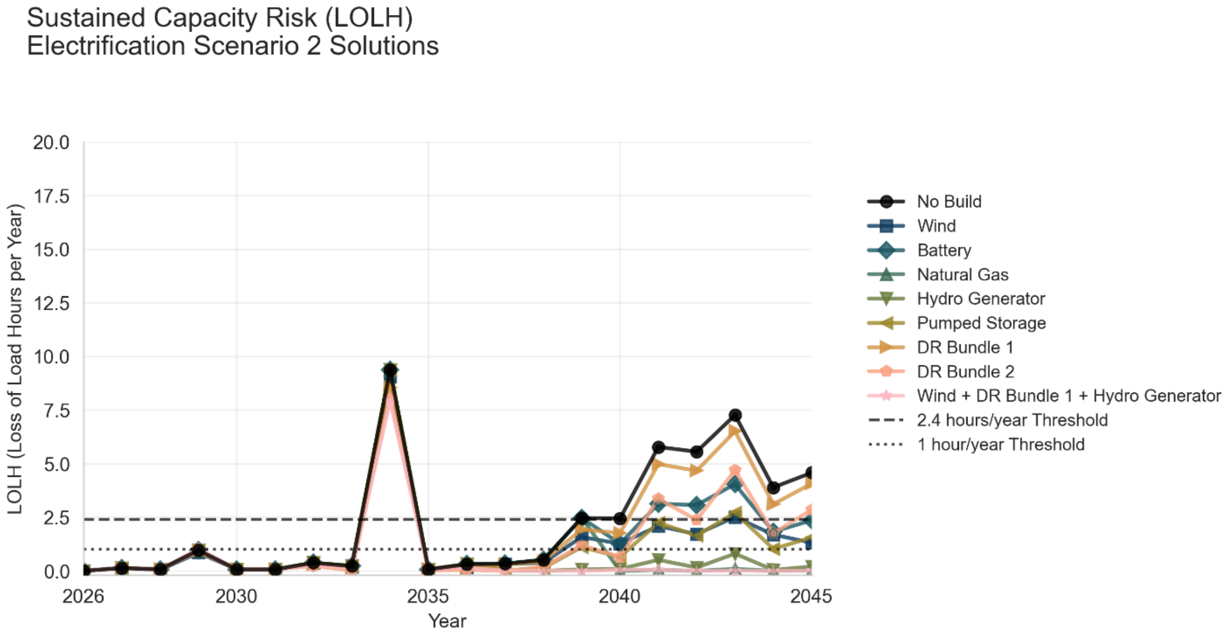
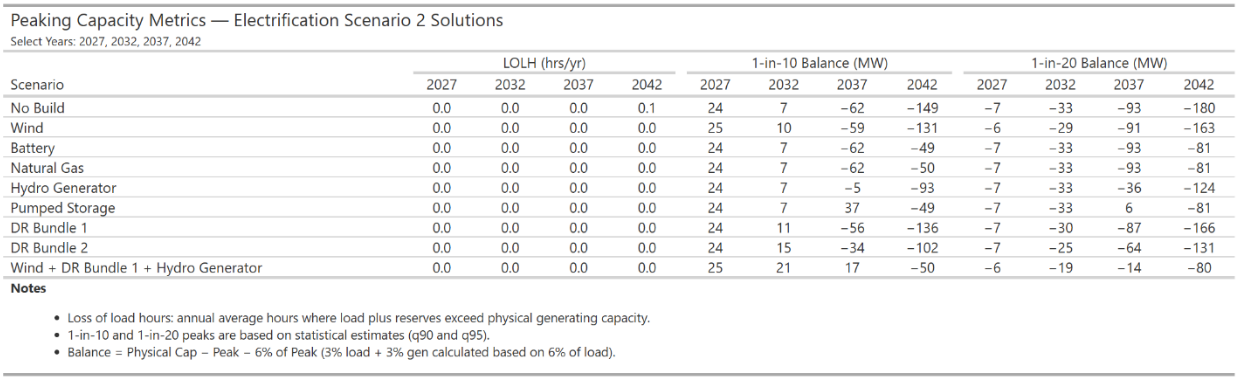


Table 7-8: Scenario 2 peaking capacity adequacy metrics after modeled resource builds



Peaking Capacity Metrics — Electrification Scenario 2 Solutions

Select Years: 2027, 2032, 2037, 2042

	LOLH (hrs/yr)				1-in-10 Balance (MW)				1-in-20 Balance (MW)			
Scenario	2027	2032	2037	2042	2027	2032	2037	2042	2027	2032	2037	2042
No Build	0.0	0.0	0.0	0.1	24	7	−62	−149	−7	−33	−93	−180
Wind	0.0	0.0	0.0	0.0	25	10	−59	−131	−6	−29	−91	−163
Battery	0.0	0.0	0.0	0.0	24	7	−62	−49	−7	−33	−93	−81
Natural Gas	0.0	0.0	0.0	0.0	24	7	−62	−50	−7	−33	−93	−81
Hydro Generator	0.0	0.0	0.0	0.0	24	7	−5	−93	−7	−33	−36	−124
Pumped Storage	0.0	0.0	0.0	0.0	24	7	37	−49	−7	−33	6	−81
DR Bundle 1	0.0	0.0	0.0	0.0	24	11	−56	−136	−7	−30	−87	−166
DR Bundle 2	0.0	0.0	0.0	0.0	24	15	−34	−102	−7	−25	−64	−131
Wind + DR Bundle 1 + Hydro Generator	0.0	0.0	0.0	0.0	25	21	17	−50	−6	−19	−14	−80

Notes

- Loss of load hours: annual average hours where load plus reserves exceed physical generating capacity.
- 1-in-10 and 1-in-20 peaks are based on statistical estimates (q90 and q95).
- Balance = Physical Cap − Peak − 6% of Peak (3% load + 3% gen calculated based on 6% of load).

Figure 7-3: Scenario 3 energy resource adequacy metric after modeled resource solutions

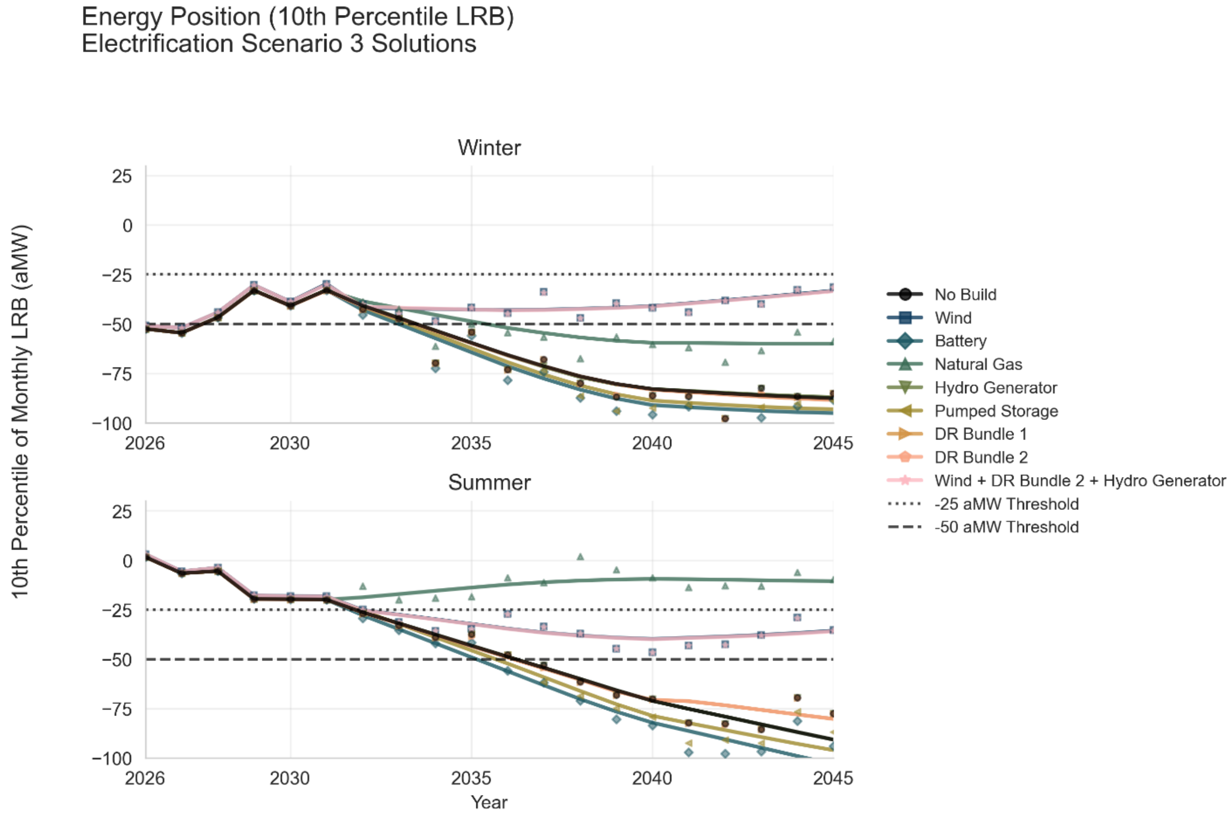


Figure 7-4: Scenario 3 sustained capacity resource adequacy metric after modeled resource solutions

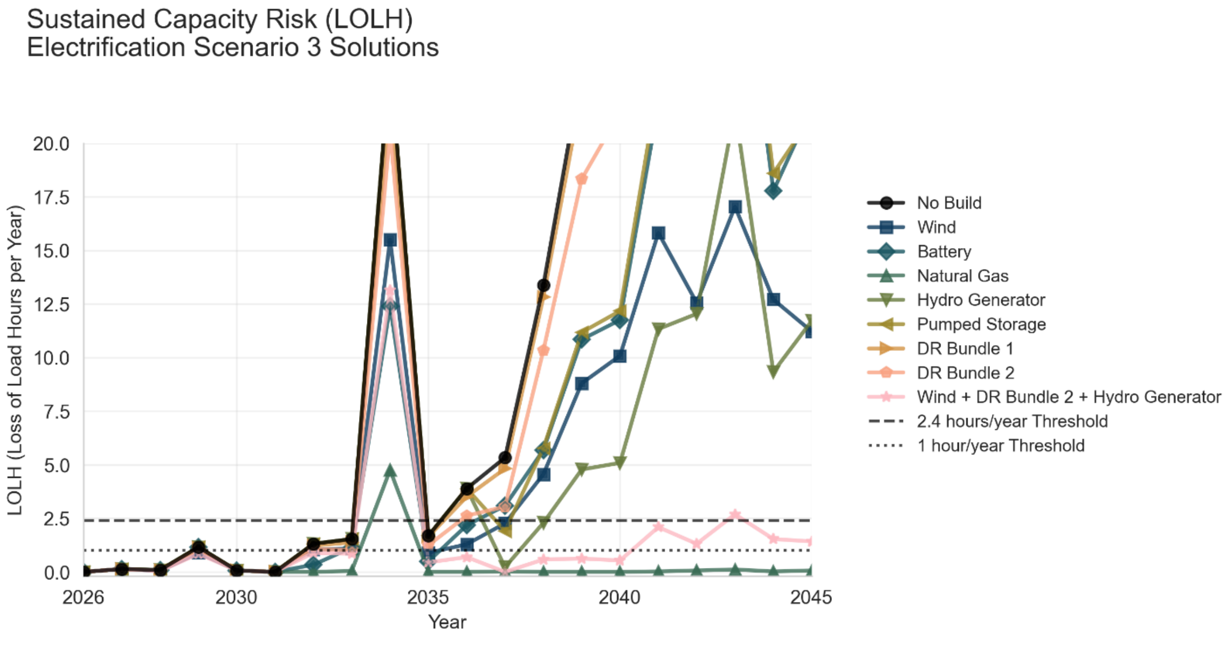
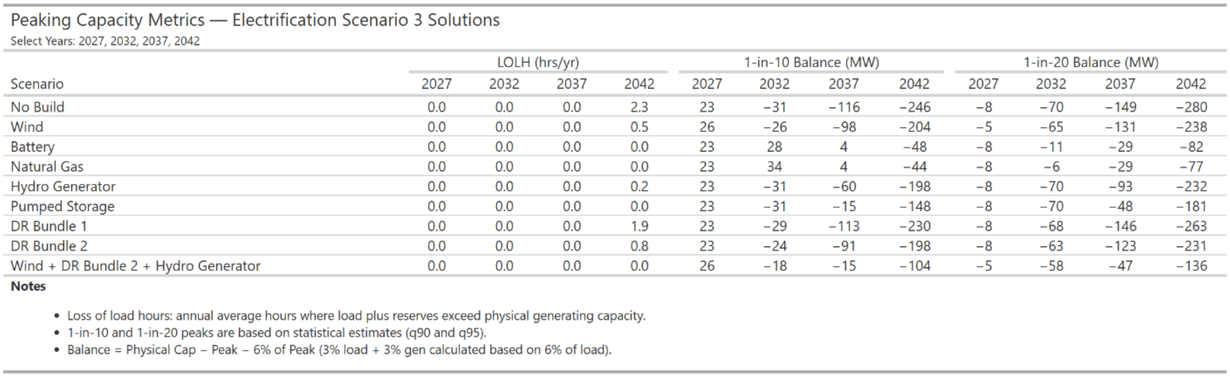


Table 7-9: Scenario 3 peaking capacity resource adequacy metrics after modeled resource solutions



Peaking Capacity Metrics — Electrification Scenario 3 Solutions

Select Years: 2027, 2032, 2037, 2042

	LOLH (hrs/yr)				1-in-10 Balance (MW)				1-in-20 Balance (MW)			
Scenario	2027	2032	2037	2042	2027	2032	2037	2042	2027	2032	2037	2042
No Build	0.0	0.0	0.0	2.3	23	−31	−116	−246	−8	−70	−149	−280
Wind	0.0	0.0	0.0	0.5	26	−26	−98	−204	−5	−65	−131	−238
Battery	0.0	0.0	0.0	0.0	23	28	4	−48	−8	−11	−29	−82
Natural Gas	0.0	0.0	0.0	0.0	23	34	4	−44	−8	−6	−29	−77
Hydro Generator	0.0	0.0	0.0	0.2	23	−31	−60	−198	−8	−70	−93	−232
Pumped Storage	0.0	0.0	0.0	0.0	23	−31	−15	−148	−8	−70	−48	−181
DR Bundle 1	0.0	0.0	0.0	1.9	23	−29	−113	−230	−8	−68	−146	−263
DR Bundle 2	0.0	0.0	0.0	0.8	23	−24	−91	−198	−8	−63	−123	−231
Wind + DR Bundle 2 + Hydro Generator	0.0	0.0	0.0	0.0	26	−18	−15	−104	−5	−58	−47	−136

Notes

- Loss of load hours: annual average hours where load plus reserves exceed physical generating capacity.
- 1-in-10 and 1-in-20 peaks are based on statistical estimates (q90 and q95).
- Balance = Physical Cap − Peak − 6% of Peak (3% load + 3% gen calculated based on 6% of load).

7.5.3 Cost

In this section, we compare the costs of different resource options. To do so, we look at costs using several different lenses:

1. **Gross resource cost:** Under this lens, we look the total present value cost of acquiring each resource portfolio. We compare this to our projected power supply and transmission budget to understand the magnitude of the impacts of the investment.
2. **Net utility cost:** Under this lens, we account for the potential value of revenues from a resource during times when it is not needed for our own resource adequacy. These revenues can help to offset the gross cost of acquiring the new resource.
3. **Market risk exposure:** We also examine how each resource alternative changes our exposure to wholesale market risk.

7.5.3.1 Gross resource cost

Figure 7-5 compares each portfolio's levelized cost of energy and capacity[32]. On a levelized cost of energy (LCOE) basis, the wind portfolios are the lowest-cost options across all scenarios. For instance, the least-cost buildout for electrification scenario 3 which builds wind in all three major wind locations is $55 per MWh. However, these energy-only portfolios are less efficient at providing capacity during peak usage within the BA than any of the capacity-only portfolios[33].

Because energy resources can provide energy when Tacoma's hydro projects face water scarcity, these resources provide a higher benefit to system capacity than their capacity contribution alone would imply. Nevertheless, their costs for capacity remain higher than dedicated, top-performing capacity resources. Our lowest-cost capacity resources are internal specialty options: demand response and upgrading our existing hydroelectric facilities. The lowest-cost option on a levelized cost of capacity basis is a small demand response package (DR Bundle 1) at $87/kW-yr, followed closely by the addition of a new 100 MW generator at Mossyrock Dam.[34]

---

[32] Peak capacity contribution is determined by resource type. Dispatchable resources like natural gas and batteries are credited with their full nameplate capacity, while the contribution from variable resources like solar and wind is based on their simulated average power output during annual system peak hours.

[33] Because energy resources can help provide energy during times when water is scarce, energy portfolios provide a stronger portfolio-level capacity boost, the levelized cost of capacity of these energy resources is smaller when evaluated in conjunction with our system than when evaluated independently but their levelized cost of capacity is still higher than the best-performing capacity resources.

[34] The Mossyrock Dam hydro generator addition could be even lower cost if IRA funds or other grant opportunities finance part of the project's costs.

While natural gas peaking generation often have competitive capacity value combined with some limited energy benefits, they are not the least-cost option for either dimension individually.[35] By combining specific low-cost capacity and energy buildouts, we can create hybrid portfolios that have a lower LCOE and feature capacity costs that approach those of a natural gas peaking plant.

Figure 7-5: Levelized cost comparison of portfolio alternatives

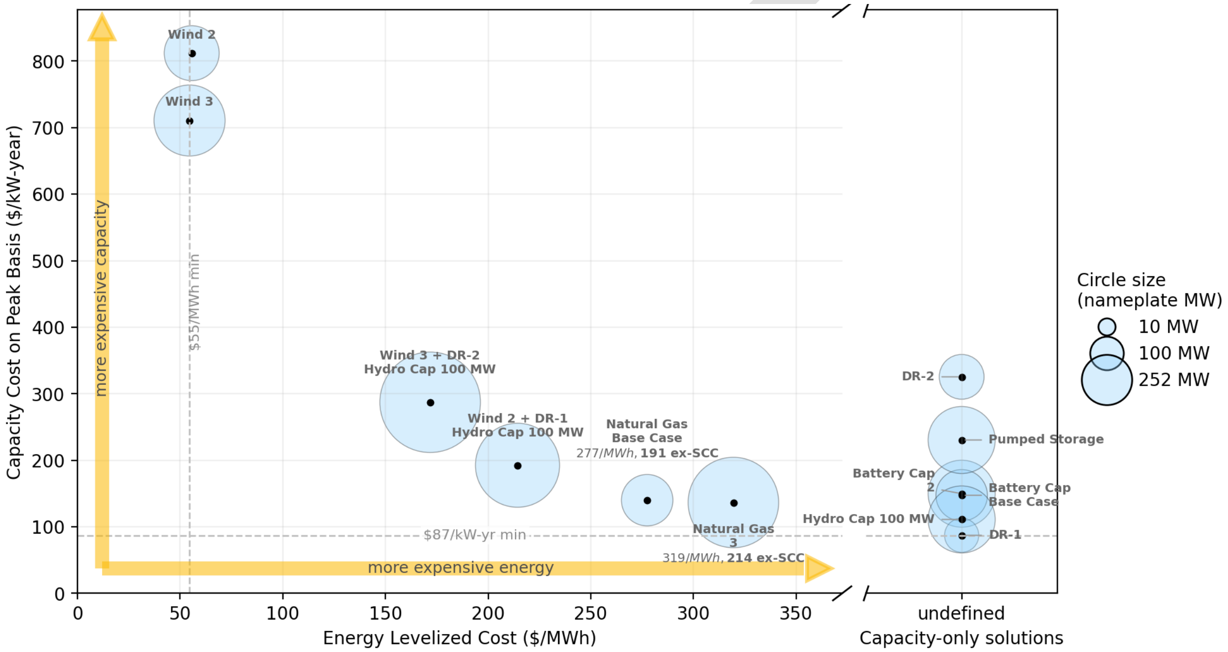


Figure 7-6 presents total 20-year present value cost of each potential resource addition, both in absolute dollars and as an estimated share of total existing resource costs. [36]

Demand Response Bundle 1 (DR-1)[37] is the least costly option by both metrics. Demand Response Bundle 2 (DR-2) is a larger portfolio of demand response programs and thus has a higher levelized cost, but its total investment is smaller than other capital-intensive capacity additions. The 100 MW hydro generator addition at Mossyrock Dam has a very low levelized cost, but its large initial investment creates a greater impact on total costs than some smaller-scaled alternatives. Given our expected capacity need is relatively small, we anticipate using a right-sized battery storage solution to solve the shortfalls will end up being somewhat more expensive per-kw than if we invested in a larger battery.

---

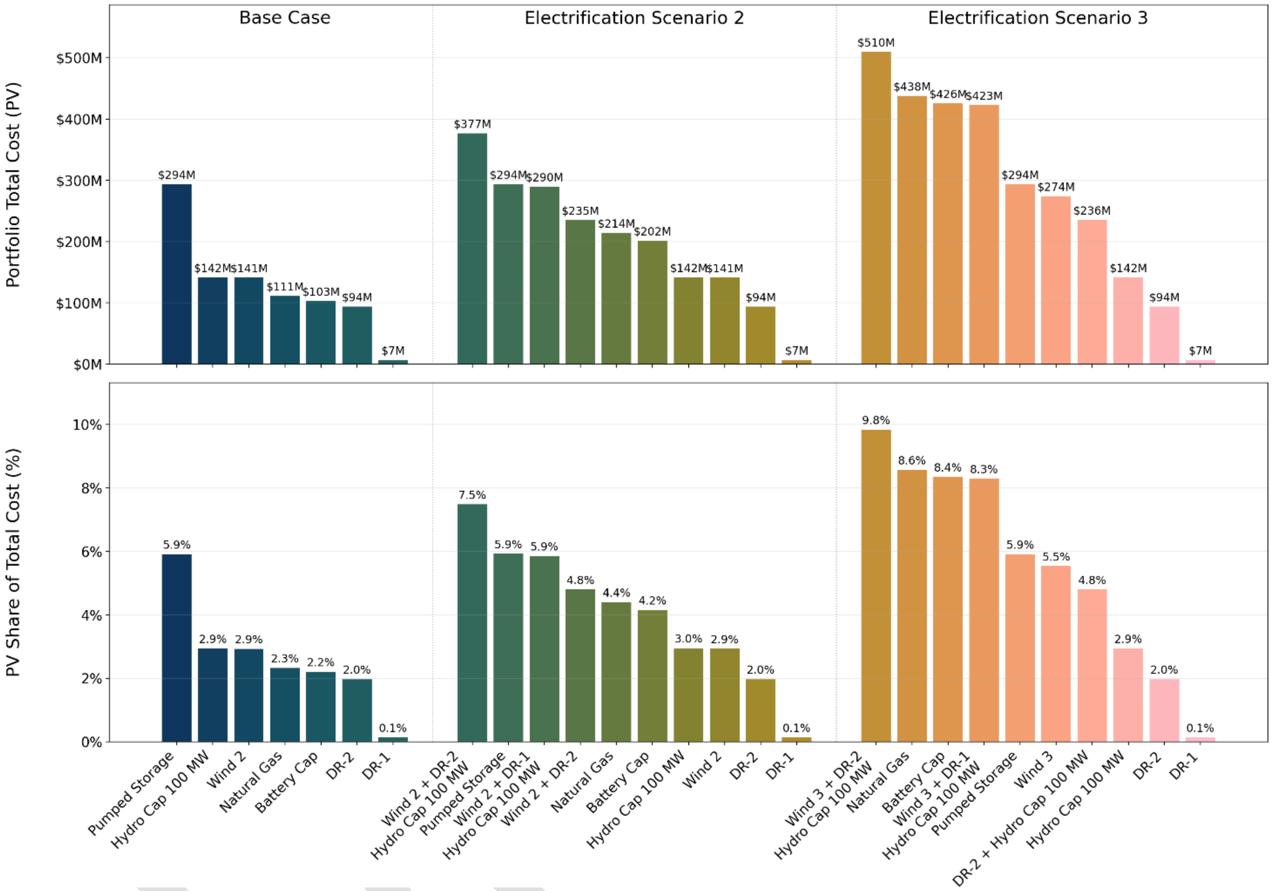
[35] The wide range of costs for natural gas peaking generators in Figure 7-5 come from differences in load scenario; which can change when the generator is chosen to dispatch, gas prices during those dispatch periods, and whether or not Washington‘s projected social cost of carbon is included as a variable cost.

[36] Annual costs are expected to rise over the next twenty years even before accounting for potential resource additions. This is due to combination of factors. One of the most prominent contributions to this trend is the fact that our Bonneville contract purchases scale to meet our load. As load grows, we purchase more power from BPA, which increases resource costs. Different load growth scenarios produce different total costs for our current resource stack.

[37] Unlike all other resources in Figure 7-5, demand response bundles, reduce peak demand as a function of load. As a result, the relative cost effectiveness changes across scenarios. In figure 76 we use the base case load to estimate capacity costs for both bundles

New resource costs appear low in part because they are concentrated in the later part of our 20-year study period. Since our energy and capacity needs arise late in the period, their apparent cost is reduced by both financial discounting and because only a fraction of their total cost falls before the end of the study period.[38]

Figure 7-6: Gross present value costs of resource alternatives



7.5.3.2 Net Utility Cost

Figure 7-7 presents projected 20-year portfolio costs net of wholesale revenues[39] for each portfolio compared to a no-buildout scenario. For the no-buildout scenario, we assume that any energy gaps between load and generation are filled with market purchases. It is important to note that this rests on the assumption that energy will always be available for purchase, which is not guaranteed.

In our model, adding new resources generally increases net costs because the wholesale energy revenue they generate is typically insufficient to offset their full cost. Because our analysis only includes energy market revenues and omits other potential power-market revenue streams from transmission and capacity, the adjustment for wholesale energy revenues benefits wind energy more than the capacity resources. Including capacity revenues and costs would likely improve the financial case for larger, capacity-heavy resources and

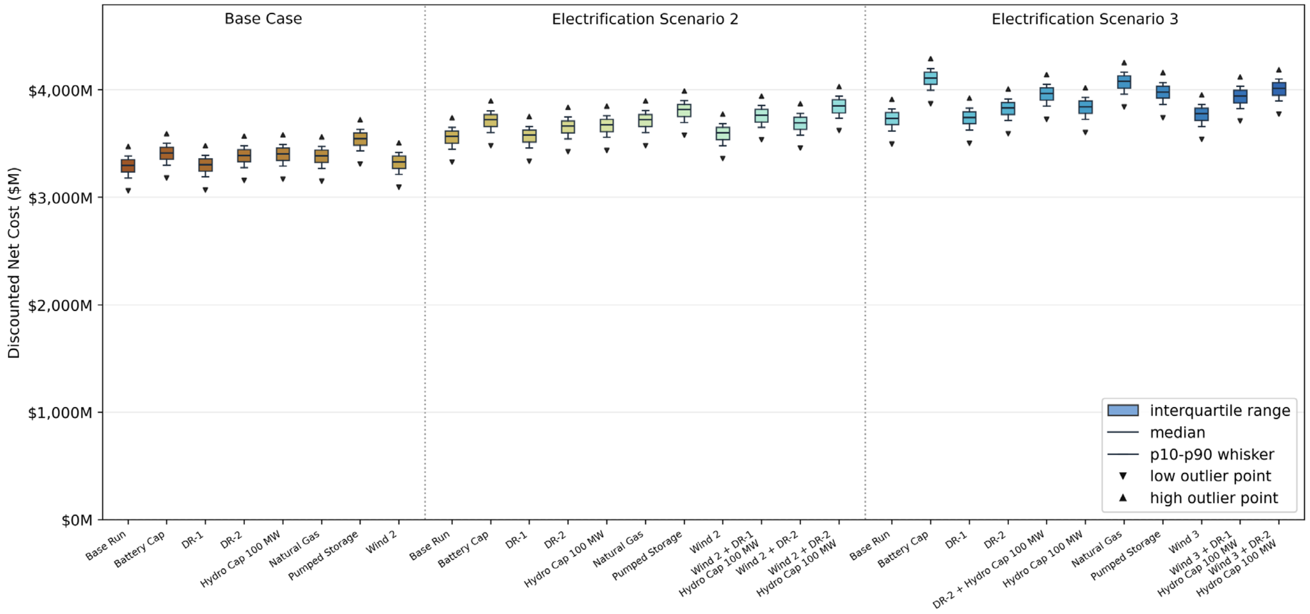
---

[38] Assume a 2.5% discount rate on total costs to reflect real interest rates paid on municipal bonds

[39] Our planning model consistently underestimates actual revenues by assuming that all revenue comes through a single real-time market. The model excludes several revenue streams: transmission sales, bilateral day-ahead transactions, term trades, arbitrage opportunities between EIM and bilateral real time markets, and premiums for low-carbon power.

provide a more complete picture of their value.

Figure 7-7: Comparison of 20-year net present value resource costs across load scenarios and resource alternatives



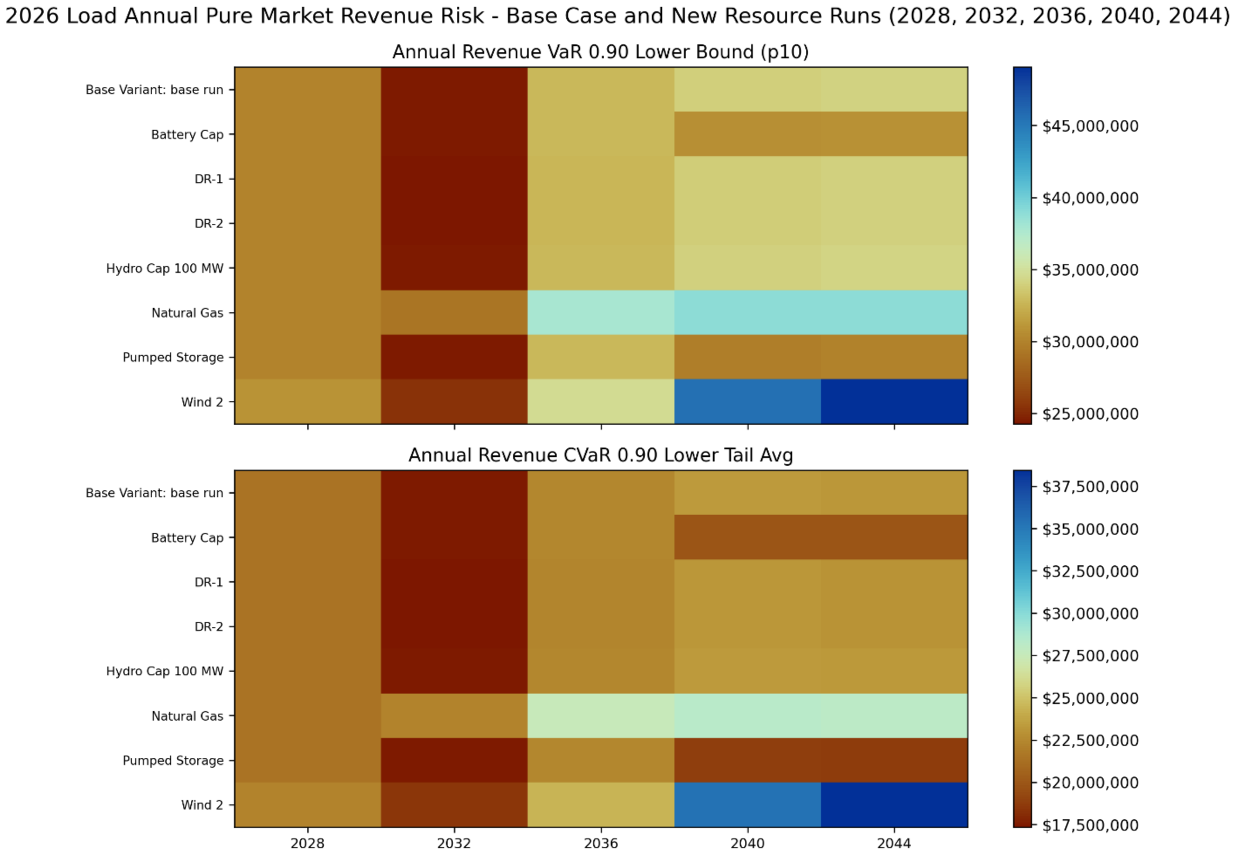
7.5.3.3 Revenue risk exposure under different resource alternatives

We also aim to limit exposure to downside risk, both within single hours and for the total portfolio. We measure this tail risk using Value at Risk (VaR) and Conditional Value at Risk (cVaR). For a given year, the VaR is defined as the revenue level of the 10th percentile of our simulated outcomes.

Figure 78 compares these revenue risk metrics across resource alternatives in our base case. Before accounting for any new resources, we project the portfolio's downside risk profile will improve over the study period. This is evidenced by the 10th percentile real revenue (VaR) increasing from approximately $35 million in 2025 to $40 million in 2044, indicating a better outcome ceiling amongst worst-case scenarios. The Conditional Value at Risk (cVaR), representing the average revenues less than or equal to the 10th percentile, is projected to increase at a slower rate, from $22 million to $24 million. This suggests that while the threshold for a "bad" year is rising, the average severity of those bad years is improving at a slower rate.

We find that storage capacity resources, like batteries and pumped hydro, tend to increase our tail-end market risk exposure compared to taking no action. The mechanism appears to be that Tacoma's generation fleet already has substantial flexibility from existing storage hydro, so the marginal value of adding more storage is limited. New storage therefore provides little additional hedge value, but still reduces net energy through round-trip efficiency losses, worsening tail-end revenue outcomes. In contrast, both the energy-only wind and the natural gas additions improve tail-end risk, with wind portfolios providing the greatest improvement. Capacity resources that do not require charging, such as demand response and additional hydro capacity, have little effect on our tail-end revenue risk profile.

Figure 7-8: Tail-end market risk exposure under resource alternatives



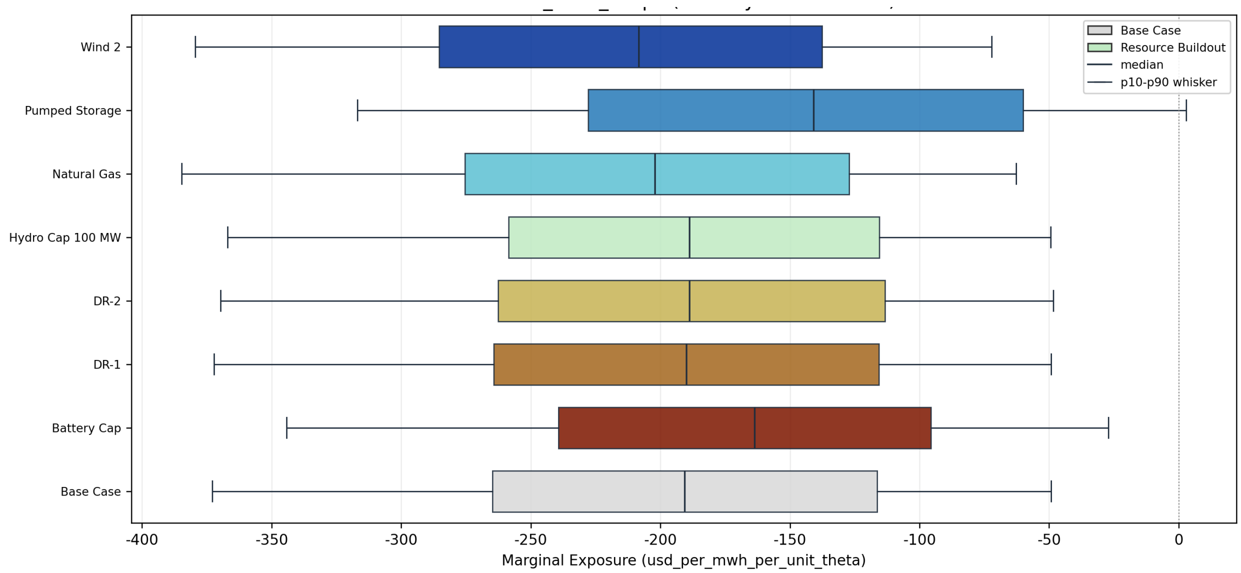
A key benefit of energy storage is its ability to hedge against future price decreases driven by expanding regional solar generation. As more solar is built, it can suppress midday prices, widening the arbitrage opportunity between cheap daytime energy and expensive evening peaks. Storage capitalizes on this by charging during low-cost hours and discharging during high-value hours. To test this, we apply a "solar-shaped" price stress to our portfolios, simulating a world with significant midday price cannibalization.[40] We then measure the resulting change in portfolio value. Portfolios with effective storage see improved financial performance under this stress, while those with inflexible midday generation suffer losses.[41] This allows us to rank each portfolio's relative vulnerability in a renewable-profile sensitive price regime.

---

[40] We perturb hourly prices P_t using the stress $P'_t = P_t + \theta \cdot g_{h(t)}$. Here, θ is the stress magnitude in \$/MWh, with $\theta > 0$ representing a solar-saturated scenario. The term $g_{h(t)}$ is a dimensionless hourly shape derived from the average solar capacity factor s_h and defined as $g_h = -\frac{s_h}{\text{mean}_h s_h}$. This construction makes $g_{h(t)}$ most negative during peak solar hours, zero at night, and average to -1. Consequently, a positive stress θ lowers the average annual price by θ \$/MWh, with the reduction concentrated in solar-productive hours. This construction makes g_h most negative during peak solar hours, zero at night, and average to -1. Consequently, a positive stress θ lowers the average annual price by θ \$/MWh, with the reduction concentrated in solar-productive hours.

[41] Storage benefits in this marginal change exceed those from a simple flat hourly price decrease, indicating particular efficiency under VER-driven price effects rather than due to a lower cost of charging

Figure 7-9: Revenue sensitivity to increase in grid-wide solar buildout



8 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.

9 Resource strategy

Our 2026 IRP identifies conservation and demand response as our preferred investment resources for now. The IRP does not recommend acquiring any new supply-side resources at this time but does identify a need for further investigation into supply-side opportunities to mitigate potential future capacity risks that begin to emerge in the early 2040s. The 2026 IRP resource strategy is described in more detail below.

1. **Continue to invest in cost-effective conservation:** We have a long history of working with our customers to invest in cost-effective conservation measures, and we must continue this collaboration with our customers. We plan to continue to invest in all conservation when it is feasible and cost-effective to do so. Our most recent Conservation Potential Assessment (CPA) set a target of 26,214 MWh (approximately 3 average megawatts, or aMW) over 2026 and 2027 and identifies 131,068 MWh (approximately 15 aMW) of cost-effective conservation potential over the next ten years. The two and ten-year potentials are equivalent to approximately 0.6% and 2.9% of expected 2026 load, respectively. We will continue to update our assessment every two years and re-evaluate existing and new conservation opportunities.
2. **Ramp up demand response programs:** As our capacity position tightens over time, we will need to expand our work with customers into demand response to help manage projected growth in peak demand. Our Demand Response Potential Assessment (DRPA) suggests that approximately 8 to 14 MW of winter demand response opportunities may be available by 2035 at a relatively low cost when compared to other capacity resources. To ensure we are progressively building the capability to offer demand response in the future when we need it, we plan to initiate at least 2 new demand response pilots and acquire 0.6 MW over the next two years and 12 MW of demand response over the next ten years.
3. **Continue our work to restore Riffe Lake elevation by 2031:** On the supply-side, we will continue to seek authorization from the Federal Energy Regulatory Commission (FERC) to restore Riffe Lake elevation to full pool (778.5 feet), which will restore approximately 35 MW of capacity to our system.
4. **Develop a strategy for mitigating intermittent capacity risks during generator rebuilds:** We find that in certain cases, long-duration outages required for the rebuild projects under the modernization program schedule create peaking capacity risks for our system that must be mitigated. Our IRP identifies resource opportunities to mitigate these risks, but acquiring a new power supply resource is not the only option for small, intermittent capacity risks of the nature we identify. Our two-year action plan includes work to analyze non-resource alternatives (for example, single-year contracts for a small amount of capacity) to cover these intermittent capacity risks during generator rebuilds. This work will inform a longer-term effort to develop and refine our strategy for mitigating these risks.
5. **Continue to explore opportunities to build upon existing hydro system:** We find that adding a conventional generator at Mossyrock Dam has the potential to be a promising resource to help meet the growing future capacity needs of our customers and the region. More detailed analysis will be needed to fully understand the full range of benefits and costs of this resource option. We plan to conduct further analysis into the potential feasibility, costs and benefits of this resource option before our next IRP and, if this option continues to look promising, determine what additional studies are necessary and appropriate to inform a decision. Any effort to make this kind of enhancement at the Cowlitz River Project would necessarily be tied to our work to relicense the project.

Renewal of existing transmission rights leaves us with sufficient access to transmission to meet customer demand currently and will continue to be sufficient to accommodate our recommended resource portfolio.

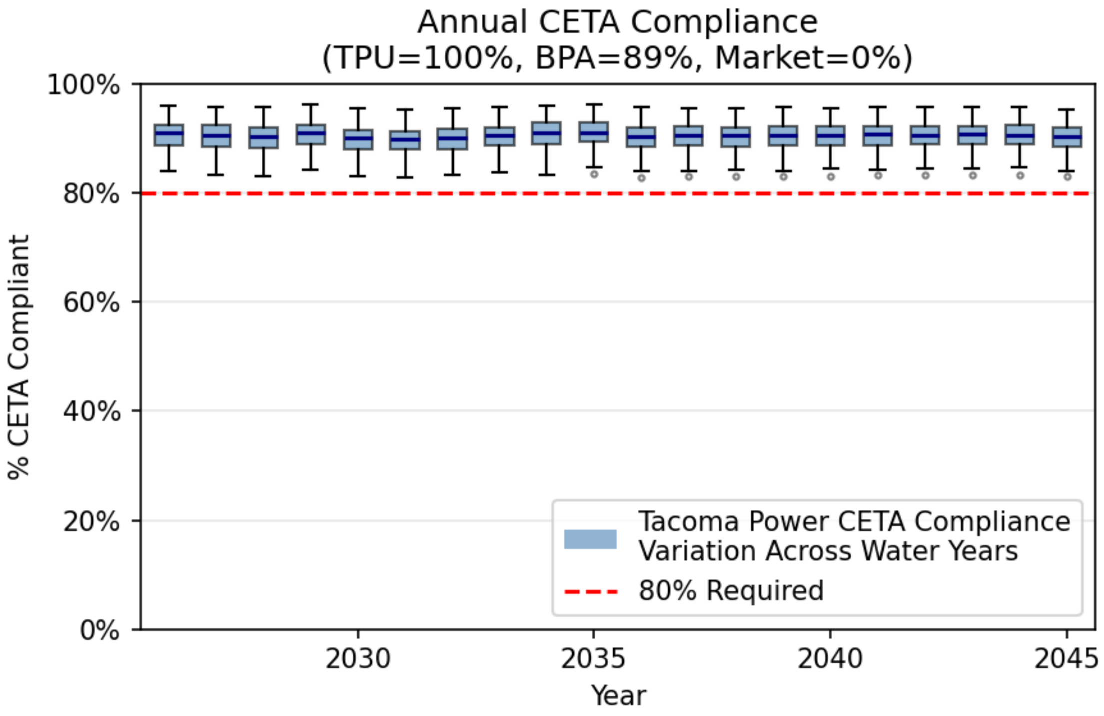
9.1 Compliance position under recommended strategy

9.1.1 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 within each hour up to a maximum of load in that hour and sum up all those megawatt-hours across the year. That number is divided to the total megawatt hours of energy demanded by customers within the simulation-year to approximate the share of retail electric load served by renewable and non-emitting output. Since hydropower is a non-emitting resource, 100% of our owned hydropower generation and non-BPA hydropower contracts are counted towards CETA compliance. We assume that 89% of the generation received from BPA counts towards CETA compliance based on a BPA emissions factor of 0.0497 MT CO_2e per MWh based on BPA's California Air Resources Board, Asset-Controlling Supplier (ACS) System Emission Factor for Data Year 2026[42]. Figure 9-1 presents results for each simulation year across the 20-year period for our base case load assumptions. The worst outcomes consistently exceed the 80% standard, demonstrating that our generating portfolio is capable of serving at least 80% of our retail load over each four-year compliance period.

Figure 9-1: Annual compliance with 80% renewable and non-emitting standard



9.1.2 WRAP forward showing position

It is critical that we meet our forward showing program 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.

WRAP supports regional grid reliability by requiring each participant to demonstrate enough dependable capacity during high-risk months. Tacoma Power can meet its share of that regional requirement with accredited capacity from owned resources or qualifying contracts. The amount Tacoma must show each

---

[42] https://ww2.arb.ca.gov/mrr-acs

month is based on a WPP-defined 1-in-2, or P50, peak load forecast using Tacoma Power's historical data, plus a planning reserve margin developed through WRAP's loss-of-load-expectation study. Because the requirement changes by month, Tacoma must be able to meet its obligation in each applicable summer and winter forward-showing month. Analyses of our WRAP forward showing position are consistent with our short-term peaking capacity analyses. We expect to be able to pass our winter forward showing requirements under most scenarios, though our position becomes tighter as electrification increases peak loads. Our winter WRAP position becomes especially tight during periods when generators are offline for extended rebuild work. Other maintenance outages may result in WRAP capacity shortfalls if our capacity obligation is especially high and the timing of these planned outages is not carefully managed.

10 Action plan

Table 10-2 summarizes our two-year action plan and our ten-year Clean Energy Action Plan. The table identifies actions we will take to invest in and explore customer-side resources and supply-side resources.

10.1 Two-year action plan

First and foremost on the customer side, we must continue to invest in all conservation when it feasible and cost-effective to do so. Our most recent Conservation Potential Assessment (CPA) set a target of 26,214 MWh (approximately 3 aMW) over 2026 and 2027. The target was approved by the Tacoma Public Utilities Board on August 13, 2025. To ensure we are progressively building the capability to offer demand response in the future when we need it, we plan to initiate at least 2 new demand response pilots over the next two years and acquire 0.6 MW of demand response.

On the supply-side, we will continue to seek FERC authorization to restore Riffe Lake elevation to full pool (778.5 feet), which will restore 35 MW of capacity to our system.

In Section 6, we find that long-duration outages required for the rebuild projects under the modernization program schedule are likely to create peaking capacity risks for our system that must be mitigated. Our IRP identifies resource opportunities to mitigate these risks, but acquiring a new power supply resource is not the only option for small, intermittent capacity risks of the nature we identify. Our two-year action plan includes work to analyze non-resource alternatives (for example, single-year contracts for a small amount of capacity) to cover these intermittent capacity risks during generator rebuilds. This work will inform a longer-term effort to develop and refine our strategy for mitigating these risks.

We also find that adding a conventional hydro generator at Mossyrock Dam may be a promising potential resource to help meet the growing future capacity needs of our customers and the region. More detailed analysis will be needed to fully understand the full range of benefits and costs of this resource option. We plan to conduct further analysis into the potential feasibility, costs and benefits of this resource option before our next IRP.

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 10-2 and are described in more detail below.

First and foremost on the customer side, we will continue to invest in all conservation when it feasible and cost-effective to do so. Our most recent CPA identifies 131,068 MWh (approximately 15 aMW) of cost-effective conservation potential over the next ten years. 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 DRPA suggests that approximately 8 to 14 MW of winter demand response opportunities may be available by 2035 at a relatively low cost when compared to other capacity resources, and our analysis suggests that these opportunities would contribute to relieving the growing capacity pressures we project for our system. Our ten-year action plan includes acquisition of 12 MW of demand response.

First and foremost on the supply-side, we plan to restore Riffe Lake to full pool once we receive FERC authorization to do so. Our target date for restoration is 2031. Second, we will build upon work to analyze non-resource alternatives to cover intermittent capacity risks during generator rebuilds and develop and continuously refine a long-term strategy for mitigating these risks. Finally, we plan to continuously evaluate opportunities to incrementally add a small amount of capacity to some of our generators during the planning stage of each rebuild.

10.2.1 Assessment of energy and nonenergy benefits and reductions of burdens to named communities

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.” In accordance with CETA requirements, we use the Washington State Department of Health (DOH) cumulative impact analysis[43] to identify Highly Impacted Communities. 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. For the 2026–2029 CEIP[44], we adopted a community-informed, data-driven approach to defining and identifying vulnerable populations within our service area. This represents a deliberate shift away from deficit-based language that is often used toward a framework that emphasizes systemic drivers of risk. Through this public process, our community defined Vulnerable Populations as customers meeting one or more of the following criteria:

- Located in an area with “Very Low” Environmental Health AND Economic components of the Tacoma Equity Index
- Located in a heat island
- Unable to pay bills (at least one service disconnection in a year or a credit worthiness score of six or more)
- Low-income senior or disabled (enrolled in LIE or BCAP discount rates)
- Relies on electric medical equipment

Tacoma Power also updated the set of indicators we track to include specific actions that provide more meaningful outcomes for vulnerable populations and highly impacted communities. Through the public process, the community recommended metrics span three equity areas: affordability, reliability, and direct customer benefits. Table 10-1 presents our updated indicators - each with associated specific actions and measurable outcome metrics. These indicators span CETA categories of reduction of burdens, equitable distribution of energy and non-energy benefits, and reliability.

---

[43] 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

[44] Available on our IRP webpage: https://www.mytpu.org/about-tpu/services/power/integrated-resource-plan

Our CEAP is expected to maintain resource adequacy at the lowest possible cost to our customers. As such, our CEAP directly contributes to maintaining our reliability metrics over time and will indirectly contribute to maintaining affordability.

Table 10-1: 2026-2029 CEIP indicators, specific actions and outcome metrics

Indicator	Specific Actions	Outcome Metrics
High-quality community input influencing energy planning	• Offer focused one-on-one conversations when group meetings are inaccessible to the public or overburdened nonprofit staff • Provide financial incentives to defray the cost of community participation	• Increased participation in the planning process among groups with historic barriers (residential customers, nonprofit staff, people with lived experience, vulnerable populations) • Evidence that stakeholder input is driving utility decisions
Renters participating in Customer Energy Solution Programs	• Expand the income-qualified renter program to allow more access to conservation program benefits	• Increase the number of renters benefitting from lower bills through customer energy solutions programs
Projects and programs evaluated for equity impacts across three equity areas	• Evaluate new and proposed services with an equity framework that prioritizes affordability, reliability, and direct benefits for Named Communities • Grid modernization projects evaluated using the Equity Analysis Framework (EAF) to influence project prioritization	**Affordability** • % of customers with service disconnections or bills sent to collections (owner vs. tenant) • Normalized home energy cost (avg. cost per sq. ft.)
		Reliability • Average annual outage frequency (customers with outages) • Average annual outage duration (customers with outages)
		Direct Customer Benefits • % of eligible customers enrolled in low-income bill assistance programs (BCAP & LIE/D) • % of customers benefitting from Customer Energy Solutions (CES) programs

10.3 2026 IRP action plan summary

Table 10-2 summarizes our two-year action plan and our ten-year Clean Energy Action Plan.

Table 10-2: 2026 IRP action plan

Strategy	Two-year action plan	Ten-year Clean Energy Action Plan
Continue to invest in cost-effective conservation	Acquire 2-year conservation target of 26,214 MWh (3 aMW) set in 2026-2045 conservation potential assessment (CPA)	Regularly update CPA and continue to acquire 2-year targets set in subsequent CPAs
Ramp up demand response programs	Implement 2 pilots and acquire 0.6 MW of demand response	Acquire 12 MW of demand response
Continue work to restore Riffe Lake elevation by 2031	Continue to seek FERC authorization to restore Riffe Lake elevation	Restore Riffe Lake elevation by 2031 if authorized by FERC
Develop a strategy for mitigating intermittent capacity risks during generator rebuilds	Analyze non-resource alternatives to prepare for intermittent capacity risks during generator rebuilds	Develop long-term strategy to prepare for intermittent capacity risks during generator rebuilds
Continue to explore opportunities to build upon existing hydro system	Conduct further analysis of costs and benefits of adding a conventional hydro generator at Mossyrock Dam	Evaluate opportunities to add incremental capacity to existing generators during planning stage of scheduled rebuilds

11 Appendix A: CCA Load and resource forecast

11.1 Purpose of CCA-specific load and resource forecast

The Climate Commitment Act (CCA) directs the WA Dept. of Ecology (Ecology) to grant no-cost utilities to an electric utility based on the utility's CCA cost burden. This cost burden is a term defined by mathematical formula in the Washington Administrative Code (WAC173-446-23). WAC 173-446-23 also defines a rank order of data sources to be used as inputs to the formula. First in that rank order is a CCA-specific forecast of supply and demand if the forecast is approved by the utility's governing body – the Utilities and Transportation commission for investor-owned utilities, and the public utility board or similar entity for consumer-owned utilities such as Tacoma Power.

11.2 Background

Tacoma Power's Public Utility Board approved a CCA cost burden methodology in August 2022[45]. This methodology and the underlying load and resource forecast was created based on the best available information at the time. Since then, Ecology has completed rulemakings and provided other forms of regulatory clarification, which has prompted changes to the CCA cost burden form. This updated CCA load and resource forecast represents an evolution of approaches in alignment with the methodology previously approved.

11.3 Main drivers of CCA cost burden:

1. *Bonneville Power Administration:* Tacoma Power's cost burden is driven primarily by the small amount of carbon emissions embedded in purchases from BPA's system. BPA's system is almost carbon-free, but Tacoma Power buys significant amounts of energy from BPA. The small amounts of carbon embedded in BPA's energy add up to tens of thousands of metric tons of CO2e for which Tacoma Power is the responsible party under the CCA. Consistent with the 2026, we assume an emissions rate of 0.0496 MT CO2e per MWh.[46]
2. *Purchases of unspecified power:* Tacoma Power's cost burden is also affected by its wholesale power marketing activities. Tacoma Power's activities in the wholesale market help the utility balance generation with load. Tacoma Power's trading and operations function pursues opportunities to purchase electricity when economically advantageous. For example, Tacoma Power may purchase energy during periods of low or negative wholesale prices, allowing hydropower facilities to hold water and generate more electricity during periods of high prices or increased system need. To account for these trading activities, the CCA load and resource forecast includes an *operational adjustment* that estimates the amount of unspecified power purchased by Tacoma Power. This operational adjustment distinguishes the CCA load and resource forecast from the rest of the IRP.

11.3.1 Approach taken to calculate operational adjustment

The operational adjustment represents MWh of electricity purchased by Tacoma Power's merchant function from unspecified sources. These purchases are not estimated as a part of the IRP model but must be included in the CCA load and resource forecast to accurately reflect the resource portfolio used – and the emission obligations and costs incurred – to serve customers.

Tacoma Power buys electricity at three different timescale categories:

- **Term trades:** quarterly or longer, sometimes balance-of-month

---

[45] See Resolution U-1138, approved on August 24, 2022.

[46] The 2026 IRP assumption is consistent with the California Air Resources Board (CARB) Asset-Controlling Supplier (ACS) System Emission Factors for BPA for Data Year 2026 (https://ww2.arb.ca.gov/mrr-acs)

- **Day-ahead:** usually one-day transactions, sometimes balance-of-month or balance-of-week depending on the situation and calendar date
- **Real-time:** balancing transactions to match load to generation within the day and within the hour; mostly but not exclusively done through the Energy Imbalance Market (EIM)

The operational adjustment is calculated using historical purchase quantities at each of these timescales. The adjustment selects historical windows that reflect the utility's expected future trading volumes in a given timescale category.

Term purchases: Term trades are made on a bilateral basis, and these types of trades are expected to continue in this fashion going forward. Therefore, the operational adjustment uses 10 years of historical actuals to arrive at a purchase volume estimate for this category.

Day-ahead purchases: Tacoma Power's anticipated participation in the new SPP Markets+ day-ahead organized market poses a challenge. Tacoma Power expects to join Markets+ when the Bonneville Power Administration (BPA) joins; BPA is targeting the fourth quarter of 2028. It is reasonable to expect that day-ahead trading volumes could change dramatically, mirroring the shift in real-time trading volumes when Tacoma Power joined EIM. Changes to day-ahead purchasing volumes are very difficult to estimate. In the absence of model runs or estimates reasonably forecasting the purchasing volume outcomes of an organized market, organized market subject matter experts at Tacoma Power recommend that this CCA load and resource forecast make the simplifying assumption that purchasing volumes in 2029-2030 will be consistent with historical actuals, which are comprised solely of bilateral transactions.

Fortunately, Tacoma Power's 2028 IRP will be completed prior to Ecology's final determination of allowances for calendar year 2029. As staff gain more information and as Tacoma Power's launch date for Markets+ participation draws near, we anticipate a higher degree of confidence in estimates of day-ahead unspecified purchases after joining Markets+.

Real-time purchases: Tacoma Power's joining the EIM in March 2022 prompted a significant shift in how the utility engaged in real-time trades. To account for this divergence, the operational adjustment relies on historical data that includes only the years where Tacoma Power has been participating in the EIM – March 2022 through February 2026. The adjustment also removes January and February 2023 from its monthly average calculations because those months were not reflective of the utility's typical trading strategy in the EIM. Finally, the anticipated timeline of Tacoma Power's joining Markets+ is expected to create a 6 month window – April to September 2028 – where the utility will not participate in any organized real-time market. For these months, the operational adjustment uses historical real-time purchase volumes prior to fully participating in the EIM.

11.4 2027-2030 Forecast

The following tables provide the numbers that will be submitted to the Department of Ecology using the spreadsheet template required for the loads and resources forecast. The resulting forecast of Tacoma Power's utility-specific emissions is equal to 1,339,597 MTCO$_2$e over the four-year compliance period, which is approximately 19% higher than for the previous compliance period. The reason for the higher projection is due to an increase in our assumption regarding the emissions rate associated with BPA power.

11.4.1 Energy to serve load

	Formula descriptions	*2027*	*2028*	*2029*	*2030*	*Field description*	*Data source and calculation method*

Energy to Serve Load (MWh)	A	4,266,027	4,241,440	4,253,065	4,303,044	Forecasted annual energy demand, including transmission and other losses.	Most recent corporate load forecast

11.4.2 Declared resources

DECLARED RESOURCES:	*Formula descriptions*	*2027*	*2028*	*2029*	*2030*	*Field description*	*Data source and calculation method*
BPA Specified-source purchases (total) (MWh)	B	3,414,122	3,386,918	3,315,479	3,334,775	Estimate of annual energy generation provided by the Bonneville Power Administration. E.g. specified-source purchases including block, slice, and load-following products or other specified ACS purchases.	2026 IRP base case
BPA Specified-source - block purchases (total) (MWh)	B_{block}	1,208,891	1,266,414	1,515,059	1,523,192	Estimate of annual energy generation provided by the Bonneville Power Administration. E.g. specified-source purchases including block, slice, and load-following products or other specified ACS purchases.	2026 IRP base case

BPA Specified-source - slice purchases (total) (MWh)	B_{slice}	2,205,232	2,120,504	1,800,419	1,811,583	Estimate of annual energy generation provided by the Bonneville Power Administration. E.g. specified-source purchases including block, slice, and load-following products or other specified ACS purchases.	2026 IRP base case
Natural Gas - Total (MWh)	C	-	-	-	-	Total forecasted generation from owned or long-term contracted specified-source natural gas resources.	2026 IRP base case
Aggregate Natural Gas Generation (Less Specified Resources)	C_1	-	-	-	-	Energy acquired from aggregate natural gas generation (less specified resources).	2026 IRP base case
Specified Natural Gas Resource #1	C_2	-	-	-	-	Generation from Specified Natural Gas Resource #1, an owned or long-term contracted resource.	2026 IRP base case
Specified Natural Gas Resource #2	C_3	-	-	-	-	Generation from Specified Natural Gas Resource #2, an owned or long-term contracted resource.	2026 IRP base case

Hydro - Total (MWh)	D	2,511,100	2,527,967	2,519,049	2,515,975	Total forecasted generation from owned or long-term contracted specified-source hydro resources. Assume "average," "P50," or "base case" hydro conditions.	2026 IRP base case
Other Renewables & Non-Emitting Resources - Total (MWh)	E	-	-	-	-	Total forecasted generation from owned or long-term contracted specified-source non-hydro renewables and other non-emitting resources.	2026 IRP base case
Unspecified Purchases (MWh)	F = A - (sum of B through E)	-	-	-	-	Estimate of generation to be acquired through unspecified wholesale market purchases. Unspecified purchases are assumed to be the backstop resource.	Energy to serve load minus the sum of all specified sources.
Operational adjustment (MWh)	G = A * 9.02%	384,688	382,471	383,519	388,026	Estimate of shorter-term balancing transactions that carry CCA compliance obligations	Energy to serve load multiplied by an estimate of balancing purchases as a percentage of total energy to serve load.

							This adder reflects expected short-term balancing transactions that carry CCA compliance obligations.
Total MWh in generation portfolio	H = sum of B through G	6,309,910	6,297,355	6,218,047	6,238,776		

11.4.3 Emissions associated with declared resources

EMISSIONS ASSOCIATED WITH DECLARED RESOURCES:	*Formula descriptions*	*2027*	*2028*	*2029*	*2030*	*Field description*	*Data source and calculation method*
MT CO2e BPA purchases	I = B * BPA's ACS emissions factor	169,340	167,991	164,448	165,405	Metric tons of CO2 equivalent associated with BPA purchases.	Total BPA purchases multiplied by BPA's ACS factor.
MT CO2e Natural gas	J = C * natural gas emissions factor(s)	-	-	-	-	Metric tons of CO2 equivalent associated with specified-source natural gas generation.	Total generation from owned or long-term contracted specified-source natural gas resources multiplied by the relevant natural gas emissions factor(s) (default natural gas factor or specific natural gas factor, when known)

MT CO2e Unspecifed purchases	K = F * unspecified emissions factor	-	-	-	-	Metric tons of CO2 equivalent associated with unspecified purchases.	Total generation estimated to be acquired through unspecified purchases multiplied by the unspecified emissions factor established in WAC 173-444-040
MT CO2e Operational adjustment	L = G * unspecified emissions factor	168,108	167,140	167,598	169,567	Metric tons of CO2 equivalent associated with the operational adjustment.	Operational adjustment value multiplied by the unspecified emissions factor established in WAC 173-444-040
Energy supplied to EITEs (MWh)	M	-	-	-	-	Energy supplied to industrial covered entities by the utility. Fill out this field ONLY IF EITEs are receiving allowances for energy consumption directly. Otherwise, assume inclusion of energy supplied to EITEs in utility-specific emissions ("R").	Assuming inclusion of energy supplied to EITEs.

EITE Emissions (MTCO$_2$e)	N = (M / A) * sum of I through L	-	-	-	-	EITE Purchased Electricity multiplied by Utility-Specific Emissions Factor	Energy provided to EITE customers divided by all energy to serve load, then multiplied by the sum of all emissions associated with declared resources.
Utility-Specific Emissions (MTCO$_2$e)	O = sum of I through L - Q	337,449	335,131	332,045	334,972	Total metric tons of CO2 equivalent associated with energy to serve load.	Sum of all emissions associated with declared resources subtracted by emissions associated with industrial covered entities.