2022 Integrated Resource Plan

Draft | December 2022

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1 Letter from the General Manager

The energy industry is undergoing enormous change.

In recent years, the cost of batteries, wind and solar generation have declined, making them among the least-cost energy sources available. At the same time, there continue to be substantial hurdles to integrating these resources into the electric grid in an efficient, cost-effective way. Dispatchable, flexible fossil fuel resources face tighter and tighter constraints, and transmission availability is anticipated to be a key limitation as new renewable generation is added to the grid to meet increasing demand.

To navigate this volatile energy landscape, EWEB's 2022 Integrated Resource Plan forecasts EWEB's energy demands and examines a variety of energy resources that may fit those future needs. As EWEB's current contracts expire over the next two to eight years, EWEB will need to decide how to procure the energy that we serve to our customers.

The results in this document include a reference case – the first version of a potential energy portfolio. The reference case is not an ideal or preferred portfolio. Rather, it's a comparison point. EWEB analysts drew clear parameters to define boundaries, and assumptions, including abiding by EWEB's Climate Change Policy, which states that our energy will be 95% carbon-free by 2030. We had our modeling software test different resources and select a portfolio that can meet EWEB's future energy needs at the lowest cost, within the boundaries.

To generate this portfolio, a team of EWEB analysts and external consultants worked to define a set of assumptions about future resource costs, inflation, regulatory standards, transmission availability and market conditions, among other factors. As we discovered during the modeling process, if you shift the assumptions, a new suggested portfolio arises. Thus, testing these assumptions will provide insight into the future resiliency of our resource decisions.

Though the details of our analysis will change as we continue modeling, we can begin to see a few key themes emerge:

EWEB's energy load will grow. In the past few decades, EWEB's energy load has remained flat, despite population growth. We expect this trend to change. Electrification is happening. Massive investments in electric vehicles and electric heating and cooling will add more demand to the grid. It's not a question of if, but rather how much and how soon.

Legacy hydropower is a good fit. EWEB has relied on hydropower from the Bonneville Power Administration (BPA) and our own projects for many decades, and for good reason. It's a cheap, carbon-free resource that can be dispatched at a moment's notice to meet our customer's demand. We will start evaluating BPA's 2028 product options in our next IRP, which we plan to publish in 2024. We will also test the sensitivity of hydro to climate changes and further fish and wildlife-driven operational constraints.

Wind and batteries offer a possible viable path forward. The reference case suggests that EWEB pursue a buildout of batteries, paired with new wind resources. This makes sense. In the greater Northwest, wind is an abundant renewable resource that generally produces power during the same seasons we have peak needs. And utility-scale batteries will help smooth gaps in that power generation.

We need to develop customer programs responsive to our energy needs. Utilities around the country are developing innovative projects and policies that partner with customer to reduce demand for electricity. Some shave peak demand through demand response programs and time-of-use rates. Others use novel rate structures to ensure that the cost of maintaining and improving the grid is equitably shared. We will need to explore similar innovations as we begin to understand our individual customer's electricity loads better.

We have a multitude of questions about possible energy portfolios that we want to explore and that will help EWEB sail towards this new energy future. Using the reference case as a baseline, we will adjust our inputs and assumptions and use the model to answer questions such as:

- How do low water years and more protective fish regulations influence hydropower resources?
- What happens if buildout if transmission capacity is constrained or the costs of new transmission rises? In other words, how much does location matter?
- To what extent are conservation and demand response programs more cost-effective compared to procuring additional generating resources?
- What happens if we're required to have a greater power reserves available in our energy planning?

We are excited to begin exploring these questions throughout the first half of 2023, and we want to know what questions you, our customer-owners, want us to explore. We'll continue the modeling process, and we'll continue generating results for our community to learn about and discuss.

We encourage you to read the report and tell us what you think at www.eweb.org/irp. We are looking forward to charting our path to a future of clean, reliable, and affordable energy.

Sincerely,

Frank Lawson
CEO & General Manager

2 Executive Summary

The Eugene Water and Electric Board (EWEB) has been providing power to the Eugene community since 1911 when the Walterville Dam on the McKenzie River was completed. EWEB is the largest publicly owned utility in Oregon and is governed by a five-member Board of Commissioners who are elected by Eugene residents.

EWEB's 2022 Integrated Resource Plan is the first in a decade, although the next one will arrive much sooner. EWEB is embarking on an iterative, biennial process in which we develop and publish a new IRP every two years. This will allow EWEB staff to continually update assumptions and forecasts to plan for a more dynamic energy future. The 2022 IRP provides directional long-term guidance; it does not mandate specific near-term actions.

What is an IRP?

An Integrated Resource Plan is a long-term planning document to identify EWEB's energy needs and the best resource options to meet those needs. The IRP relies on modeling, analysis and public input to provide a 20-year look at future portfolio options and identify a nearer-term (2-5 year) action plan.

Aurora Modeling Software

EWEB's energy resource modeling software, Aurora, relies on hour-by-hour data to forecast energy prices and demand in the Western U.S. Aurora is used by utilities across the region for long-term energy resource planning.

Goals of EWEB's 2022 IRP:

1. Modernize our approach to energy resource planning to make it more robust, dynamic, routine, and useful, while developing in-house expertise.
2. Understand EWEB's needs for energy and capacity in the future.
3. Identify least-cost, "best fit" resources.
4. Consider trade-offs and values when developing action plans.

Climate Change

EWEB expects that climate change will impact both energy loads and resource performance in the future. EWEB staff continue to look for opportunities to incorporate climate change assumptions into our analysis.

Modeling Results: Reference Case Inputs and Assumptions

The draft 2022 IRP contains a reference case that represents a baseline upon which to conduct additional sensitivity analysis and answer further questions. The reference case is the energy resource portfolio suggested by EWEB's modeling software based on a specific set of inputs and assumptions. *It is not a preferred portfolio*.

Reference Case Peak Capacity Additions by 2042	
Demand Response	7 MW
Conservation	18 MW
Battery	100 MW
Wind	50 MW
Small Modular Nuclear	10 MW

EWEB staff designed the modeling process to select the lowest cost, optimized portfolio within the constraints set by EWEB Board Policy and regulatory obligations. These constraints include a requirement for EWEB's energy to be 95% carbon-free by 2030.

The calculated reference case results showed that continuation of EWEB's contract with the Bonneville Power Administration (BPA) was a key element of EWEB's least-cost portfolio. Currently, that contract includes Block and Slice products, but BPA may change those products in the future. The reference case suggested that additional resource needs could primarily be met with conservation, demand response, batteries and wind power.

Key Insights from the Reference Case

Energy demand will rise. While our overall demand has fallen or remained flat in recent years due to conservation investments, we expect this trend to change starting around 2030 due to electrification.

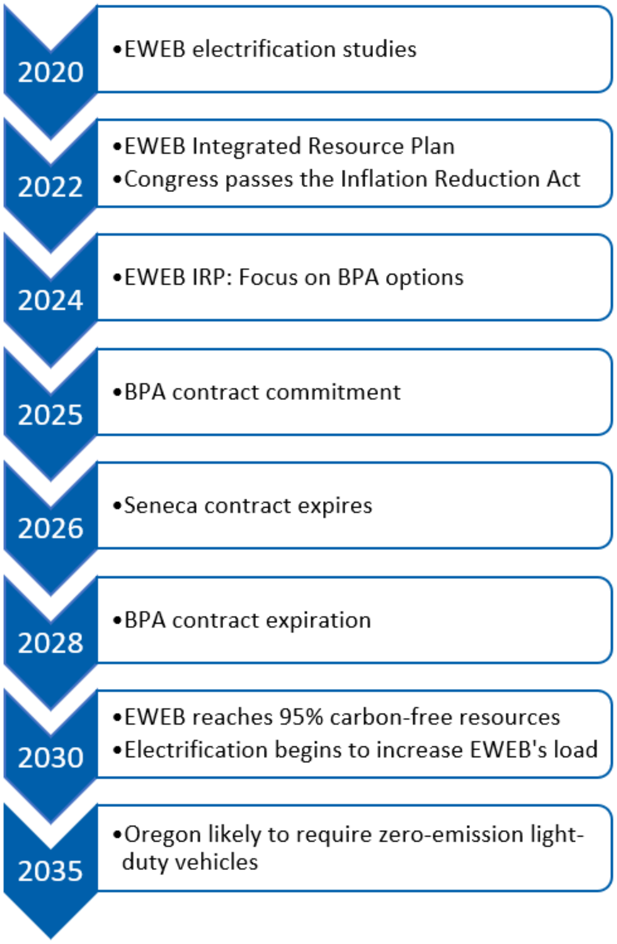
Peak needs are during the winter. EWEB's capacity needs are calculated using a 1-in-2 peak hour standard, meaning the portfolio of resources should be sufficient to meet EWEB's highest hour of load in a typical year. Throughout the study period, EWEB is assumed to be a winter peaking utility and the primary driver for increased peak energy use is due to unmanaged EV charging behavior.

We need new resources starting in 2026. Based on an average single-hour winter peak, EWEB begins to need a small amount of capacity starting in 2026.

Hydropower is a good fit: Currently, more than 80% of EWEB's energy comes from hydropower, both from the Bonneville Power Administration (BPA) and EWEB-owned projects on the McKenzie and Clackamas Rivers. Initial analysis points towards BPA hydropower remaining as a cost-effective, low-carbon way to meet most of EWEB's needs.

Wind and batteries are a promising option. The modeling software selected primarily a combination of wind and batteries to meet growing demand in the future.

Customer partnerships will be vital. Customers are likely to play an integral role in helping reduce peak energy usage. Programs such as conservation, demand response and new rate designs, such as time-of-use rates, were all selected in the reference case portfolio.



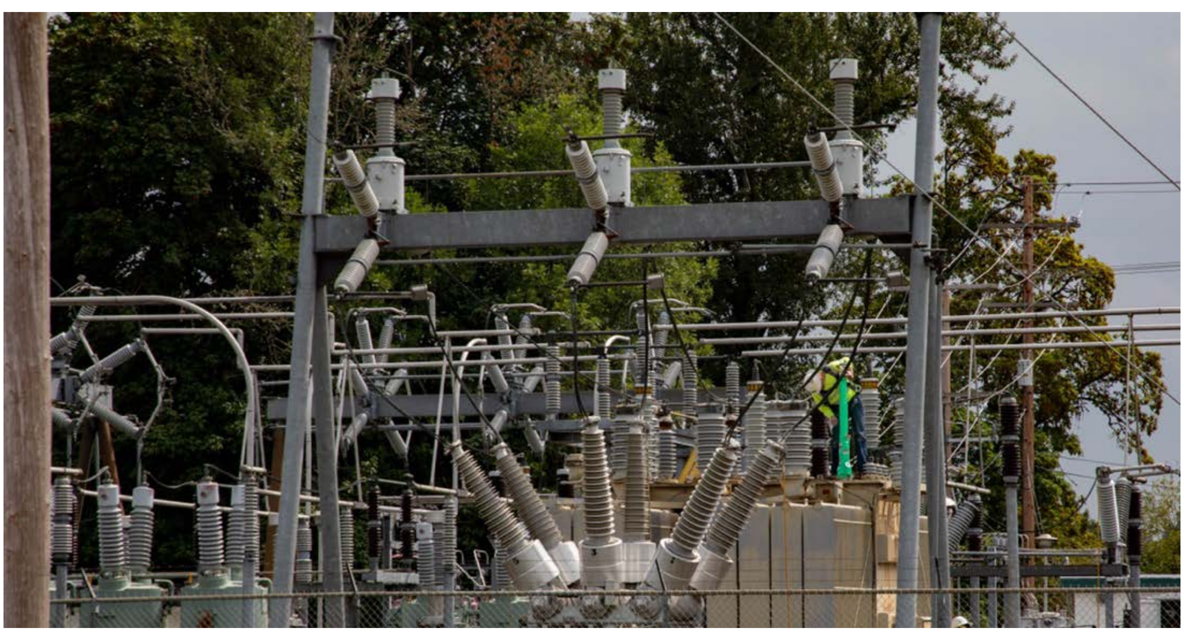
Next Steps – 2023 and Beyond

For the next six months, staff will engage the public to seek input and feedback. This feedback will guide additional sensitivity analysis before we release the final IRP in June 2023. This sensitivity analysis will be useful for understanding future uncertainty and developing a portfolio of resources that is more resilient to a rapidly changing electricity market.

As part of the final IRP, the Board of Commissioners will endorse/approve an action plan informed by EWEB's values, public feedback, staff analysis and modeling results. Typically, these action plans identify steps that can be taken in the next 2-5 years based on the 20-year planning horizon of the IRP.

Prior to 2028, EWEB will need to reassemble an electric supply portfolio as our existing power contracts are coming to an end. Our new, iterative IRP process will allow EWEB to develop near-term strategies while adapting to new information, assumptions, and operational conditions.

Due to a rapidly changing energy landscape – as well as uncertainty around electrification, future technologies and costs, and climate change – the future is increasingly difficult to predict. In response, EWEB's IRP process is evolving to continuously adapt to new assumptions about EWEB's electricity demands and the potential resources that could meet those demands in the future.



3 Action Plan Informed By Our Values

As a publicly owned utility, EWEB is committed to working with our customer-owners to solve problems. EWEB's elected Board of Commissioners takes seriously their responsibility to steward the utility's resources and carefully weigh the tradeoffs inherent in difficult decisions.

The IRP and future energy resource decisions are no different.

At the end of this IRP process, the Board will be responsible for approving an action plan of next steps and priorities to be undertaken by the utility leading up to the next IRP cycle. These action plans can include directing management to look into procuring long-term resources, conducting research to better inform demand-side programs such as conservation or demand response, or directing staff to analyze new topics or questions for the next IRP cycle. The community's values will inform this action plan.

The IRP process is built to provide a roadmap to a future energy resource portfolio that is:

- **Reliable:** Any potential resource portfolio must reliably meet our customers' energy needs, including peak demand.
- **Affordable:** The energy resource modeling software we use always selects energy resource mixes that are the lowest cost, while remaining within certain constraints.
- **Responsible:** All modeled portfolios will meet regulatory and environmental goals, including achieving a 95% carbon-free mix by 2030.
- **Community-aligned:** The IRP Action Plan, including any future resource decisions, will be approved by our elected Board of Commissioners, who weigh tradeoffs to align choices with community values.

In addition to these core values, EWEB is seeking to understand if there are other metrics or values that community members believe should be incorporated into resource decisions. Potential metrics are listed in the table to the right.

Potential Metrics/Values
Cost
Reliability
Local Resiliency
DEI
Carbon
Air Quality
Local Control

EWEB has also begun exploring how values of Diversity, Equity, and Inclusion (DEI) can be incorporated into utility practices and resource decisions in the future. To help generate ideas, the final IRP will include a review of how other utilities in the region are incorporating DEI values into their planning processes.

Diversity

Who is in the room?
– include individuals of different backgrounds and identities.

Equity

How are decisions being made?
– consider power imbalances and impacts to different groups.

Inclusion

Have all voices been heard?
– all perspectives matter.

EWEB Board Goal:

Developing and nurturing an environment based on the principles of diversity, equity, and inclusion.

4 PUBLIC ENGAGEMENT PROCESS

During the first half of 2023, EWEB will conduct a robust public engagement effort, educating customers about the initial IRP results and soliciting comments that will help inform our ongoing analysis process. We have questions about the initial modeling results, and we know customers will, too. We will seek to answer as many of those questions as possible through further analysis.

Customer questions will help inform both our sensitivity analysis in 2023 and our action plans. EWEB's Board of Commissioners will ultimately approve the action plan.

Integrated resource planning is a complex, multifaceted process that will affect EWEB's customers in numerous ways. Some of those effects are behind the scenes; other effects are ones that customers will experience in their daily lives. As we move forward in this process, it's vital that we **educate** customers about the tradeoffs and nuances inherent in energy resource planning. And it's crucial that we have a **dialogue** with customers to verify that we are moving in the right direction.

There are three key pillars of our public engagement plan:

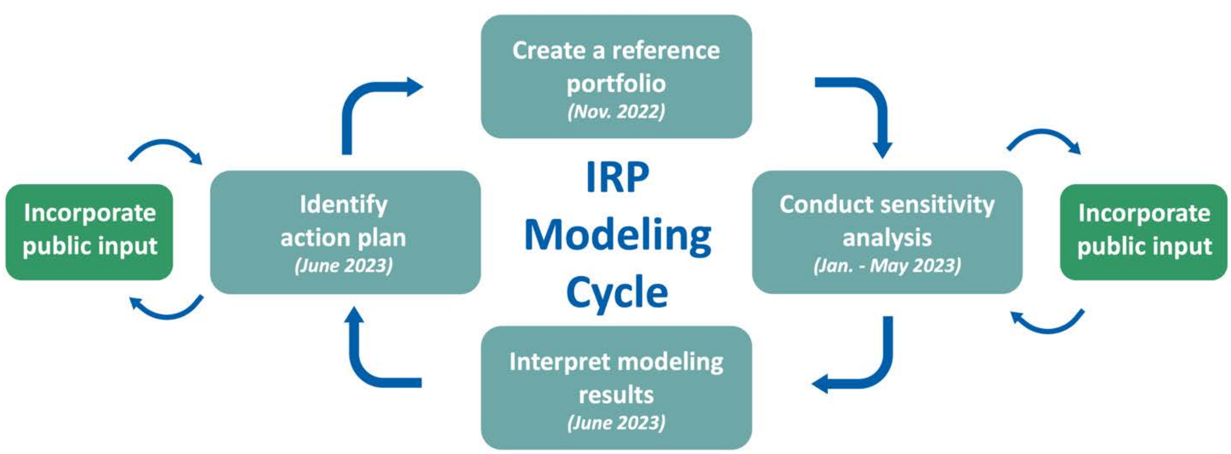
Direct dialogue: We will host dialogue-driven meetings with a broad cross-section of community organizations to present the initial IRP findings and solicit questions. We will strive to reach groups such as: agency and government partners, traditionally under-represented communities, environmental justice organizations, business groups, neighborhood groups and major customers.

- Dialogue events include an EWEB-hosted town hall scheduled for Feb. 21.

Ongoing education: We will implement a robust story-driven public education effort through traditional media, EWEB website content, social media, email newsletters and other channels.

- Educational tools include: PowerPoint presentation for public events, Fast Facts (a one-pager explaining the IRP and main takeaways), a Q&A handout and a key findings handout.

Customer questions: We will collect customer questions via a comment form at **eweb.org/irp**, as well as via comment forms distributed during in-person meetings. Customer questions will help guide EWEB's sensitivity analysis during the first half of 2023, as well as the action items for the 2024 IRP.



5 UPCOMING SENSITIVITY ANALYSIS

The calculated reference case is the output of a specific set of assumptions and modeling choices, but uncertainty exists around many of these assumptions. Because of this, staff are planning to run several sensitivities to test different assumptions and understand the drawbacks and benefits of different portfolio approaches.

Modeling work and sensitivity analysis are designed to help inform the IRP action plan but should not be construed as the only information the Board will consider when developing IRP action plans. In addition to the sensitivities identified by staff below, EWEB is also seeking input and questions from the Board and community prior to the final IRP publication which will be released in June 2023.

Sensitivity analysis will help inform EWEB's action plan and set the stage for the 2024 IRP.

Staff plan to conduct sensitivity analysis on the following inputs:

- **Transmission availability and cost**: Staff will limit transmission availability and/or increase transmission costs to reflect potential future constraints on the existing system. This will provide a new portfolio to be compared to the reference case.
- **EWEB load growth trajectory**: Sensitivities will explore possible resource acquisition strategies for both faster and slower load growth to account for uncertainty around electrification and other factors.
- **Planning reserve margin:** This sensitivity will explore the costs of procuring additional resources to meet a planning reserve margin similar to potential standards required by the Western Resource Adequacy Program. (These standards are still under development.)
- **Hydropower and gas risk:** Staff will conduct risk modeling simulations to test portfolio performance under different hydropower and gas conditions.

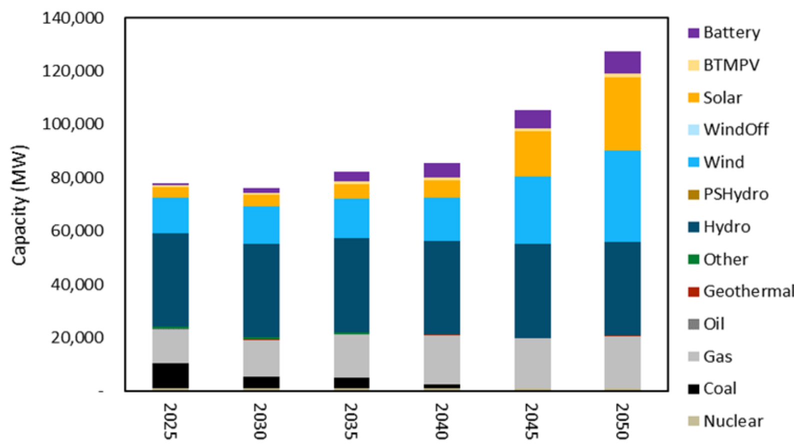
Staff will be seeking guidance and input on additional sensitivity analysis. Potential topics include:

- **Solar**: The calculated reference case did not select solar as a least-cost option, most likely because it contributes little to peak winter needs. Sensitivities could explore the impact of adding solar to the portfolio, or test whether solar is selected if we assume that EWEB's summer needs significantly increase.
- **Resource cost trajectories:** Resource cost trajectories, whether for renewables such as wind and solar, or for emerging technologies such as long-duration storage, are likely to diverge from current forecasts. Sensitivities could explore how falling or rising costs influence possible energy resource portfolios.
- **Other:** Additional sensitivities as identified by staff, the Board or public questions can be included in IRP analysis, time permitting. These could include emerging carbon policies, market price changes and others.

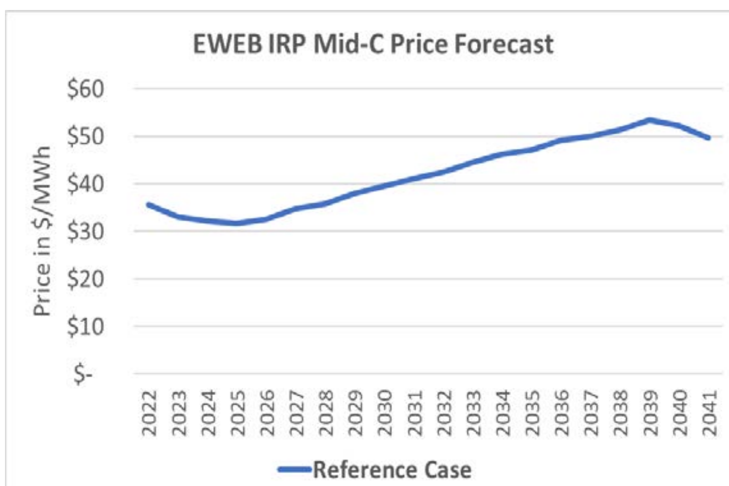
6 Future Electric System

The future electric system is unlikely to resemble the past. Local, state, and national policies focused on carbon reduction continue to evolve, putting constraints on some resources and creating incentives for others. Technological development and government subsidies have brought down the price of many variable renewable resources, making them some of the most cost-effective options on an energy basis.

At the same time, the Northwest region is retiring dispatchable generation such as coal power plants and losing flexibility from hydropower resources due to fish and wildlife considerations. Additionally, many high-quality renewable resources are located far from cities and other load centers, creating challenges in securing firm transmission to deliver the power where it is needed. These changes are putting increased strain on the electric grid and creating concerns about future system reliability.

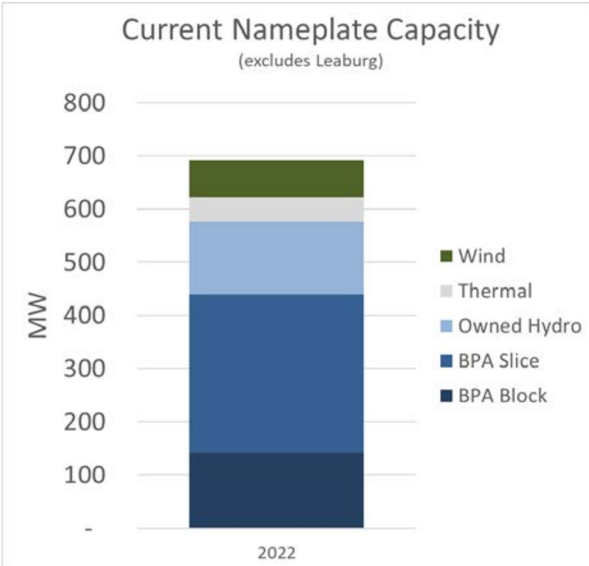


For the IRP, EWEB staff worked with consultants at Energy and Environmental Economics, Inc. (E3) to develop a forecasted future electric system. In the Northwest, E3 is forecasting a decline in dispatchable fossil-fuel generation and an increase in renewable generation and batteries (see chart above). This future assumes that natural gas generators will be needed to integrate renewables and will set market prices. In addition, the increase in electric demand from electrification, and an assumed increase in carbon prices, lead to higher market prices over the 20-year planning horizon.



In the calculated reference case, EWEB's modeling results indicate that these elevated prices can (on average) help reduce EWEB's future portfolio costs since we can sell surplus energy to the market. In addition, daily market price volatility can provide an opportunity for batteries to charge during off-peak periods and discharge during peaks, creating an additional opportunity to generate revenue. However, this surplus energy position can expose EWEB's portfolio to the risk of falling market prices in the future. EWEB staff plan to conduct additional analysis as part of the IRP to understand the potential price risk of the calculated reference case portfolio.

7 EWEB's Existing Resources

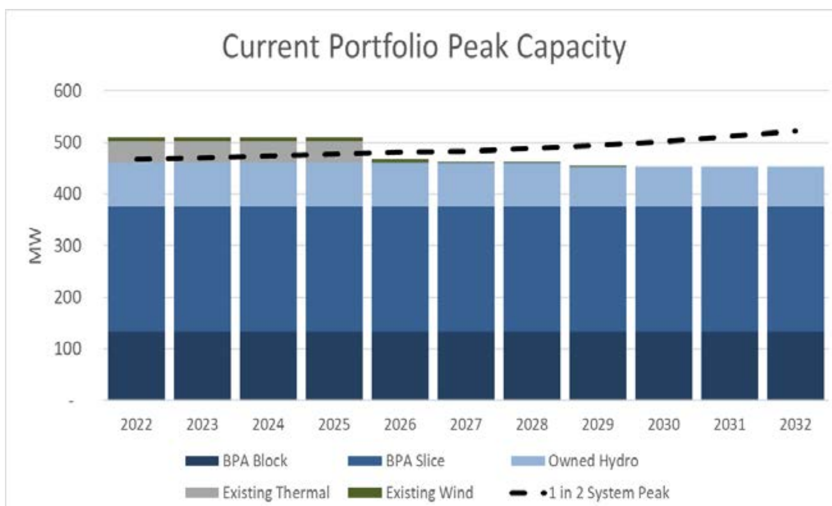


More than 80% of EWEB's power currently comes from hydropower resources. These include EWEB-owned projects on the McKenzie River and one project on the Clackamas River, as well as contracted power from the Bonneville Power Administration (BPA), a federal agency that manages and markets the generation from federal dams in the Columbia River system. In addition to these hydro resources, EWEB has contracts and ownership agreements for several wind farms, as well as biomass and co-generation facilities.

Due to the composition of this existing portfolio, EWEB's resource-based carbon emissions are a fraction of the state and national average. Depending on water conditions and hydro generation, EWEB's portfolio is currently about 90% carbon-free, with the majority of emissions coming from market purchases.

There are several events within the next 10 years that will shape EWEB's portfolio in the future:

- Expiration of EWEB's power contract with BPA in 2028, upcoming decisions on whether to renew that contract going forward, and which products/options to select if renewing[1].
- Licensing requirements and structural issues at several of EWEB's owned hydro plants that have or could lead to these being removed from generation.
- The assumed expiration of thermal contracts in 2025 and wind power contracts between 2026 and 2029.



Peak capacity represents the amount of a resource's nameplate capacity that is expected to be available to serve load during EWEB's single-hour winter system peak.

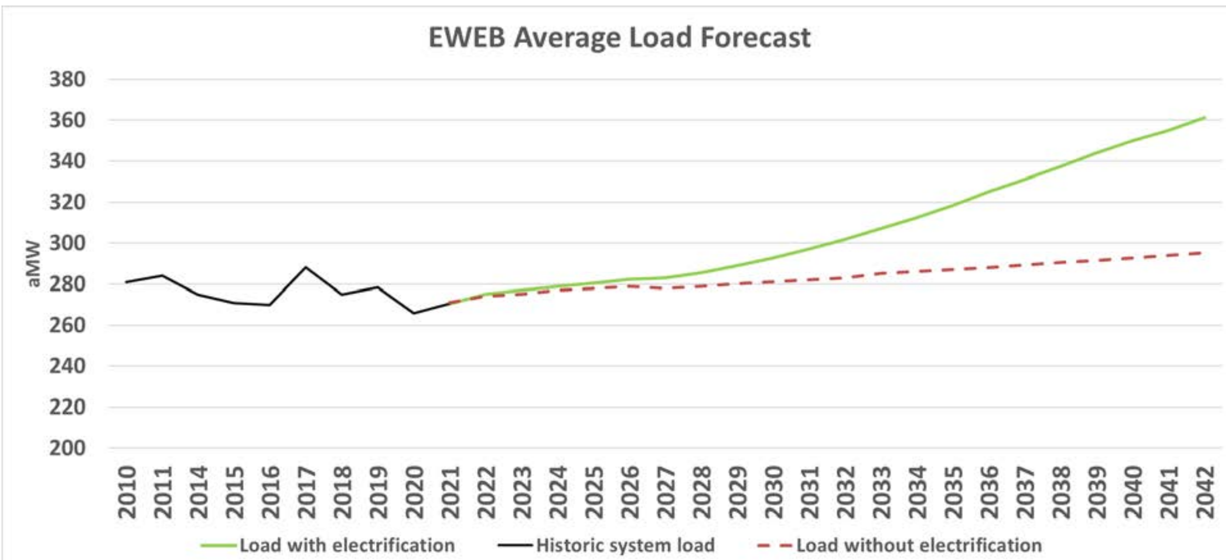
Due to these changes, EWEB will have resource decisions to make over the next two to five years regardless of uncertainty about load growth, electrification, regulations or other factors.

[1] Staff analysis during the reference case modeling found that continuation of the BPA contract after 2028 was one of EWEB's least-cost portfolio strategies. This assumes BPA products would continue at roughly the same pricing as they are today. Further analysis on BPA products and costs will be a key focus of the 2024 IRP.

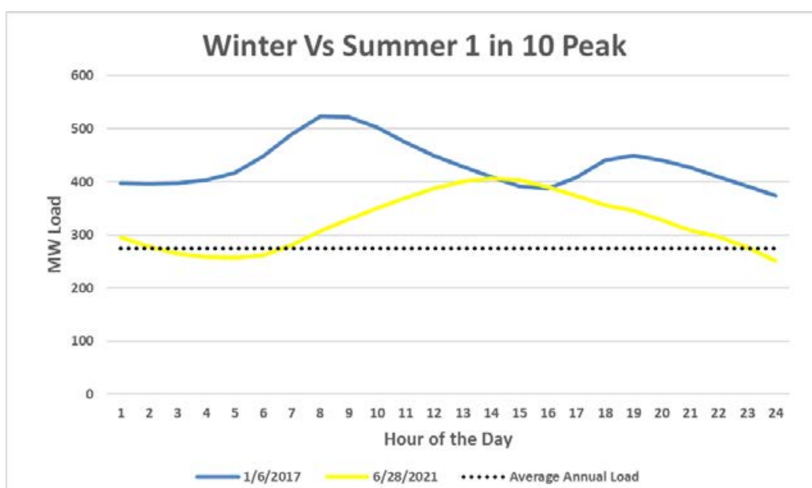
8 EWEB'S FORECASTED LOAD

EWEB currently serves roughly 200,000 customers in the Eugene area, with total average annual load of approximately 270 aMW. EWEB's load has remained flat or declined over much of the past decade due to the loss of industrial facilities, as well as the success of EWEB's energy efficiency programs.

However, with changing technologies such as heat pumps and electric vehicles (EVs), as well as policies that promote electrification, EWEB expects to see increasing load growth over the next decade. This view is informed by EWEB's 2020 electrification study and is consistent with other utility IRPs and analysis by industry leaders. Major impacts from electrification are not anticipated until around 2030 when light-duty EV adoption becomes more widespread.



EWEB is a winter peaking utility, with average single hour peaks of roughly 465 MW, and once in ten-year peaks of over 500 MW. In contrast, recent summer peaks have been between 380 and 410 MW, although these have generally trended upwards. EWEB's load can fluctuate by over 100 MW within 24 hours due to changes in temperature and customer behavior.



9 New Resource Options

New resource options have shifted dramatically over the past decade as carbon policies have made investment in fossil fuel plants challenging and risky, and the costs of solar and wind generation have declined dramatically.

The wind and solar resources included in the 2022 IRP are some of the most cost-effective resource options available to EWEB. However, renewable resources are not dispatchable (available on-demand), and their energy production may not align with EWEB's needs. Other resources, such as biomass, hydro, batteries, and demand response, provide this type of dispatchable capability. Because the value of renewable resources is highly location-dependent, the IRP includes several distinct wind and solar options, including local community and residential rooftop solar.

It's important to note that resource options in the IRP do not represent specific power purchase agreements or resources available for sale, but instead use publicly available data to estimate the costs of typical new generation or demand-side programs. The list of resources under consideration is not meant to be exhaustive, but instead provides touchpoints to understand what types of options might be valuable to EWEB in the future.

In the 2022 IRP, EWEB used a standard approach to evaluating model candidate resources. To be considered, a resource must be:

- An existing or proven technology
- Deliverable to EWEB load
- Commercially operational today, or under contract to be operational within the next 10 years

Below is a table of the resources considered in the IRP:

Key Energy, Cost, and Carbon Attributes

Resource Category	Resource Type	Levelized Cost of Energy $/MWh	Cost of Winter Peaking Capacity $/kW-mo	Transmission Risk/Cost	Carbon Intensity MTCO2e/MWh
Wind	MT/WY Wind	22	16	High	-
	Offshore Wind	102	102	High	-
Solar	Residential Rooftop Solar	196	451	-	-
	Community Solar	69	161	-	-
	Utility Solar (Eastern OR)	28	51	Moderate	-
Battery and DR	Battery (4hr)	N/A	15	-	N/A
	Demand Response	N/A	22	-	N/A
Conservation	Energy Efficiency Bin 1	33	16	-	Savings
Thermal	Natural Gas SCCT (40%)	74	9	Moderate	0.53
	Cogeneration/Biomass	74	48	Low	0.39
	Small Modular Nuclear (80%)	76	43	Moderate	-
BPA	BPA Contract (Slice & Block)	33	18	Low	0.02

10 Modeling Approach – Calculated Reference Case

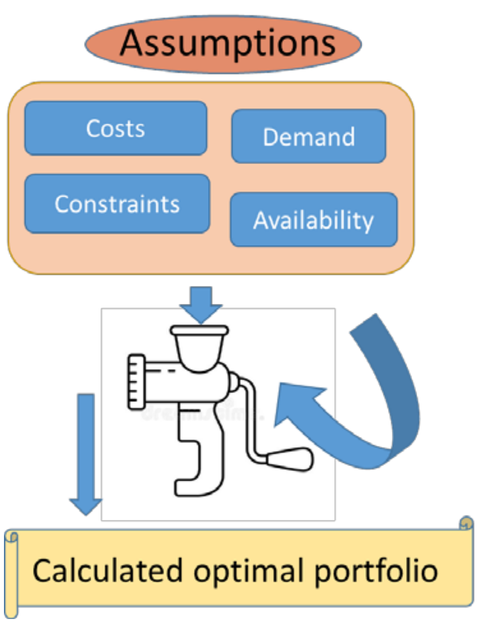
EWEB's planning team uses Aurora simulation software, in addition to other tools and analysis, to explore EWEB's resource needs and portfolio options. This practice is standard across the energy industry, as it allows for more granular and sophisticated examination of different scenarios and uncertainties. Modeling allows staff to look at resource performance under a variety of conditions. We can also create optimized solutions that reduce both cost and risk based on the assumptions used.

The draft 2022 IRP includes a single, modeled future portfolio, called the calculated reference case. This is intended to serve as the starting point for further analysis and feedback from the Board and community.

Key Assumptions

- The calculated reference case modeling is constrained to select just enough resources to meet an average winter single-hour peak load event.
- EWEB's BPA contract is assumed to continue throughout the study period (post-2028), with cost adjustments for inflation starting in 2027.
- Transmission availability for new resources is not materially constrained or adjusted for future cost risk.
- Results assume typical planning conditions, including median water years.
- EWEB's portfolio is constrained to meet Board Policy SD15, which requires our portfolio to be 95% carbon-free by 2030.
- Additional assumptions are listed in the Appendix (such as carbon pricing and resource costs).

The reference case represents the portfolio of future resources that the Aurora model selected through simulation, given a specific set of inputs and assumptions. ***The goal of the calculated reference case is to provide a reasonable benchmark against which to compare other sensitivities and portfolios***. In general, we relied on 'business as usual' constraints and assumptions to generate the reference case. Almost any assumption can be explored in sensitivity analysis, discussed further in the Appendix.



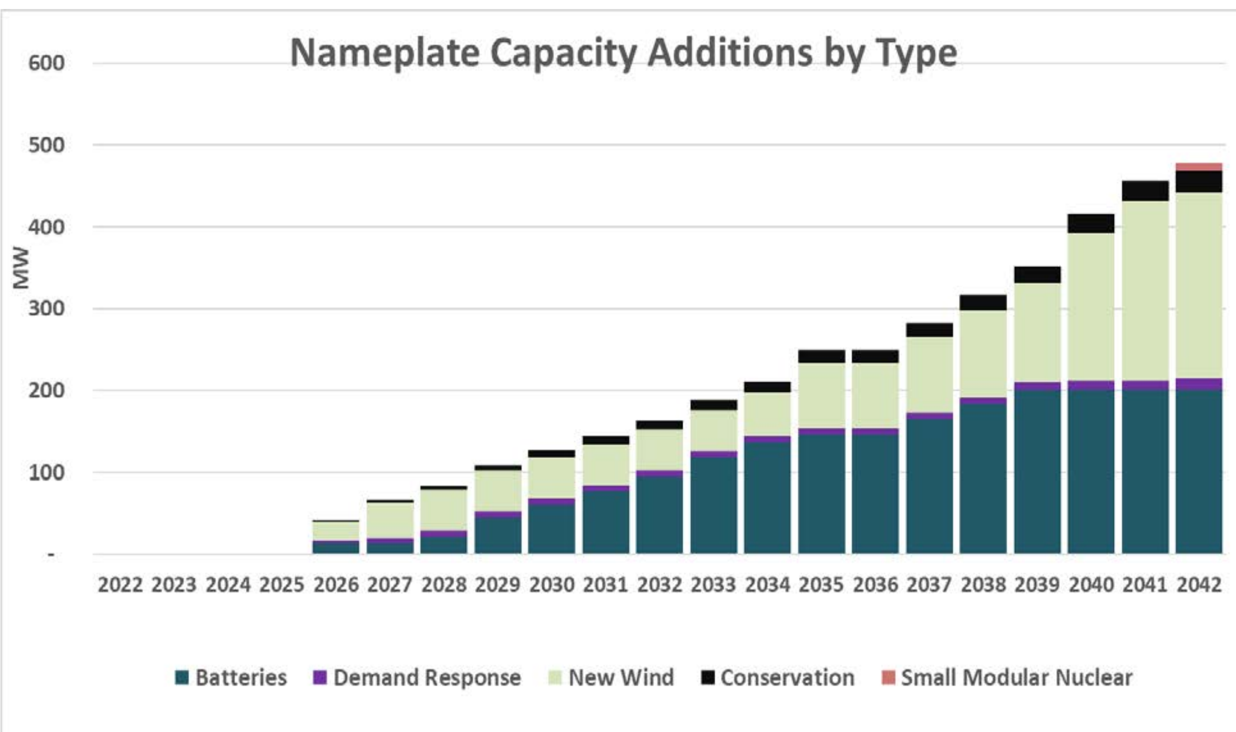
Key Reference Case Assumptions	
Electrification load growth?	Yes
Transmission availability?	No major constraints
BPA cost?	Similar to today
Peak load?	Average winter
Carbon limit?	95% carbon-free by 2030

11 MODELING RESULTS - CALCULATED REFERENCE CASE

Initial Modeling Results

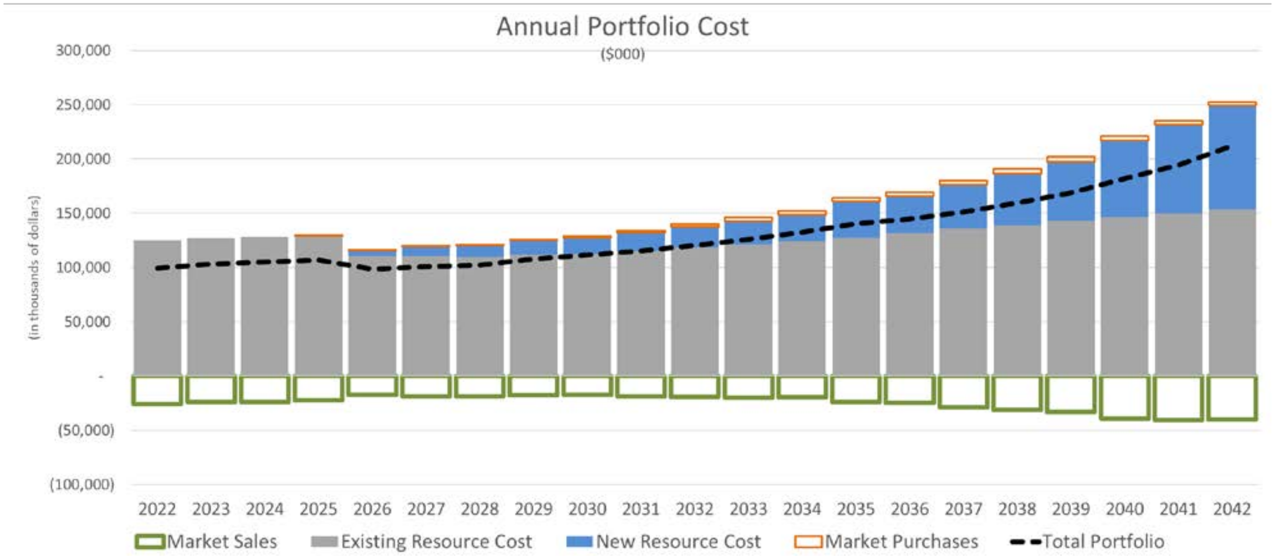
- Using a 1-in-2 planning standard, EWEB does not have a need to acquire resources until 2026, when existing thermal and wind resource contracts expire.
- Starting in 2030, forecasted unmanaged electric vehicle (EV) charging begins to increase peak capacity needs by 2% per year, driving increased portfolio costs.
- BPA products appear to be one of EWEB's least-cost portfolio options. The assumption that these products will be similar in price and design to today is a key factor in the least-cost calculated reference case results.
- Calculated reference case portfolio additions are primarily batteries, wind, demand response and energy efficiency throughout the study period.
- 10 MW of small modular nuclear reactors (SMR) are added in the final year of the study period, 2042.
    - SMR additions represent a potential future need for a firm, dispatchable resource in the future. The exact technology, however, may change by 2042.

The calculated reference case is a suggested portfolio based on modeling results and certain inputs and assumptions. These results are not EWEB's preferred or expected portfolio, but instead are computed results which act as a benchmark for further iteration, informing EWEB's future strategic decisions. The modeling results discussed herein are the beginning of a longer process and discussion that will include conducting sensitivity analysis and developing an IRP action plan.



In the chart below, EWEB's portfolio cost remains relatively stable through the 2020's, despite some retirements of existing contracts for wind and biomass. During this time period, EWEB expects relatively flat or small load growth, which keeps the need for additional resources, and by proxy additional cost, to a minimum.

However, increases in annual load due to vehicle electrification begin in the early 2030's. This increase in turn drives the need for more energy and capacity resources to serve the load, raising portfolio costs throughout the 2030's. Starting in 2033, the portfolio also begins to make market purchases (represented by the orange boxes below) of approximately 10 aMW instead of building more resources. This indicates that market purchases may be part of EWEB's least-cost portfolio strategy.



Over the study period, total portfolio costs increase an average of 4% annually, which includes both the impacts of load growth from electrification (2% growth per year) and inflation, indicating that portfolio costs relative to load would remain relatively flat. Portfolio costs represent one portion of end-use customers' retail rates. In the Reference Case, although total portfolio costs are expected to increase, so is energy demand, which would spread those costs among more kilowatt-hours. In effect, rates could remain stable even if overall costs increase.

A key aspect of meeting demand with intermittent renewable generation is the generation of surplus energy. Renewable resources – whether wind, solar, or hydro – generate energy at times when EWEB does not need them to serve load. EWEB's ability to create revenue from this surplus energy is an important part of reducing total portfolio costs.

Throughout the study period, sales of excess energy (represented by the green boxes above) averaged approximately $60/MWh and generated an average annual benefit of $25 million per year. Assumptions around future market prices and the value of surplus energy are a key driver of resource selection and portfolio cost and risk.

12 Planning Context – Overview

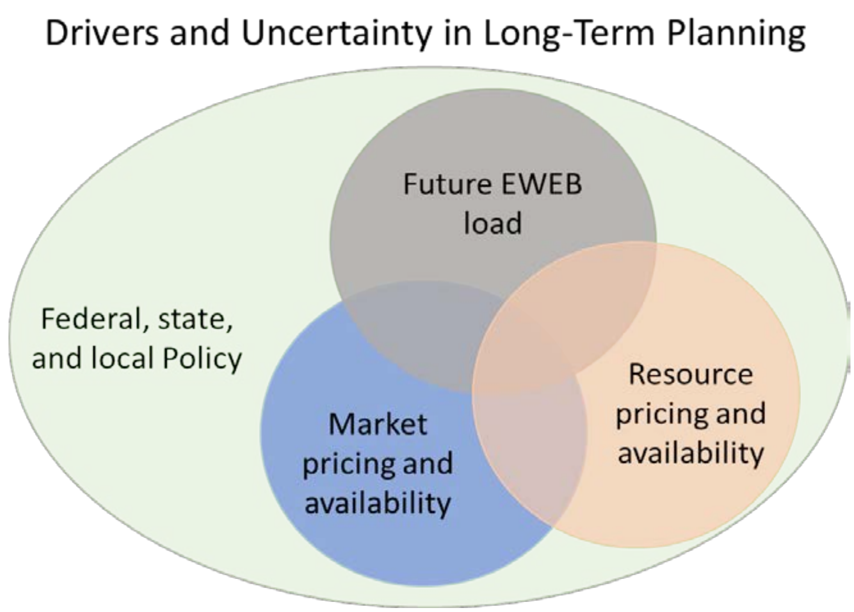
The following several "Planning Context" sections of the IRP aim to give an overview of the broader environment in which EWEB will be making resource decisions over the next decade.

Utilities and others in the energy industry have talked about oncoming dramatic change for well over a decade, and there are signs that it is here. For example, in just the past few years, renewable resources have become the cheapest source of power on an energy basis and are the resources of choice in nearly all IRPs in the region.

Additionally, in August 2022, the federal government passed the Inflation Reduction Act, which contains unprecedented levels of funding for renewable and clean resources, as well as incentives for homeowners to invest in fuel-switching technologies that could increase electricity demand.

Even though there does not appear to be anything on the horizon that would cause a shift back to the old dynamics, there is a large amount of uncertainty over the speed of change. EWEB needs to have a plan that considers these trends and uncertainties, as well as the supply risks associated with action or inaction. EWEB staff have worked closely with leading industry consultants to incorporate assumptions around key drivers into the 2022 IRP. In addition, sensitivities and future IRP work will analyze alternate assumptions to find tipping points and areas of opportunity or risk.

Key Context sections include:



- **Policy**: EWEB expects that carbon policies will have a substantial impact on future resource costs and acquisition strategies. EWEB does not expect backsliding from current policy directions.
- **Adequacy, Risk, and Planning Standards:** As the Northwest region retires dispatchable fossil fuel generators, it is expected that tangible, physical investments will be needed to maintain system reliability.
- **Electrification**: Electrification is expected to be a major driver of increased load by 2030, with most of this coming from the shift to electric vehicles.
- **Transmission:** Transmission constraints and cost will be key drivers of resource acquisition decisions. Many of the best solar and wind locations are in Eastern Oregon or Montana and Wyoming, where transmission availability is limited.

13 Planning Context - Policy

Federal, state, and local policies impact EWEB's portfolio by imposing standards, fees or other constraints on resource and generation decisions.

Over the past decade, carbon policies have been one of the significant drivers of resource decisions, as legislators and others have attempted to mitigate or prevent the worst impacts of climate change. In general, policies have the potential to both increase electric demand (through promoting technologies that lead to electrification) and alter electric supply (through incentives or fees on certain types of resources).

Future carbon legislation and policies may create incentives to develop new clean resources, streamline transmission builds, or implement a price on carbon that would impact electric market dispatch. Uncertainty around these outcomes presents a supply risk to EWEB's future portfolio. To the extent possible, IRP modeling includes existing carbon legislation (excluding the Inflation Reduction Act) and uses constraints to represent EWEB's obligations to Board policy and Oregon Renewable Portfolio Standard requirements.

Key Policies:

- **Inflation Reduction Act**: The Inflation Reduction Act, passed in August of 2022, includes billions of dollars for additional tax incentives and rebates for clean and renewable technologies, both on the supply side (such as renewables and clean generation) and on the demand side (such as heat pumps and electric vehicles). This is likely to make renewable resources cheaper, while increasing demand for electricity.
- **Renewable Portfolio Standards (RPS)**: EWEB is currently subject to Oregon RPS, which requires EWEB to purchase the output of wind, solar or other designated "renewable" resources. (EWEB also receives an exemption for its hydro resources and contracts.)
- **Carbon Taxes or Cap-and-Trade:** Both California and Washington have passed cap-and-trade bills that require regulated entities to purchase allowances for their emissions. Oregon may also institute a carbon market. But even if the state doesn't, neighboring carbon markets will affect buildout of renewable resources regionwide.
- **Vehicle Emissions Standards:** Oregon is poised to follow both California and Washington in requiring all new light-duty vehicles to meet zero-emission standards by 2035. This is likely to increase electricity demand.
- **Building Standards:** Many municipalities, including Eugene, have passed, or are considering some level of bans on natural gas usage for heating buildings. A local natural gas ban would likely cause only a small increase in electricity demand in Eugene– much lower than other types of electrification.
- **EWEB Board Policies:** EWEB's Board has passed Strategic Direction 15, requiring EWEB's portfolio to be at least 95% carbon free by 2030.

As EWEB navigates these policies, we seek to limit cost and risk, while also maintaining compliance. Additionally, not all policies are equally effective, and some may have unintended adverse consequences. To manage these risks and represent the interests of the Eugene community, EWEB staff remain engaged in policy development at all levels.

14 Planning Context – Adequacy, Planning Standards, and Risk Management

EWEB cannot eliminate supply risk, but we can manage it through planning.

A key part of the IRP is defining EWEB's supply needs. This involves assembling information not just about EWEB's historical load, but also planning standards and risk tolerances. The 2022 IRP uses EWEB's forecasted average annual peak hour (also called 1-in-2 peak) as the Calculated Reference Case planning standard. As described in the section "Upcoming Sensitivity Analysis," exploration of other planning standards will be included in IRP analysis.

Because EWEB is not a balancing authority charged with managing the electric grid, it is unlikely that EWEB would experience blackouts if the utility does not procure enough resources to serve load. However, there are likely to be serious financial consequences for not doing so. EWEB's adequacy obligations, planning standards and risk policies are discussed further in the Appendices.

Resource selection and portfolio optimization are a balancing act between EWEB's specific needs and the broader electric system. If market prices are high, it is beneficial for EWEB to build resources and sell surplus energy on the market. If market prices are low, it is more cost-effective for EWEB to rely on the market rather than make large capital investments. Each approach carries its own benefits and risks. For much of the past decade, EWEB's portfolio has been 'long' to its average energy needs, meaning that the utility has had rights to more generation than it needed to serve average load.

Balancing Authority

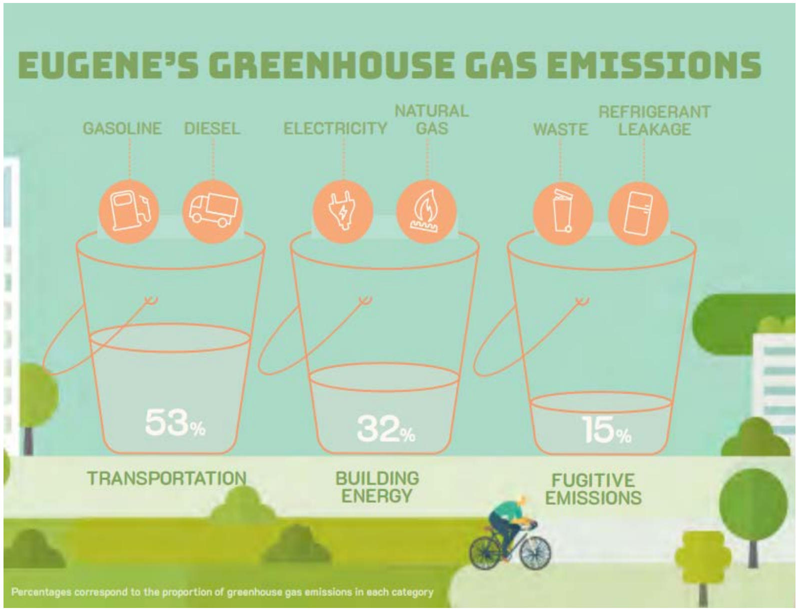
The reliability of any electrical grid is based on supply equaling demand at all times. Any over- or under-supply will cause instability in the grid. The national power grid is divided into independent "balancing areas" (BA), where each BA has assigned a utility or other entity that is responsible for keeping that balance – the Balancing Area Authority (BAA). EWEB is not a BAA, but instead operates within the Bonneville Power Administration's BA.

Several factors contributed to this trend, among them the departure of several energy-intensive industrial customers, as well as EWEB's primarily hydro-based resource mix, which often provides excess energy depending upon water conditions. Having ownership or contractual rights to more power than our average needs puts EWEB in a net selling position. When market prices for power are below the cost of the investments EWEB has made, this surplus power presents a risk. However, with recent increases in natural gas and energy prices, EWEB's long portfolio has insulated the utility from some cost exposure.

Going forward, a number of factors point to continued market volatility and higher prices, as well as potential resource shortages if the region does not invest in new generating facilities. EWEB cannot eliminate supply risk, but we can manage it. The 2022 IRP is intended to continue laying the groundwork for developing strategies for planning standards, long-term risk management, portfolio optimization and alignment with community values.

15 Planning Context – Electrification

The impacts of electrification are expected to be significant by 2030. However, the benefits of electrification depend on the cost and carbon content of electric power.



Currently, most societal carbon emissions come from sources other than the electric industry. However, as new technologies become available, many energy-intensive processes are expected to be transitioned from fossil-fuel energy sources to electric ones. This process is referred to as electrification. While electrification is expected to substantially reduce carbon emissions, there is still uncertainty about how quickly change will occur, and whether these changes can happen without increasing costs.[2]

In 2021, EWEB partnered with energy consultant E3 to conduct an electrification study. The study looked at the economics and trends behind electrification to determine potential impacts to EWEB's service territory and to identify areas of opportunity for the utility. The study found that transportation electrification, particularly light-duty cars and trucks, was likely to increase average and peak loads in EWEB's service territory by the 2030s. In contrast, fuel switching for heating was expected to be less likely in 2021 because individual customers would not see significant financial benefit. This could change with mandates or legislative incentives.

Obtaining the benefits of electrification is highly dependent on several factors, chief among these being:

1. **The carbon content of electric power**. Any carbon reduction benefit of electrification is directly related to the carbon emissions associated with generating electricity. The lower the carbon content of the electric grid, and EWEB's portfolio, the greater the carbon reduction of electrification will be.
2. **The cost of electric power**. If the shift to low-carbon power supplies causes a material increase in electric rates, the incentive to electrify will be reduced, and the overall cost burden on average customers will increase. Although EWEB's portfolio is already low cost and low carbon compared to the average U.S. utility, EWEB must continue to manage these factors.

For the 2022 IRP, staff included the "base case" electrification scenario from the electrification study into the load forecast. This anticipates that EWEB's average load will increase 21% by 2040 due to EV adoption and assumes unmanaged peak charging would increase EWEB's system peak by 26% by 2040.

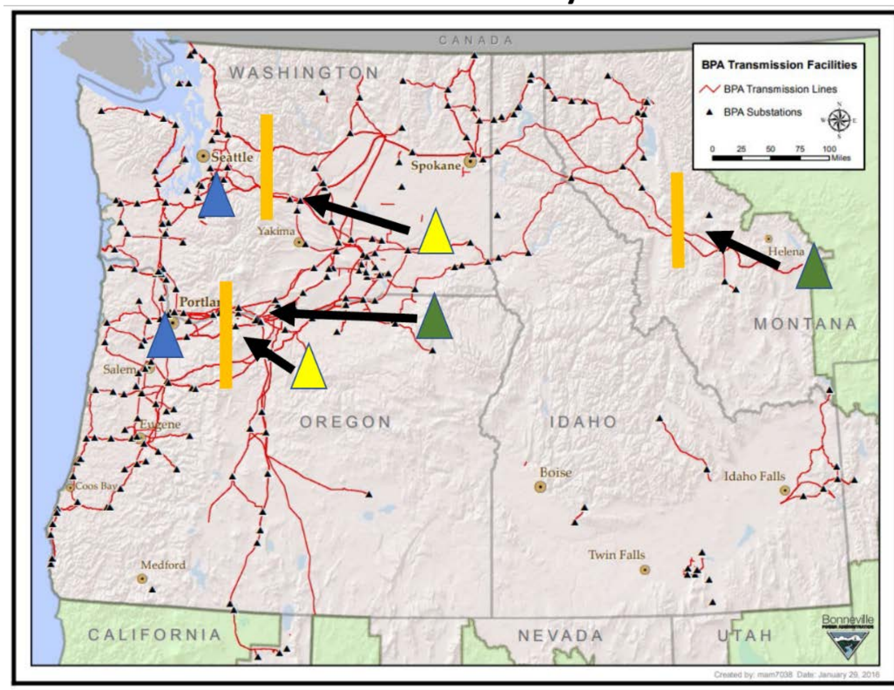
[2] Sources of Greenhouse Gas Emissions | US EPA

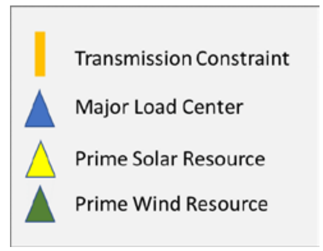
16 Planning Context – Transmission

Limited transmission availability is a major challenge to integrating new renewable resources.

To be useful, an energy source, whether it is wind, solar, or a thermal generator, must be delivered from where it is produced to where it is needed. Over the past century, utilities, and other entities such as the Bonneville Power Administration (BPA), constructed thousands of miles of transmission lines to accomplish this. These transmission lines allow energy transfer from one area to another and allow use of the most economically efficient energy resource options.

BPA Transmission Lines and Key Constraints





In Oregon, the best locations for renewable energy are east of the Cascade Mountains, where both solar and wind potential are the highest. Meanwhile, the greatest need for energy is west of the Cascades along the I-5 corridor. However, the existing transmission infrastructure has reached its maximum transfer capability on key east-west paths, and new transmission is notoriously difficult to build[3]. Because of these factors, transmission constraints are one of the biggest challenges to procuring new, high-quality renewable resources and meeting state or local clean energy goals.

BPA, as the primary transmission owner and operator in the Northwest, conducts annual studies to determine the need and cost for new transmission. In 2021, of the roughly 6,000 MW of transmission demand studied, there was only 305 MW of capacity available to offer without a need for transmission upgrades.

Potential BPA Upgrades

Recent BPA transmission studies identified key upgrades on the Cross-Cascades South path near Portland that could provide EWEB access to more renewable resources. These projects are expected to take 8 years to complete.

[3] How are we going to build all that clean energy infrastructure? (niskanencenter.org)

17 GLOSSARY

Assumptions:
Theorized data such as future load, used to model portfolio options.
Carbon:
Short for carbon dioxide, a greenhouse gas produced by burning fossil fuels and other sources.
Capacity:

- Nameplate: The maximum amount of power a resource can generate.
- Peaking: The amount of power that a resource can generate on demand.

Carbon Price:
A charge placed on greenhouse gas pollution mainly from burning fossil fuels. Often involves a cap on the amount of carbon that can be produced, and sometimes allows producers to trade allowances.
Climate Change:
The rise in average surface temperatures on Earth due primarily to the human use of fossil fuels, which releases carbon dioxide and other greenhouse gases into the air.
Demand:
The rate at which energy is being used by the customer.
Distributed Generation (DG):
The process of generating energy close to its point of delivery. Rooftop solar is an example of DG.
Demand Response:
Incentive-based programs that encourage customers to temporarily reduce their demand for power at certain times in exchange for a reduction in their electricity bills.
Demand Management (also Demand-side Resources):
Activities or programs undertaken by a utility or its customers to influence the amount or timing of electricity they use. DM is often used in order to reduce customer load during peak demand and/or in times of supply constraint.
Energy Efficiency:
Refers to programs that are aimed at reducing amount energy used in homes and other building Examples include high-efficiency appliances, lighting, and heating systems.
Forecasting:
Making projections about future load, resource options, economics, etc.
Generation:
The process of producing electricity from hydroelectric turbines, wind, solar, fossil fuels and other sources.
Load:
The amount of electricity on the grid at any given time, as it makes its journey from the power source to all the homes, businesses.
Megawatt:
The standard term of measurement for bulk electricity. One megawatt is 1 million watts. One million watts delivered continuously 24 hours a day for a year (8,760 hours) is called an average megawatt.
Modeling:
Using industry software and other tools to study and analyze portfolio options.
Peak Demand:
The largest instance of power usage in a given time frame.
Planning Standard:
Planning standards are a set of metrics to define an acceptable level of risk where generation may not equal load. A 1-in-2 standard requires resource procurement to meet a single-hour peak load in an

average year. A 1-in-10 standard requires resource procurement to meet a single hour peak load that is expected to occur once every 10 years.

Planning Reserve Margin:

Planning Reserve Margin (PRM) refers to the amount of additional resource procurement desired above a forecasted peak load to ensure that there is enough generation in the event of unforeseen outages or other emergency situations.

Renewable Portfolio Standard:

A renewable portfolio standard ("RPS") is a regulation that requires the increased production of energy from renewable sources, such as wind, solar, geothermal, and biomethane.

Resource Adequacy:

Ensuring there are sufficient resources when and where they are needed to serve the demands of electrical load in "real time" (i.e., instantaneously).

Resource Portfolio:

All of the sources of electricity provided by the utility.

Scope:

Focus areas for the current planning cycle.

Scenarios:

Possible future conditions outside of EWEB's control that might affect how we meet customers' electricity needs.

Sensitivity:

Changes in input assumptions to test how these impact modeling outcomes.

Supply (also Supply-side Resources)

Power generating resources used to meet electricity needs.

Transmission:

An interconnected group of power lines and associated equipment for the movement or transfer of bulk energy products from where they are generated to distribution lines that carry the electricity to consumers.

Appendices

Appendix A: EWEB Existing Resources

EWEB's existing portfolio of resources is shaped by decisions and investments made decades ago, and augmented by nearer term actions and developments. EWEB owns and operates several 'legacy' hydro resources in the McKenzie River basin that date to the 1920's to 1960's and have provided clean, reliable power for much of the past century. Over the past few years, several of these resources have had alterations to their operations - either to provide environmental benefits such as fish passage, or because structural issues made power generation untenable. These resources are discussed at greater length below.

In addition to these long-lived local hydro assets, EWEB manages a series of resource contracts and ownership agreements. The largest and most important of these contracts is with the Bonneville Power Administration, a federal power marketing authority that provides roughly 80% of EWEB's annual energy. In addition to the BPA contract, EWEB's long-term contracts include wind farms, biomass facilities, and small-scale solar, among others.

EWEB staff manage these contracts to best fit EWEB's needs each year and to alleviate risk associated with serving load with variable resources. This means that in practical terms, in addition to long-term resource procurement, EWEB has mid-term and short-term energy traders to actively buy and sell power as more granular information about EWEB generation and load is available. For example, if the Northwest is having a good water year, EWEB might have energy excess to its needs, and EWEB's traders would sell surplus energy to help offset the costs of investment. Buying and selling power to align with EWEB's needs is part of EWEB's risk management practices and helps maximize the value of EWEB investments and provide stability to EWEB power rates.

EWEB staff also manage the portfolio to account for resources that are more difficult to integrate or bring 'home' to load. For example, the variability of wind resources can require a large amount of dispatchable resources to smooth the wind output and make it useable for a utility of EWEB's size. In these situations, EWEB might sell the generation to another party, or pay another entity (such as BPA or PacifiCorp) to manage the resource's variability and deliver EWEB a more stable generation profile. This type of shaping can account for between one third and one half the cost of a renewable resource power purchase agreement. These costs are discussed in more detail in the New Resource Options section of the IRP.

EWEB-owned resources

Carmen-Smith Hydroelectric Project

EWEB owns and operates the Carmen-Smith Hydroelectric Project (Carmen-Smith Project) within the McKenzie River basin. Carmen-Smith was built in 1963 and a new 40-year federal operating license for the project was issued on May 17, 2019. The Carmen-Smith Project comprises two distinct plants, the Carmen Powerhouse and the Trail Bridge re-regulating unit.

The Carmen Powerhouse houses two generating units with a nameplate capacity of 52 MW each and average annual generation of roughly 23 aMW. Carmen is a highly flexible, energy-limited resource. This means that it can vary power output from hour to hour, but if it operates near peak capacity it will run out of water to generate. For this reason, the output of the Carmen facility is typically shaped within-day to meet EWEB's peak load hours or capture value from high market prices.

The Carmen-Smith Project also includes the Trail Bridge re-regulating facility, which has an additional generating unit with a nameplate capacity of 10 MW. As part of the Carmen-Smith Project operating license, EWEB will be modifying Trail Bridge Dam for fish passage. When the fish passage project is complete, Trail Bridge Powerhouse will transition from a re-regulating generation facility to a low-level outlet from Trail Bridge Reservoir. This means that it will no longer produce power on a regular basis, and only come online for routine maintenance. The date of last generation for Trail Bridge is currently uncertain, as it is dependent on completion of the fish passage projects. This is likely to occur between 2026 and 2028. The 2022 IRP modeling assumes that the Trail Bridge facility will operate until 2028.

Leaburg-Walterville Hydroelectric Project

Below the Carmen-Smith Project on the McKenzie River, EWEB owns and operates the Leaburg-Walterville Hydroelectric Project (L-W Project). The L-W Project is comprised of two separate run-of-river facilities -Leaburg and Walterville. Leaburg is a 15.9 MW facility with an average annual generation of roughly 10 aMW; Walterville is rated for 9MW and delivers about 6 aMW annually. In April 2000, FERC granted a 40-year license for the L-W Project.

In 2018, upon discovering excessive seepage and internal erosion in portions of the Leaburg canal embankment, FERC ordered EWEB to dewater the canal until sufficient repairs had been made. This resulted in loss of generation at the Leaburg facility, which remains offline today. Initial analysis by consultants and EWEB staff indicates that repairing the canal and restoring generation would be very costly. EWEB's Board is poised to provide direction on future operations of the Leaburg facility in early 2023.

Due to the substantial amount of additional analysis required for the Leaburg decision, and because it is a one-off resource decision, EWEB has been pursuing a decision process separate from the IRP for Leaburg. The 2022 IRP assumes that Leaburg will remain offline until 2036, which is the earliest projected date that it could return to service. EWEB currently fills any gaps from the non-operation of Leaburg with market purchases. To the extent that the loss of Leaburg leaves a gap in EWEB's long-term power supply, the IRP will select cost-effective resources to meet EWEB's needs.

Similar to Leaburg, the 9 MW Walterville facility includes a canal diverting water from the McKenzie River. Because Leaburg and Walterville operate under the same operating license, any changes to the Leaburg facility, such as decommissioning or altering powerhouse functions, will cause a reevaluation of the FERC license, with possible repercussions for Walterville's operation. It is currently expected that EWEB staff will conduct additional analysis for Walterville and that the Board will provide direction on its future prior to 2030.

Stone Creek Hydroelectric Project

Stone Creek Project is a 12 MW run-of-river hydro facility on the Clackamas River approximately 45 miles southeast of Portland. The project is located between two hydroelectric facilities that are owned and operated by Portland General Electric (PGE). The Stone Creek facility is operated and maintained for EWEB by Energy Northwest and is licensed through August 2039.

International Paper Industrial Energy Center Cogeneration Project

EWEB and International Paper Company jointly operate a cogeneration facility at the International Paper Springfield plant. The generation unit, which has a nameplate capacity of 25.4 MW and an average output of approximately 20 aMW, is owned by EWEB, with International Paper providing operation support and fuel. Because power output is dependent on industrial processes, IP is not typically operated to maximize power production or react to market price fluctuations. However, there is ability to shape generation if needed. Under the terms of the current agreement, which expires in September 2023, the project costs and output for the IP unit are shared equally by the parties. For the 2022 IRP, it was assumed that the contract will be extended until 2025 as EWEB continues to evaluate future BPA product offerings.

Jointly owned resources

Harvest Wind Project

EWEB owns a 20% share of the Harvest Wind Project in Klickitat County, Washington. EWEB's share of the 99 MW Harvest Wind nameplate capacity is 20 MW, which yields an average annual generation of about 6 aMW. Harvest Wind's annual energy output is relatively stable but tends to be higher in spring and early summer months. The ownership agreement has an expiration date of December 2029.

Contract resources

Bonneville Power Administration

The Bonneville Power Administration (BPA) is a federal power marketing authority that sells the electric output of the federal dams in the Columbia River System as well as the output of the Columbia Generating Station nuclear facility in Washington state. BPA was created by the Bonneville Project Act of 1937 and directed by statute to provide preference in electric sales to public bodies and cooperatives in the Pacific Northwest, EWEB among them. BPA power accounts for roughly one third of the electric generation in the Northwest region.

<u>Current BPA Products</u>

In 2008, EWEB signed a 20-year take-or-pay power contract with BPA called the Regional Dialogue Contract. EWEB's BPA Regional Dialogue Contract consists of two primary products: Block and Slice. Block is a guaranteed, flat delivery of energy that varies by month. Because of the way the product is designed, Block provides EWEB with a very high level of certainty about how much power EWEB will receive from BPA, and what price EWEB will pay for that power.

In contrast the amount of power EWEB receives through the Slice product can vary dramatically each year. This is because Slice represents EWEB's share of the output of the federal system, which changes with water conditions and other factors. At some times of the year, particularly in the late spring and early summer, runoff from snowmelt is high and Slice provides power in excess of EWEB's needs. At other times of the year, or due to weather conditions and high load events, power from Slice and BPA is not sufficient to serve EWEB's needs. EWEB's power traders actively manage this risk as part of EWEB's overall portfolio by buying and selling power to align with EWEB's load expectations and risk tolerances.

2028 BPA Contracts

EWEB's current BPA contract will expire on September 30, 2028. One of the Board's pivotal areas of guidance will be whether to continue purchasing power from BPA post-2028, and if so, at what volumes. While 2028 seems a long way away, system planning and resource procurement have long lead times, and discussions between EWEB staff, BPA, and other utilities in the region have already begun. It is currently expected that contract offerings will be finalized in 2023-24, and contracts would be signed in 2025. Future Board materials, as well as the 2024 IRP, will contain more information about post-2028 BPA contract design.

Stateline Wind Project

In 2002, EWEB purchased 25 MW of capacity from Stateline Wind Project, located in Walla Walla County, Washington and Umatilla County, Oregon. The project consists of 454 wind turbines with a total project nameplate capacity of 300 MW. EWEB receives about 6 aMW of energy from Stateline and the contract expires on December 31, 2026.

Klondike III Wind Project

In 2006, EWEB purchased 25 MW of capacity from the Klondike Wind project located near the town of Wasco in Sherman County, Oregon. The project consists of 125 wind turbines with a total nameplate capacity of 224 MW. Klondike provides about 7 aMW of energy and the contract expires on October 31, 2027.

Sierra Pacific Industries - Seneca Sustainable Energy

In 2010, EWEB signed a Power Purchase Agreement with Seneca Sustainable Energy LLC to purchase the total output of the biomass fueled cogeneration facility located in Eugene, Oregon. Seneca's nameplate capacity is 19.8 MW and expected average output is approximately 14 aMW. The contract for this power expires on April 5, 2026.

Priest Rapids and Wanapum Hydroelectric Projects

EWEB purchases power from the Priest Rapids Project, which is owned and managed by Grant County PUD. The project is composed of the Priest Rapids Dam and the Wanapum Dam, two large hydroelectric facilities on the Columbia River. Under this contract, EWEB's share of physical power from Grant County PUD is 0.14% of the project output, or about 1.4 aMW per year. The contract for this power continues through March 31, 2052.

Solar PV Purchases

EWEB purchases the output of local solar facilities through the provision of net metering rates to customers with small systems that wish to self-generate power, and renewable generation rates for customers with larger systems. To date, EWEB's Net Metered program has a total installed capacity of slightly over 6.8 MW and 0.85 aMW of energy and direct generation contracts with a total capacity of just over 2.8 MW and 0.36 aMW of energy.

APPENDIX B: EWEB LOAD

A first step in the IRP process is defining EWEB's needs. Without knowledge about EWEB's specific loads and consumption profiles, as well as a projection of these into the future, it would be impossible to determine the quantity of resources to procure, including both generation and demand-side resources. While the IRP is focused on EWEB's long-term needs to inform resource strategy, it also includes information about within-year variations in loads. This approach allows EWEB to consider whether the utility has both enough resources to meet customers' average demand for energy over the coming years, as well as enough flexibility and capacity to meet peak demands.

Historic Electricity Consumption

EWEB's average energy consumption can look very different than its peak demands. This is because averaging load information mutes the variability that EWEB's system regularly sees. Using only average energy to think about EWEB's needs would lead to significant under-procurement or the selection of insufficient resources. As a former EWEB employee used to say, "you can't fly through the mountains at an average altitude."

Key Concept - Peak and Average Energy:

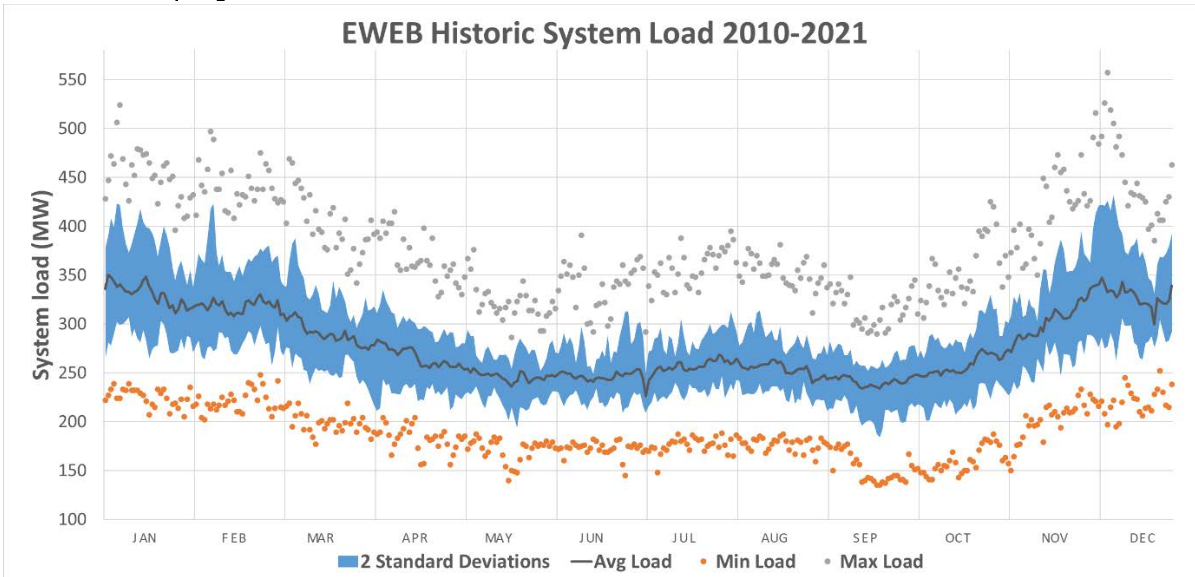
- Average energy usage is the *average* amount of energy used over an extended period of time. This value is typically presented in average megawatts (aMW). This provides a simplified way to think about EWEB's needs, as well as a good reference point to compare long-term trends in electricity consumption or generation.
    - For example, if EWEB customers consume 2.4 million MWhs of electricity over a year, the average energy consumed over that time is 274 aMW. (2.4 million MWhs divided by 8,760 hours in a year.)
- Peak energy use refers to the *maximum* one-hour load within a specific timeframe. Peak can refer to the maximum hour in a day, week, month, or year and is typically presented in megawatts (MW). This is a good reference point for infrequent, extreme energy use.

The chart below shows 2010-2021 historical load data for EWEB's service territory and highlights the extent of recent historical load variability.

Key takeaways:

- The black line represents EWEB's average daily load.
    - EWEB's average daily load shifts seasonally, with winter loads consistently higher than summer loads. **The average daily load ranges from about 240 to 350 MW, depending on the season.**
- The shaded blue portion of the graph that surrounds the black line shows the range of average daily loads that fall within two standard deviations of average. For reference, in a normal distribution curve, two standard deviations cover about ninety-five percent of data points. This does not include within-day variability.
    - **95% of EWEB's historic average daily load falls between 200 and 400 MW.**

- The gray and orange dots represent EWEB's maximum and minimum single-hour loads.
    - **Peak hour (maximum load) events are infrequent, but they can be hundreds of megawatts higher than average loads.** Establishing planning standards to meet these events, and understanding risk tolerances, will be part of ongoing discussions as the IRP progresses.

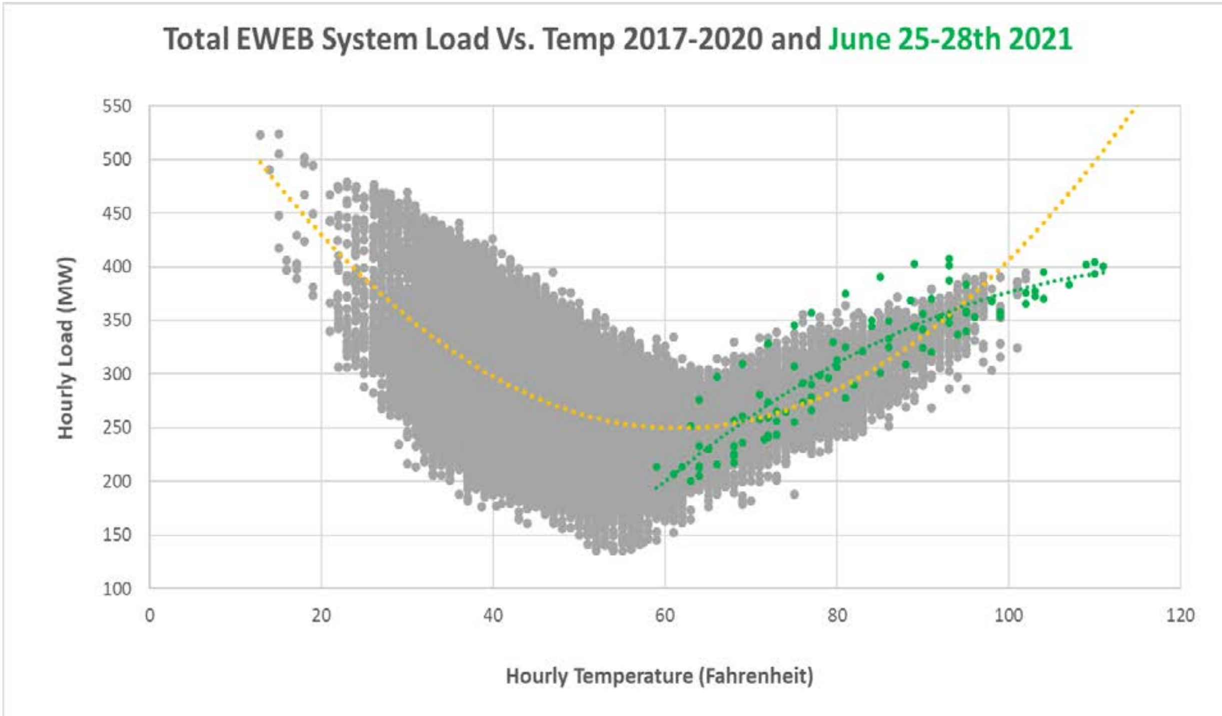


Weather – A Seasonal and Daily Driver of Consumption

Fluctuations in EWEB's loads are driven substantially by the weather due to space heating and cooling energy needs. The chart below shows the correlation between temperatures and EWEB's loads. Each gray dot represents a distinct temperature/load combination for 2017-2020, while each green dot represents the June 25-28th 2021 "Heat Dome" event last summer.

- EWEB's lowest load hours occur when temperatures are between 55 and 65 degrees, conditions with minimal need for heating or cooling.
- The yellow trend line shows the overall correlation between temperature and load. As outdoor air temperatures diverge from a normal indoor temperature "comfort range," load increases. Utilities such as EWEB use Heating Degree Days (HDD) and Cooling Degree Days (CDD)[4] to quantify deviation from the "comfort range" and estimate energy use.
- **Because of our local climate, EWEB historically and presently has more HDD than CDD and the peak winter needs are more frequent and more extreme than the peak summer needs.**
    - Even the 2021 Heat Dome (green dots), which set multiple temperature records, did not match recent winter peak loads.
- Note the variability in load at each temperature – indicating there are a lot of factors that influence load beyond just temperature. For example, **at 40°F the daily load has ranged between 175MW to 425MW.** Factors other than weather that influence load include industrial demands, holidays, day of the week and even the previous day's temperatures[5].

[4] https://www.weather.gov/key/climate_heat_cool - HDD and CDD quantify deviation from the "comfort range" (defined as 65 degrees Fahrenheit). A day with a mean temperature of 76 degrees represents 11 CDDs.
[5] The thermal load of a building changes at a slower pace than the air temperature changes. This can sometimes cause a lag between air temperature change and heating or cooling energy use.



Although air conditioning is becoming more common in the Northwest, it has still not reached full saturation in the building stock. This means that heating still accounts for much more energy use than cooling. The Northwest Power and Conservation Council's 2021 Power Plan estimated that approximately 30% of residential households and 55% of multifamily households do not have air conditioning today. However, it is likely that 98% of residential buildings will have air conditioning by 2050[6] because of rising temperatures and increasingly common heat pump technology. EWEB does not have local information about air conditioning saturation within our service territory; instead, we rely on this kind of regional data to estimate energy consumption associated with cooling.

Summer and Winter Daily Load Shapes

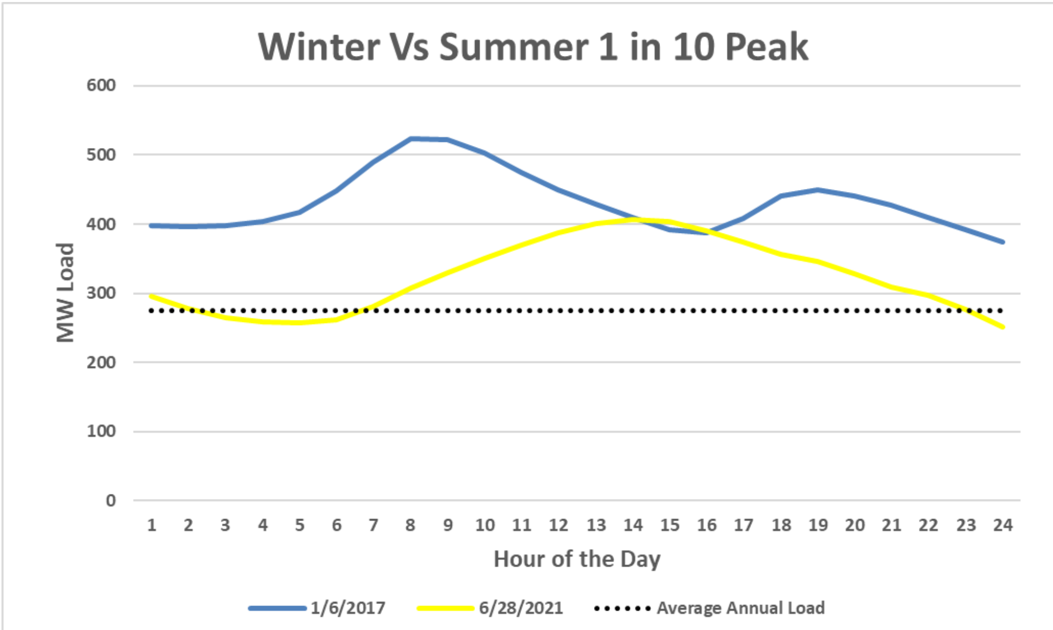
In addition to the broad trend of weather impacts to load discussed above, there are more nuanced and specific load shapes for the winter and summer. The graph below highlights a peak winter day and a peak summer day from the last five years. The winter day has a classic "double hump," which corresponds to heaters being turned on in the morning and evening. In contrast, the load during a summer day gradually increases until it peaks in the mid-afternoon when air conditioners are running the most. These shapes are typical of peak load events when heating and cooling are the major load drivers.

Key takeaways:

- The peak hour of the winter day is presently about 100 MW higher than the summer day.
- For both summer and winter days, the difference between their peaks and troughs is more than 125 MW. This indicates that resources need to be flexible enough to handle this "ramping."

[6] https://www.nwcouncil.org/2021-northwest-power-plan/

- Peak events are longer than just one hour and high load events can last for days due to cold fronts. While some short-duration resources can help meet 1-hour peaks, dispatchable resources or long-duration storage are necessary to meet multi-day needs.



Daily Variability

Not only do EWEB's load and load shapes vary dramatically over the course of the year, but they can vary in unexpected ways or at unexpected times. Holidays, weekends, or events like University of Oregon football games can all impact the load shape during a day and peak usage. Some of these variables are relatively predictable, as they have been observed many times before. Others are less known, and EWEB needs to be adaptable and have access to flexible resources to respond accordingly.

One example of how customer behavior shapes load was the peak event during the Heat Dome (the Monday load profile for 6/28/2021 shown above). Because weekends typically see less commercial and industrial loads, and many people are not at work, weekends tend to have lower loads than weekdays. For this reason, although the hottest days of the Heat Dome were Saturday and Sunday, the actual peak load was on Monday, even as the temperatures began to cool. Interestingly, the 2021 summer peak was a weekday in August, which peaked at 409 MW, in comparison to 407 MW for the June Heat Dome event.

In the past, the shape and timing of these load characteristics were less important from a long-term system planning perspective than they are now, due to the relatively large amounts of dispatchable generating resources, such as coal and natural gas generation, that were available on the system. Now, because of the increasing penetration of non-dispatchable (or variable) renewable resources, the accelerating retirement of coal facilities, climate impacts on water supplies, increasing operating restrictions on hydroelectric facilities, and moratoriums on new gas and nuclear facilities in Oregon, it will be important to consider which resources best match the timing, shape, and variability of EWEB's needs.

Load forecasting – Planning for Future Load

The discussion and graphs in the materials above are all based on historical EWEB data. Historical loads provide context and understanding for what the future might look like, as well as an appreciation for the variability in loads EWEB experiences in a given year, season, day, or hour. To forecast future load, EWEB uses an econometric model with several variables, including Heating and Cooling Degree Days, expected population growth, and Lane County's unemployment rate. In addition, conservation and electrification represent two key variables that impact EWEB's load forecast. It is important to understand each of these key drivers of EWEB's load forecast in greater detail.

Population and Unemployment

As an input to its load forecast, EWEB uses population data for Eugene provided by Portland State University (PSU). PSU forecasts that Eugene's population is expected to grow at 0.8% annually through 2045, and at 0.5% annually after that.[7] For context, since 1970, EWEB's historical population growth rate has ranged from 0.6% to 2.9% and has been about 1% for the past two decades. Increasing population correlates with a higher electricity load, so this indicates that EWEB should expect slight load growth over time due to population increases.

Unemployment data and forecasts come from Oregon's Office of Economic Analysis.[8] The COVID-19 pandemic has had a significant impact on employment over the past two years, and the Office of Economic Analysis Base Case predicts a recovery from this over the next several years. Under baseline assumptions, Oregon unemployment is assumed to remain low (4% to 5.5%) in the next 5 years of recovery before returning to the median 6.6% unemployment rate in 2027.

Electrification

Another major contributor to EWEB's forecasted load is the transition from fossil-based energy sources to electric vehicles and electric space and water heating. This process is referred to as electrification. EWEB's 2021 Electrification Study analyzed the ways in which electrification might impact EWEB. In defining EWEB's energy needs for the IRP, two specific questions posed by the Electrification Study are important:

1. Will EWEB customers transition to electric-based technologies, and at what pace?
2. How will this switch impact EWEB's peak and average energy needs?

Electrification impacts are included as part of EWEB's Reference load forecast for the 2022 IRP. In addition to Reference Case load assumptions, the IRP also considers resource needs for flat load trajectories and increased load/high electrification. Assumptions will be reassessed in future IRPs as actual electric vehicle, water and space heating adoption rates are monitored. IRP sections on *Planning Environment* discuss the drivers of electrification in more detail. Specific load assumption inputs to IRP modeling are discussed in the *Modeling and Analysis* section.

The chart below highlights potential impacts by 2040:

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[7] Past Forecasts | Portland State University (pdx.edu)
[8] forecast1221.pdf (oregon.gov)

- The *average* electric energy increase from transportation electrification is between 57-63 aMW in *both* scenarios. In other words, EWEB is highly likely to see increased load from electric vehicles.
- The impact to *peak* loads will be dependent on whether EWEB can develop policies and incentives that effectively manage customer charging behavior.
- Impacts from replacing gas furnaces with heat pumps could be material by 2040 under an Aggressive Carbon scenario, but these are expected to be less than impacts from the shift to electric vehicles.

EWEB Phase 2 Electrification Study – Cumulative Impacts

2040 - Base Case					
Electrification Measure	% Electrified	Average Energy Increase (aMW)	% Increase	1-in-10 Peak Increase (MW)	% Increase
Electric Vehicle - Managed	85%	57	21%	77	15%
Electric Vehicle - Unmanaged	85%	57	21%	131	26%
Heat Pump Water Heater	50%	1	0.3%	1.5	0.3%
Standard Performance Heat Pump	< 2%	Without significant incentives or mandates, impactful space heating electrification is unlikely if driven by participant economics (consumer choice).			
Cold Climate Heat Pump	< 2%				
Dual Fuel Heat Pump	< 2%				

2040 - Aggressive Carbon Reduction					
Electrification Measure	% Electrified	Average Energy Increase (aMW)	% Increase	1-in-10 Peak Increase (MW)	% Increase
Electric Vehicle - Managed	95%	63	24%	85	17%
Electric Vehicle - Unmanaged	95%	63	24%	145	28%
Heat Pump Water Heater	85%	2	1%	3	1%
Standard Performance Heat Pump*	50%	8	3%	33-61	6-12%
Cold Climate Heat Pump*	50%	4	2%	17-31	3-6%
Dual Fuel Heat Pump*	50%	6	2%	Minimal	Minimal

*Space heating energy impacts shown assume 100% of space heating electrifcation assuming a single technology to illustrate that space heating technology choice matters. In reality, customers will choose a mix of the 3 different space heating technologies. Peak impacts are presented in ranges due to uncertainty regarding coincident load of units. Utilizing AMI data in the future, EWEB could better estimate the coincident load of these space heating technologies.

Conservation (Energy Efficiency)

The last time EWEB conducted an IRP, in 2011, energy efficiency was the most cost-effective resource to meet growth in EWEB's consumption needs. Since that time, it has been EWEB policy to meet 100% of new load growth through conservation. For this reason, it is by far the most common and largest demand-side management strategy that EWEB uses today. EWEB currently sets the conservation financial budget based on load growth forecasts and maximizes energy efficiency acquisition within this constraint.

As shown in the chart below, EWEB efficiency programs are effective in reducing both overall energy consumption and peak demand. In fact, while some measures are more effective than others in managing peak demand, in aggregate, EWEB conservation programs typically have two to three times the impact on peak load than on average load. Staff believe that future residential and commercial conservation efforts may be able to achieve this high ratio of peak reduction, though in industrial settings, peak load energy savings may be roughly equal to average load savings. It is likely that new demand programs will need to specifically target mitigating peak demands, either by reducing consumption or shifting it to another time.

	Load Reductions from Conservation Programs					
	2019		2020		2021	
	aMW	Peak MW	aMW	Peak MW	aMW	Peak MW
Residential	0.3	1	0.27	0.85	0.3	0.96
Commercial and Industrial	0.95	1.2	1.45	2.88	0.91	2.13
Total	1.25	2.2	1.72	3.73	1.21	3.09

Because conservation efforts impact the size and shape of EWEB's loads, the effect of past conservation shows up in historical data. This is important to keep in mind when thinking about EWEB's future load growth, because without conservation, current loads would undoubtedly be higher. Although conservation has been used to meet past load growth, the 2022 IRP does not presuppose that conservation will be the best option for EWEB in the future. Instead, it will be treated the same as all other new resources: If it is cost-effective, it will be selected to meet EWEB's energy and capacity needs. This distinction will be visible in the IRP load forecast, which does not include a reduction to load due to conservation purchases. The IRP's assumptions around conservation as a resource will be discussed in greater detail in August.

Impact of Climate Change on the Load Forecast

Analysis in the Northwest Power and Conservation Council's 2021 Power Plan gives some indication about how loads and resource performance may vary over the several decades due to climate change. As temperatures rise, winter loads are expected to decrease slightly on average, and summer loads are expected to increase on average. Many climate change models also show that the Northwest region will have wetter, rainier winters, and drier, hotter summers.

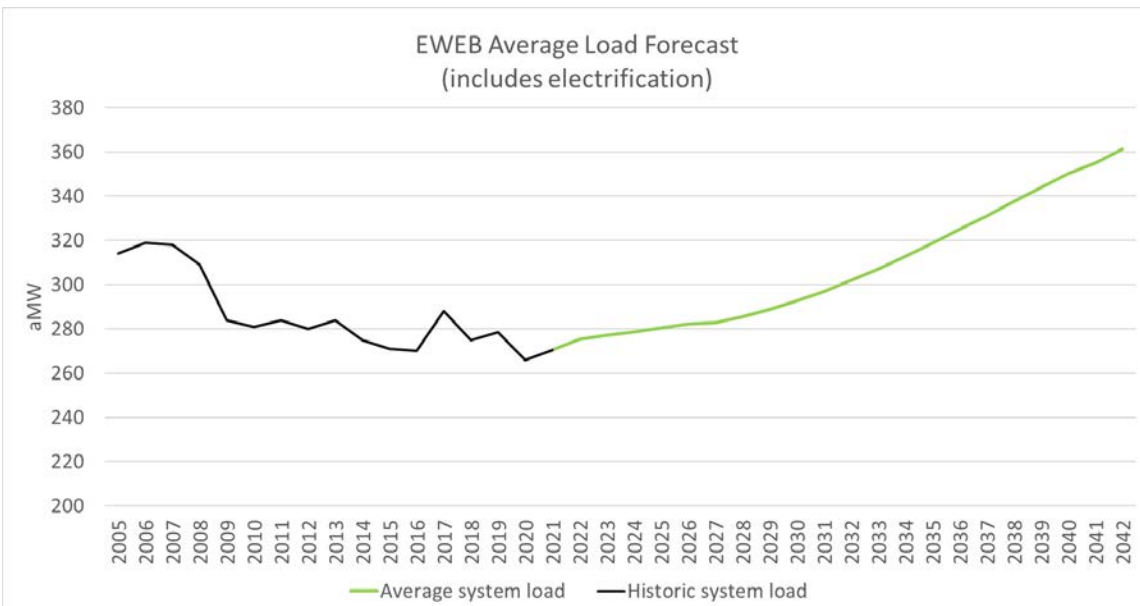
Because the region has significant hydropower resources, these trends will impact not just loads but also generation capabilities. Less water stored as snowpack, along with operational restrictions because of stricter fish and wildlife requirements, may significantly limit hydroelectric flexibility and peak capacity. Over time, with today's resource portfolio, it is likely that the risk of high market prices or reliability events in the summer will increase. Resource characteristics will be discussed in greater detail in August.

To account for the impact of climate change on load, EWEB staff are using the most recent 10 years of summer load data, rather than a full historical data set. Historical climate events such as the 2021 Heat Dome are being factored into modeling as part of the input data. However, forecasted impacts of future climate change on EWEB's loads are not going to be directly modeled in the 2022 IRP. The 2022 IRP is foundational in nature and future iterations of the IRP can include more complex modeling scenarios.

There are several other important things that we know about climate change and EWEB's load that we can use in our IRP planning. First, as described in many of the charts and graphs above, EWEB is a winter-peaking utility. Even with outlier events such as the 2021 Heat Dome, winter loads are consistently higher than summer loads, and outlier winter events drive EWEB's peak load far more than summer events. Additionally, the unpredictability of either summer or winter outlier events will be far more impactful on EWEB's ability to plan and meet load than a gradual shift in annual average temperatures. This means that flexibility and peaking capacity throughout the year are essential when considering generation and demand-side resources.

System Load Forecast: Average Energy

The 2022 system load forecast is prepared by analyzing the key drivers discussed above. With forecasted population increases and electrification, and without a significant increase in commercial/industrial consumption, EWEB expects to see moderate load growth over the next two decades. As described above, our IRP modeling will include electrification but will not assume that conservation purchases will remain at current levels. Instead, our modeling work will examine load (demand) by incorporating population growth and electrification, but will treat conservation as a resource (supply) that can be used to meet that demand.



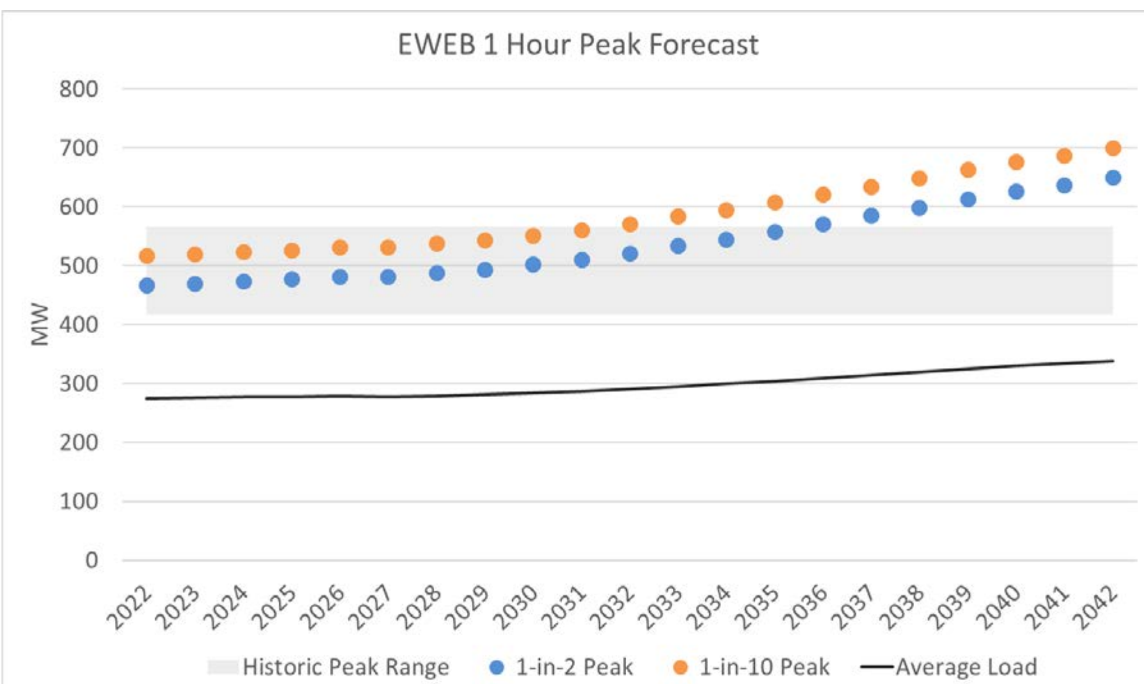
Forecasted population growth and electrification alone are not estimated to increase average energy use beyond 2006 levels (which included approximately 20 aMW from the large Hynix semiconductor plant that closed in 2008) until 2035. Current conservation programs can help mitigate the pace of growth as new resource options are considered before 2028. However, staff recognize that EWEB has seen load decreases over the past fifteen years and the load forecast assumptions have uncertainty. The IRP modeling work can include sensitivities to recognize uncertainties around load growth and the resources the utility may need in the future. These sensitivities can provide guideposts within which to make future resource decisions.

System Load Forecast: Peak energy

Key Concept – Peak Load Probabilities
• Utility planners use "1-in-2" and "1-in-10" to speak about the likelihood of a specific event occurring. A 1-in-2 peak event is expected to occur once every two years – in other words, it has a 50% chance of occurring in any given year. • A 1-in-10 peak event only happens once every 10 years – it has a 10% chance of occurring in a given year. • EWEB uses 1-in-2 and 1-in-10 peak events to analyze how many resources we need in a typical year or under more extreme and infrequent conditions.

As noted earlier, the annual average forecast is a simplified metric that is useful for planning long-term energy needs but does not represent the load variability that EWEB experiences throughout the year. The chart below shows the typical (1-in-2) and less frequent (1-in-10) single-hour peak forecast. It provides a comparison between the average load EWEB experiences and the typical 1-hour system peak.

- EWEB's peak load is expected to grow as average load increases.
- Electric car charging is the primary driver of load growth over time.
    - Demand-side resources such as conservation, demand response programs and time-of-use rates are tools that can be used to "manage" the peak.
    - Many of these programs are considered resources in the IRP, and will be discussed further at the August board meeting.



All peak data presented above represents “unmanaged” load without the influence of EWEB demand-side programs. Unmanaged peak assumes no conservation programs and unmanaged EV charging behavior where customers do not make any effort to shift their charging away from EWEB’s system peaks.

Using peak energy to assess EWEB’s resource needs is a way to ensure that the utility has secured enough resources to meet higher, infrequent (1-in-2) energy needs without routinely relying on energy markets. However, at the same time, purchasing more resources to meet *very* infrequent events (like 1-in-10 peaks) is often not cost-effective. EWEB has historically utilized energy markets to meet the most infrequent peak load needs and to balance our loads and resources. This strategy helps reduce costs but does expose the utility to purchasing energy from the market, which can be costly when the entire Northwest region faces scarcity. Staff plan to explore EWEB’s long-term peak planning standards and market exposure further as the IRP modeling work continues.

Key takeaways

The shape of EWEB’s energy needs vary from day to day and season to season:

- EWEB is a winter peaking utility. Our biggest needs occur on cold days between December and February, and the typical summer peak is 80% of the typical winter peak. These winter peak needs can last for days or weeks, depending on the duration of the cold snap.
- EWEB’s average annual load of 270 aMW only tells a small part of the story. Our system commonly sees loads fluctuate between 200MW and 400MW throughout the year primarily due to customer behavior and temperature variation.
- The load for the typical annual peak hour is 1.7 times greater than the annual average load. Planning for 1-in-2 peak energy usage can help us plan for infrequent events.
- The shape, timing, and daily variability of EWEB’s load will be important to consider as we analyze which resources best match EWEB’s needs.

EWEB’s energy needs are likely to grow:

- EWEB expects to continue seeing population growth, which will drive load growth.
- Transportation electrification is likely to increase both peak and average loads in the coming decades.
- Uncertainty around future load growth can be handled with sensitivity analysis in the IRP.

Appendix C - Policies

Carbon policies

Federal, state, and local governments have all attempted various methods of lowering carbon emissions. These policies can broadly be broken into two groups: 1) incentives and financial support to invest in certain resources, and 2) disincentives and taxes or fees to applied to certain resources or resource characteristics (e.g. carbon emissions). In general, legislators at the state and national level have had more success passing measures that create incentives for resources than they have in passing and implementing taxes or fees. A recent example was in 2019 when Oregon House Republicans walked out of the legislative session to prevent Democrats from passing a comprehensive cap-and-trade bill. In contrast, the federal legislature recently passed the Inflation Reduction Act, which largely provides financial support and incentives for certain investments.

- Policies to incentivize or support investment in resources or characteristics include:
  - **Renewable Portfolio Standard** – a requirement that a certain amount of energy (for a utility or state) must come from a specific list of renewable resources.
    - Renewable Energy Credit (REC) – traceable documentation that represents energy generation from a qualifying facility.
  - **Production Tax Credit** – tax credits (money) given to specific renewable resources for every hour of electric generation they produce.
  - **Investment Tax Credit** – tax credits (money) given to resource developers to help offset the cost of building specific renewable resources.
- Policies to limit or disincentivize certain resources or characteristics include:
  - **Resource bans** – laws that prohibit the construction, operation, or imports of energy from specific resources (largely coal, natural gas, or nuclear).
  - **Carbon Tax** – a tax on carbon emissions, such that low or zero emitting resources pay no or very little tax, while higher emitting resources, such as coal and gas pay a fee.
  - **Cap and Trade** – a cap is placed on total emissions, and regulated entities buy and sell emissions allowances.

Federal Policies

Investment Tax Credit, Production Tax Credit, and EV Tax Rebate

The solar investment tax credit (ICT) was created by the Energy Policy Act of 2005 and provided a tax credit to cover 30% of capital costs to install a solar project. The solar ITC has been used both in large, utility-scale solar projects and behind-the-meter projects on individual homeowner residences. In contrast to this funding mechanism, the wind production tax credit (PTC) provides funding for actual output from a facility. In general, these tax credits allowed developers to offer cheaper prices on power purchase agreements, and spurred investment in wind and solar resources. The federal government has also provided incentives for investment in electric cars through the EV tax rebate, which provides up to $7500 for qualifying new EV purchases.

Inflation Reduction Act

The Inflation Reduction Act (IRA), passed by Congress in August 2022, maintains tax credits as a favored method of spurring development of renewable energy resources. It had previously been expected that all three types of tax credits (ITC, PTC, and EV rebate) would phase out over the next few years. Now, the Inflation Reduction Act has guaranteed funding for these measures for roughly another decade. On top of these incentives, the IRA provides money for individual homeowners to invest in efficient electric appliances and other upgrades. These include incentives to purchase fuel-switching technologies such as heat pumps and heat pump water heaters among other things. All told, the IRA will provide $369 billion dollars on provisions related to climate change and energy security.

With these substantial investments, the IRA is expected to promote development of new clean technologies like battery storage and small modular nuclear reactors, while at the same time further hastening electrification and penetration of wind and solar generators. For EWEB, the IRA will impact both supply-side resource costs, as well as load forecasts. The 2022 IRP will contain sensitivities related to different load trajectories, as well as resource cost trajectories (pending public feedback).

State Policies

Oregon statutes

The Oregon Renewable Energy Act (2007) dictates that each utility in Oregon, including EWEB, must meet certain thresholds for renewable energy, called the Renewable Portfolio Standard (RPS). Currently, EWEB's annual percentage obligation is 20% of qualifying electricity, which increases to 25% in 2025. Although EWEB's hydro facilities and contracts are not considered renewable resources, they are exempt from the RPS standard, meaning that EWEB rarely has additional RPS obligations. In 2021, as in previous years, EWEB had no additional RPS obligations. EWEB's future RPS obligations function as a constraint in IRP modeling work, and these will also be considered in any resource acquisition strategy.

Washington and California statutes

While energy policies in Washington and California don't directly affect EWEB, those policies influence energy markets. For example, both states have passed cap and trade bills that limit carbon emissions and effectively add a cost for carbon emitting resources. This means that when EWEB sells power to other entities in Washington or California, the carbon content of the resource impacts compliance costs.

Local Policies

EWEB's Board amended the SD15 Climate Change Policy in 2021 to support a low-carbon electric power portfolio that maintains, on a planning basis, over 90% of annual energy from carbon-free resources and targets over 95% of annual energy from carbon-free resources by 2030 to the extent possible and practical without distinct adverse impacts to customer-owners. Both the legislated OR RPS requirements and EWEB's Climate Change policies will serve as requirements for planning EWEB's future electricity supply.

APPENDIX D: PHYSICAL VS FINANCIAL RISK

If there are insufficient resources to reliably meet loads in the region, there is potential of increased physical and financial risk and uncertainty for EWEB. Because of this, EWEB monitors market conditions and regional adequacy developments such as the Western Resource Adequacy Program (WRAP), and advocates for improvements to processes and standards.

Physical reliability of the electric grid is governed by the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation (FERC/NERC), and is regionally monitored by the Western Electric Coordinating Council (WECC). This reliability obligation is enforced at the Balancing Authority Area (BAA) Level. Because EWEB is a Load Serving Entity (LSE) and not a BAA, EWEB does not have a direct obligation to ensure physical reliability of the grid. Instead, EWEB's reliability is managed by the BPA BAA.

However, as a load serving entity within the BPA BAA, EWEB is subject to the business practices developed by BPA to ensure its ability to manage the reliability requirements imposed on it by FERC/NERC/WECC. Embedded in these business practices are obligations for EWEB to share load and resource information, as well as maintain a balanced system. To the extent that EWEB fails to perform these tasks, BPA will impose financial penalties proportionate to the size and impact of the infraction. For these reasons, while EWEB doesn't have a direct physical reliability obligation, it does have financial penalty risk from failing to properly manage its service territory.

Balancing Authority

The reliability of any electrical grid is based on supply equaling demand at all times. Any over- or under- supply will cause instability in the grid. The national power grid is divided into independent "balancing areas (BA)" where each BA has assigned a utility or other entity that is responsible for keeping that balance – the Balancing Area Authority. EWEB is not a BAA, but instead operates within the BPA BA.

Simply stated, EWEB cannot generally cause or prevent a loss of load event (blackout), but it is exposed to financial penalties for failing to adhere to BPA business practices and "leaning on" the BAA to serve its needs. EWEB carries the financial risk associated with balancing it's physical position in resource constrained markets, as well as risk of BAA penalties for failing to do so and relying on the BAA to provide balancing services to meet our needs. It is in EWEB's financial interest to properly manage its own physical system.

EWEB Risk Management

Historically, the northwest has ensured reliability through large amounts of surplus energy and capacity from a robust combination of hydro, thermal, and wind resources. Because of this, EWEB has had little difficulty sourcing additional energy to supplement its needs. However, as the region's electric resource mix shifts, sourcing supplemental energy could become more difficult and/or expensive.

Consistent with industry standards, EWEB adheres to its Power Risk Management Procedures, as developed in accordance with Board Strategic Direction Policy 8 (SD8).[9] Through adherence to these procedures, in addition to the risk tolerances built into our Long-Term Financial Plan, EWEB continues to

[9] see: https://www.eweb.org/documents/documents-publications-policies/board-policies.pdf, Pg 46

manage its financial risk exposure. In addition to these procedural tools for managing risk, EWEB has implemented a Financial Reserves Policy which is intended to ensure that we have sufficient reserves to deal with both load and market uncertainties, and to protect our customer owners from unnecessary or unexpected rate increases.

APPENDIX E: RESOURCE ADEQUACY

Over the last several years the region's fleet of electric generating resources has substantially shifted from dispatchable to non-dispatchable[10] units. The primary drivers for this change are 1) a collection of state environmental policies designed to reduce the region's reliance on conventional/combustion resources (e.g., coal, natural gas, and petroleum); and 2) a substantial reduction in costs for renewable resources and battery storage. Despite these changes, many utilities continue to rely on market purchases and liquidity to meet their portfolio needs, especially during periods of peak demand when the need for dispatchable capacity is the highest. This has led to some concern in the Northwest about the impact these changes may have on regional Resource Adequacy (RA):

> **Resource Adequacy** means there is adequate, deliverable generating capability to serve all load requirements peak demand, planning, and operating reserves, at all times.

Resource Adequacy Planning and the WRAP

To plan for resource adequacy, utilities typically perform modeling to consider the probability of reliability events (i.e. blackouts or brownouts) occurring. This analysis is done by simulating thousands of hourly scenarios and is designed to handle load uncertainty (often driven by weather), load forecasting errors, and unplanned generation and transmission outages. This modeling can be used to calculate the likelihood of a resource adequacy issue or "event,"; that is, an hour or more in the study where there is not enough energy to serve the demand load. This is critical information for power planners who use it to estimate if further resources are required to lower the risk to acceptable levels.

Since 2018, EWEB and many other western utilities have been working with the Western Power Pool (formerly Northwest Power Pool) to develop a Western Resource Adequacy Program (WRAP) with the goal of ensuring that participants have access to sufficient resources to meet load during all periods. As part of the WRAP, the region is working to establish a single, shared set of planning standards which would be applied across all program participants. These planning standards are designed to identify the capacity needed to meet a Loss of Load Event (LOLE) objective of "a one day in 10 years" event.

Impacts of WRAP on EWEB

Today, the WRAP is in the non-binding phase of implementation and is anticipated to be fully functional by 2024. EWEB will be deciding whether to participate in the non-binding phase of the WRAP in December 2022. EWEB staff and management believe that the current, voluntary WRAP will likely become a compulsory requirement in the future. As such, it is very likely that EWEB's portfolio will be held to the program standards either directly as a Load Serving Entity (LSE), or indirectly through its contract with BPA.

Current WRAP standards would obligate EWEB to procure resources to meet its 1 in 2 peak hourly load, plus a planning reserve margin. The PRM represents the amount of dependable capacity needed beyond

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[10] A generation plant is dispatchable when, among other things, its fuel supply can be controlled by operators. Plants that burn fossil fuels are dispatchable as long as they have a reliable flow of fuel. Hydro plants with reservoir storage are also dispatchable until the point that the reservoir runs low. Wind plants are *non*-dispatchable since their fuel - wind - cannot be controlled.

the P50 (1-in-2, average peak) load forecast, required to meet an unforeseen period of high demand, unexpected resource outage, or other unexpected condition. Preliminary analysis conducted by the WRAP program indicates that the PRM for the summer will be 10-17% above the 1 in 2 peak, whereas the winter PRM will be closer to 17-27% above. This is a more rigorous standard than currently used by EWEB and is likely to increase portfolio costs.

At this time, final WRAP program details are still being established. As such, EWEB does not currently have a concrete set of RA specifications from WRAP for use in IRP modeling. Staff are planning to include WRAP standards as an additional sensitivity analysis as soon as the necessary information is available.. The results from this analysis will inform future RA policy at EWEB, as well as IRPs, and other capacity related analysis. Until WRAP program details are finalized, and EWEB decides on continued participation, EWEB will continue to utilize the policy and procedural risk mitigation standards that originated with the 2011 IRP and SD8.

Resource Adequacy Metrics

Today, there is no single reliability metric shared across the Pacific Northwest, but instead individual entities have developed their own metrics for measuring and addressing resource adequacy risk. The conventional resource adequacy metric, loss of load expectation (LOLE), quantifies the expected number of days when electric generating capacity is insufficient to meet load. A common reliability criterion is one day of outage in 10 years, often simplified to 0.1 days per year LOLE. Since 2011, the North American Electric Reliability Corporation (NERC) recommended that utilities and other electric service entities use additional metrics to consider the frequency, duration, and magnitude of events. A brief description of these metrics are as follows:

> **LOLEV (Loss of Load Events)**: an incidence metric, is the expected (or average) number of shortfall events per year, where a shortfall event is defined as a contiguous set of hours when load exceeds generating capacity.
>
> **LOLH (Loss of Load Hours)**: a duration metric, is the expected number of hours per year when load exceeds generating capacity.
>
> **EUE (Expected Unserved Energy)**: a magnitude metric, is the expected amount of unserved energy (or the average sum of the positive differences between hourly load and generating capacity) per year, in units of megawatt-hour per year.[11]
>
> **LOLP (Loss of Load Probability)**: a frequency metric, used by the Northwest Power and Conservation Council (NWPCC) to analyze the probability that a given year will have an adequacy shortfall. The LOLP is calculated as the number of simulations in which at least one shortfall event occurred divided by the total number of simulations. The Council deems the power supply to be adequate if the LOLP is 5 percent or less. That is, the power supply is adequate if the likelihood of having one or more shortfalls in an operating year is 5% or less[12].

[11] Three probabilistic metrics for adequacy assessment of the Pacific Northwest power system https://www.sciencedirect.com/science/article/pii/S0378779619301713
[12] NWPCC – 2021 Northwest Power Plan. https://www.nwcouncil.org/reports/2022-3/

Individual Resource Capacity Accreditation

Similar to metrics used for measuring resource adequacy, there are also multiple metrics for measuring an individual resource's contribution to system adequacy. The WRAP's QCC metrics are intended to provide a consistent and sound method for evaluating the value of existing and new resources towards meeting load obligations. QCC values incorporate one of the more common resource evaluation metrics, called Effective Load Carrying Capability (ELCC). ELCC is calculated by simulating the operations of the electric system both with and without a specific resource and measuring the amount of additional load that can be served by adding that resource.

Dispatchable resources (like thermal generating units) often receive a capacity value close to 1:1, which accounts for forced outages or other derating due to operating constraints. Variable resources (like wind, solar, and run-of-river hydro) typically have ELCC values that reflect their coincidence with peak system needs. Storage hydro, which has the ability to be dispatched in response to changes in load (subject to water variability), can be assigned a capacity value using ELCC or other methods which consider both variability and dispatchability characteristics unique to the resource. Given the challenge of modeling for ELCC values, planning analysts often rely on reputable ELCC studies or other simplified capacity accreditation methods to reduce modeling and analysis time when assessing resource adequacy.

APPENDIX F: NEW RESOURCE OPTIONS

For the 2022 IRP, the list of resources under consideration is not meant to be exhaustive, but instead provides touchpoints to understand what types of options might be valuable to EWEB in the future. These resource options do not represent specific power purchase agreements or power generating resources available for sale, but instead uses publicly available data to estimate the costs of new generation or demand-side programs.

In the 2022 IRP, EWEB used a standard approach to model candidate resources, where a resource must be:

- An existing or proven technology
- Deliverable to EWEB load
- Commercially operational today, or under contract to be operational within the next 10 years

For the 2022 IRP, staff is keeping a wide-ranging list of new resource options on the table. This approach is intended to provide the Board with as much information as possible about the tradeoffs between different portfolio options. The tradeoffs communicated will go beyond a single cost metric and provide color on performance under various market conditions, reliability value, risk factors, and fit to EWEB's values.

Resource cost, potential, and performance assumptions are the output of a collaboration between EWEB staff and Energy and Environmental Economics, Inc. (E3), a leading energy consulting firm. Source data includes other utilities' IRPs, reliability studies, industry standard software (Aurora), Energy Information Agency (EIA), the National Renewable Energy Laboratory (NREL), the Oregon Department of Energy, Bonneville Power Administration, the Northwest Power and Conservation Council, proprietary E3 analysis, and publicly available E3 studies.

The broad categories of resources considered in 2022 IRP analysis are listed in the table below. A more detailed list of resources and attributes is provided below.

Resource Type	Examples of Available Options
Natural Gas Generation	• **Simple-cycle combustion turbines (SCCTs)** • **Combined-cycle combustion turbines (CCCTs)**
Renewable Generation	• **Utility Scale Solar PV** • **Community Solar Projects** • **Residential rooftop solar** • **Wind (onshore & offshore)**

	• **Cogeneration/Biomass**
Energy Storage	• **Battery storage (4 hour)**
BPA Products	• **Block** • **Slice**
Customer Technologies	• **Energy efficiency** • **Demand response**
Additional Resource Options	• **Nuclear small modular reactors (SMRs)**
Resource options not considered in 2022 IRP cycle*	• ***Pumped storage (>12 hour)*** • ***Long duration storage*** • ***Geothermal*** • ***Other zero-carbon firm technologies (biomethane, hydrogen, fossil fuel generation with carbon capture technology, etc.)***

*Options listed in italics are emerging or less accessible technologies and are not included as resource options in the current IRP cycle but could be considered in future IRPs.

New Resource Descriptions & Discussion

BPA

The majority of EWEB's energy comes from the Bonneville Power Administration, a federal power marketing authority that sells the generation output of federal dams in the Pacific Northwest (along with other resources such as the Columbia Generating Station nuclear facility). EWEB's Bonneville contract will expire in 2028, and EWEB will need to decide whether to renegotiate with another long-term contract. This BPA contract decision is planned for 2025 to allow adequate time for implementation prior to 2028.

EWEB's current power contract is broken into two main products: Block and Slice. The Block product requires that BPA deliver a specified, guaranteed amount of energy to EWEB every month. It is not shapeable or variable. In contrast, the Slice product represents EWEB's share of the Federal Columbia

River Power System (FCRPS) output. The output of the FCRPS is shapeable and flexible, but it is also highly variable seasonally. Slice generation fluctuates over the course of the year and from year to year, depending on water conditions and fish and wildlife requirements. With Slice, EWEB accounts for BPA hydro variability in its budget hedging and portfolio management processes. With Block, the impacts of hydro variability will manifest as biennial changes to BPA rates for the block product. In almost all years, changes in hydro generation represent one of the most significant risks to EWEB's power costs.

Analytical work for the 2022 IRP assumes that future BPA products and service options will look similar to those that exist today. As a business-as-usual assumption in the 2022 IRP, the quantity and costs of energy & capacity available from BPA are roughly the same throughout the study period, accounting for inflation. Information about near-term rate trajectories, namely that BPA rates are projected to remain roughly flat through 2025, was included in the analysis.

As 2028 BPA contract negotiations continue and more specifics are available, EWEB staff will incorporate these into future modeling work. Aside from contract details, other risks for the BPA product include climate change and operational changes for fish passage. Regional discussions include breaching the Lower Snake River Dams to benefit Snake River Salmon, and litigation over the operations of the federal dams' limits flexibility. See the Fuel Cost Risk section below for further discussion.

Other Hydro

Due to the difficulty in siting and permitting new hydroelectric resources, rehabilitation of EWEB's Leaburg facility is the only 'new' hydro resource that will potentially be considered in the 2022 IRP. Power Planning staff is coordinating with EWEB's finance and generation team and participating in ongoing Leaburg analysis discussions to determine whether sufficient information on Leaburg rehabilitation costs and power attributes will be available in time to include them in modeling work. Staff will update the Board as more information is available.

Solar

Solar resources have dropped significantly in cost over the past decade and are expected to account for nearly half of new resource builds in the US in 2022[13]. Most solar resources that are planned in the Pacific Northwest are being sited to the East of the Cascades where cloudy skies are less frequent, and solar generation potential is higher.

Utility-Scale Solar

Because the value of solar resources is highly location-dependent, the 2022 IRP uses several different location assumptions for utility-scale projects. These include sites across Eastern Oregon and Idaho. Utility-scale solar annual **capacity factors**[14] in the IRP range from about 21% to 28%. However, for winter-peaking utilities like EWEB, it is also important to consider winter peaking capacity contribution[15]. For utility-scale solar this can range between 7-14% depending on the region. To the extent that EWEB remains a winter-peaking utility into the future, the value of solar may be less

[13] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis

[14] Capacity factor measures how often a plant is running at maximum power. A plant with a capacity factor of 100% means it's producing power all the time. Capacity factors can be calculated by month (to illustrate seasonality) or annually to show the resources ability to meet annual energy needs.

[15] See Peak Capacity Contribution section below for more details.

desirable compared to other resources. Solar resources may also have different transmission costs and risk depending on location. Transmission costs and availability are discussed in more detail below in the *Transmission* subsection.

Community Solar

Community solar, where project benefits flow to multiple EWEB customers instead of individual homeowners, is expected to have roughly a 13.5% capacity factor in Eugene. This lower capacity factor is primarily due to siting in the Willamette valley as opposed to Eastern Oregon for utility-scale solar. Community solar also requires a larger capital investment per installed MW compared to utility-scale resources due to lack of economies of scale, and lack of ideal siting options. However, community solar's proximity to EWEB loads means that it will have lower transmission costs and may provide other resiliency/local benefits. To facilitate community solar programs, EWEB may need to invest in billing system upgrades or other administrative support functions.

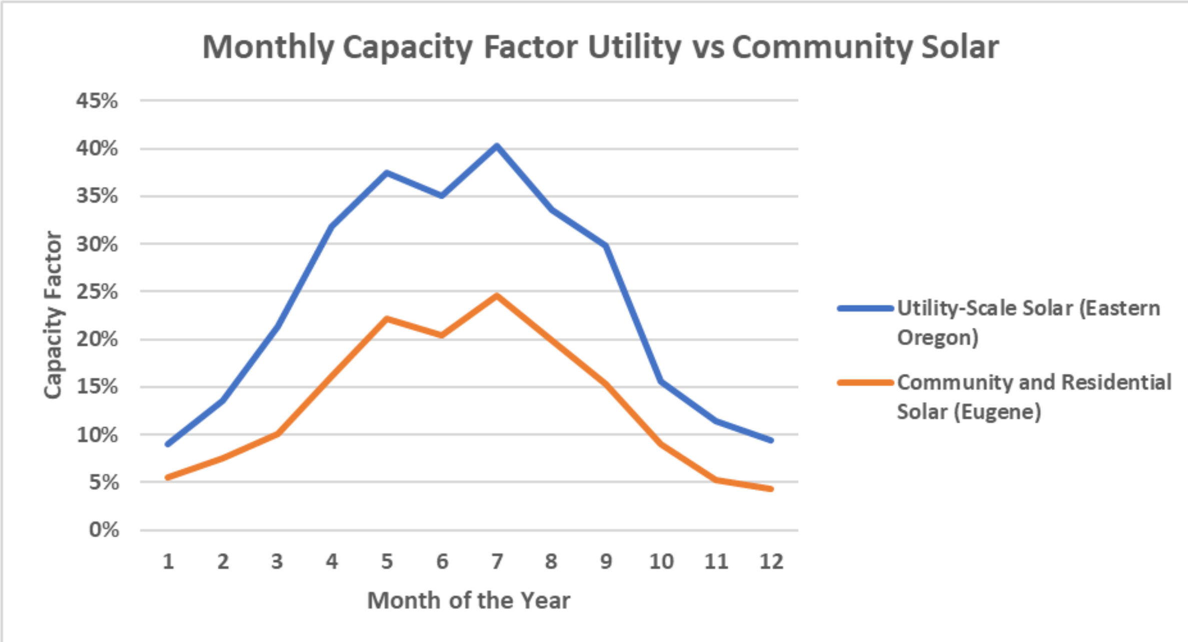
Residential Rooftop Solar

The IRP will include residential rooftop solar as a new resource option. Although residential rooftop solar has roughly the same capacity factor as community solar, and many similar benefits, it is more expensive per kW due to siting and other considerations. It is also typically less accessible to all customers than community solar options due to financial hurdles and home-ownership requirements. Cost assumptions for residential solar in the IRP use actual installation costs from projects in EWEB's service territory. Current analysis does not include program incentives, as the intent of the IRP is to compare resource costs on a level playing field by estimating typical costs across a wide population of customers. The levelized cost of energy for residential rooftop solar is estimated to be between $120/MWh to $350/MWh depending on assumptions such as useful life, energy production, federal incentives, cost of borrowing and installation costs.

Solar resource comparison

The graph below provides a monthly comparison of utility-scale solar vs community solar capacity factors. Across all months, a utility-scale facility is likely to output more generation than community solar. The reason for this is due to different climates and sun exposure between Eugene and Eastern Oregon.

The graph also shows that during peak winter loads when days are short and there is often significant cloud cover, solar resources are likely to have a capacity factor less than 10%. For this reason, solar resources are generally a more expensive option for meeting winter needs. Not shown here, the diurnal pattern of solar production means that it does not align with morning and evening peak loads (see peaking capacity contribution metric).



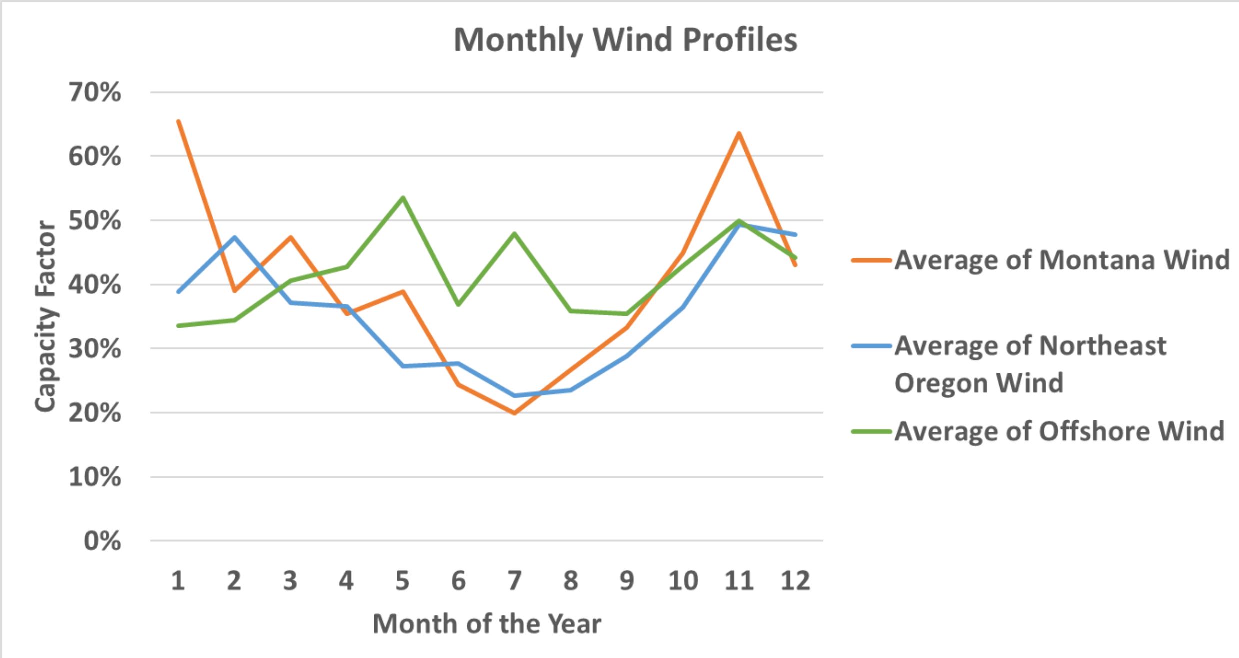
Solar resources typically contribute less than 10% of their nameplate capacity[16] during peak winter loads when days are short and there is significant cloud cover. For this reason, solar resources are generally a more expensive option for meeting winter needs. Additionally, the diurnal pattern of solar production means that it does not align with morning and evening peak loads.

Wind

Like solar, the cost of wind resources has declined over the past decade and wind is expected to account for roughly 17% of new resource builds in the US in 2022[17]. Wind resources in the 2022 IRP can be generally categorized into three broad buckets: 1) Eastern Oregon and Washington, 2) Montana and Wyoming, and 3) Offshore. Like solar resources, wind development is highly location dependent, and the specific value and attributes of a given wind farm are impacted by siting.

In general, Montana and Wyoming resources have better winter profiles than Oregon and Washington wind. However, there are substantial limitations to transmission availability from Eastern Montana and Wyoming into the Pacific Northwest. Offshore wind (OSW) has a relatively high year-round capacity factor, but it also has high initial capital costs and transmission development challenges. As with solar resources, transmission cost and availability are discussed in greater detail in the *Transmission* section.

[16] A power plant or generating facility has a "nameplate capacity" which indicates the maximum output that the generator can produce.
[17] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis



Natural Gas

The 2022 IRP includes natural gas plants as a resource option because they are an energy industry standard generator that has low up-front capital costs, provide baseload capacity, and can have the flexibility to meet peak loads. Despite these benefits, natural gas plants have tradeoffs, primarily related to fuel risk, carbon emissions, and policy constraints. For example, Oregon and Washington have passed legislation that prohibits or discourages building natural gas generation within state boundaries. This means that while gas plants could be cited in Idaho and delivered to EWEB load, developing a gas plant presents a substantial risk and challenge.

Studies by E3 and other energy analytical groups have found that natural gas plants could play a key role in maintaining electric system reliability in the transition to renewable energy sources[18]. This is because natural gas is easily stored, and gas plants can sit idle most of the year and only operate during peak load events.

There are two primary types of gas generators: simple-cycle combustion turbines and combined-cycle combustion turbines. Simple-cycle turbines are less efficient, but they have lower capital costs, are more flexible, and have faster startup times. Combined-cycle turbines are more efficient, but they are less flexible and can take longer to come online. Combined-cycle systems generally serve base and intermediate loads to the grid, while simple-cycle systems generally serve peak load.

Cogeneration/Biomass

[18] Pacific Northwest Pathways to 2050 – E3
https://www.ethree.com/wp-content/uploads/2018/11/E3_Pacific_Northwest_Pathways_to_2050.pdf

The IRP includes a generic cogeneration/biomass plant Cogeneration and biomass plants are two types of thermal generation resources that offer efficiency or environmental benefits over traditional gas turbines. A cogeneration plant recycles the excess heat waste from power generation for other uses, and biomass plants use plant matter, rather than gas, for an energy source. Biomass plants can receive renewable energy credits for their energy and may be considered carbon neutral depending on methodology. These resources tend to have significantly higher capital costs than natural gas plants because they are more complex and tend to be 'one-off.' Most biomass and some cogeneration can be operated flexibly and dispatched to meet peak loads. However, these generation facilities are highly location specific and can have fuel constraints and operational considerations other than power generation which limit their ability to meet peak needs of the utility

Small Modular Nuclear

Multiple companies have been working to develop small modular reactor (SMR) power generation over the past decade. Their designs have passed numerous legal and regulatory hurdles, and several are under contract to be constructed by 2030. SMR facilities are intended to alleviate some of the downsides of older nuclear facilities, such as scalability, flexibility, and safety risks. They can be deployed at smaller MW capacities and 'scaled' up if demand exists. They also incorporate passive safety technology that is designed to be a failsafe in the event of an emergency. Aside from hydro, nuclear is one of the few carbon-free resources that is flexible and dispatchable.

Still, there has not yet been a new SMR resource built in the US, and there is substantial uncertainty about whether future cost estimates will be accurate. Additionally, Oregon has deemed that no nuclear plants should be built within state boundaries until a national nuclear waste facility is established. Staff have included SMRs in the IRP as a new resource option as a 'proxy' clean, firm resource. If carbon policies continue to become more stringent, there may be a point at which more expensive emerging technologies such as SMR (or hydrogen and other forms of energy storage) become necessary or financially viable. SMR facilities could potentially be sited in Washington or Idaho.

Batteries (4-hour)

The IRP includes 4-hour lithium-ion batteries as a new resource option. Batteries have both a storage capacity value and a dispatchable nameplate capacity value. For example, a 400 MWh battery with a 100 MW nameplate has enough storage to dispatch at its total capacity for 4 hours, at which point it will be out of energy. This size of battery is relatively standard in the utility industry because it pairs well with solar resources to help meet evening peaks in hot, sunny climates. Batteries are useful for providing capacity at critical times but have limited amounts of energy. This technology represents a "capacity only" value to the utility where it can be used to provide energy to meet peak needs.

In the Pacific Northwest, these short-duration energy storage resources can contribute to reliability but have important limitations in their ability to meet the region's resource adequacy[19]. Meaning that during long-duration cold-weather events, the battery will be unable to provide enough energy for a sufficient amount of time. Longer-duration storage can solve this issue, but because battery costs are

[19] https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf

directly related to the amount of storage they can provide, an 8-hr lithium-ion battery is significantly more expensive than a 4-hour battery.

Pumped hydro storage was not included in the 2022 IRP because it is much less common due to high capital costs and lack of siting options. Other emerging storage technologies such as power to gas and other battery types were also excluded as they are unlikely to be realistic resource options for EWEB within the next 10 years. Future IRP work can consider these options.

Energy Efficiency

Over the past decade, EWEB Board policy has prioritized energy efficiency as the preferred resource to meet load growth. This is because energy efficiency is often a cost-effective resource, is available in the Eugene community, has carbon reduction benefits, can reduce the need for transmission/distribution investments, and can be acquired in smaller amounts than traditional resources. The 2022 IRP will treat energy efficiency options the same as other new resources, meaning that it will have cost assumptions, energy and capacity values, and it will be evaluated and selected based on cost-effectiveness.

To create modeling inputs, staff grouped energy efficiency options in Eugene into bins by analyzing data from the Northwest Power and Conservation Council and Bonneville Power Administration's Utility Energy Efficiency Potential Calculator[20]. In total, the model will include 6 cost bins each of commercial and residential energy efficiency measures (12 total). The bins lump together measures that have similar costs, and include items such as ductless heat pump upgrades, weatherization, LED lighting, and water heaters, among others. Each bin will have its own potential (resource availability per year) at a specific cost with the next bin having progressively higher levelized costs. This approach will help EWEB identify the extent to which energy efficiency is a least-cost resource compared to other alternatives. To illustrate the attributes of Energy Efficiency compared to other resource options, the 12 energy efficiency bins have been consolidated into two large cost bins (see Appendix A).

One of the tradeoffs to energy efficiency as a resource is its scalability. Although energy efficiency is effective for managing small amounts of load growth, there are limits to how much conservation can be acquired, and acquisition rates take time and effort to increase. While more conservation is available, EWEB has acquired less than 2 aMW of conservation each year for the past decade (for context, EWEB's average load is around 270 aMW).

Many of the current energy efficiency measures that EWEB pursues are in the residential sector (heat pumps, weatherization etc.). However, initial analysis of cost-effective potential, as well as information from internal EWEB discussions, indicates that there is likely substantial un-tapped conservation in the commercial sector that is less expensive on a $/kWh basis than in the residential sector. Further analysis of EWEB's conservation program, combined with a future conservation potential assessment, could provide more granular information on these issues and opportunities.

Demand Response (DR)

Demand response is a tool that EWEB can use to reduce peak loads by means of incentives to shape customer behavior. Similar to batteries, DR is a capacity only type resource and has a limited amount of energy that can be provided for a short duration of time. Demand response can apply to commercial,

[20] Utility Toolkit - Bonneville Power Administration (bpa.gov)

industrial, or residential customers, although programs for these can vary dramatically. Industrial demand response programs are typically a unique agreement to reduce load under certain conditions, such as peak events or high market prices. In contrast to this, residential demand response programs can be generic, with the same rules or incentives applying to many customers. These can vary from voluntary participation, such as a notice to receive a discount for reducing load on a certain day, to 'automatic' participation, where EWEB directly controls customer thermostats or other smart devices.

IRP modeling is based on 8 different program options, which are represented in the broad categories below. Most demand response programs are opt-in, meaning that customers choose to participate.

- **Time of Use Rates:** EWEB would charge different rates at different times of day to incentivize customers shifting high-use activities to hours when power is less expensive.
- **Direct Load Control:** EWEB would have direct control over customer appliances such as HVAC and water heaters, and be able to turn them off or down during peak events.
- **Critical Peak Pricing:** EWEB would implement very high prices, or offer rebates for lowered electric usage, during peak load events.
- **Managed EV Charging:** EWEB would have control over customer smart charging stations and shift charging to more desired times of day.
- **Commercial and Industrial Curtailment:** EWEB would pay large industrial or commercial customers to reduce their load, typically by shutting down production.

Each program's cost and performance characteristics are different. The costs are based on estimates from Cadmus consulting work from 2018 as well as Northwest Power & Conservation Council's DR cost estimates. Overall, DR pricing programs like time of use and critical peak pricing are estimated to be the least-cost options for demand response, as there are not many additional investments needed once advanced metering and billing systems are in place. Other programs are likely to require more investment to establish. A future demand-response potential assessment could provide more granular data as well as a better estimate of the costs needed to establish effective DR programs.

Although demand response may reduce EWEB's peak load, it does not typically reduce EWEB's energy needs. Instead, it is likely to shift those needs to other hours. For example, a demand response program to control HVAC during a heat wave will need to pre-cool the building before the event, and then re-cool it after the event. Demand response is also limited duration, meaning that it will be less effective during prolonged peak events.

Demand response programs often have small marginal costs to provide incentives to participants, meaning that there is not a significant investment for EWEB to add additional participants once programs are established. However, many demand response programs require large investments in metering infrastructure, installation of switches, or 3rd party software subscriptions to aggregate and control smart devices. In addition, programs can require marketing and staff time to support. Additionally, DR programs are similar to energy efficiency in that there is limited potential to implement them, and they typically cannot be scaled more than several MW at a time.

Resource Characteristics

Every resource has unique attributes, and tradeoffs, that must be considered when assembling a portfolio. The subsections below discuss several of the primary attributes that will be used to evaluate resources for the 2022 IRP.

Levelized Cost of Energy (LCOE) – shown in $/MWh

Each resource has different capital costs, operating costs, and energy profiles, among other factors. These differences can make it difficult to compare the relative value of one resource to another. To create a more 'apples to apples' comparison, utility planners frequently use levelized cost of energy. LCOE looks at the total cost of building and operating a resource in comparison to how much energy that resource produces over its lifespan. If a resource has a high LCOE, that means every MWh of energy it produces costs more than other resources. Similarly, a resource with a lower LCOE is less expensive per MWh. LCOE is generally a good tool for understanding the value of a resource's ability to produce energy over many years of operation.

The drawback to using LCOE as a comparison tool is that it is agnostic about the timing of a resource's energy production, or other resource characteristics. For example, the shape of energy output for wind and nuclear facilities are completely different, but that information cannot be gleaned from comparing their LCOE, which only looks at the total amount of energy they produce. This means that a resource with a lower LCOE might appear favorable compared to an alternate resource that better aligns with the seasonal shape of EWEB's needs. Similarly, LCOE does not consider a resource's dispatchability, flexibility, or carbon emissions. Because they are only used a few hours per year to ensure grid reliability, resources that are used for peaking capacity produce fewer MWh of energy annually. These resources will have higher LCOE as the costs are allocated among fewer MWh of energy production.

Peak Capacity Contribution - shown as a percentage of nameplate capacity

A resource's peak capacity contribution is its ability to provide energy during EWEB's peak load events. This number is important for planning because it represents the value a resource will have under times of high system stress. In the past, calculating this value was simple; most resources (aside from hydro) were thermal plants like coal and natural gas that could be ramped up and down when peak load events were expected. They effectively had a peak contribution close to one hundred percent, meaning for every MW of installed nameplate capacity, you could count on that resource for about one MW of capacity during peak needs. As the region shifts to greater penetrations of renewable energy, calculating a resource's contribution during peak events has become much more complex. This is because peak contribution depends not just on a resource's attributes, but also on overall system needs and the portfolio mix that serves the system.

EWEB's peak capacity contribution values for new resources are driven by peak winter and summer needs, as well as the ability of existing resources to meet those needs. If EWEB is short on resources in the summer but not the winter, a new resource with a strong summer profile will have more value than a resource that is available in the winter.

In addition to the considerations above, there are diminishing returns as more capacity of a given resource is installed. This is especially true of variable resources. This occurs because renewable generation typically does not align with peak needs and this energy cannot be shifted to other times without using another resource type (e.g., battery storage or hydro).

The peak capacity contribution values in the IRP are reflective of EWEB's needs as well as E3 studies on resource adequacy in the Pacific Northwest. In addition to these values, future analytics work will reflect resource Qualifying Capacity Contribution (QCC) metrics from the Western Resource Adequacy Program (WRAP).

The WRAP is a regional program intended to ensure that load serving entities invest in sufficient resources to meet their peak needs[21]. Although EWEB does not currently have an obligation to meet WRAP standards, these standards could become binding in the future. If this occurs, the QCC value that the WRAP assigns to new and existing resources will be materially impactful on EWEB's portfolio costs and selection. QCC values are similar to EWEB's peak capacity contribution values but use a different methodology and reflect the needs of the entire Northwest electric system. See the *Resource Adequacy* section for more information.

Cost of Peak Capacity Contribution - shown in $/kW-month

The cost of peak capacity contribution is the cost to add 1 MW of peak capacity for a given resource. This number is intended to contrast with LCOE and give an indication of the cost of a resource for meeting EWEB's peak needs. Because the cost of peaking capacity is focused on a limited number of hours, it is agnostic to the energy produced at other times of the year. In general, resources that are flexible and dispatchable will have lower cost of peak capacity contribution. The cost of peak capacity is expressed in $/kW-yr. This can be thought of as the recurring payment to have a resource on standby and ready to deliver energy if EWEB has a need.

Key factors that impact a resource's peak carrying capacity:

- Annual and daily energy shape – if a variable energy resource has an energy shape that does not align with EWEB's (or regional) peak needs, it will not be able to be relied upon during those times.
- Dispatchability – If a resource can be turned on in times of need, it will have a higher carrying capacity.
- Flexibility – If a resource can increase or decrease output over a short amount of time, it will be able to help meet peak hours within a day.
- Energy limitation – Resources that rely on limited fuel supply (e.g., some hydro and battery) will be less valuable in longer-duration load events.

Carbon Intensity – shown in MTCO2e/MWh

Board Policy SD15 states that on a planning basis EWEB should target a portfolio that gets 95% of its annual energy from carbon free resources by 2030. The 2022 IRP includes carbon-emission assumptions for each resource option, as well as constraints to include only portfolios that meet EWEB's carbon

[21] WPP (westernpowerpool.org)

goals. IRP modeling is currently limited to emissions associated with the production of energy, and not life-cycle emissions for each resource.

Based on the emissions associated with energy production, wind, solar, hydro, energy efficiency, and nuclear are all treated as carbon-free. BPA's carbon intensity is low based on Oregon DEQ requirements and its carbon content is primarily caused by unspecified market purchases. The carbon intensity of electric output for all thermal resources is a function of both the efficiency of the unit, and the fuel that is burned. For cogeneration and biomass, accounting for carbon and other particulate emissions is more complex. Burning waste products has an inherent efficiency for the operations of a facility, but it also impacts the emissions profile of the electricity generated.

Battery storage and demand response have a carbon intensity unless they are specifically paired with a carbon-free resource. Batteries that charge from the market will have some level of emissions related to market carbon intensity, and demand response typically moves energy consumption, but does not eliminate it. Thus, accounting for the carbon intensity of battery storage and DR depends on the circumstances. For 2022 IRP modeling, EWEB has chosen not to assign a carbon intensity to DR or batteries.

The *MTCO2e/MWh* value in EWEB's cost comparison matrix is a standard metric used in the energy industry and represents 'metric tons of CO2 emission equivalent per MWh of energy produced.' The emission rates for natural gas plants reflect inputs from EWEB's Aurora IRP model. Market emissions rates vary daily, but EWEB is conservatively assuming that any market purchases to serve load or charge batteries reflect natural gas emissions.

The analysis of the 2022 IRP has been focused on direct (scope 1) carbon emissions from the use-phase of various resource operations. From a climate perspective, we recognize that there are additional emissions associated with the manufacture of generating resource infrastructure (the making of solar panels, wind turbines, hydroelectric dams or thermal plants for example) as well as the decommissioning of this infrastructure at the end of its useful life. These upstream and downstream emissions are outside the scope of this 2022 IRP. Additionally, we know and acknowledge that every resource has a variety of other environmental and social impacts. These include but are not limited to: Mining impacts for raw materials; water use and pollution; land use for raw material extraction, project development or transmission; local air pollution; disposal or storage of waste; ecosystem, biodiversity, species impacts and disruptions; human health impacts; worker treatment impacts; environmental justice and equity impacts; and economic development impacts, among others.

Although these impacts were not included on the resource attributes in Appendix A, they may factor into future decision making. The Board will contribute to what types of additional impacts they wish to consider, and these may become the focus of future analytical work.

Fuel Cost Risk

Fuel is a major cost driver for many resources and volatility in fuel prices can be a large risk factor for these. The Fuel Cost Risk attribute on the resource comparison scorecard is meant to capture a qualitative assessment of the fuel risk for a given resource. In general, renewable energy resources have low fuel risk, as these fuels are 'free.' In contrast, natural gas prices can be extremely volatile and have uncertainty both in the long-term and short-term. Nuclear facilities rely on refined uranium, and while there is some uncertainty and volatility in fuel prices, these are a much smaller part of overall operational costs than for natural gas plants.

Bonneville power contracts hold some fuel cost risk because there is uncertainty about generation year to year, in addition to potential impacts of climate change. There is also significant regional political advocacy to breach dams on the Lower Snake River, as well as litigation that could limit the flexibility of the federal hydro system in the future. This risk is somewhat reduced by the fact that federal dams are congressionally authorized to serve specific purposes, including power production, and an act of congress would be required to change this (through dam breaching or other actions).

Transmission Cost (shown in $/kw-month) & Transmission Risk

Transmission cost and availability are likely to be key factors in the viability of new resource options. With the proliferation of clean energy policies in Washington and Oregon states, and declining costs of renewable resources, there is significant interest in developing wind and solar facilities in the region. Due to high solar and wind potentials East of the Cascades, most new renewable development interest is in those areas. However, the primary large load centers (cities) are along the I5 corridor. The current transmission system does not have capacity to accommodate most new transmission requests from East to West across the Cascades.

Demonstrating this challenge, BPA's 2022 transmission cluster study had 11,831 MW of transmission requests, of which only 275 MW were offered firm service without an upgrade. To accommodate much of the planned renewable buildout, BPA and other transmission providers will need to invest in infrastructure upgrades and/or new transmission lines. The costs for these can range from tens of millions to billions of dollars. Some of these costs are born directly by those who are requesting service, while other costs are shared among broader transmission users. If EWEB pursues resources that require new or upgraded transmission, it is possible that it would incur some form of costs for this. Additionally, new transmission builds, especially those that cross state lines, can take decades to complete. This presents a serious risk for any new resources that do not have access to existing transmission system capacity.

The 2022 IRP will include sensitivity analysis to account for uncertainty around transmission costs and availability. This will be accomplished by using different 'buckets' of estimated transmission costs to examine if there are tipping points at which a resource would be selected or not selected as the buckets of estimated transmission costs become progressively more expensive.

Other Resource Considerations

Development Risk

Resource development timelines can vary dramatically, ranging from several months for some energy efficiency measures to nearly a decade for small modular nuclear facilities. Almost any new project that requires physical steel in the ground and transmission interconnection will require a minimum of several years to move from bid requests to operational readiness. This is the case for renewable resources as well as more traditional thermal generators. Research by E3 found that most Requests for Proposal submitted in 2021 are looking for project operational dates between 2024 and 2026.

The Covid pandemic has impacted supply chain and development processes for many resource builds, including renewable resources. As a result of inflation, limited resources and high demand, the average cost of power purchase agreements for wind and solar resources in the US has increased by double digits over the past two years. Similarly, a shortage of lithium is putting a strain on battery storage projects. While long-term forecasts predict that costs will decrease, the next several years may continue to be volatile as inflation and supply chain issues impact the development of power generation.

Scalability

Scalability refers to the potential to increase acquisition of a resource as desired. Most renewable resources have high scalability because their unit cost is small, and it is straightforward to add additional units. In contrast, energy efficiency and demand response are limited by the potential in the Eugene area. Bonneville contracts have low scalability because EWEB has a set allocation of the federal system, and this is limited to existing resources (by contract). Natural gas and nuclear plants have moderate scalability because while they can be scaled up, the commitment required to build a new plant is substantial and presents a large hurdle to development.

Dispatchability

Resources that are ‘dispatchable’ can reliably be turned on by grid operators. Solar and wind resources are not dispatchable because they are ‘intermittent’ and have long periods when they do not produce energy. Energy efficiency is not dispatchable because grid operators do not have control over whether it is running – efficiency investments are always ‘on’. Batteries and demand response programs have moderate dispatchability because they have energy limitations that prevent their continual use. Gas and nuclear plants have the highest dispatchability because their fuel source is not typically limited, and they can be turned on and off as desired. The BPA contract has moderate/high dispatchability because it is very reliable, and the federal hydro system typically has sufficient storage to follow load and meet peak events.

Flexibility

Flexibility represents a resource’s ability to dispatch a resource both up and down over a short period of time, often within hour or even 5-minute increments. Flexibility is an important resource attribute for integrating renewable resources, and for following load shapes. Flexible resources will back down generation as load falls or renewables increase output, and ramp back up when load increases or renewable output falls.

Local Control

Local control includes resource attributes such as proximity to EWEB loads, EWEB operational control and/or ownership, and direct impact to the EWEB community. These attributes can generally be thought to benefit EWEB and its customers by providing local jobs, social and equity benefits, and resiliency benefits. Further, local control allows EWEB to consider resiliency, equity or other environmental considerations. The greater the amount of local control the more impact EWEB’s triple bottom line decision making can have on the resource.

Key takeaways

1. There is no perfect resource

Every new resource option under consideration in the 2022 IRP has tradeoffs. These include costs, carbon emissions, and impact on the local Eugene area, among other factors.

2. The cost of capacity is at least as important as the cost of energy

With the proliferation of renewable resources, the cost of energy has decreased dramatically over the past few years because renewable resources have no fuel costs. However, the value of capacity (i.e., the ability to generate power on demand) has increased and is a major driver in regional power markets and resource acquisition strategy.

3. Transmission risk (and cost) could be significant

Transmission risk for new resources represents one of the biggest potential challenges for EWEB and other utilities to meet their clean energy goals. Without significant investment in the regional transmission system, least-cost, carbon-free resources to the East of the Cascades or in Montana/Wyoming will not be able to serve load in the Western parts of Oregon. EWEB's preference rights to BPA power may alleviate some of this risk, but it will be one of the biggest regional challenges in the coming decades. The potential costs of transmission are included in EWEB's modeling of new resources to reflect the true cost of development.

4. Resources act as a portfolio

Although there is no perfect resource, the goal of the IRP is to provide the best possible information to select a generation portfolio to meet EWEB's needs over the coming decades. By mixing the different attributes of resources in a portfolio, EWEB can identify resource strategies to help reduce costs and risks for the electric utility.

Resource Metrics

Metrics highlighted in red are meant to indicate areas of tradeoff or 'negative' attributes. Metrics highlighted in green are positive or desirable attributes.

Key Energy, Cost, and Carbon Attributes

Resource Category	Resource Type	LCOE $/MWh	Transmission Cost $/kW-mo	Transmission Risk	Fuel Cost Risk	Cost of Summer Peaking Capacity $/kW-mo	Cost of Winter Peaking Capacity $/kW-mo	Summer Peaking Capacity Contribution	Winter Peaking Capacity Contribution	Carbon Intensity MTCO2e/MWh
Wind	MT/WY Wind	22	$10-$25	High	-	38	16	18%	44%	-
	North East OR Wind	29	$3-$10	Moderate	-	40	22	18%	34%	-
	Offshore Wind	102	$10-20	High	-	103	102	30%	30%	-
Solar	Residential Rooftop Solar	196	-	-	-	117	451	16%	4%	-
	Community Solar	69	-	-	-	42	161	16%	4%	-
	Utility Solar (Eastern OR)	28	$3-$10	Moderate	-	19	51	30%	11%	-
Battery and DR	Battery (4hr)	N/A	Savings	-	-	15	15	50%	50%	N/A
	Demand Response	N/A	Savings	-	-	22	22	50%	50%	N/A
Conservation	Energy Efficiency Bin 1	33	Savings	-	-	16	16	100%	100%	Savings
	Energy Efficiency Bin 2	291	Savings	-	-	98	98	100%	100%	Savings
Thermal	Natural Gas SCCT (40%)	74	$3-$10	Moderate	High	9	9	95%	95%	0.53
	Natural Gas CCCT (80%)	40	$3-$10	Moderate	High	11	11	90%	90%	0.34
	Cogeneration/Biomass	74	$3-$10	Low	Moderate	48	48	90%	90%	0.39
	Small Modular Nuclear (80%)	76	$3-$10	Moderate	Low	43	43	95%	95%	0
BPA	BPA Contract (Slice & Block)	33	$3-$10	Low	Low/Moderate	18	18	90%	90%	0.02

Other Resource Considerations

Resource Category	Resource Type	Development Risk	Flexibility	Scalability	Dispatchability	Local Control
Wind	MT/WY Wind	Low/Moderate	None	High	None	Low
	North East OR Wind	Low/Moderate	None	High	None	Low
	Offshore Wind	High	None	Moderate	None	Low
Solar	Residential Rooftop Solar	Low	None	Moderate	None	High
	Community Solar	Low/Moderate	None	Moderate	None	High
	Utility Solar (Eastern OR)	Low/Moderate	None	High	None	Low
Battery and DR	Battery (4hr)	Low	High	High	Moderate	High
	Demand Response	Low/Moderate	Moderate	Limited	Moderate	High
Conservation	Energy Efficiency Bin 1	Low	None	Limited	None	High
	Energy Efficiency Bin 2	Low	None	Limited	None	High
Thermal	Natural Gas SCCT (40%)	High	High	Moderate	High	Low
	Natural Gas CCCT (80%)	High	Moderate/High	Moderate	High	Low
	Cogeneration/Biomass	Moderate	Moderate	Limited	Moderate/High	Low/Moderate
	Small Modular Nuclear (80%)	High	High	Moderate	High	Low
BPA	BPA Contract (Slice & Block)	Low	Moderate/High	Limited	Moderate/High	Moderate

APPENDIX G: CALCULATED REFERENCE CASE MODELING RESULTS

The Calculated Reference Case refers to the portfolio of future resources that the Aurora model has arrived at through simulation. The goal of the Calculated Reference Case is to provide a reasonable data point against which to compare other sensitivities and portfolios. The Calculated Reference Case relies on a variety of assumptions, and generally represents 'business as usual' constraints. These assumptions are substantial drivers of the resources selected throughout the study.

The table below shows the peak capacity of resources selected in the Calculated Reference Case. Peak capacity refers to a resource's ability to generate energy during the peak hour of EWEB's load each year. In the Calculated Reference Case, EWEB's peak hour occurs mid-December under load assumptions that mirror a 1-in-2 winter cold front.

Peak Capacity (MW)	2025	2026	2027	2028	2029	2030	…2042
Existing Portfolio	509	467	462	461	454	453	465
Conservation		1	2	3	4	5	18
Demand Response		2	3	4	4	4	7
Wind		4	8	10	10	10	50
Batteries (4 hour)		7	7	10	22	30	100
Nuclear (SMR)							10
Total Peak Capacity	**509**	**481**	**482**	**488**	**494**	**502**	**650**
1-in-2 Peak Load*	**477**	**481**	**482**	**488**	**494**	**502**	**650**

The 2022 IRP is focused on two central questions: How much energy and capacity does EWEB need; and what resources are the "best fit" for EWEB? As shown in the chart above for 2025, given current assumptions, EWEB's current portfolio is surplus to 1-in-2 peak capacity needs, and the model replaces only enough capacity to meet peak needs in 2026. However, EWEB's long-term energy and capacity

needs are expected increase with electrification. As this occurs, EWEB's portfolio and total costs grow.

The model generally selected "best fit" resources that provide winter energy or within-day flexibility and capacity. These characteristics help EWEB to meet winter peaks and shape energy into the times of day when EWEB's loads are highest.

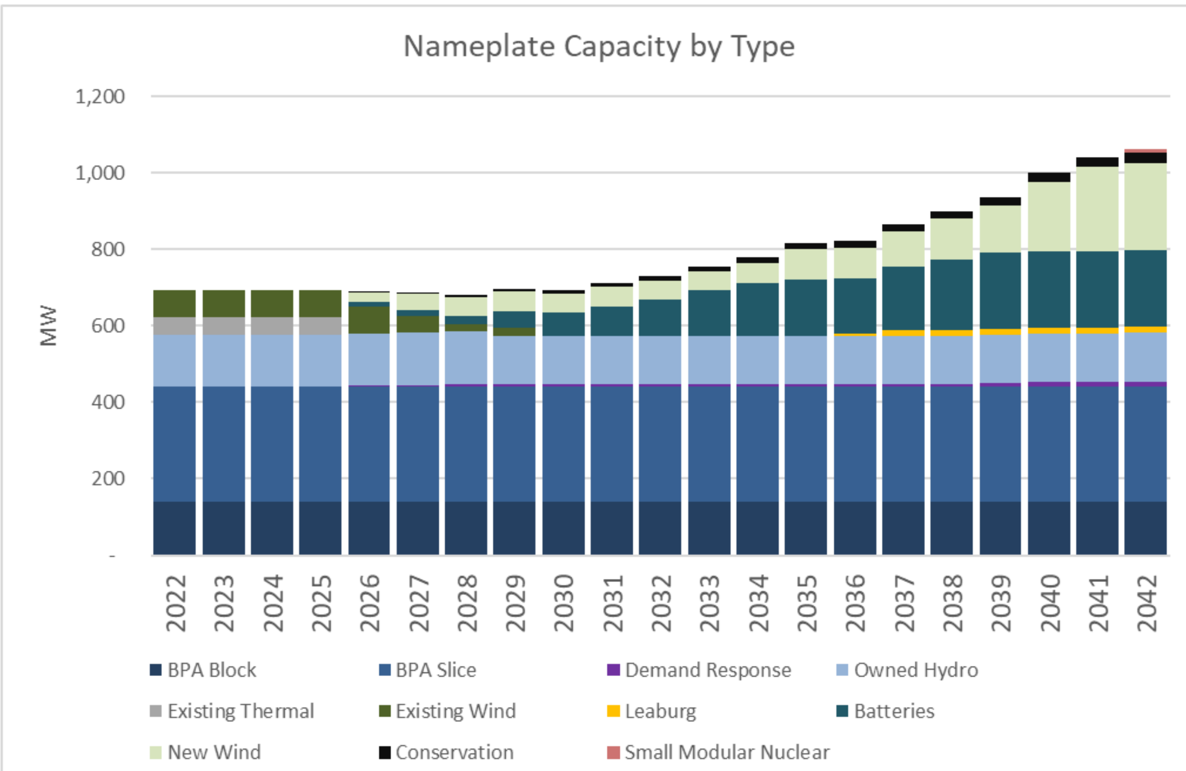
***Peak Load Planning Standards**

- Utility planners use "1-in-2" to refer to the likelihood of a specific event occurring. A 1-in-2 peak event is an 'average' peak, expected to occur once every two years – in other words, it has a 50% chance of occurring in any given year.
- A planning reserve margin (PRM) is the procurement of additional resources beyond 1-in-2 or other standards as a 'safety net' to ensure that if an unexpected outage or other event occurs, the utility will have enough resources to serve load.
- EWEB will test the impact of using a 1-in-10 (10% likelihood) planning standard or larger PRM on EWEB's forecasted portfolio needs and cost.

Calculated Reference Case Nameplate Capacity

The Calculated Reference Case refers to the portfolio of future resources that the Aurora model has arrived at through simulation. The goal of the Calculated Reference Case is to provide a reasonable data point against which to compare other sensitivities and portfolios. The Calculated Reference Case relies on a variety of assumptions, and generally represents 'business as usual' constraints. These assumptions are substantial drivers of the resources selected throughout the study.

The Calculated Reference Case portfolio nameplate capacity is shown in the chart below. Nameplate capacity refers to the maximum amount of energy a resource can produce. For variable renewable resources like wind and solar facilities, or peaking thermal plants, nameplate capacity is typically higher than the average amount energy a resource produces during the year.

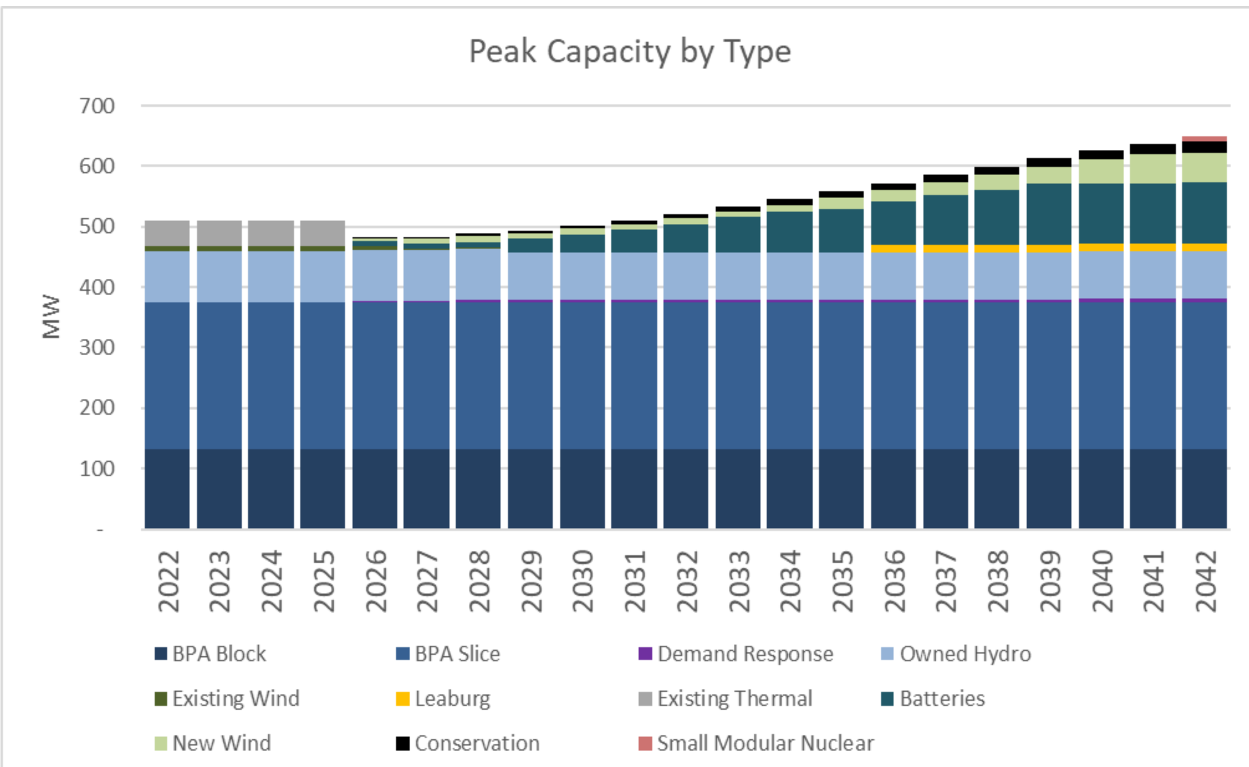


The Calculated Reference Case portfolio changes over the years as existing contracts expire and new ones are added. The modeling study begins in 2022 with EWEB's existing portfolio, which consists of BPA Slice and Block, owned hydro (excluding Leaburg until 2036), contracts with International Paper and Seneca thermal plants, and existing wind resources. As discussed in greater detail in the *BPA in the Calculated Reference Case* section below, EWEB's BPA contract is assumed to continue throughout the study period.

In the mid to late 2020's, existing wind and thermal contracts expire and are replaced with batteries, wind, and small amounts of low-cost energy efficiency and demand response programs. Resource acquisition picks up pace beginning about 2030 in response to expected electrification – primarily driven by the adoption of electric vehicles. 10 MW of small modular nuclear reactor (SMR) capacity is added in 2042. In general, nameplate capacity additions to the Calculated Reference Case are key portfolio cost drivers, as many of the selected resources have high up-front costs, but low operational and marginal costs.

Reference Portfolio Capacity

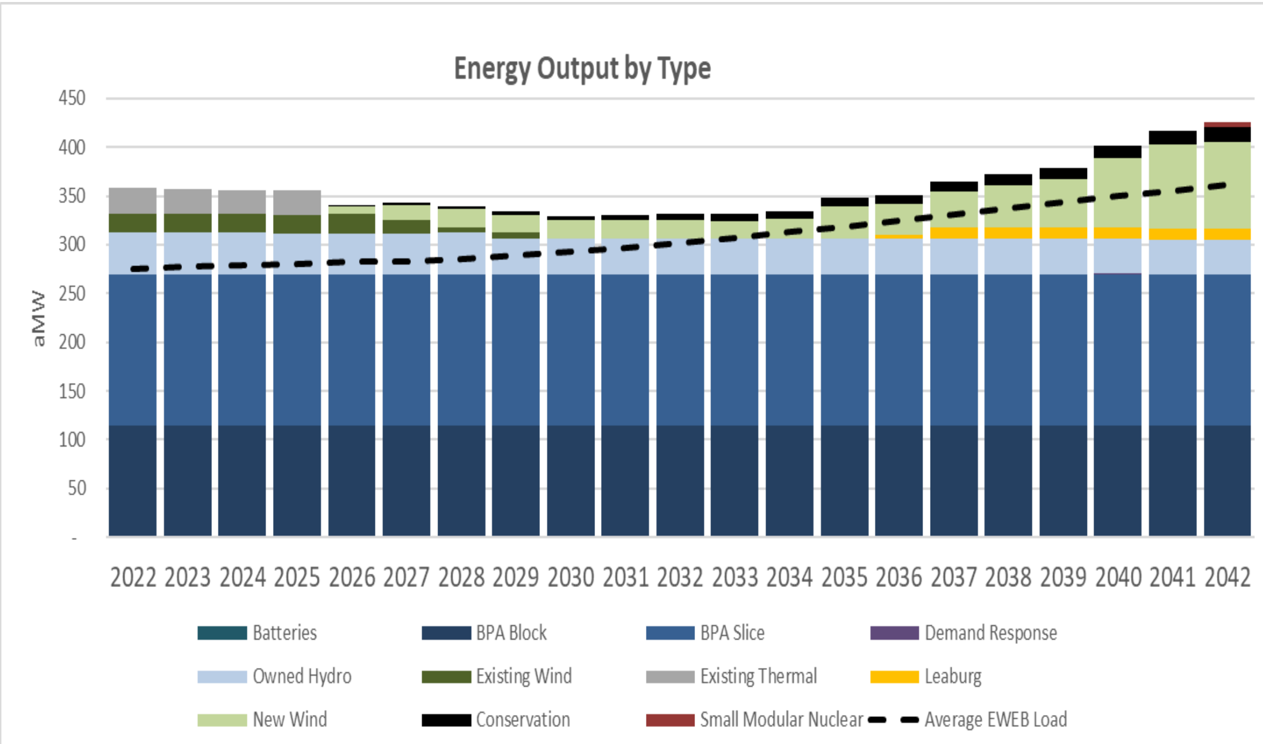
The Calculated Reference Case modeling results for peak capacity are shown below. Peak capacity represents the amount of a resource's nameplate capacity that is expected to be available to serve load during EWEB's single hour winter system peak. Peak capacity is less than, or in rare cases equal to, the nameplate capacity for a resource. Wind and solar patterns, planned and unplanned outages, fuel supply issues, and other operational uncertainties can result in capacity not being available at certain times in the year. The end result is that EWEB's portfolio will always have a nameplate capacity greater than its peak capacity.



The Calculated Reference Case portfolio's peak capacity decreases in 2026 as existing contracts expire and EWEB does not have additional capacity needs to meet a 1-in-2 standard. In the 2030's the total peak capacity of the portfolio then increases incrementally to keep pace with expected load growth. In general, for the 2022 IRP, peak capacity is a key driver of modeling results, as staff have required the model to match EWEB's 1-in-2 peak winter needs. Staff chose the 1-in-2 standard as a starting point because it represents a reference point to cover normal peak conditions. Exploring the appropriateness of a 1-in-2 standard, and the cost impacts of increasing reserve margins, will be part of the broader IRP process.

Calculated Reference Case Portfolio Energy

The Calculated Reference Case portfolio energy production is shown below. Although energy production varies throughout each year, average energy gives an indication of long-term trends.



The Calculated Reference Case modeling assumes that EWEB's average energy need is approximately 270 aMW in 2022, growing to 361 aMW by 2042. Throughout the study period, the portfolio produces between 30-80 aMW of energy that is 'surplus' to EWEB's average energy needs (the area above the dotted line). This is because EWEB plans to meet *peak capacity* needs rather than *average energy* needs. To the extent that peak needs are met with renewable resources (including hydro and wind) that produce zero marginal cost energy at other times of the year, EWEB will always have surplus energy. This is a trait of EWEB's current portfolio, which is managed by selling and buying energy to realign with EWEB's needs.

From 2026 until the early 2030's, given the assumptions in the Calculated Reference Case portfolio, EWEB would actually have less surplus energy than it does now. This is largely due to the addition of batteries to EWEB's portfolio in 2026. Rather than generate more power, batteries shape energy into times that are more useful for EWEB, resulting in fewer hours of surplus energy. Batteries do not appear on the *Energy Output* chart above because they do not create energy.

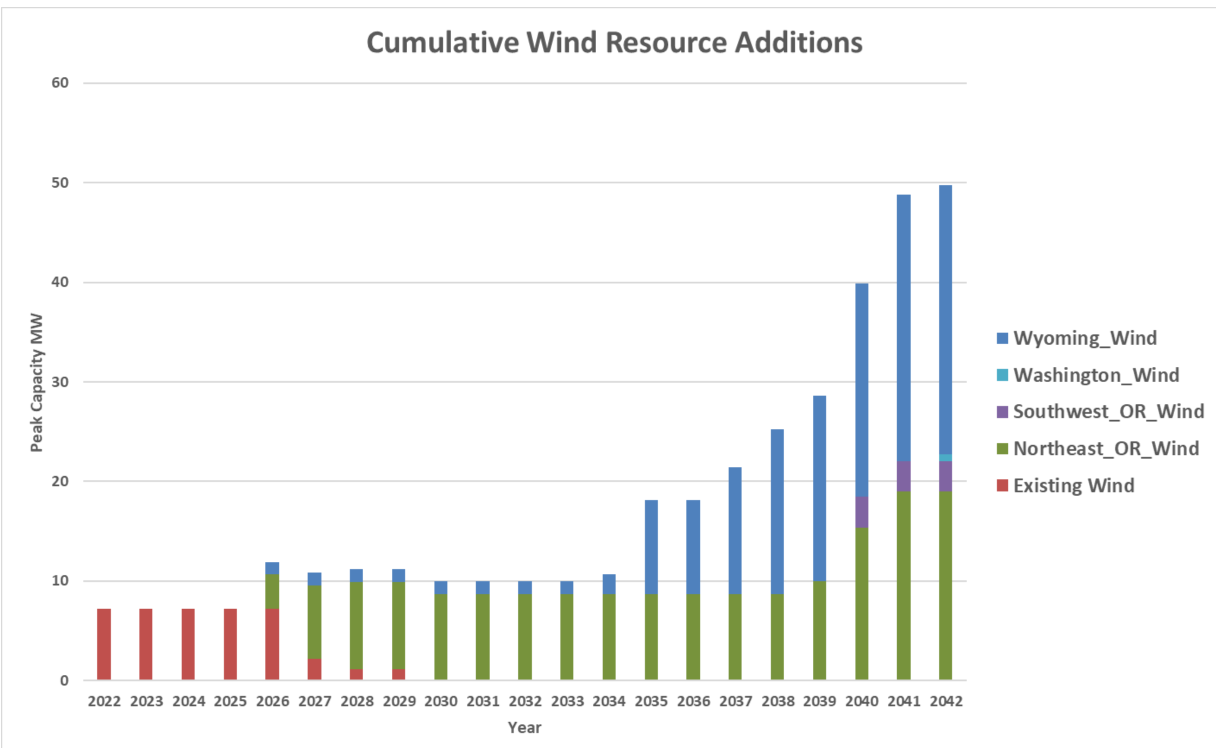
Resource Specific Discussion

BPA in the Calculated Reference Case

Through early modeling tests and analysis, staff have found that continuing the BPA power contract post-2028 appears to be one of EWEB's least cost portfolio options. As such, the Calculated Reference Case assumes that EWEB will renew its BPA contract post-2028. This approach maintains 'business as usual' and provides a baseline against which to compare alternate portfolios. The Calculated Reference Case assumes that BPA's costs and products are similar to today, and future BPA contracts escalate at the rate of inflation starting in 2027. Because of this, changes to EWEB's total portfolio cost are primarily driven by resource additions to meet forecasted load growth from electrification. Once staff have more information about future BPA product options and costs, these will be included in the model.

Wind

Wind has been part of EWEB's portfolio for some time, as tax incentives, RPS requirements, and wind potential in the Northwest made it a desirable resource. Given current cost trajectories and other assumptions, the Calculated Reference Case portfolio includes meaningful amounts of wind acquisition throughout the next several decades. The specific resources selected tend to have winter peaking profiles, which makes them more likely to contribute to meeting EWEB's peak winter needs.



Northeast Oregon wind was selected to replace existing wind and thermal contracts in the mid to late 2020's, and Wyoming wind was selected to meet load growth later in the 2030's. However, the Calculated Reference Case does not substantially limit transmission availability for these resources, and transmission is a large risk factor. Due to this, there is potential that EWEB would not be able to access these resources even if they were determined to be least-cost, best-fit. The *Transmission Sensitivity* (discussed below) and analysis in the IRP will provide further information about transmission cost, availability, and risk.

Demand Response

Demand response (DR) is a set of programs that allow EWEB to partner with its customers to shift energy usage from times of high demand to off-peak hours, reducing the need for steel-in-the-ground supply-side resources and infrastructure investments. Demand response has a variety of costs and energy profiles depending on the specifics of the program. In the Calculated Reference Case, residential demand response programs that cost below $12/KW-month were selected in 2026-2028. These programs included residential Time of Use (TOU) rates, Critical Peak Pricing rates, and Residential Space & Water Heating Direct Load Control programs.

However, after 2028, batteries appear to displace additional investments in DR programs. Utility-controlled managed electric vehicle charging is a more expensive demand response program to implement ($19/KW-month), and was only selected in 2039, 2040 and 2042. However, it is possible that demand-side pricing programs like Time of Use rates may create voluntary managed EV charging behavior, thus diminishing the need for utility-controlled EV charging programs. Further study of customer behavior and characteristics could refine DR cost and availability information and better shape EWEB's demand-side management strategy.

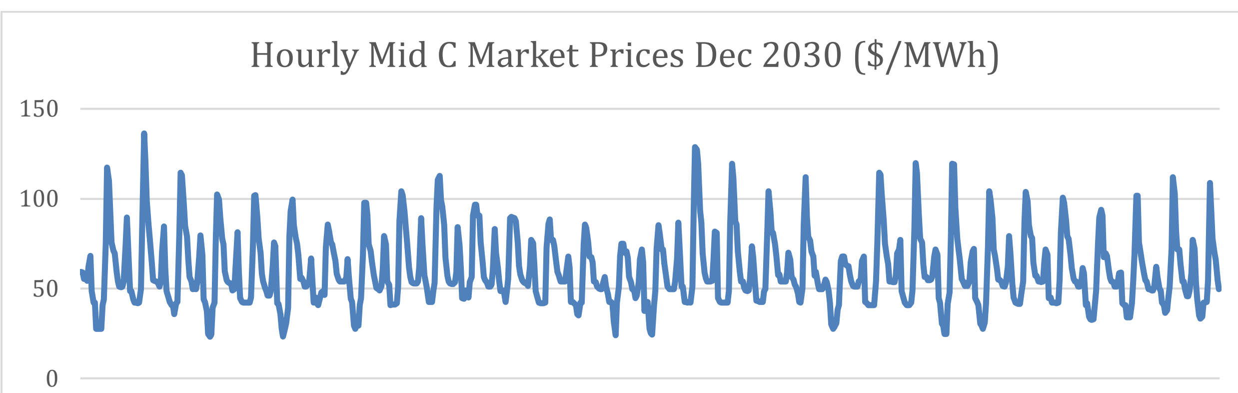
Batteries

EWEB staff modeled 4-hour lithium-ion batteries in the Calculated Reference Case. These types of batteries are becoming fairly standard as utility-scale resources, and longer-duration storage has not yet been demonstrated to be commercially viable. 4-hour batteries do not have enough energy storage to be useful for long-term, long-duration storage. Instead, they are typically used for within-day energy shaping to meet morning or evening peak loads.

Battery Nameplate Capacity vs Energy

- Nameplate capacity is the maximum power the battery can deliver at once.
- Energy is the total amount of power a battery can deliver.
- A 4-hr 100 MW battery can deliver 100 MW of energy for four hours, at which point it will need to recharge.

The cost-effectiveness of these batteries depends on daily price spreads, as the battery will be charged during hours that are cheaper and discharged when prices are high. EWEB's Calculated Reference Case shows large within-day price variations by the late 2020's, when the model selects batteries as part of the portfolio. The chart below shows the daily prices at the Mid-Columbia trading hub where EWEB often transacts to buy and sell power. The chart demonstrates that prices fluctuate by $50-$75/MWh every day, creating a pricing arbitrage opportunity for batteries.



Energy Efficiency

Energy efficiency has been a key part of EWEB's resource strategy for the past decade. However, energy efficiency supply curves are becoming more expensive, and renewable resources are becoming a less-expensive source of clean energy. In the Calculated Reference Case, energy efficiency programs with a levelized cost of $15/MWh and below were selected throughout the study period, whereas conservation higher than $45/MWh was not selected until 2040.

However, energy efficiency has very clear local benefits such as reduced needs for infrastructure upgrades, and equity impacts for customers whose bills are reduced or homes made more comfortable. Additionally, unlike many supply-side resources, energy efficiency does not have transmission risk, and has limited capital or build risk because it is local and small-scale. Sensitivities on transmission availability may show increased value for energy efficiency or other local resources. Future studies of customer characteristics could inform conservation potential in EWEB's service territory and help to better define programs.

Small Modular Reactor

The Calculated Reference Case selects 10 MW of a Small Modular Reactor resource (SMR) late in the study period. SMR's are dispatchable, have a high peak capacity accreditation, and do not have carbon emissions. This indicates that EWEB's system sees a need for these attributes as EWEB and the regional grid transition to a greater penetration of renewable resources. In the Calculated Reference Case, SMRs are being used as a stand-in for non-energy-limited, dispatchable, clean resources. The actual technology that can provide these characteristics may change over the course of the next 15-20 years. For example, other alternatives to SMR, such as hydrogen generation or multiple-day energy storage, may become commercially available by the time EWEB needs this capacity. The specific technology choice of a small nuclear reactor is less important than the attributes the model calculates are needed to assemble a least-cost portfolio in 2042.

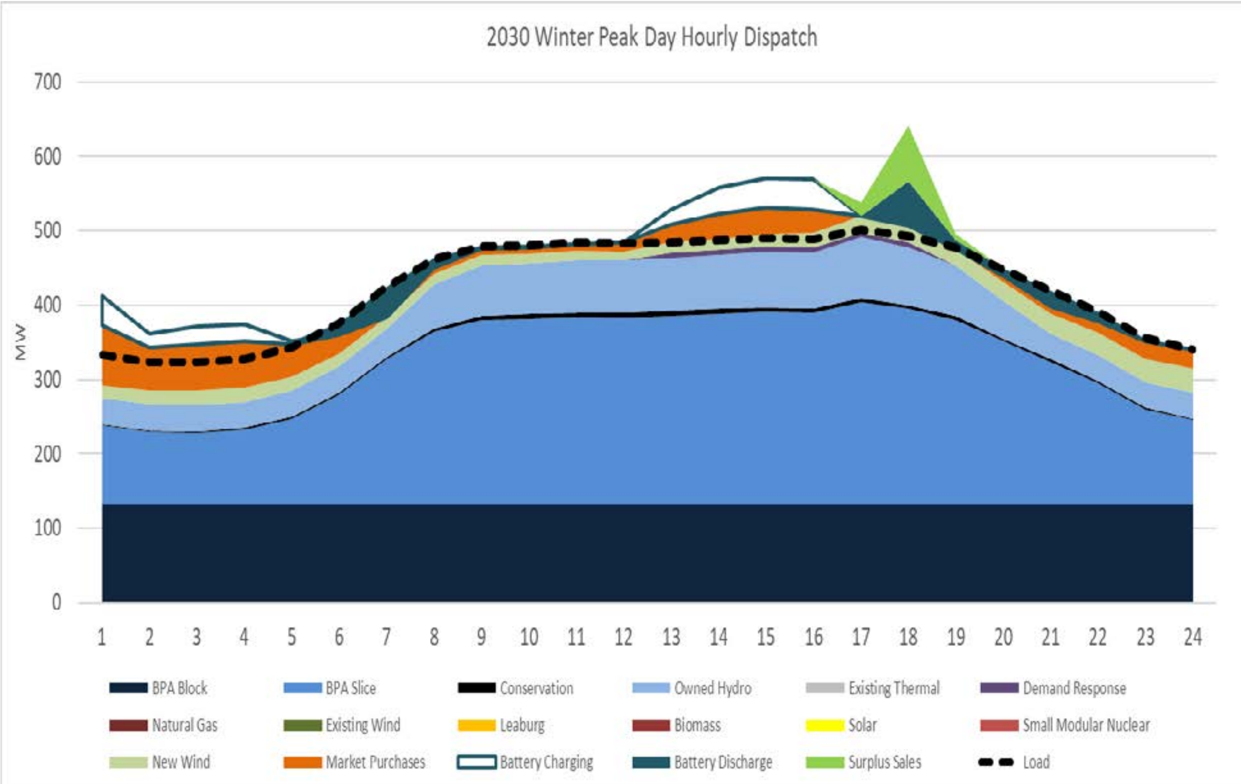
Solar

The Calculated Reference Case did not select solar as a resource for EWEB. This does not mean that there might not be a role for solar in EWEB's portfolio, or that other sensitivities will not select solar. As discussed in the August Board Memo, solar is a cost-effective resource for energy, but it is one of the more expensive resources for providing peak winter capacity. Changes in assumptions about EWEB's load or resource needs, or inclusion of metrics beyond cost may bring solar forward as an option.

Portfolio Dispatch

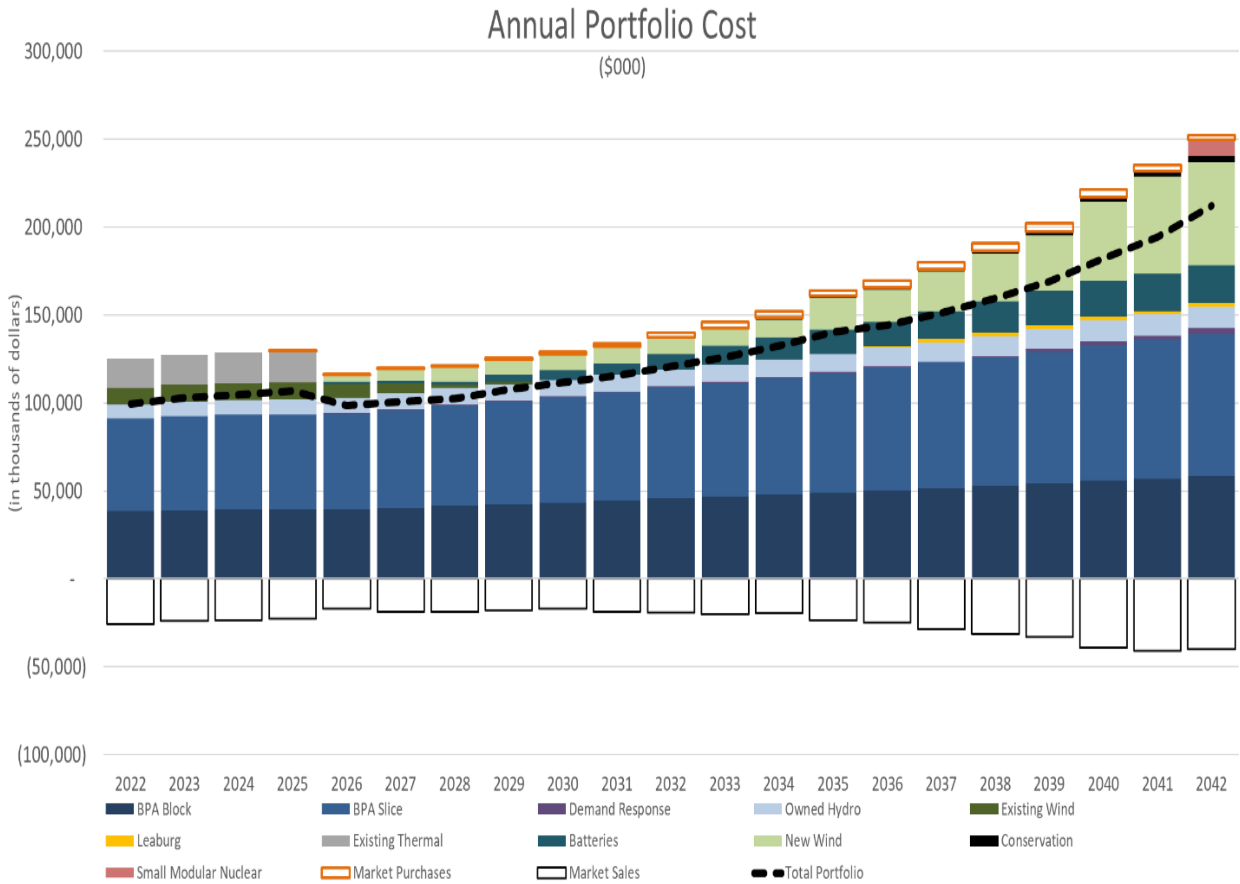
The chart below shows the dispatch of EWEB's portfolio during EWEB's peak winter day in 2030. In 2030, batteries, new DR, energy efficiency, and wind have all been added to the existing portfolio. The flat navy blue at the bottom of the stack is BPA Block, followed by Slice and EWEB-owned hydro in lighter blue (with conservation sandwiched between). New wind, market purchases, batteries, and demand response are on top of these. Battery charging is shown in the blue outline at the top of the image, with discharge shown by the dark blue section to the right of these. Market purchases are in orange towards the top of the stack, and market sales are in bright green at the very top right. EWEB's load is represented by the dotted line towards the top of the stack.

On this peak day in 2030, EWEB's load reaches a high of 502 MW in hour 17. In general, BPA Slice and EWEB hydro are shaped to follow EWEB's load. Wind resources provide energy during the 24-hour period, but their peak output is late at night (to the far right on the graph). Batteries charge at night and late afternoon and are dispatched in the morning ramping period between 6AM and 8AM, as well as Hours 17-22, to meet load or generate sales.



Reference Portfolio Cost

The Calculated Reference Case portfolio cost estimate is shown below. These results are in nominal dollars and include the influence of an assumed inflation rate of 2.5%.



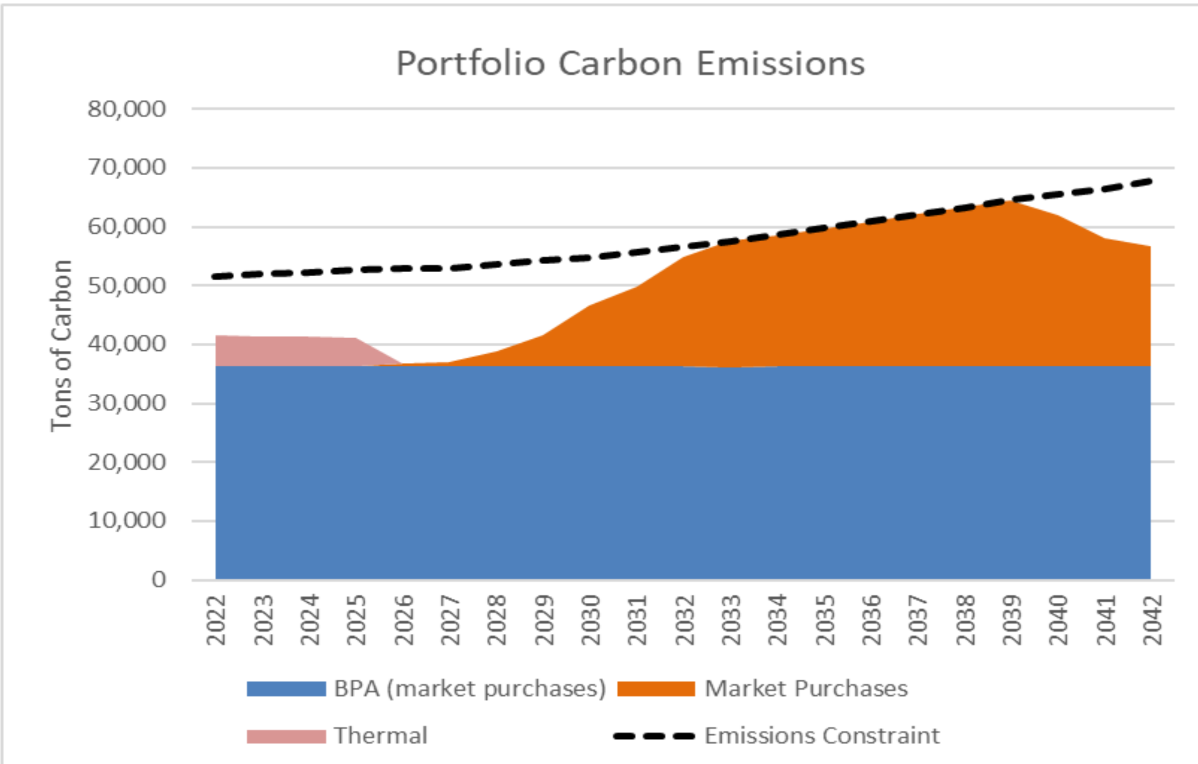
In the chart above, EWEB's portfolio cost remains relatively stable through the 2020's, despite some retirements of existing contracts for wind and biomass. During this time period, EWEB expects relatively flat or small load growth, which keeps the need for additional resources, and by proxy additional cost, to a minimum. However, increases in annual load due to vehicle electrification begin in the early 2030's. This increase in turn drives the need for more energy and capacity resources to serve the load, raising portfolio costs throughout the 2030's. Starting in 2033, the portfolio also begins to make market purchases of approximately 10 aMW instead of building more resources. This indicates that market purchases may be part of EWEB's least-cost portfolio strategy starting in 2033.

Over the study period, total portfolio costs increase an average of 4% annually, which includes both the impacts of load growth from electrification (2% growth per year) and inflation, indicating that portfolio costs relative to load would remain relatively flat.

As discussed in the *Portfolio Energy* section above, a key aspect of meeting growing demand with intermittent renewable generation is the generation of surplus energy. EWEB's ability to create revenue from this energy is an important part of reducing total portfolio costs. Throughout the study period, sales of excess energy averaged approximately $60/MWh and generated an average annual benefit of $25 million per year.

Carbon Emissions and RPS

EWEB has committed to have a portfolio that is 95% carbon-free on a planning basis by 2030. The carbon emissions constraint in the Aurora model assumed a “carbon budget” (in tons) equivalent to 5% of EWEB’s energy needs being served by a carbon-emitting generator. The model is constrained by the carbon emission limit between 2033 and 2042.



Today, the vast majority of EWEB’s portfolio emissions are attributed to BPA, which provides the majority of EWEB’s energy. While BPA’s resources are mostly carbon-free, the market purchases that BPA makes have an assumed carbon emissions rate, because market purchases (unless otherwise specified) are assumed to come from natural gas generators which often set the price for market-based electricity. Early in the study period, there are some calculated emissions from EWEB’s existing thermal contracts (IP and Seneca), but after these contracts are assumed to expire in 2025, there are no new carbon-emitting resources selected by the model. Hence, market purchases and BPA products are the only source of carbon emissions in the modeling results. Making a different assumption about the carbon intensity of BPA or future markets could allow the model to select alternative emitting resources, or show a reduction in EWEB portfolio emissions.

All of the portfolios constructed by the model comply with the Oregon Renewable Portfolio Standards, which require that 20% of EWEB’s power come from renewable sources. Because of EWEB’s legacy hydro exemptions and the addition of wind energy in the Calculated Reference Case, this portfolio will have sufficient renewable energy to meet the RPS targets throughout the study period.

Sensitivity Analysis

EWEB's Calculated Reference Case does not represent EWEB's preferred or expected portfolio. Instead, the Calculated Reference Case is an output of a specific set of assumptions and modeling choices based upon best available information and geared towards a 'business as usual' outcome. There is uncertainty around many of these inputs, and further analysis is required to understand the risk or drawbacks to different portfolio approaches. Hydro and gas risk are treated separately from other sensitivities, as they are key inputs that will impact portfolio performance under all outcomes. Staff will conduct Aurora Risk modeling on several, if not most, portfolios to examine how fluctuations in water conditions and natural gas prices impact portfolio costs.

Below, staff have identified three key assumptions which will be explored through further sensitivity analysis. These sensitivities will be included in the Final IRP document in June 2023 and will inform EWEB's 2022 IRP Action Plan. Staff is also seeking feedback from the Board, as well as information gathered through public outreach, to inform additional IRP sensitivities. Potential topics for these sensitivities are listed below those that staff is already planning to conduct.

Staff will conduct sensitivity analysis on the following three key assumptions:

- **Transmission availability and cost**: There is almost no transmission availability for new resources across key East-West pathways that would connect EWEB to high value wind and solar, including those selected in the Calculated Reference Case. Staff believe that sensitivities on transmission cost and availability will be important for understanding portfolio alternatives and costs if access to these resources is limited.
- **EWEB Load Growth Trajectory**: The Calculated Reference Case assumes that EWEB's load will grow due to electrification. However, there is substantial uncertainty around this. Sensitivities would explore resource acquisition strategies for both faster growth and flatter load.
- **Planning Reserve Margin:** The Calculated Reference Case assumes that EWEB will build enough resources to meet 1-in-2 peak loads and nothing more. However, regional developments such as the Western Resource Adequacy Program (WRAP) may require EWEB to procure additional resources to meet a planning reserve margin (PRM). This sensitivity would explore the costs of procuring resources to meet WRAP standards.

Staff will be seeking guidance and input on additional sensitivity analysis. Potential topics include:

- **Solar**: The Calculated Reference Case did not select solar as a least-cost option, likely because it performs poorly during EWEB's peak winter load events. Sensitivities could explore the impact of adding solar to the portfolio, or test whether solar is selected if EWEB's summer needs increase. For example, while the current modeling assumes that EWEB will continue to be a winter-peaking utility, climate change and heat pump (air conditioning) penetration could result in EWEB becoming a dual-peaking utility, where summer and winter needs both drive resource decisions.
- **Carbon Limitations:** Analysis of resource selection under deep decarbonization can inform portfolio strategy.
- **Resource cost trajectories:** Resource cost trajectories, whether for renewables like wind and solar, or for emerging technologies like long-duration storage, are likely to diverge from current forecasts. For example, the Inflation Reduction Act created substantial tax incentives and other funding mechanisms that would reduce costs for a wide range of future resources.
- **Other:** Additional sensitivities as identified by staff, the Board, or public feedback can be included in IRP analysis, time permitting. (e.g. policy changes, market price changes, etc.)

Hydro and gas risk analysis will be conducted for multiple sensitivities listed above.

- **Hydro and Gas Risk:** Water conditions and natural gas prices are key drivers of portfolio costs, and both of these inputs are subject to a high degree of uncertainty. Aurora Risk analysis can provide information about portfolio costs under a wide range of gas and hydro inputs.

Feedback and Public Input

The Calculated Reference Case portfolio represents the starting point of the 2022 IRP analysis and can be used to inform next steps. Staff will be seeking guidance from the Board on several topics, including:

- What types of analysis or information has not been covered to date that you would like to see?
- What sensitivities do you believe should be included in the final 2022 IRP?
- What types of information can staff gather from public outreach that would help inform your decisions for a future Action Plan?

Staff will continue to work on analysis and supporting materials for the IRP over the coming months in preparation to release the Final IRP in June of 2023.

Calculated Reference Case Assumptions

Aurora Model

EWEB's planning group uses a modeling program called Aurora to forecast market prices and inform future portfolio strategies. Aurora is also used by many utilities and other regional planning authorities, like the Northwest Power and Conservation Council. Aurora simulates load, generation, and transmission of the entire western interconnected power grid on an hourly basis. For each hour of the simulation, Aurora chooses the most economical generators to meet loads, given policy and system constraints. This hourly 'dispatch logic' allows Aurora to create simulated market prices based on the marginal generating unit for any given hour. Aurora then uses these market price forecasts and resource dispatch information to select the least-cost new resource options under a specific set of circumstances. By changing inputs such as transmission constraints or natural gas prices, analysts can test tipping points and tradeoffs between different resource strategies, while letting the model solve for the least-cost portfolio based on those inputs.

Calculated Reference Case Assumptions and Modeling Inputs

- **Peak Planning Standard –** EWEB's resource needs are calculated using a peak planning standard of a P50 or 1-in-2, single hour system peak. In 2022, this is 467 MW which is the highest hour of load forecasted in a 'typical' year. To account uncertainty, some utilities use other planning standards around less frequent peaks like 1-in-10 or 1-in-25. Peak planning standards combine with planning reserve margins to calculate resource needs to for the utility.
- **Planning Reserve Margin** – The Calculated Reference Case does not assume any planning reserve margin in addition to the peak planning standard. Sensitivities will test different reserve margins, which could be necessary to meet future requirements of the Western Resource Adequacy Program.
- **New Resource Costs** – Various: Assumptions were developed in partnership with E3 consulting and presented in the August Board meeting. Costs for renewables and battery storage tend to decline over time with assumed supply chain and technology improvements.
- **Peak Capacity Credit –** The peak capacity credit for new resources reflects a resource's ability to help meet EWEB's peak load. For the Reference Case, this is reflective of December generation profiles given the specific data samples provided by E3 for use in the model.

- **BPA 2028 Contract Pricing** – The Calculated Reference Case assumes no rate increases through 2025, consistent with the current BPA BP-24 rate settlement. From 2026, BPA rates are assumed to increase with inflation.
- **Median Water Year** – The results shown in the Calculated Reference Case use median hydrological conditions and do not assume an increase or decrease in the performance of hydro generation. This assumption should be evaluated as part of portfolio risk analysis (understanding how a given portfolio may vary in cost based on hydrological conditions, which can change each year due to precipitation).
- **Leaburg Return to Service** – The 15.9 MW nameplate capacity of Leaburg hydro generation is assumed to return to service in October 2036 and assumes historic operating costs. However, there are significant investments required at Leaburg in order to return to service and the Board is evaluating this decision using a Triple Bottom Line analysis. The Calculated Reference Case can be updated based on the Board's direction and the modeling can use updated cost assumptions from the Leaburg TBL analysis as needed.
- **Transmission Costs** – Transmission costs for existing transmission are based on published OATT rates. Costs for future transmission is a composite estimate based on staff research and analysis.
- **Inflation Reduction Act (IRA)–** The cost of solar, wind, batteries, and small modular nuclear reactors are expected to be lower as the result of the Inflation Reduction Act. The tax credits approved as part of the IRA are not yet reflected in the new resource cost assumptions for wind, solar and batteries which comes from E3. EWEB staff did reduce the cost assumptions for small modular nuclear to try to estimate the impacts, but a more thorough analysis will be required to estimate the cost reductions for these carbon-free technologies and update the model new resource cost assumptions.
- **Transmission and New Resource Build Limits**– Annual build limits of 100 MW were placed on each of the new renewable resource options in the Calculated Reference Case. Staff considers this a 'relaxed' assumption, and sensitivities will further constrain or add costs to resources outside of EWEB's area to reflect the uncertainty around building or upgrading transmission lines in the future.
- **EWEB Existing Resources** – Various: Owned plant assumptions are based on historical EWEB generation data and costs. Contracts are assumed to expire at their end dates, except for International Paper, which is assumed to be extended through 2025. The Calculated Reference Case assumes median hydro conditions.
- **Carbon Constraints** – EWEB's portfolio is constrained to be 95% carbon-free, meaning that roughly 5% of EWEB's annual load could be served by carbon-emitting resources throughout the study period. Individual resource emissions are included in the August memo. Market purchases are assumed to have emissions of 'average' regional generation, which is expected to decrease over time.
- **Carbon Pricing** – Carbon pricing is assumed for future years, consistent with CA and WA cap and trade programs.
- **RPS Constraint** – EWEB's future annual load (in MWh) must be served by either exempt or RPS compliant resources. This constraint ensures that all portfolios developed by the model comply with RPS requirements.
- **Natural Gas Prices** – The Calculated Reference Case assumes prices decline over time from current highs near $6/mmBTU to roughly $4/mmBTU at Henry Hub, with seasonal variations. Assumptions were developed in partnership with E3 consulting. IRP sensitivities will test various gas prices.
- **Inflation** – This is assumed to be 2.5% for the study period. Although there is uncertainty in future inflation rates, this factor would be applied equally to costs incurred under a resource strategy, reducing some variability due to inflation rate changes.
- **Discount Rate** – Not applicable. All financial data presented in the 2022 IRP is in nominal dollars and has not been discounted or presented in real dollars.
- **Market Limitations** – EWEB's simulated area is allowed 150 MW of imports and 150 MW of exports to exchange with BPA's area at all hours of the study period. Further, the import of energy is limited to

approximately 25 aMW for each month of the study period. These market access limits were added to ensure that the calculated portfolio in the simulation does not routinely lean on the market to meet EWEB's energy needs. Sensitivities can test this assumption and be used to understand how different levels of market availability can impact EWEB's ideal mix of resources.

- **Load Forecast** – The Calculated Reference Case assumes load growth due to economic and population growth, as well as base case electrification expectations from the Phase 2 Electrification Study in 2021. This was covered in greater detail in the April 2022 Board memo entitled "EWEB's Electricity Consumption Profile and Forecasting". Sensitivities can be used to better understand low load growth and/or high electrification scenarios.
- **Unmanaged Electric Vehicle Peak Growth** - The peak forecast assumes unmanaged EV charging as a key driver of peak load growth. A managed charging demand response program to offset some of that peak load growth was modeled as a potential supply-side resource option.
- **WECC Build** – The Calculated Reference Case Western electric system buildout comes from E3's most recent Aurora price forecast and includes load increases from electrification and the impact of regional policies. This is discussed further in the Regional Environment section below.
- **Climate Change** – The Calculated Reference Case does not include specific climate change modeling. Sensitivities can test increased or decreased summer and winter loads to account for this, and future IRPs may include more comprehensive climate change analysis, pending Board direction and feedback.

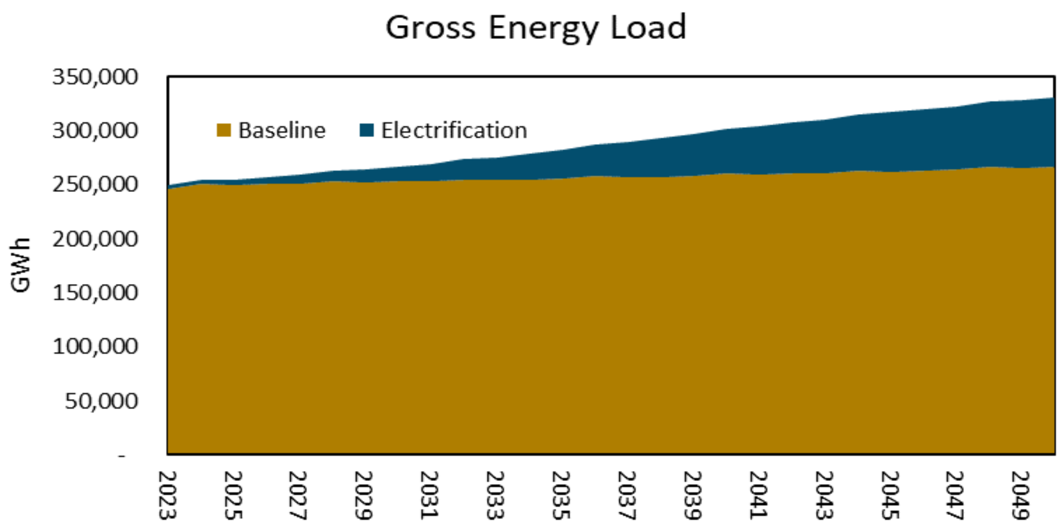
Key Context: Pacific Northwest Energy Market Forecast

Resource selection and portfolio optimization are a balancing act between EWEB's specific needs and the broader electric system. If market prices are high, it is beneficial for EWEB to build resources and sell surplus energy on the market. If market prices are low, it is more cost-effective for EWEB to rely on the market rather than make large capital investments. To examine these interactions, EWEB partnered with E3 to incorporate their latest market price forecast and regional outlook into the 2022 IRP.

E3's forecast feeds modeling inputs and serves as the foundation for the Calculated Reference Case results. However, although the E3 view of the future electric system is informed by best available information and practices, as with any forecast, there is uncertainty. Future analysis will build upon the work with E3 and provide opportunities to explore multiple futures.

E3 Northwest Load Forecast

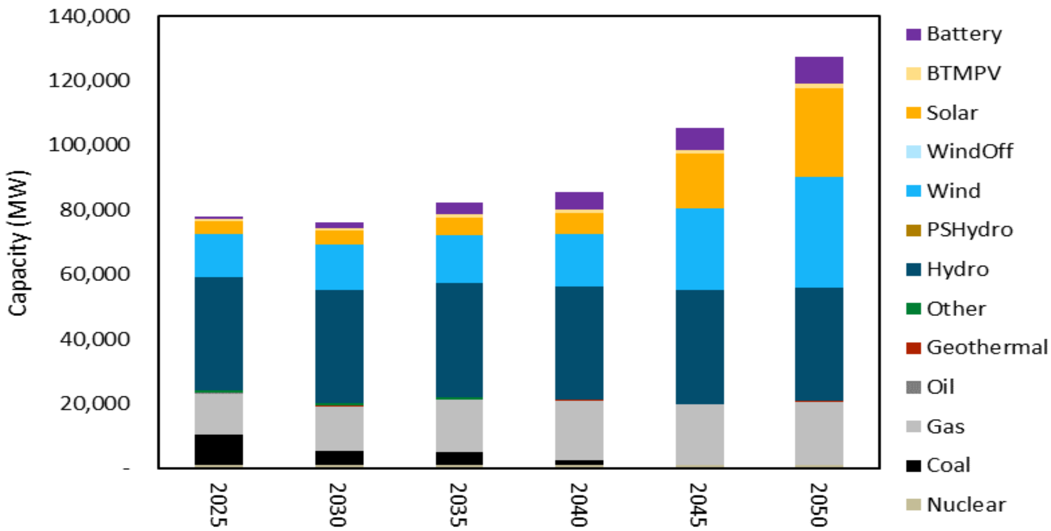
As with EWEB's load forecast, E3 expects that the primary driver of increased load in the future will be electrification. This is not expected to be impactful until closer to 2030, and in that year would represent roughly five percent of total annual load. In comparison, impacts of electrification in 2045 could be between fifteen to twenty percent of total annual load.



E3 Northwest Resource Build

E3's analysis incorporates planned resource retirements, as well as policy constraints and resource cost projections. As the table below shows, this leads to a reduction in coal capacity in the Northwest, which is replaced over time primarily by a mix of wind, solar, and battery storage. The amount of solar expected in the region is not as substantial as in areas like the desert Southwest that have growing peak summer needs, fewer existing clean energy resources, and higher solar capacity factors. Batteries are not expected to make up a material portion of the Pacific Northwest portfolio until after 2030.

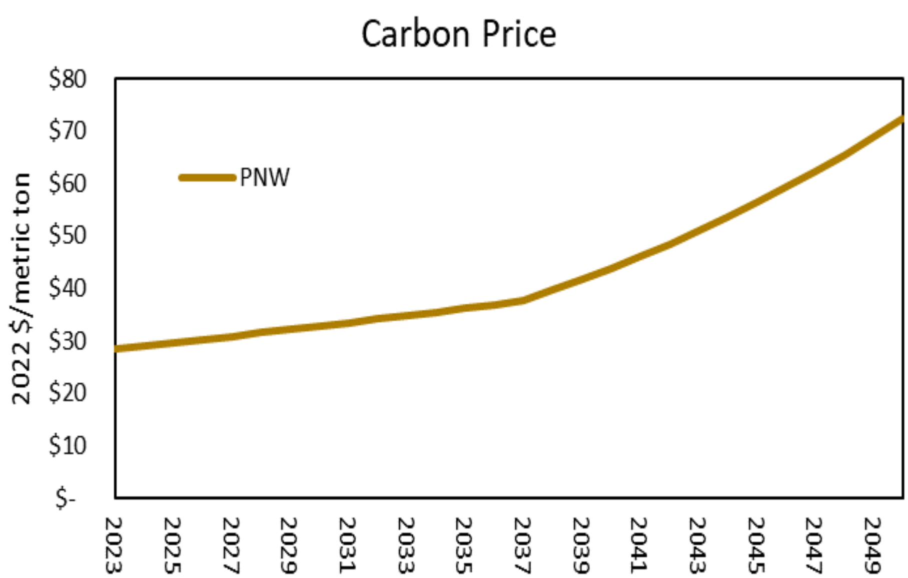
E3 Northwest Buildout



In general, because the Northwest already has a number of low-carbon hydro resources, E3's modeling does not predict substantial new resource builds to meet carbon policies before 2040; instead, a retention of firm capacity and new resource builds keep pace with growing peak and energy demands. This resource build forecast aligns with the IRPs of every major utility, where wind, solar and batteries make up the vast majority least-cost, best fit options.

E3 Carbon Pricing

E3's model includes a price on carbon, which influences resource build decisions and dispatch. With the passage of Washington State's Climate Commitment Act, a cap-and-trade program, carbon pricing is quickly becoming a reality in the Northwest. Regardless of whether Oregon passes a carbon pricing bill, Washington and California cap-and-trade programs will impact market liquidity and pricing. Washington State has already revised its initial forecast of carbon prices since allowances went from $18.80/ton in May 2021, to $27/ton in August 2022. Because natural gas plants are often the marginal generating unit, especially in evening hours and seasons when hydro and renewable generation is less abundant, carbon prices increase overall market prices.



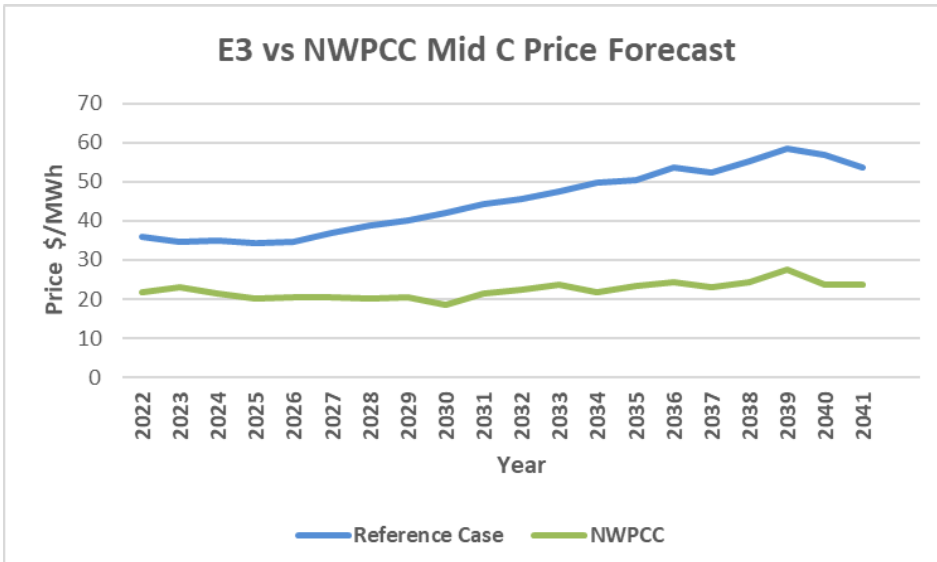
E3 Market Prices: Mid-C Prices –

Electricity market price forecasts are useful for estimating the future price of electricity as traded on the wholesale, short-term (spot) market at the Mid-Columbia trading hub. This forecasted price represents the marginal cost of electricity at the trading hub based on the economic dispatch of resources and transmission constraints between other trading hubs. Aurora simulates both load and generation dispatch for the entire WECC[22] and the market price formation in each region is based on economic dispatch logic for the full system. The cost to run the last unit that is dispatched to meet regional load determines the spot market price.

Spot markets are typically where power is sold after utilities secure enough resources to meet their loads. Utilities do not choose to build resources solely for their value in the spot market, but also consider other value streams like capacity value and their ability to generate renewable energy certificates. Below is a comparison between the price forecast for the Calculated Reference Case and price forecasting from the 2021 Power Plan from the Northwest Power and Conservation Council (NWPCC). The Calculated Reference Case portfolio valuation estimates the value of market purchases and sales for the calculated portfolio using these Mid-C prices.

The primary causes for differences among price forecasts are related to:

1) the amount of new renewable generation developed in the future.
2) the amount and type electricity generation needed to maintain grid reliability.
3) the estimated future loads in the Pacific Northwest based on population changes, electrification, and conservation.



The NWPCC 2021 Power Plan forecast is substantially lower due to overbuilding renewables assumed to be needed to meet the various policy requirements put on Western electric utilities. This overbuild creates an oversupply of electricity and depresses market prices. EWEB's Calculated Reference Case Mid-C forecast, on the other hand, does not anticipate the same oversupply of electricity. Instead, rising demand for electricity keeps gas on the margin and carbon pricing puts upward pressure on the cost of electricity in the spot market.

[22] WECC is the Western Electrical Coordinating Council. It coordinates reliability for the Western Interconnect.