MEMORANDUM

EUGENE WATER & ELECTRIC BOARD

Rely on us.

TO: Commissioners Brown, Carlson, Barofsky, McRae and Schlossberg

FROM: Megan Capper, Energy Resources Manager; Ben Ulrich, Senior Energy Resource Analyst; Aaron Bush, Energy Resource Analyst II

DATE: July 22, 2022

SUBJECT: New Resource Characteristics in the 2022 IRP

OBJECTIVE: Information and Board Discussion

Issue

EWEB's 2022 Organizational Goals state that by year end, staff will complete a "public draft" of an Integrated Resource Plan (IRP) in order to gather feedback during a public comment period in early 2023. As part of the 2022 Integrated Resource Plan (IRP), staff will be working throughout the year to inform and engage the Board about key IRP topics. The IRP modeling will analyze different combinations of resources to create an electricity supply portfolio (i.e., a mix of supply-side and demand-side resources). Each of these resources has unique trade-offs between cost, reliability, carbon. Staff is providing additional information about the characteristics and attributes of new resource options which will be considered in the 2022 IRP.

Background & Discussion

Refresher on EWEB's Needs

At the April Board meeting, staff presented information on trends and forecasts for EWEB's electricity consumption needs. The key takeaways from that presentation were:

1. EWEB is a winter peaking utility. Our greatest needs occur on cold days between December and February, and the typical summer peak is 80% of the typical winter peak.
2. EWEB's loads fluctuate throughout the year and can vary by over 100 MWs within a 24-hour period. These shifts in load are driven primarily by customer behavior and temperature changes.
3. The load for the typical annual peak hour is 1.7 times greater than the annual average load.

These takeaways are important to keep in mind as EWEB evaluates new resource options because the value of a given resource will depend on how well it aligns with EWEB's needs (consumption patterns). Additionally, each resource has tradeoffs and there is no perfect dispatchable, low-cost, carbon-free resource option that meets all EWEB's needs. The IRP will evaluate how potential resources work as a *portfolio*. This means that in addition to fit with EWEB's consumption needs, how resources interact *with each other* will also be important.

For example, over the course of a year, EWEB's load rarely falls below 200 MW. There may be cost-effective 'baseload' resources that can dispatch a consistent, flat amount of energy that EWEB will always want to have to meet this base need, except when forced outages or maintenance occurs. A 'baseload' resource would need to be paired with a flexible resource that can follow EWEB's loads more closely. Similarly, variable renewable resources might provide energy at the right time of year to coincide with peak EWEB loads, but because they are not dispatchable they need to be paired with a highly flexible or storage resources (e.g., storage hydro or batteries).

Modeling work for the 2022 IRP will sample different resource blends and select the least-cost combination to meet EWEB's needs given the constraints provided by the Board, such as EWEB's carbon policy. It will then be up to the Board to weigh the various trade-offs between resources.

Key questions being addressed in this memo include:

- What resources are being considered in the 2022 IRP?
- What are the key characteristics and tradeoffs of different resources?
- How do these characteristics and resources align with EWEB's needs?

Resource Options and Data Sources

The goal of the IRP is to provide information about future resource decision making. For this reason, resources that EWEB already owns, as well as resources that are currently under contract, are not listed as new resource options in this memo (except for the 2028 BPA contract). Many of these existing resource contracts will sunset within the next six years, and it is possible that EWEB will have the opportunity to renegotiate some of these existing agreements. The findings of the 2022 IRP and future IRPs will inform EWEB's strategy for future resource decision making, including the renegotiations of resource contracts. EWEB's existing agreements will be included in modeling and analytical work as a part of EWEB's current portfolio and will remain in alignment with the assumptions used in the long-term financial plan.

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 and performance 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

At this point in the IRP process, 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 details on performance under various market conditions, reliability value, risk factors, and fit to EWEB's values. After the initial modeling results are compiled and presented to the Board in November, it will be up to the Board to provide feedback and begin considering potential action items. These action items could include additional analysis, requesting sensitivities to be conducted by the EWEB Power Planning team, issuance of a Request for Information to developers, development of demand-side products and prices, or separate studies to better understand and characterize specific resources.

Resource cost and performance assumptions are the output of a collaboration between EWEB staff and Energy and Environmental Economics, Inc. (E3), a leading energy consulting firm. Assumptions regarding costs, energy generation profiles, carbon attributes, and other technology characteristics were determined using a broad variety of sources. These include 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 in Appendix A.

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)*** • ***Mid- & Long- duration storage (e.g. formic acid/hydrogen*** • ***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 based on new product/contract options being developed by BPA. 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 and requires EWEB manage the variability through our power trading and scheduling operation. 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 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 although they are likely to change. As a business-as-usual assumption in the 2022 IRP, the quantity and costs of energy and capacity available from BPA are roughly the same throughout the study period.

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[1]. 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, solar generation potential is higher, and transmission access and costs need to be considered.

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**[2] 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[3], which for utility-scale solar 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 desirable compared to other resources that offer more winter-peaking contributions. 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 located in Eugene, where project benefits could flow to multiple EWEB customers instead of individual homeowners, has a 13.5% capacity factor. 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 will 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 and has about the same capacity factor as community solar. Residential rooftop solar has many of the same characteristics as community solar but 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. Even with federal incentives or tax rebates, residential solar is substantially more expensive than other resource options. 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

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1 U.S. Energy Information Administration - EIA - Independent Statistics and Analysis

2 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.

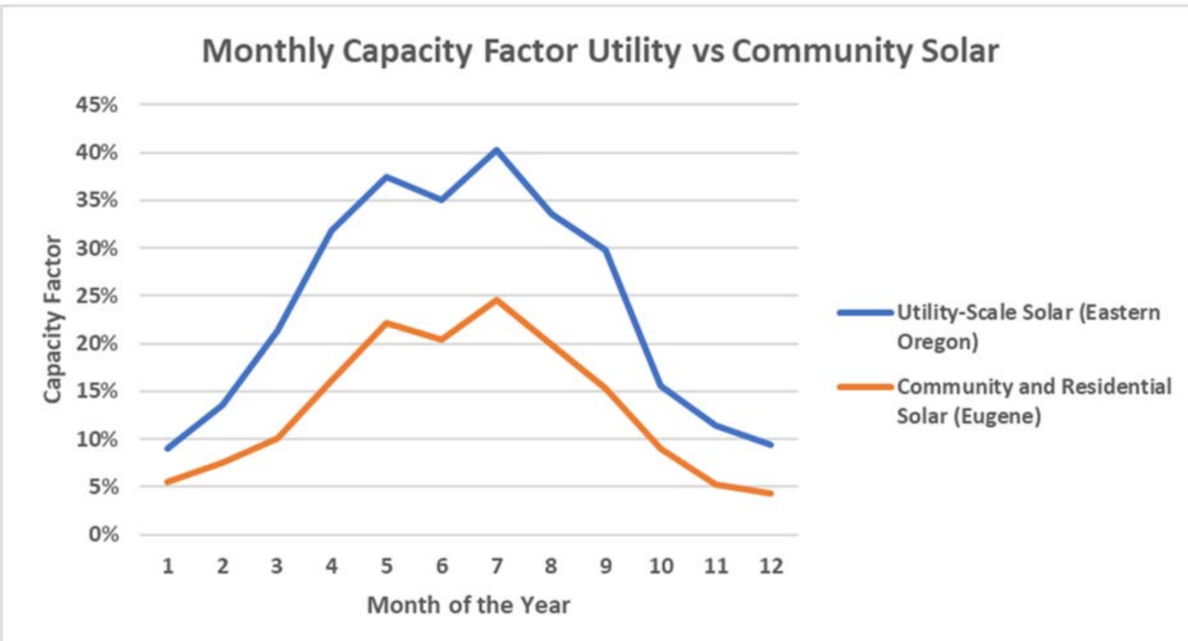
3 See Peak Capacity Contribution section below for more details.

borrowing and installation costs.

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[4] 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.

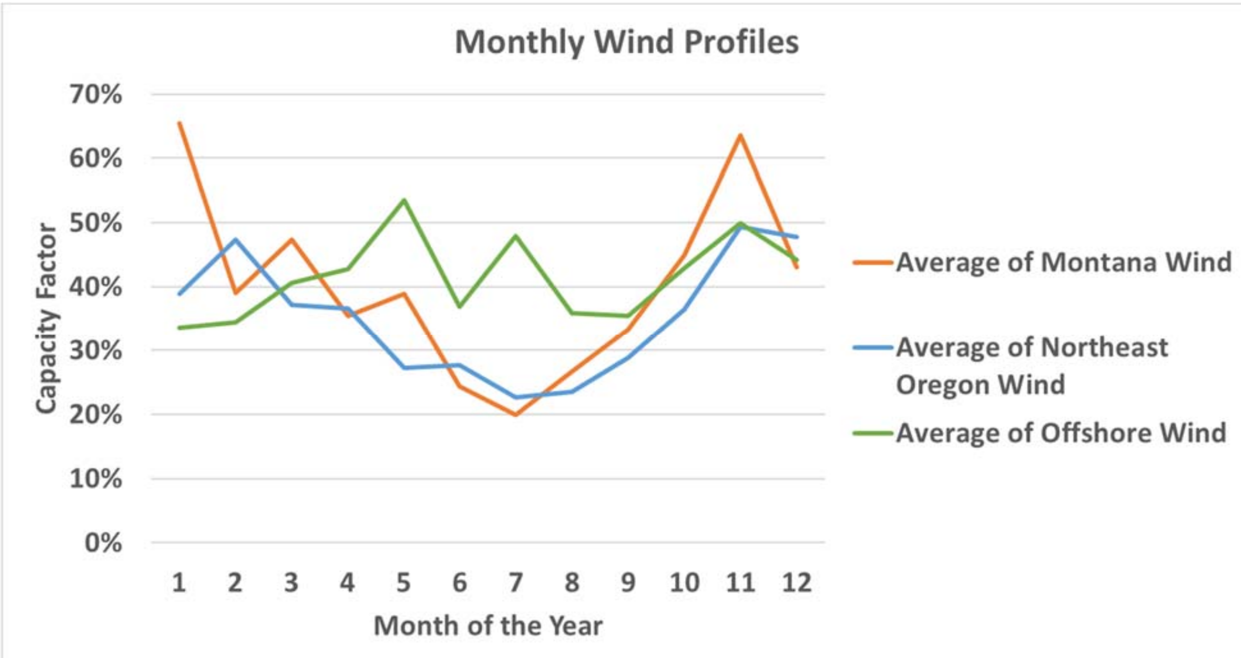
Wind

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[5]. 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.

4 A power plant or generating facility has a "nameplate capacity" which indicates the maximum output that the generator can produce.

5 U.S. Energy Information Administration - EIA - Independent Statistics and Analysis

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.



Natural Gas

Natural gas power plants are relied on across the energy industry because they have relatively low up-front capital costs, provide baseload capacity, have significantly lower emissions that coal generation, and have the flexibility to meet peak loads. Despite these benefits, natural gas plants have tradeoffs, primarily related to fuel risk, carbon emissions (using present fuel technologies), 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 sited in Idaho and delivered to EWEB load, developing a gas plant presents a substantial risk and challenge without fuel innovation (non-fossil-based).

Studies by E3 and other energy analytical groups have found that natural gas plants need to play a key role in maintaining electric system reliability in the transition to renewable energy sources[6]. This is because natural gas is easily stored, and gas plants can remain idle most of the year and only operate during peak load events or at times of shortfall from variable renewable generators. Additionally, despite risks related to fuel cost and carbon emissions, natural gas plants are one of the least expensive options to provide capacity and flexibility.

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

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

Cogeneration and biomass plants are two types of thermal generation resources that offer efficiency and/or environmental benefits over traditional gas turbines. A cogeneration plant recycles the excess heat waste from other uses for power generation (or visa versa), and biomass plants use plant matter, rather than gas, for an energy source. In Oregon, many biomass plants are considered renewable (e.g. Seneca Sustainable Generation) and 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' designs. 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 can limit their ability to meet peak needs of the utility.

Small Modular Nuclear

Multiple companies, including NuScale Power in Corvallis, 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 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 will become 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 can 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 and a carbon content equivalent to the resources used for charging. 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[7]. 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 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. Other mid-term storage options, like hydrogen or other intermediate chemistries (e.g. formic acid) will eventually need to be developed.

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 until their innovation timing is clarified but may be including in upcoming IRP updates.

Energy Efficiency

Over the past decade, EWEB policy has prioritized energy efficiency as the preferred resource to meet 'organic' 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 the Bonneville Power Administration's Utility Energy Efficiency Potential Calculator[8]. 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).

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7 https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf
8 Utility Toolkit - Bonneville Power Administration (bpa.gov)

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 available 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 impact 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, 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 aggregating across 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 (See Appendix A)

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 baseline 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 long as fuel was available. As the region shifts to greater penetrations of renewable energy that is produced based on variable conditions (e.g. wind), 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 this memo are reflective of EWEB's needs as well as E3 studies on resource adequacy in the Pacific Northwest. In addition to these values, analytical work in the 2022 IRP will include sensitivities to 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 (like EWEB) invest in sufficient resources to meet their peak needs[9]. 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.

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-month. 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

9 WPP (westernpowerpool.org)

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 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, even though they may produce indirect carbon emissions. 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, the accounting for carbon and other particulate emissions is more complex. The burning of 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 may 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. However, this will be analyzed further.

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. It will be up to the Board to determine 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 I-5 corridor. The current transmission system does not have capacity to accommodate most new transmission requests from East to West across the Cascades, and transmission siting, permitting, and construction takes decades.

Demonstrating this challenge, BPA's 2022 transmission cluster study had 11,831 MW of transmission requests, of which only 275 MW (2.3%) 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 likely to incur 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 (See Appendix A)

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 the 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.

<u>Key takeaways</u>

1. There is no perfect resource
   Every new resource option under consideration in the 2022 IRP has tradeoffs. These include costs, carbon emissions, political constraints, 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.

Recommendation & Requested Board Action
No action is requested at this time. The information is provided to facilitate Board understanding and discussion.

Appendix A

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%	-
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