2022 IRP Resource Assumptions

1 Background

In each IRP, we consider utility scale renewable and nonrenewable generating technologies as well as demand-side resources as options to meet our future resource needs and combine them together into logical portfolios. This document describes the resources we plan to consider in the 2022 IRP and the assumptions we make to model them. The list of resources we plan to consider in the 2022 IRP are:

(1) Renewal of our BPA contract in 2028
(2) Utility-scale wind
(3) Utility-scale solar
(4) Utility-scale battery storage
(5) Demand response (DR)
(6) Conservation
(7) Small nuclear reactors

In addition to the above resources, we plan to include the hydropower resources currently owned by Tacoma Power in all of the portfolios we consider. We may also find the need to consider additional resources not listed above (e.g. pumped storage, renewable and/or non-renewable natural gas generation, etc.) as we analyze initial results, particularly in scenarios where a large resource need exists.

2 BPA Contract

2.1 Products Considered

Under our current BPA contract, we receive energy through a hybrid Slice/Block product. In the “Slice” part of the contract, we receive approximately 3% of the wholesale power that BPA produces, an amount that varies by year and by season depending on streamflow conditions. In the “Block” part of the contract, we are guaranteed a certain constant amount of energy every month that does not change with streamflow conditions. About half of the firm power we receive from BPA comes from the Slice portion of the contract and half comes from the Block portion in an average year.

Our 2022 IRP will model the same products as we did in 2020 IRP: the Slice/Block product that we currently purchase and the Block with Shaping Capacity product. We may also consider a more basic monthly diurnal product and one additional type of product that is not currently available today: a product that combines Slice and the monthly diurnal bock. While we do not know for sure whether such a product will exist in the post-2028 period, we think that this product (or something similar) would be a valuable addition to BPA’s list of product choices and is an option we should consider if BPA does offer it.

2.2 Contract assumptions and resource dispatch

We model the Slice/Block product in two parts. The Slice portion is modeled as a profile that is simulated based on weather year, and is therefore based on historical inflows, demand, and right to power (RTP). The Block portion is modeled as a fixed amount that changes every year based on our load forecast and according the net requirement calculation set in our contract. Alternative block-only products are also modeled as a fixed annual amount that adjusts based on our load forecast. The monthly shape of that annual amount is set in our existing contract and was based upon the historical shape of our load. For the Block with Shaping Capacity, which allows some ability to shape block energy into heavy load hours (HLH), we use simulated load for a given run to determine how the resource gets shaped.

In the 2022 IRP, we will continue to model BPA products using our current contract construct and current BPA assumptions regarding Slice capability under critical water. These assumptions will affect our net requirement calculation under Slice/Block (i.e. how much Block we receive for a given load) as well as our contract high water mark (i.e. the maximum amount of Block we could receive if loads were to continue to grow). We also assume that our monthly block shaping factors (i.e. what share of our annual Block energy comes in each month of the year) remain constant at current contract levels. However, we have advocated for BPA to allow block shaping factors to adjust in the next contract so that they can better meet utility needs as their load profiles change. We know that BPA will likely change their assumption regarding Slice capability under critical water and may change some contract terms, but we do not yet know exactly how these assumptions will change. We will incorporate updated contract assumptions into our 2024 IRP.

2.3 Cost Assumptions

For all of its current products, BPA charges are divided into 4 key components: (1) a composite charge, (2) a non-slice charge, which often ends up being a bill credit for Tacoma Power, (3) a load shaping charge, and (4) a demand charge. A detailed description of each component is available in Section 11.1.2 of our 2020 IRP. We will maintain the same basic framework for calculating BPA costs as that used in the 2020 IRP and assume status quo terms for allocating costs but will update cost estimates based on BPA's BP-22 rate case.

We will also explore the potential BPA cost implications of lower Snake River Dam (LSRD) removal. We will likely use data from the Columbia River System Operations Environmental Impact Statement (CRSO EIS). For the purposes of this LSRD removal sensitivity analysis, we will assume that BPA replaces the resources to maintain an equivalent level of power supply. As a result, we will only explore cost implications of LSRD removal in our analysis and will not assume any change to the capability or shape of the federal system's power supply.

3 Wind and Solar

3.1 Generation Profiles

Wind and solar generation profiles were developed from simulated wind speed and global horizontal irradiance (GHI) values, respectively. NREL has produced these simulated data for thousands of locations across the US. This IRP will include wind sites from locations in Eastern Washington, Gorge, and Montana and solar sites from Eastern Washington only[1]. Because the NREL dataset only has six years of simulated data, several sites in these locations were selected to produce 90 unique 8760 hourly wind profiles and 20 unique 8760 hourly solar profiles for each location.

3.1.1 Wind Profiles

Figure 1 through Figure 6 compare the monthly capacity factors and distribution of wind across these various sites for each of the three aforementioned locations. From these profiles, Gorge wind provides more wind power on average during the spring and summer months. The opposite is true for Montana wind, which provides more power

[1] We selected just a single location to model solar because profiles across different locations were very similar, so long as the solar resource was located east of the Cascades.

during the winter and fall months. Eastern Washington wind tends to have a flatter monthly profile, with a slight dip in average power output in part of the summer.

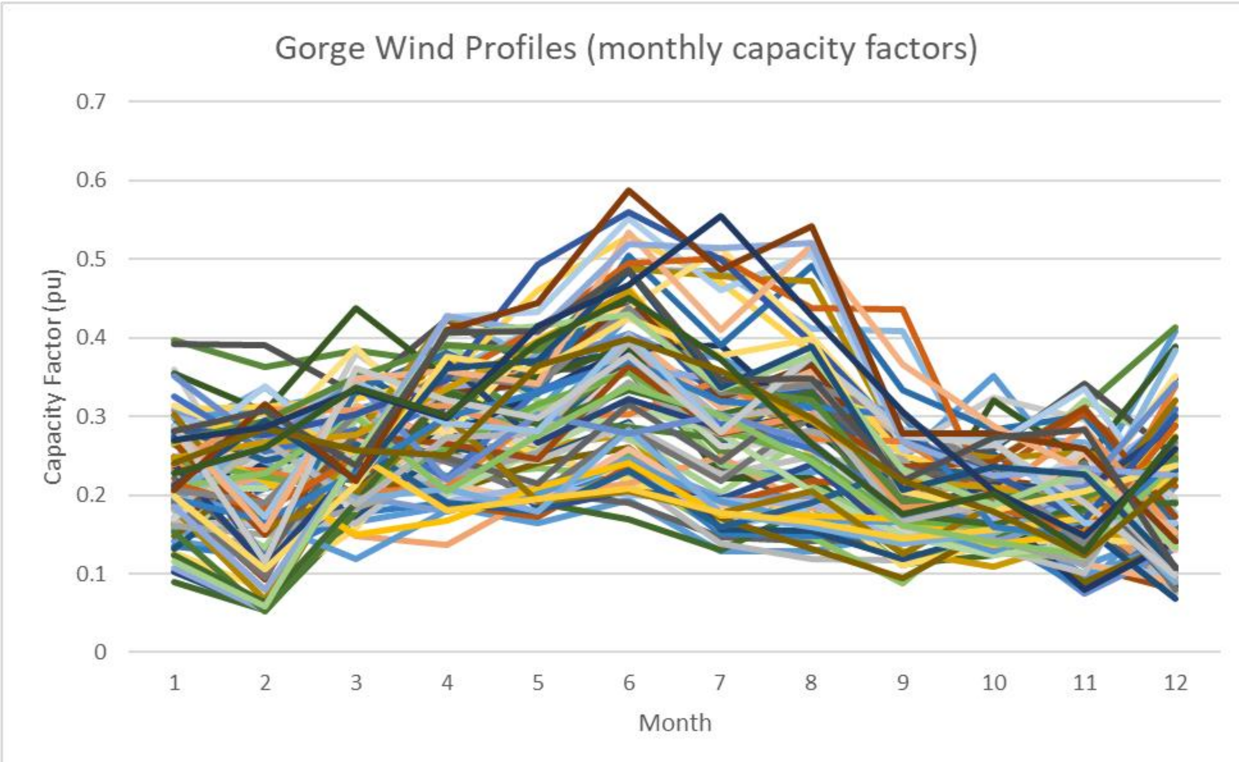

FIGURE 1. GORGE WIND MONTHLY CAPACITY FACTORS

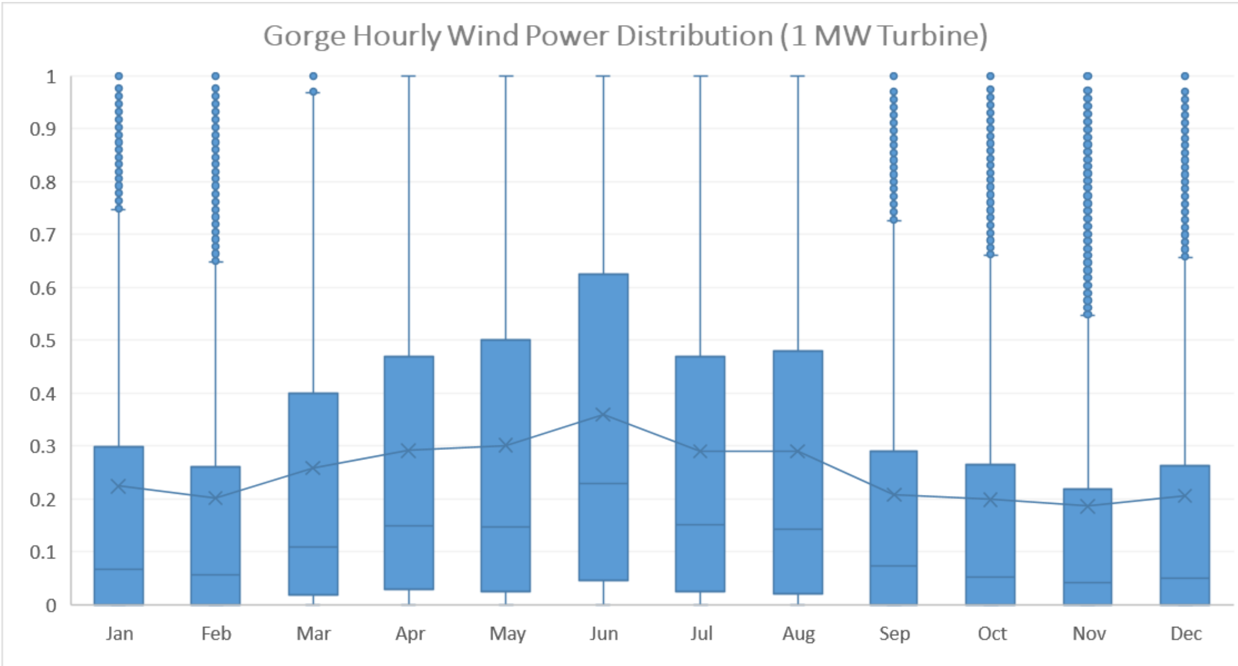

FIGURE 2. DISTRIBUTION OF HOURLY WIND POWER OUTPUT - GORGE WIND

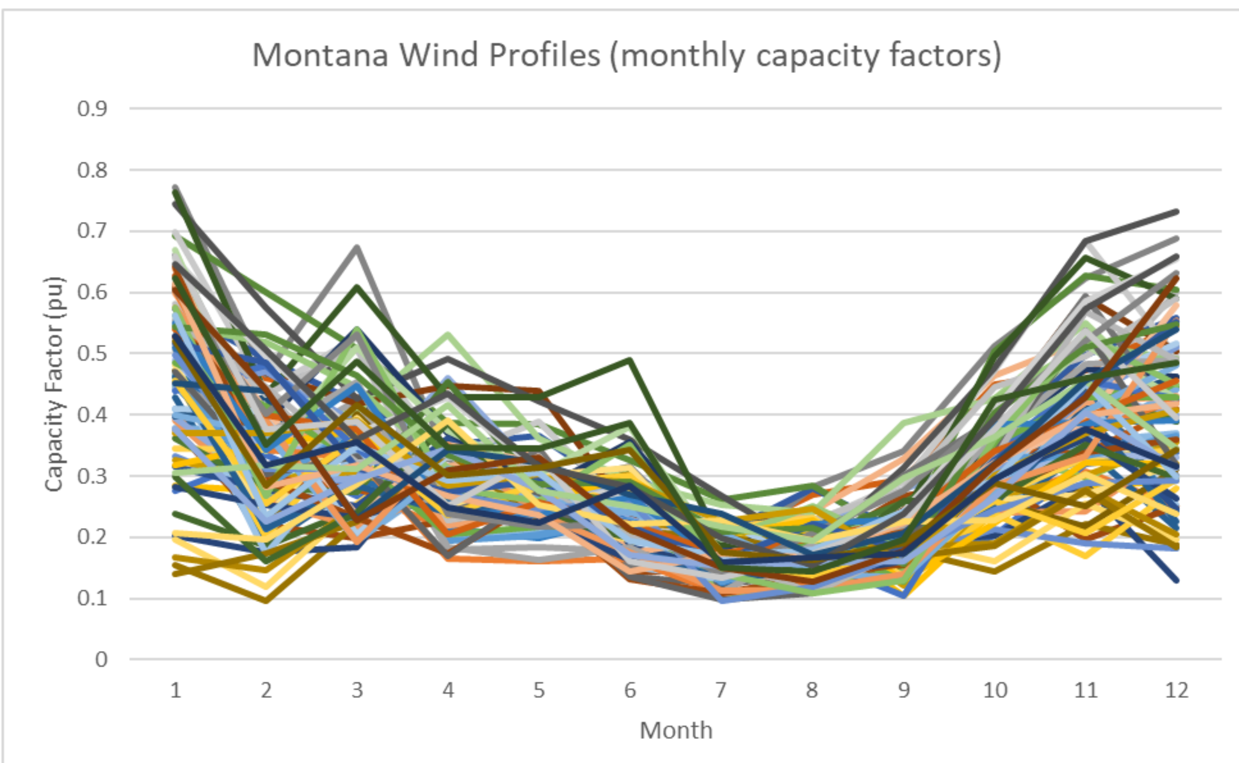

FIGURE 3. MONTANA WIND MONTHLY CAPACITY FACTORS

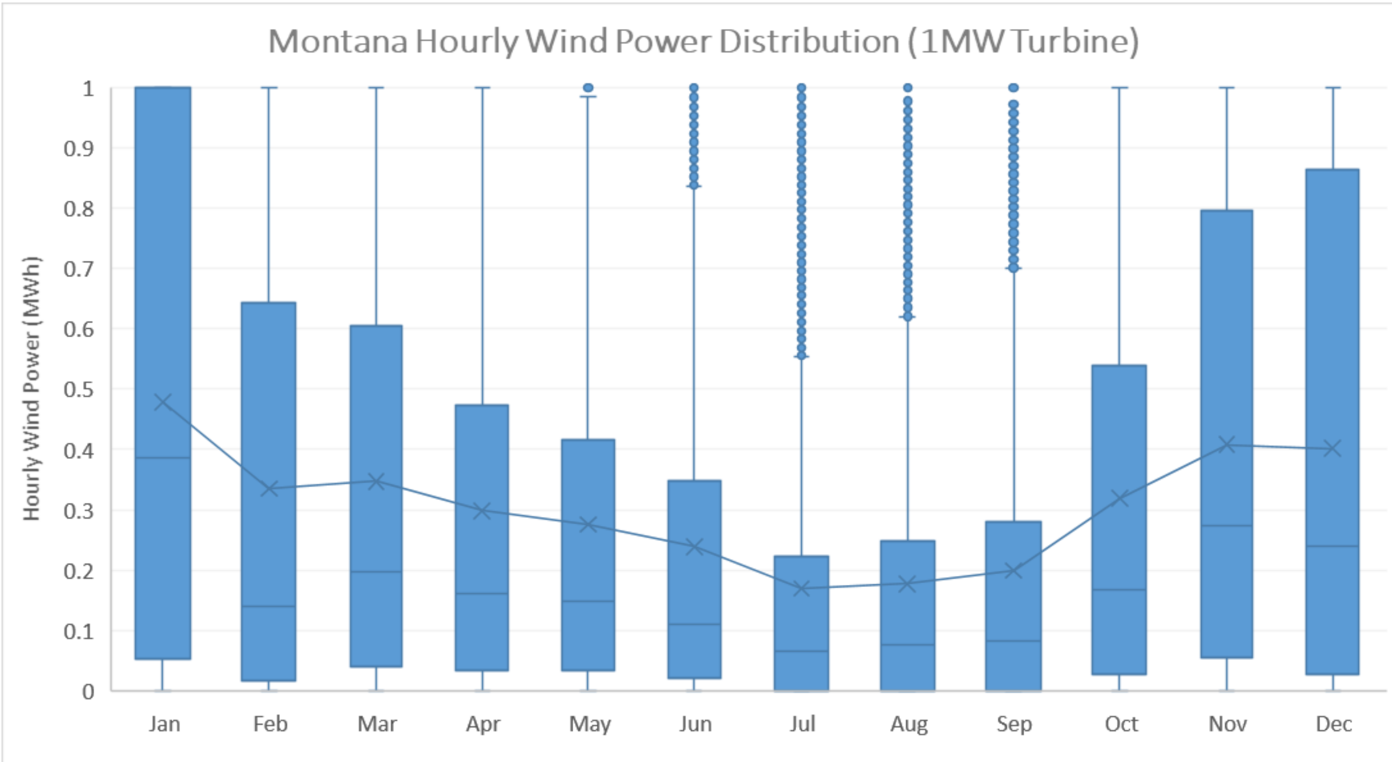

FIGURE 4. DISTRIBUTION OF HOURLY WIND POWER OUTPUT - MONTANA WIND

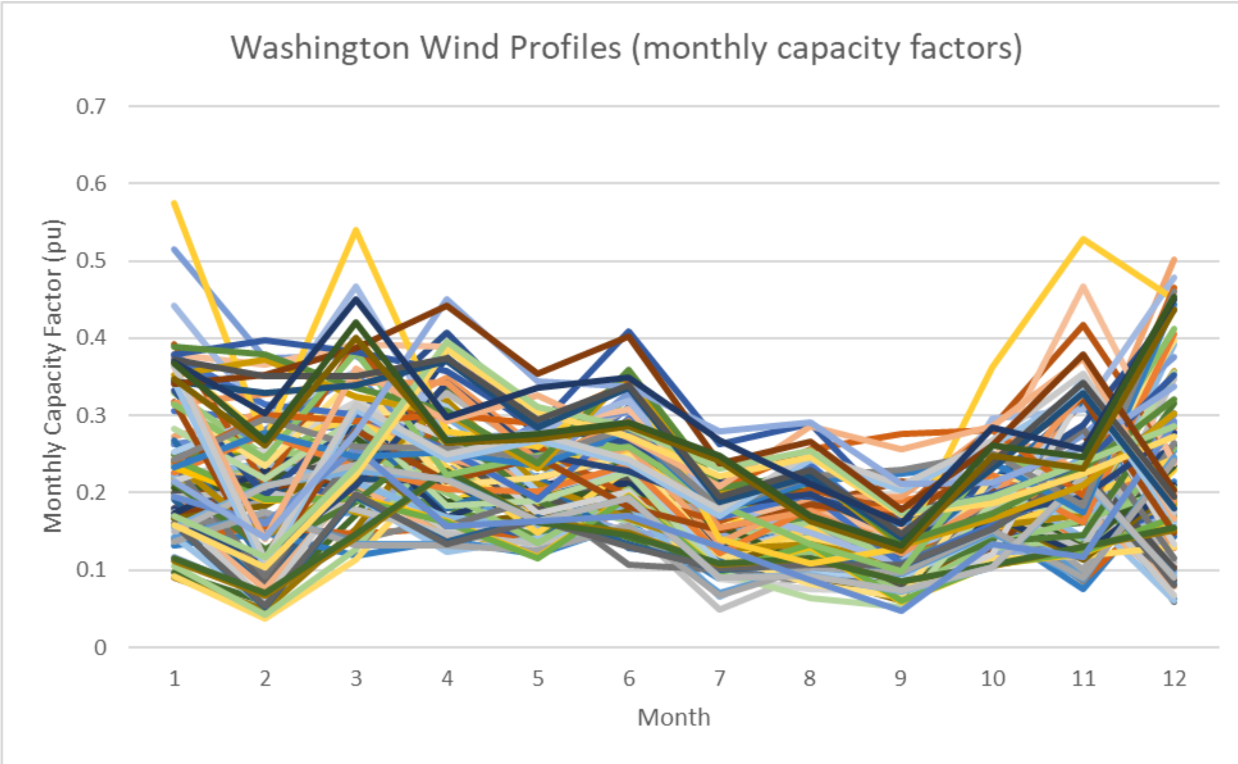

FIGURE 5. WASHINGTON WIND MONTHLY CAPACITY FACTORS

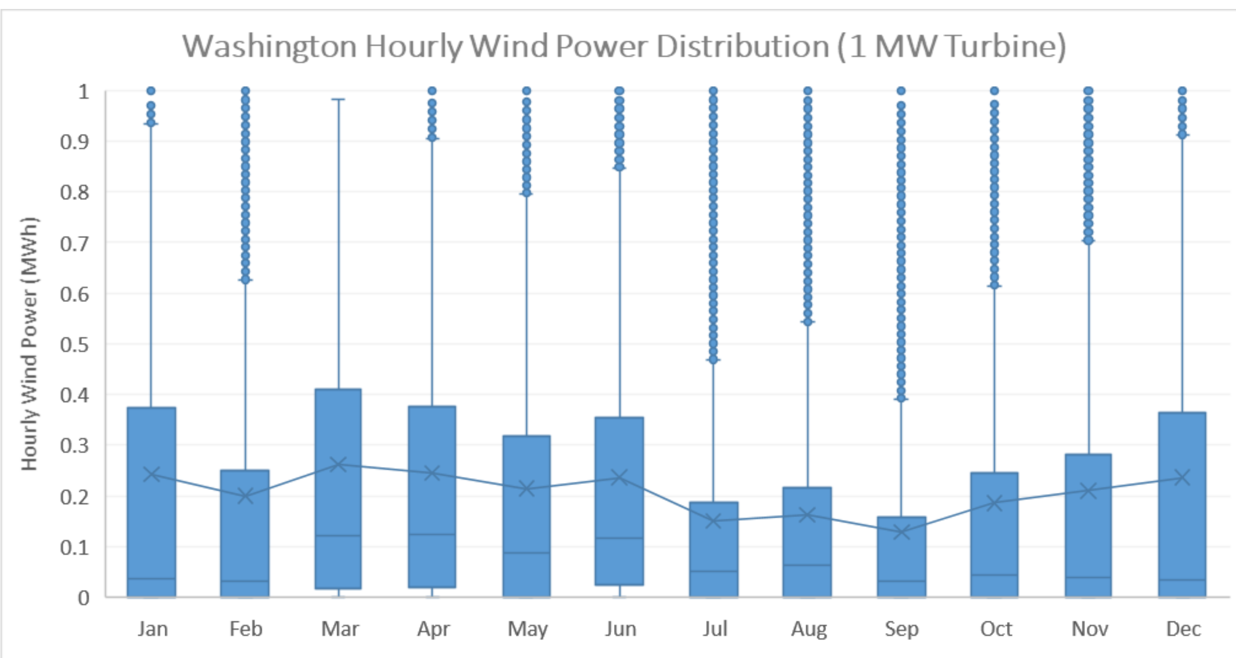

FIGURE 6. DISTRIBUTION OF HOURLY WIND POWER OUTPUT - WASHINGTON WIND

3.1.2 Solar Profiles

Figure 7 and Figure 8 compare the monthly capacity factors and distribution of solar across various sites in Eastern Washington. Unlike the simulated wind profiles, there is not very much monthly variation in capacity factors for different sites. There is, however, still significant variation between sites on an hourly basis.

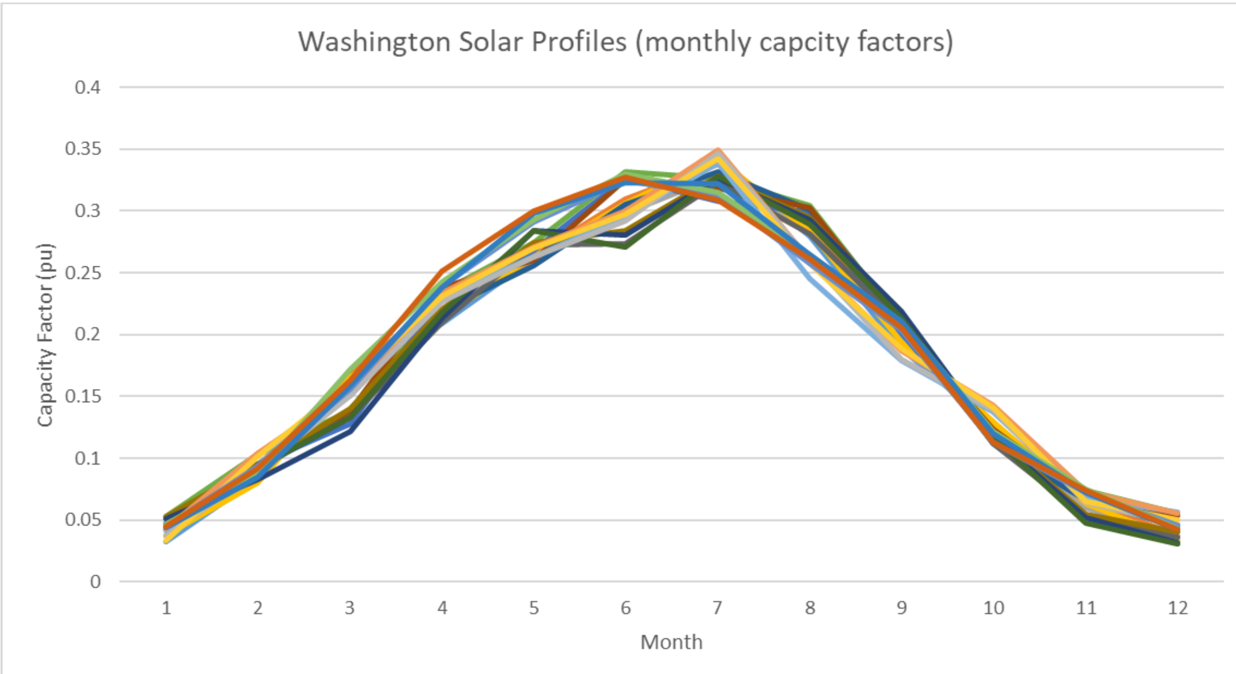

FIGURE 7. WASHINGTON SOLAR MONTHLY CAPACITY FACTORS

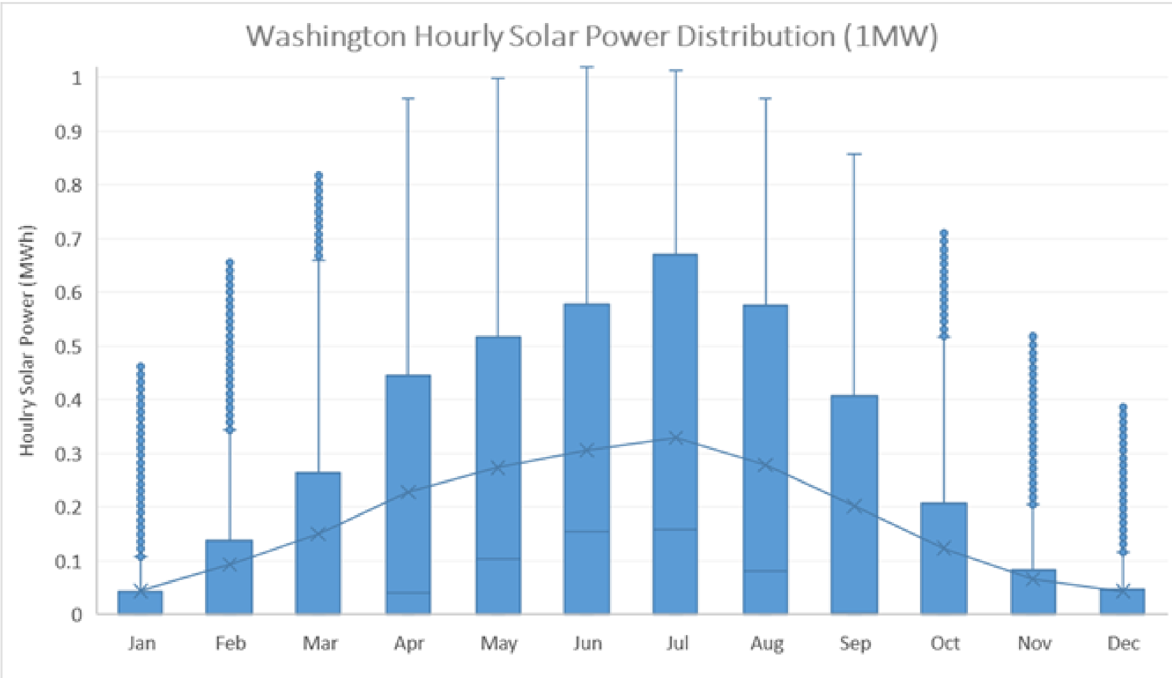

FIGURE 8. DISTRIBUTION OF HOURLY SOLAR POWER OUTPUT - WASHINGTON WIND

3.2 Generation Dispatch

Our system model (SAM)[2] selects a specific 8760 hourly profile from a site within a location (Gorge, Eastern Washington, etc.), and adds specific profiles from additional sites as the size of the requested resource increases. SAM iterates through solar resource sites for every 50 MW of capacity. For example, a 160 MW solar plant located in Eastern Washington for a specific simulation year (i.e. a specific weather profile) would be comprised of the following:

- 60 MW at Site 1 using Weather Profile 0
- 50 MW at Site 2 using Weather Profile 0
- 50 MW at Site 3 using Weather Profile 0

For wind, we have data on subsites within a site. SAM selects first from additional subsites within a site and adds profiles from those additional sub-sites in 20MW increments. Once all subsites within a site have been exhausted, SAM moves on to the next site within a location and repeats the process, iterating through sites and subsites in 20MW increments. For example, a 160 MW wind plant located at the Gorge for a specific simulation year (i.e. a specific weather profile) would be comprised of the following:

- 20 MW at Gorge Site 1, sub-site 1 using Weather Profile 0
- 20 MW at Gorge Site 1, sub-site 2 using Weather Profile 0
- 20 MW at Gorge Site 1, sub-site 3 using Weather Profile 0
- 20 MW at Gorge Site 1, sub-site 4 using Weather Profile 0
- 20 MW at Gorge Site 1, sub-site 5 using Weather Profile 0

[2] For more information on our system model, please see pre-workshop materials provided for our first 2022 IRP workshop on March 2, 2022.

- 20 MW at Gorge Site 2, sub-site 1 using Weather Profile 0
- 20 MW at Gorge Site 2, sub-site 2 using Weather Profile 0
- 20 MW at Gorge Site 2, sub-site 3 using Weather Profile 0

For both solar and wind resources, SAM loops through the simulated profiles from our six different weather years through the end of the simulation period.

3.3 Cost Assumptions

Solar and wind costs are based on the 2021 National Renewable Energy Laboratory (NREL) [Annual Technology Baseline (ATB)](). This report provides low, medium and high cost scenarios for different types of resources. Cost estimates exclude transmission, other grid connection assumptions, and costs of integrating wind and solar. We account for transmission and integration costs separately (see Section 7).

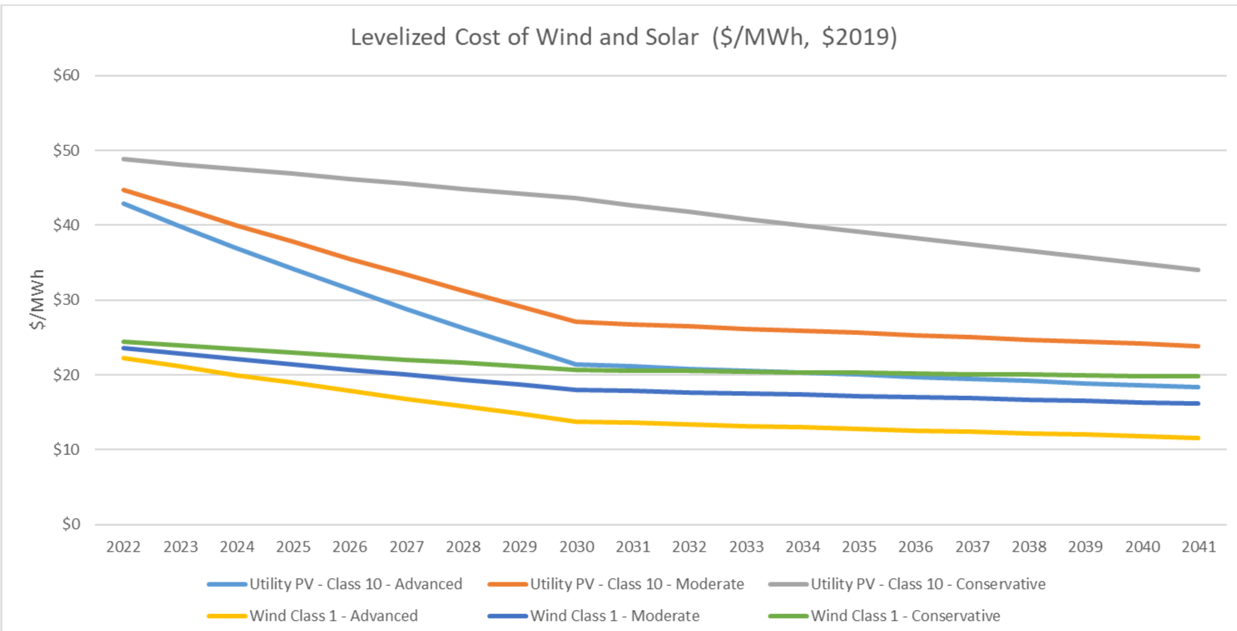

FIGURE 9. LEVELIZED COST OF WIND AND SOLAR. (SOURCE: NREL 2021 ATB). CLASS 1 WIND ASSUMPTIONS ARE FOR AREAS TURBINES WITH RATED WIND SPEED GREATER THAN 9M/S^2. CLASS 10 PV IS FOR AREAS WITH ANNUAL CAPACITY FACTORS LESS THAN 20%

4 Demand Response (DR) & Storage

Our 2020 IRP modeled a very simple DR product that never dispatched and simply served as operating reserves, reducing the required level of operating reserves held by our generation by 1MW for every 1MW of DR. One of our 2020 IRP action items was to improve upon how we model DR in SAM. SAM now models three distinct types of DR resources: "Economic", "Auto Recover" and "Time Between Calls". From these three basic model structures, various types of storage, flexible load and DR programs can be represented in SAM.

4.1 Dispatch Logic

Table 1 compares the distinguishing features of these three basic DR model types, including Offer Price (price at which DR dispatches) and Bid Price (price at which curtailed load can be recovered). One of the primary DR resource features is whether the dispatch logic considers the resource's "remaining energy equivalent" that is available in a given period. The remaining energy equivalent is the DR resource's peak load reduction in (MW) multiplied by the total duration of hours available for dispatch in a given period (month or year). If that energy equivalent is low, it becomes expensive to dispatch the resource because it is scarce and more valuable. Likewise, if the energy equivalent is abundant it becomes cheap to dispatch.

All DR resources (whether economic or reliability programs) are dispatched in the model when economic. Dispatch is considered economic when the market price is above the resource's "offer price". That offer price differs depending upon the type of DR being considered as shown in Table 1. The offer price is defined as the sum of the resource's opportunity cost (e.g. retail electricity price) and an "offer adder". The offer adder is a function of the remaining number of DR dispatches available in a given period (month or year) as well as the "energy equivalent" of those remaining dispatches (in the case of economic type DR).

After a DR event, the DR resource is allowed to recover load curtailed during the event. Conditions for recovering load dispatched during DR events depends on the type of DR program modeled as follows:

a) **Economic:** Load is recovered when it is economic, where economic means that market price is below the "Bid Price". Here, the bid price is a function of the remaining "energy equivalent" of the resource.
b) **Auto Recover:** Load is recovered automatically after the end of DR event
c) **Time Between Calls:** Load is recovered when it is economic, where economic means that the market price is below the "Bid Price". Here, the bid price is NOT a function of the remaining "energy equivalent" of the resource.

TABLE 1. COMPARISON OF SAM'S THREE DIFFERENT DR TYPES. THESE DR TYPES DIFFER IN THEIR FEATURES, INCLUDING THEIR DISPATCH AND LOAD RECOVERY CONDITIONS.

	Economic	**Auto Recover**	**Time Between Calls**
DR Dispatch Condition	When Market Price is above the Offer Price (sell price)	When Market Price is above the Offer Price (sell price)	When Market Price is above the Offer Price (sell price)
Load Recovery Condition	When Market Price is below the Bid Price (buy price)	Automatically without regard to price or cost	When Market Price is below the Bid Price (buy price)
Offer Price	Function of 1. remaining dispatches 2. opportunity cost 3. storage level	Function of 1. remaining dispatches 2. opportunity cost 3. storage level	Function of 1. remaining dispatches 2. opportunity cost
Bid Price	Function of 1. remaining dispatches 2. opportunity cost 3. storage level	No Bid Price	Function of 1. remaining dispatches 2. opportunity cost
Summary of Dispatch/Load Recovery Features	Dispatch logic considers "energy equivalent"	Dispatch logic considers "energy equivalent"	Dispatch logic does not consider "energy equivalent"

	Load recovers economically	Load recovers immediately after DR event	Load recovers economically

4.2 DR Programs Modeled and Their Dispatch Assumptions

Table 2 summarizes the key storage and DR resources we plan to model in the 2022 IRP: a) a 6-hour battery, b) an industrial DR resource used for reliability purposes only, c) a water heater DR resource and c) a highly flexible electrolyzer load. The opportunity cost for the "industrial load – reliability DR" is set quite high ($150/MWh) in order to ensure this resource is only dispatched during times the system is under stress. For the 6-hr battery, the electrolyzer, and the water heaters, the opportunity costs are set to retail electricity rates for those loads.

In the 2022 IRP, we will run a sensitivity analysis around the adequacy implications of a large electrolyzer load locating within our service area. Electrolyzer loads will be modeled in two parts. The additional load will be modeled as a fixed industrial load addition, and the flexibility of that load will be modeled using our DR resource described below. The size of the electrolyzer load in Table 2 is only a placeholder for the load we will ultimately model in our sensitivity analysis.

The list of DR resources in Table 2 is not comprehensive of all potential DR and storage resources. In certain of our sensitivity analyses (for example, an acceleration of vehicle and building electrification), we may find the need to consider some additional demand response programs for EV charging or space heating. The final size of a potential battery resource may also change depending on what resource needs are identified.

TABLE 2. DR MODEL PARAMETERS IN SAM FOR VARIOUS TYPES OF FLEXIBLE LOADS.

	DR LOAD TYPE:	INDUSTRIAL LOAD - RELIABILITY DR	6-HR BATTERY	LARGE ELECTROLYZER	RESIDENTIAL WATER HEATERS
	DR Model Type:	Monthly - Auto Recover	Monthly - Economic	Monthly - Time Between Calls	Monthly - Auto Recover
MODEL PARAMETER:	Units:				
BID ADDER	($/MWh)	5	5	5	5
DEPLOYMENTS	(Number Per Period)	6	744	2,190	90
LOOK AHEAD HOURS	(Hours)	6	6	6	6
MAX CHARGE	(MW)	3	25	0	14
MAX DISCHARGE	(MW)	9	25	200	14
MAX HOURS PER CALL	(Hours)	6	6	2,190	2
MAX STORAGE	(MWh)	324	150	438,000	28
MIN HOURS PER CALL	(Hours)	6	1	1	1
MIN STORAGE	(MWh)	0	0	0	0
MIN TIME BETWEEN CALLS	(Hours)	72	0	0	0
OFFER ADDER	($/MWh)	5	5	5	5

OPPORTUNITY COST	**($/MWh)**	150	45	36	45

Figure 10 through Figure 13 show a sample period of dispatch for each of the DR programs modeled. A brief discussion of the dispatch is provided in each figure caption. Note that both the Industrial Load and Water Heater Load (Figure 10 and Figure 11) use the “auto recover” DR model type in SAM. The dispatch logic for “auto recover” resources does not consider the Bid Price when recovering load, so load will recover immediately after the end of DR regardless of whether market price is below the bid price.

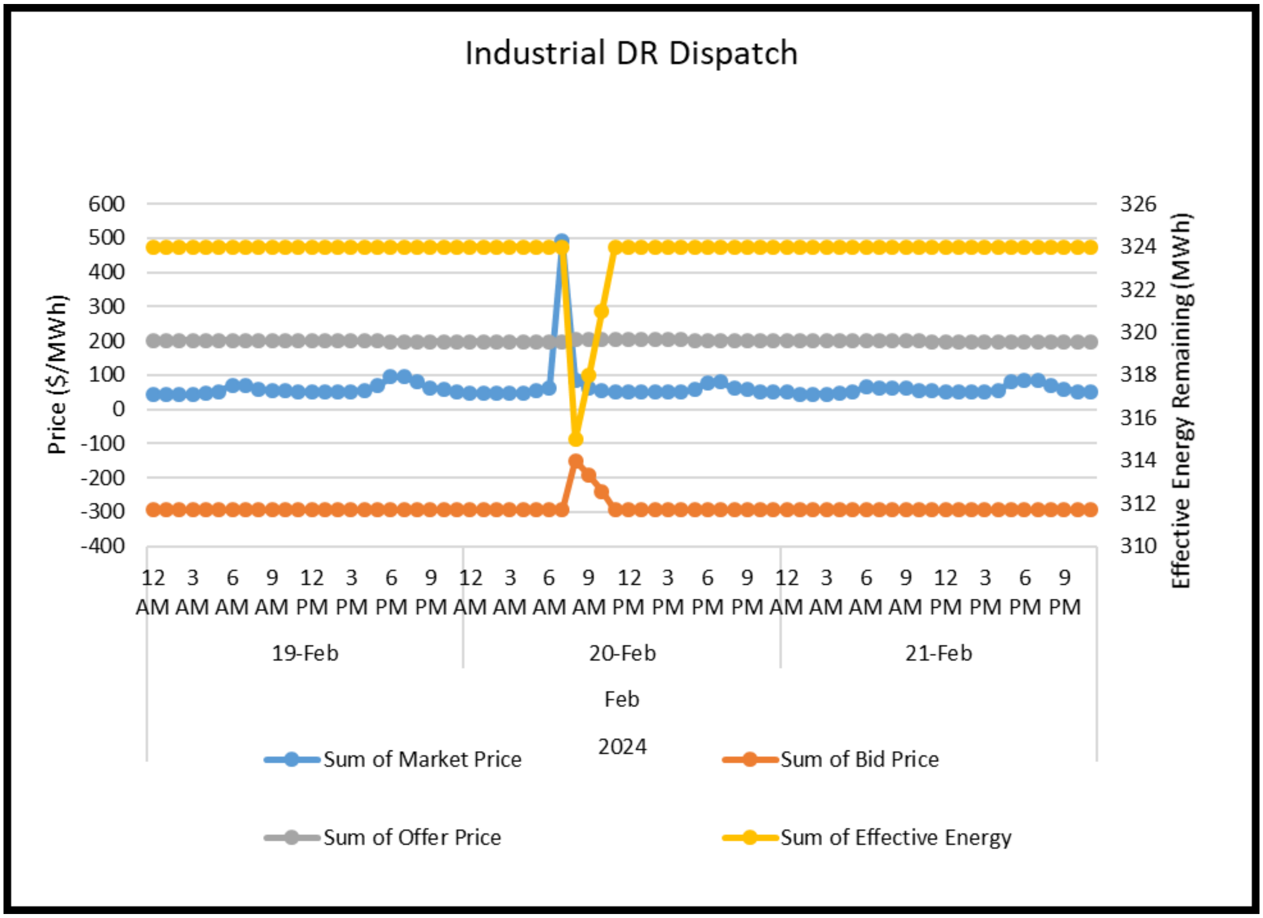

FIGURE 10. DISPATCH OF THIS INDUSTRIAL LOAD DR IS FOR RELIABILITY PURPOSES ONLY, HENCE THE VERY HIGH (AND LOW) OFFER AND BID PRICES, RESPECTIVELY. NOTE, SINCE THIS IS AN AUTO-RECOVERY TYPE DR, THE LOAD WILL "RECOVER" IMMEDIATELY AFTER A DISPATCH EVENT.

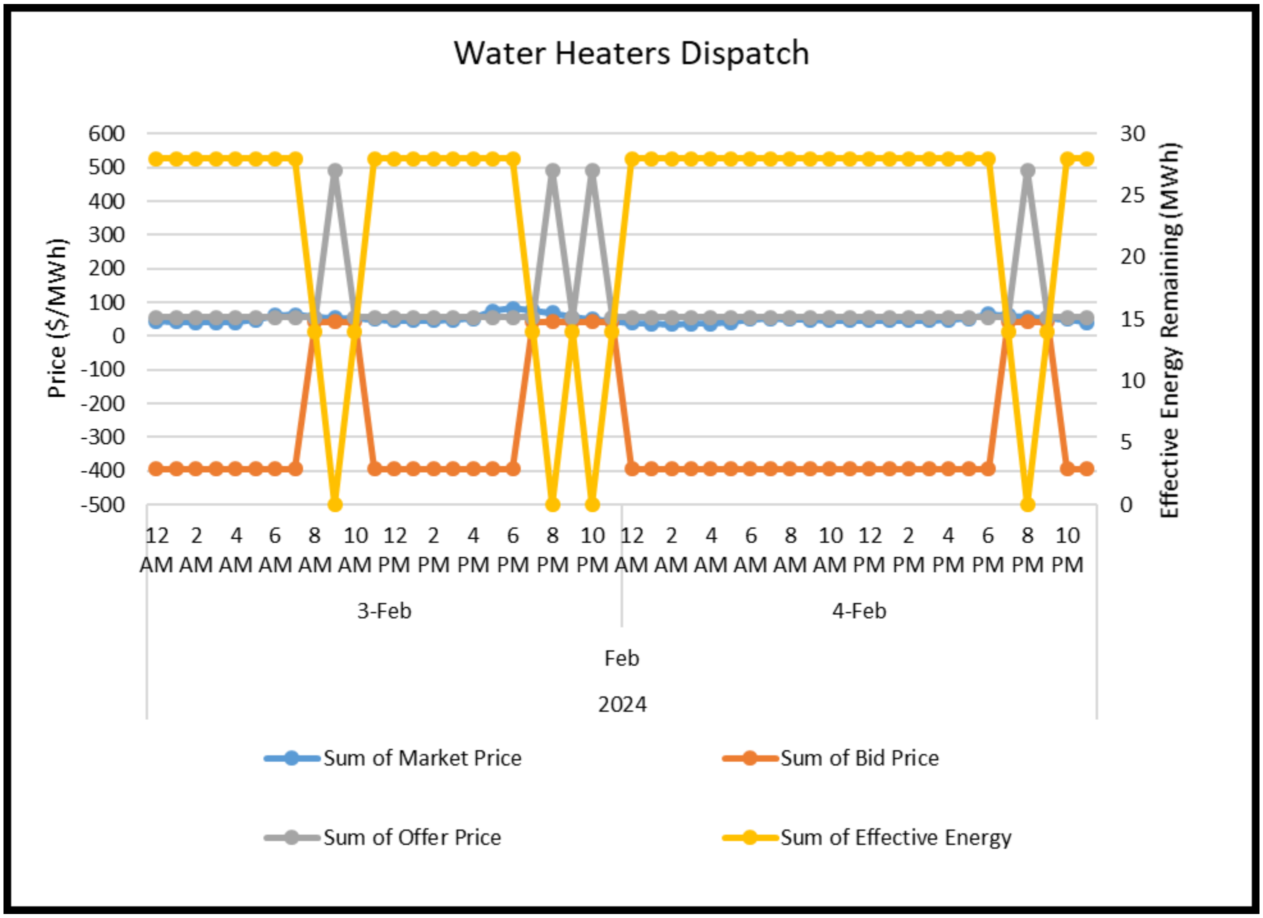

FIGURE 11. DISPATCH OF WATER HEATERS. NOTE THAT SOME DAYS (LIKE FEB 3RD) HAVE BOTH A MORNING AND EVENING DR EVENT, WHILE OTHER DAYS (LIKE FEB 4TH) ONLY HAVE AN EVENING EVENT. SINCE WATER HEATERS MAY NOT BE ON DURING THE EVENING, THIS MODEL COULD POTENTIALLY OVERSTATE THE IMPACT OF WATER HEATERS DURING EVENING PEAKS.

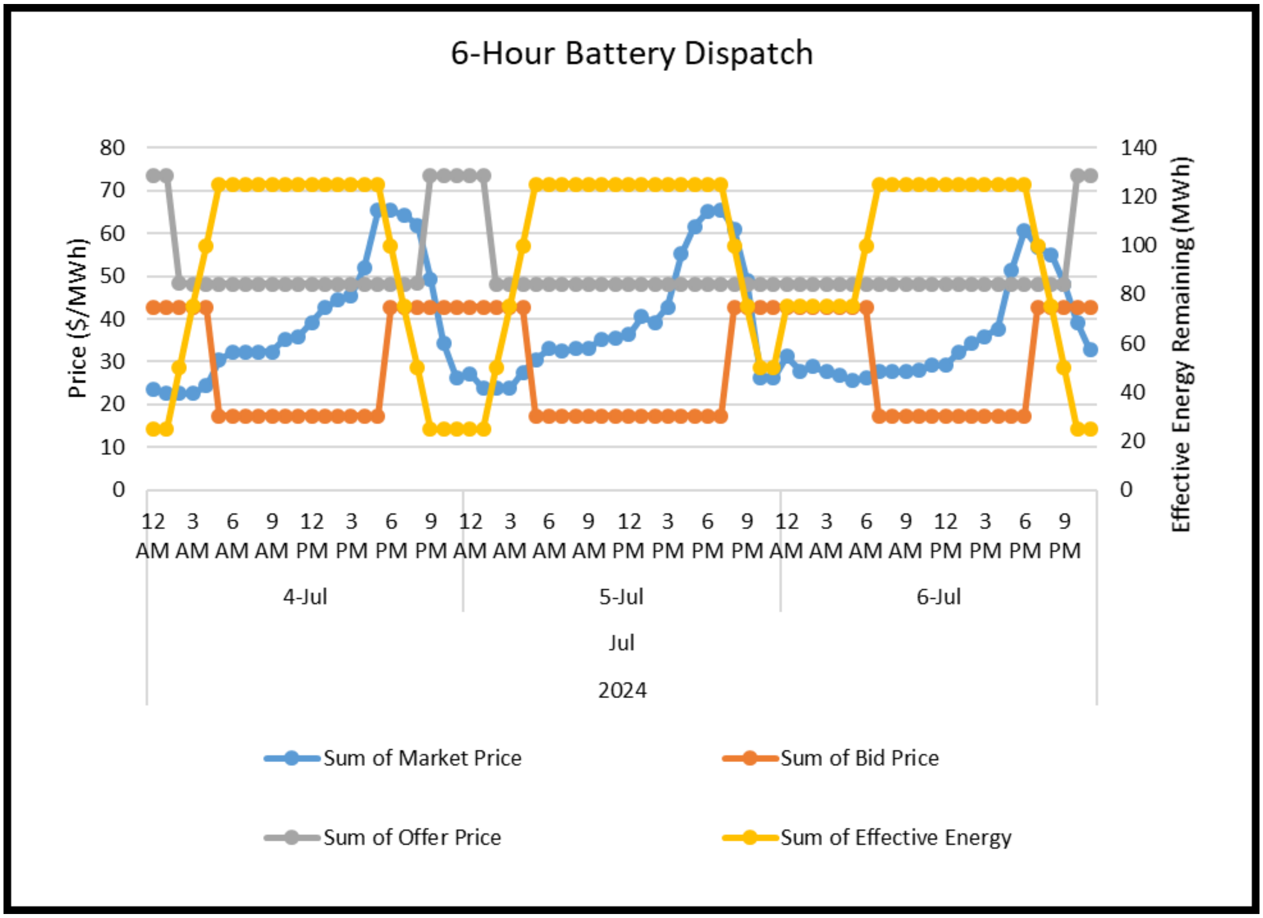

FIGURE 12. DISPATCH OF A 25MW, 6-HR BATTERY. THIS IS AN ECONOMIC RESOURCE SO CHARGING AND DISCHARGING ARE PURELY ECONOMICS DRIVEN. NOTE THAT ALTHOUGH THIS IS A 6-HR BATTERY, THE RESOURCE ONLY DISPATCHES FOR 4 HOURS DUE TO BUG #2 MENTIONED IN TABLE 1 (MODEL LOGIC WAITS FOR HIGHEST PEAK HOUR TO BEGIN DISPATCHING AND THEREFORE MISSES SEVERAL HOURS OF ECONOMIC OPPORTUNITY TO DISPATCH).

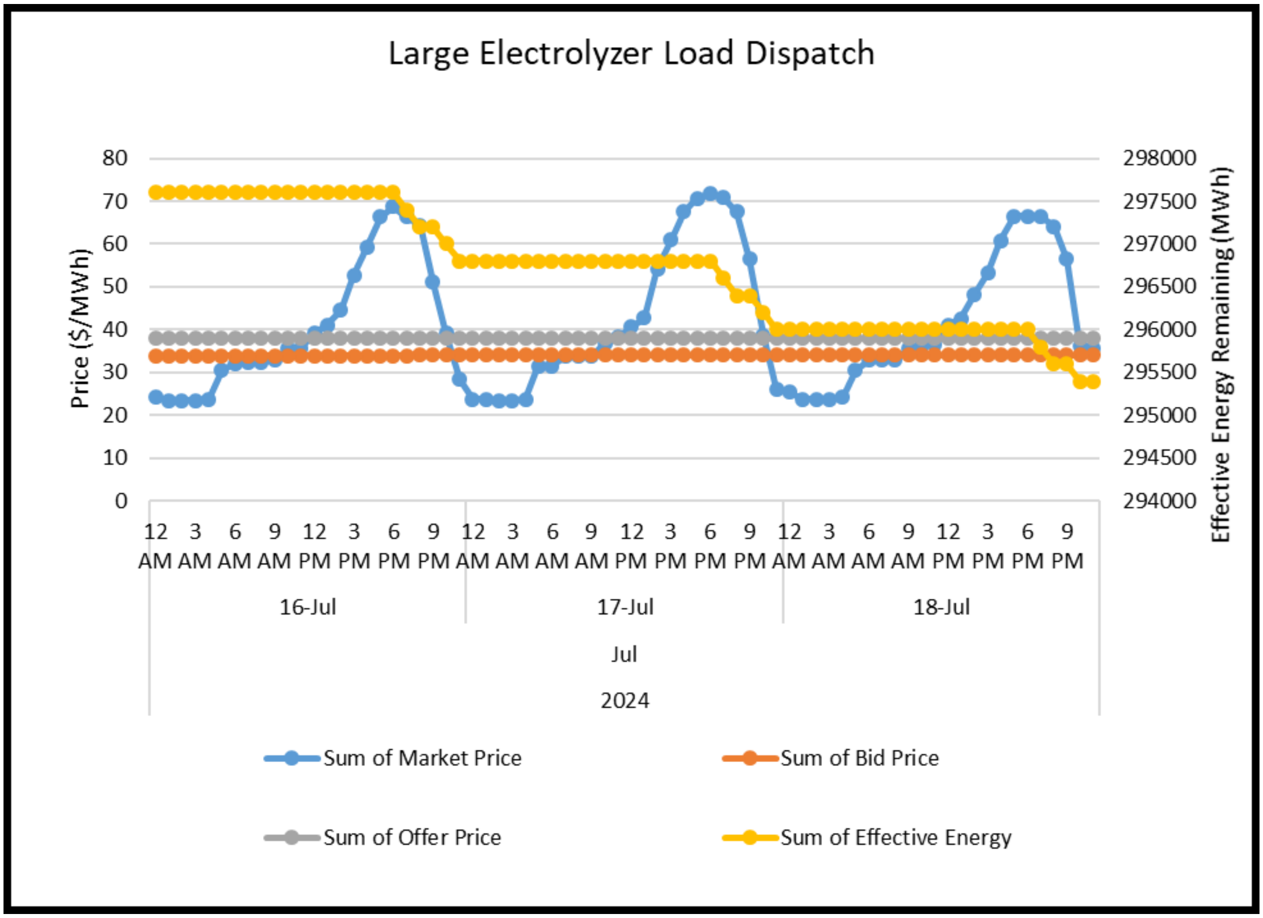

FIGURE 13. DISPATCH OF A LARGE ELECTROLYZER LOAD. NOTE THAT ALTHOUGH THIS TYPE OF RESOURCE CAN BE MODELED TO RECOVER LOAD CURTAILED DURING DR EVENTS, THIS PARTICULAR RESOURCE WAS DESIGNED WITH A "CHARGE" PARAMETER SET TO ZERO IN ORDER TO MATCH TACOMA POWER'S ELECTROFUEL RATE: THE LOAD IS GUARANTEED A 75% LOAD FACTOR AND THEREFORE HAS NO NEED TO "RECOVER CURTAILED LOAD" WHEN ITS NORMAL OPERATION IS ALWAYS AT MAX LOAD AND 25% OF HOURS ARE AVAILABLE FOR FULL CURTAILMENT. IF THE "CHARGE" PARAMETER HAD BEEN SET TO A NON-ZERO VALUE (MEANING THE RESOURCE RECOVERS LOAD), WE WOULD SEE THIS TYPE OF RESOURCE RECOVERING LOAD WHEN THE MARKET PRICE IS BELOW THE BID PRICE. THE CHOICE NOT TO RECOVER LOAD WAS DELIBERATE.

4.3 Cost Assumptions

For all cases, we assume that the DR resource is customer owned (except the 25 MW battery). Tacoma Power is currently developing a rate for industrial customers to provide emergency demand response. Therefore, the cost for the Industrial Load Reliability DR will likely be tied to a market price for capacity. Here, we assume an all-in cost of $120/kw-yr. Tacoma Power also recently completed a demand response potential assessment. This assessment identified 37 MW of total electric resistance water heater potential in both the summer and winter (across industrial/commercial and residential customers) at a total cost of $165/kw-yr in 2031 (total costs includes program costs). That potential rises to 141 MW at a total cost of $140/kw-yr (includes program costs) by 2041. As a conservative estimate, we assume the 2031 costs and potential for this IRP. As for the battery, since it is modeled as an "economic" resource, we assume that the battery is primarily used for energy arbitrage and has a capacity factor of 24.9%. Figure 14 shows the capital and O&M cost assumptions for a utility scale 6-hr battery based on NREL's 2021 ATB data.

Finally, the electrolyzer load's cost is similar to a customer-owned battery, except we do not assume that curtailed load is recovered. In that case, the incentive cost is the sum of the hourly difference between the wholesale price and electrofuel rate multiplied by the electrolyzer load. We assume that the program costs for this program are negligible.

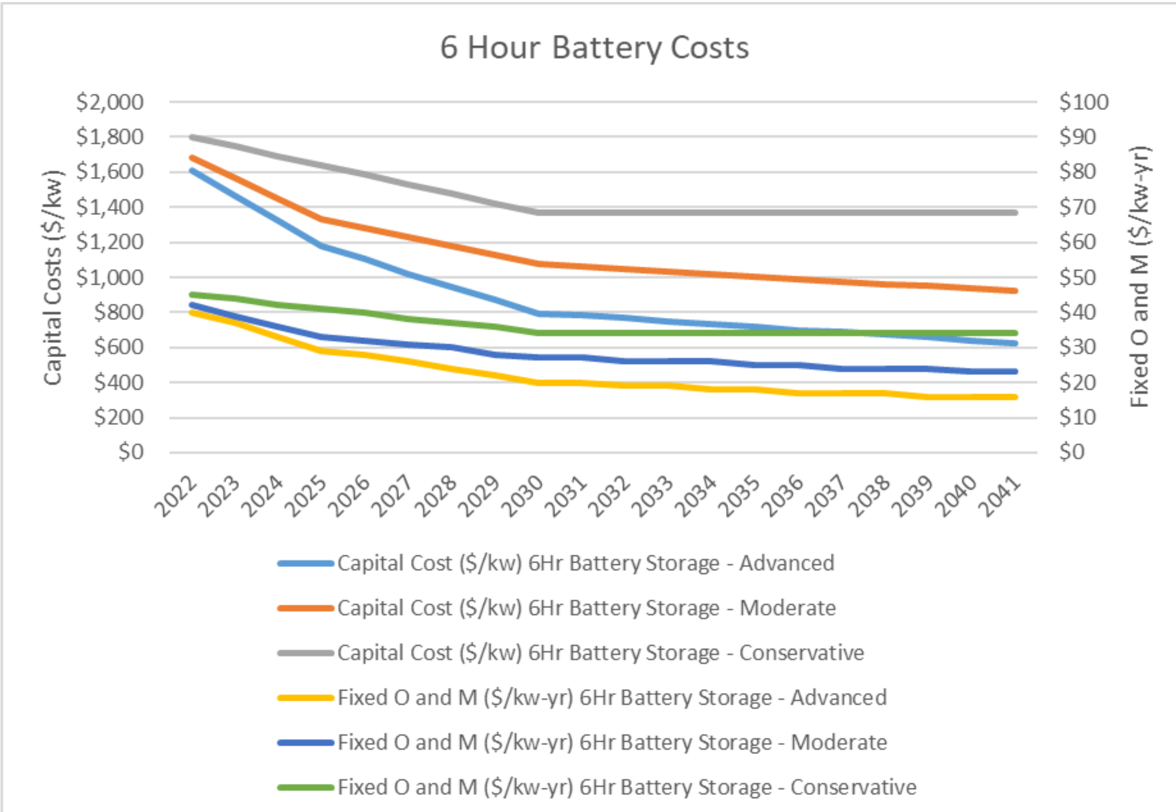

FIGURE 14. BATTERY COSTS. (SOURCE: NREL 2021 ATB). ASSUMES 85% ROUND TRIP EFFICIENCY AND 24.9% CAPACITY FACTOR

5 SMALL MODULAR NUCLEAR REACTORS (SMRS)

While nuclear power is a well-understood technology that is both carbon-free and reliable enough to serve as a baseload plant, small modular reactors (SMRs) are a relatively new technology. The Utah Associated Municipal Power Systems (UAMPS)[3] project with NuScale Power to develop a SMR facility in Idaho serves as the basis for the SMR resource we model in the IRP. While the modular nature of SMRs could allow them to be more flexible than a traditional nuclear plant, we assume a constant fixed generation profile because the cost of operating SMRs at a low load factor would be prohibitively high. Recognizing this and given that available price data is indicative for a plant with 24/7 operations, we modelled the SMR plant as a constant power generation output. Because refueling can be batched by module, we assume constant operation at a constant capacity factor of 95%.

Recent cost estimates of the UAMPS project with NuScale range from $40/MWh to $65/MWh[4], but there is still quite a bit of uncertainty around what final costs will be for small modular nuclear reactors. Costs for these types of projects have often ended up significantly higher than what was initially projected—anywhere from double to

[3] https://www.uamps.com/
[4] https://www.powermag.com/commercial-nuscale-smr-in-sight-as-uamps-secures-1-4b-for-plant/

twenty times higher. In our 2022 IRP, we start with the $65/MWh and assume that costs are 15% lower ($55.25/MWh) in our low-cost case and 20% higher than the current estimate ($78/MWh) in the medium cost case and twice as high as current estimates ($130/MWh) for our high-cost case. We assume values stay constant across our IRP study period in real terms (i.e. costs rise at the rate of inflation). For reference, estimates of NuScale's technology developed by an independent study commissioned by Australia's Royal Commission[5] come in even higher at $182/MWh after adjusting for inflation.

It is common for very large generation investments of any kind (and especially nuclear generation investments) to experience not only cost overruns but also build times that are longer than expected. At the time we finalized our 2020 IRP, UAMPS had planned to have twelve modular reactors built and in operation by 2027, just prior to the end of the region's BPA contracts. There have been delays since then, however, and UAMPS has both scaled back the size of their project and delayed its start date. They currently expect to have six reactors in operation before the end of 2030.

6 Conservation

Energy conservation is one of our first-choice energy resources. It is the only resource that we have acquired for many years and remains a priority resource in the 2022 IRP. Energy conservation helps limit load growth, which defers the need to acquire more costly generating resources, supports the local economy and is good for the environment. Our customers also benefit because conservation helps them reduce their heating, lighting and other costs.

The IRP model currently takes the total cost-effective conservation potential identified in our most recent Conservation Potential Assessment (CPA)[6] as a given and deducts it directly from our load forecast. As in previous years, the CPA was developed using a bottom-up approach that included (1) a sector-level characterization of the residential, commercial, industrial, street lighting, and JBLM sectors, (2) a baseline projection of energy consumption by sector, segment, end use, and technology, (3) identification of several hundred energy conservation measures to be applied to all sectors, segments, and end uses and (4) and estimate of Technical potential, Technical Achievable potential, and Economic Achievable potential energy savings at the measure level. The 2022-2041 CPA identified a ten-year potential of 226,174 MWh, or 25.8 aMW, by 2031. Key opportunities for savings included residential building shell measures (insulation, ducting, etc.), commercial and industrial lighting, commercial refrigeration, industrial motor upgrades and commercial and industrial strategic energy management programs.

7 Other resource costs

7.1 Transmission

We assume that transmission costs remain constant in real terms for existing Tacoma Power resources and existing purchase power contracts (BPA contract, etc.). In portfolios where we contemplate replacing a small part of our BPA contract with another resource, we assume that transmission costs associated with our BPA contract are slightly lower (equivalent to the reduction in what we receive from BPA). Transmission costs for other resources are assumed

[5] http://nuclearrc.sa.gov.au/app/uploads/2016/05/WSP-Parsons-Brinckerhoff-Report.pdf
[6] The 2022-2041 CPA is available on our IRP webpage (https://www.mytpu.org/about-tpu/services/power/integrated-resource-plan/) under "Other Resources".

to be $1.964/kW-month ($1.648 for BPA firm point-to-point transmission[7] plus $0.316 for scheduling, system control and dispatch service[8]) when they are located within Oregon or Washington (solar, Eastern Washington wind, Gorge wind, etc.). For resources located in Montana and Idaho (wind and small nuclear reactors, respectively), transmission is assumed to cost $50/kW-year[9] to get generation into Oregon and Washington plus $1.964/kW-month for transmission within Oregon and Washington.

7.2 Integration/balancing costs

Integration costs are added to variable energy resources (i.e. wind and solar). We considered different alternatives to modeling integration costs and determined the best proxy for integration costs would be to assume that we purchase integration services from BPA. As of BPA's most recent BP-22 rate case, these services are referred to as Variable Energy Resource Balancing Service (VERBS). We apply BPA's integration charge to 100% of the wind or solar capacity. VERBS charges are currently $0.753/kW-month for wind ($0.358 for regulating services and $0.395 for non-regulating services) and $0.456/kW-month for solar ($0.282 for regulating services and $0.174 for non-regulating services).[10] We assume no escalation in the real value of VERBS charges over the period of the IRP.

7.3 Social cost of carbon

Because our own generation is 100% carbon-free and most of the resources we consider are also comprised entirely of carbon-free generating resources, the main source of carbon in each of the portfolios examined is unspecified market purchases—either Tacoma Power purchases or BPA purchases. Market purchases are charged at an annual emissions rate assumption that is equal to the average of the hourly Mid-C marginal emissions rate modeled in each year for each scenario in our AURORA model. For emissions associated with the BPA contract, we assume a fixed mix of resources based on BPA's most recent fuel mix report[11] and charge 4.3% of BPA power (3.7% non-specified purchases and 0.6% wind without RECs) the market emissions rate. Emissions are charged the social cost of carbon prescribed by the Department of Commerce in Phase One rulemaking for CETA.[12] Values escalate from $84.25/MT in 2022 to $111.20/MT in 2041 (values are in October 2021 dollars[13]).

[7] See page 15 of BPA's 2022 Transmission, Ancillary and Control Area Service Rate Schedules and General Rate Schedule Provisions

[8] See page 42 of BPA's 2022 Transmission, Ancillary and Control Area Service Rate Schedules and General Rate Schedule Provisions

[9] This assumption was taken from a 2019 study conducted by E3 for Public Generation Pool (https://static1.squarespace.com/static/5e9fc98ab8d9586057ba8496/t/5ee52f8fdd4fcc4948f809e2/1592078233508/E3_NW_RA_Presentation-2018-01-05.pdf , slide 19)

[10] See pages 61 and 62 of BPA's 2022 Transmission, Ancillary and Control Area Service Rate Schedules and General Rate Schedule Provisions

[11] See "Hydropower Fuel Mix" at https://www.bpa.gov/energy-and-services/power/hydropower-impact

[12] https://www.commerce.wa.gov/wp-content/uploads/2019/12/2019-12-30-CETA-Phase-One-Rule-Making-Order.pdf (WAC-194-40-100)

[13] Our price simulations and other cost assumptions are in 2022 dollar. Washington State Department of Commerce requires use of the GDP deflator published by the US Department of Commerce to adjust social cost of carbon estimates, but October 2021 is the most recent period for which an official price deflator is available.