# 2020 Electric Integrated Resource Plan


# 9. Supply-Side Resource Options

Avista evaluates several generation supply-side resource options to meet future resource deficits. The resource categories evaluated for this IRP include upgrading existing resources, building and owning new generation facilities, and contracting with other energy companies. This section describes resource options Avista considers in the 2020 IRP. The options are mostly generic, as actual resources are typically acquired through competitive processes. This process may yield resources that differ in size, cost, and operating characteristics due to siting, engineering, or financial requirements.

**Section Highlights**

- Solar, wind, and other renewable resource options are modeled as Purchase Power Agreements (PPA) instead of utility ownership.
- Upgrades to Avista's hydroelectric, natural gas and biomass facilities are included as resource options.
- Future competitive acquisition processes might identify different technologies available to Avista.
- Renewable resource costs assume no extensions of current state and federal tax incentives.
- Avista models several energy storage options including pumped storage hydro, lithium-ion, vanadium flow, zinc bromide flow, liquid air, and hydrogen.

## Assumptions

Avista models only commercially available resources with well-known costs and generation profiles priced as if Avista developed and owned the generation or acquires generation from Independent Power Producers (IPPs) with a Purchase Power Agreement (PPA). Resources modelled as PPAs include pumped storage, wind, solar, geothermal, and nuclear resources. Avista modeled these resource types as PPAs since IPPs are able to financially capture tax benefits for these resources earlier, which reduces the cost to customers. Other resource options assume utility ownership include natural gas-fired combined cycle combustion turbines (CCCT), simple cycle combustion turbines (SCCT), natural gas-fired reciprocating engines, energy storage, biomass, hydroelectric upgrades, hydroelectric contracts, and thermal unit upgrades. Upgrades to coal-fired units are not included or considered in the IRP analysis. Modeling resources as PPA or ownership does not preclude the utility from acquiring new resources in other manners, but serves as an appropriate cost estimate for the new resources. Several other resource options described later in the chapter are not included in the PRS analysis, but we discuss them as potential resource options since they may appear in a request for a future resource acquisition.

It is difficult to accurately model potential contractual arrangements with other energy companies as an option in the plan, but such arrangements may offer a lower customer cost when a competitive acquisition process is completed. Avista plans to use a competitive RFP process for all resource acquisition where possible to ensure the lowest cost resource is acquired for our customers; although other acquisition process may yield better pricing on a case-by--case basis – especially for existing resources for shorter time periods. When evaluating upgrades to existing facilities Avista uses the IRP, RFPs, and market intelligence to determine and validate its assumptions to pursue the upgrade. Upgrades typically require competitive bidding processes for contractors and equipment when available.

The costs of each resource option do not include the transmission expenses described in Chapter 8 – Transmission & Distribution Planning, all cost are considered at the bus bar. Avista excludes these costs in this chapter to allow for cost comparison as resource costs at specific locations depend on the location chosen. When Avista evaluates the resources for selection in the IRP, it includes these costs. All costs are levelized by discounting nominal cash flows by a 6.68 percent-weighted average cost of capital approved by the Idaho and Washington Commissions in recent rate case filings. All costs in this section are in 2020 nominal dollars unless otherwise noted. All cost and characteristic assumptions for generic resources and how PPA pricing is calculated is available in Appendix F.

Avista relies on several sources including the NPCC, press releases, regulatory filings, internal analysis, developer estimates, and Avista's experience with certain technologies for its generic resource assumptions. For this IRP, Avista also engaged Black and Veatch to perform a reasonability test of our resource assumptions. This report is available Appendix G.

Levelized resource costs illustrate the differences between generator types. The values show the cost of energy if the plants generate electricity during all available hours of the year. In reality, plants do not operate to their maximum generating potential because of market and system conditions. Costs are separated between energy in $/MWh, and capacity in $/kW-year, to better compare technologies[1]. Without this separation of costs, resources operating very infrequently during peak-load periods would appear more expensive than baseload CCCTs, even though peaking resources are lower total cost when operating only a few hours each year. Avista levelizes the cost using the production capability of the resource. For example, a natural gas turbine is available 92 to 95 percent of the time when taking into account maintenance and forced outage rate. Avista divides the cost by the amount of megawatt hours the machine is capable of producing. For resources that are available but may not have the fuel available, such as a wind project, the resource costs are divided by its expected production.

Tables at the end of this section show incremental capacity, heat rates, generation capital costs, fixed O&M, variable costs, and peak credits for each resource option.[2] Table 9.1 compares the levelized costs of different resource types over a 30-year asset life.

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[1] Storage technologies use a $ per kWh rather than $ per kW because the resource is both energy and capacity limited.
[2] Peak credit is the amount of capacity a resource contributes at the time of system one-hour peak load.

## Natural Gas-Fired Combined Cycle Combustion Turbine

Natural gas-fired CCCT plants provide reliable capacity and energy for a relatively modest capital investment. The main disadvantages of a CCCT are generation cost volatility due to reliance on natural gas, unless utilizing hedged fuel prices, and the emission of carbon dioxide. This IRP models CCCTs as "one-on-one" (1x1) configurations, using hybrid air/water cooling technology and zero liquid discharge. The 1x1 configuration consists of a single gas turbine with a heat recovery steam generator (HRSG) and a duct burner to gain more generation from the steam turbine. The plants have nameplate ratings between 250 MW and 350 MW each depending on configuration and location. A two-on-one (2x1) CCCT plant configuration is possible with two turbines and one HRSG, generating up to 650 MW. Avista would need to share a 2x1 plant to take advantage of the modest economies of scale and efficiency of a 2x1 plant configuration due to its large size relative to Avista's needs.

Cooling technology is a major cost driver for CCCTs. Depending on water availability, lower-cost wet cooling technology could be an option, similar to Avista's Coyote Springs 2 plant. However, absent water rights, a more capital-intensive and less efficient air-cooled technology may be used. For this IRP, Avista assumes water is available for plant cooling based on its internal analysis, but only enough for a hybrid system utilizing the benefits of combined evaporative and convective technologies.

This IRP models five types of CCCT plants, ranging in sizes from 235 MW to 480 MW as 1x1 configuration. Avista reviewed many CCCT technologies and sizes, and selected these plants due to the range in size to have the potential for the best fit for the needs of Avista's customers. If Avista pursues a CCCT, a competitive acquisition process will allow analysis of other CCCT technologies and sizes at both Avista's preferred location and at other locations. It is also possible Avista could acquire an existing combined cycle resource from one of the many in the Pacific Northwest.

The most likely location for a new CCCT is in Idaho, mainly due to Idaho's lack of an excise tax on natural gas consumed for power generation, a lower sales tax rate relative to Washington, and no state taxes or fees on the emission of carbon dioxide.[3] CCCT sites likely would be on or near our transmission system to avoid third-party wheeling costs. Another advantage of siting a CCCT resource in Avista's Idaho service territory is access to relatively low-cost natural gas on the GTN pipeline. Avista previously secured a site with these potential connection points in the event it needs to add additional capacity from either a CCCT or another technology.

Combined cycle technology efficiency has improved since Avista's current generating fleet entered service with higher heating value heat rates as low as 6,500 Btu/kWh for a larger facility and 6,600 for smaller configurations. Duct burners can add additional capacity with heat rates in the 7,200 to 8,400 btu/kWh range.

[3] Washington state applies an excise tax on all fuel consumed for wholesale power generation, the same as it does for retail natural gas service, at approximately 3.875 percent. Washington also has higher sales taxes and has carbon dioxide mitigation fees for new plants.

The anticipated capital costs for the two modeled CCCTs, located in Idaho on Avista's transmission system with AFUDC on a greenfield site range between $905 to $1,529 per kW in 2020 dollars. A likely configuration of the modern technology is $1,052 per kW. These estimates exclude the cost of transmission and interconnection. Table 9.1 shows levelized plant cost assumptions split between capacity and energy for both the combined cycle options discussed here and the natural gas peaking resource discussed in the next section. The costs include firm natural gas transportation, fixed and variable O&M, and transmission. Table 9.2 summarizes key cost and operating components of natural gas-fired resource options. With competition from alternative technologies and the need for additional flexibility for intermittent resources is likely to put downward pressure on future CCCT costs.

### Natural Gas-Fired Peakers

Natural gas-fired SCCTs and reciprocating engines, or peaking resources, provide low-cost capacity capable of providing energy as needed. Technological advances and their simpler design relative to CCCTs allow them to start and ramp quickly, providing regulation services and reserves for load following and variable resources integration. Natural gas-fired peakers have similar benefits and costs as CCCTs.

This IRP models frame, hybrid-intercooled, reciprocating engines, and aero-derivative peaking resource options. The peaking technologies have different load following abilities, costs, generating capabilities, and energy-conversion efficiencies. Table 9.2 shows cost and operational characteristics based on internal engineering estimates and reviewed by Black & Veatch. All peaking plants assume 0.5 percent annual real dollar cost decreases and forced outage and maintenance rates. The levelized cost for each of the technologies is in Table 9.1.

Firm natural gas fuel transportation is an electric reliability issue with FERC and the subject of regional and extra-regional forums. For this IRP, Avista continues to assume it will not procure firm natural gas transportation for peaking resources and will use its current supply or short-term transportation for peaking needs. Firm transportation could be necessary where pipeline capacity becomes scarce during utility peak hours. Where non-firm transportation options become inadequate for system reliability, four options exist: contracting for firm natural gas transportation rights, purchasing an option to exercise the rights of another firm natural gas transportation customer during times of peak demand, on-site fuel oil, and liquefied natural gas storage.

**Table 9.1: 2020 Natural Gas-Fired Plant Levelized Costs**

| Plant Name | Total $/MWh | $/kW-Yr (Capability) | Variable $/MWh | Winter Capacity (MW) |
|---|---|---|---|---|
| Advanced Large Frame CT | 48 | 118 | 35 | 220 |
| Advanced Small Frame CT | 62 | 163 | 43 | 186 |
| Frame/Aero Hybrid CT | 54 | 159 | 35 | 106 |
| Large Reciprocating Engine Facility | 52 | 165 | 33 | 189 |
| Small Reciprocating Engine Facility | 54 | 183 | 33 | 47 |
| Modern Small Frame CT | 58 | 172 | 39 | 49 |
| Aero CT | 59 | 195 | 36 | 45 |
| 1x1 Advanced CCCT | 46 | 151 | 29 | 362 |
| 1x1 Modern CCCT | 48 | 171 | 27 | 306 |

**Table 9.2: Natural Gas-Fired Plant Cost and Operational Characteristics**

| Item | Capital Cost with AFUDC ($2020/kW) | Fixed O&M ($2020/kW- yr) | Heat Rate (Btu/ kWh) | Variable O&M ($/MWh) | Total Project Size (MW) | Total Cost (Mil$-2020) |
|---|---|---|---|---|---|---|
| Advanced Large Frame CT | 679 | 2.08 | 9,148 | 2.08 | 245 | 166 |
| Advanced Small Frame CT | 969 | 5.20 | 11,049 | 3.12 | 84 | 81 |
| Frame/Aero Hybrid CT | 1,031 | 3.12 | 8,856 | 3.12 | 92 | 95 |
| Large Reciprocating Engine Facility | 1,055 | 7.28 | 8,296 | 3.12 | 184 | 194 |
| Small Reciprocating Engine Facility | 1,162 | 13.53 | 7,891 | 4.16 | 91 | 106 |
| Modern Small Frame CT | 1,088 | 4.16 | 9,931 | 2.60 | 48 | 52 |
| Aero CT | 1,239 | 6.24 | 10,335 | 2.60 | 45 | 56 |
| 1x1 Modern CCCT | 1,052 | 14.57 | 6,668 | 3.12 | 413 | 434 |
| 1x1 Advanced CCCT | 979 | 17.69 | 6,586 | 3.90 | 308 | 302 |

## Wind Generation

Wind resources benefit from having no direct emissions or fuel costs, but they are not typically dispatchable to meet load. Avista is modeling four wind location options in the plan: Montana, Eastern Washington, Columbia Basin, and offshore. Configurations of facilities are changing given transmission limitations in the region and the benefits of tax credits, low construction prices, and the potential for storage. These factors allow for sites being built with higher capacity levels than the transmission system can integrate. When the wind facilities generate additional MWh above the physical transmission limitations[4], the generators typically feather or could store energy using on site energy storage. At this time, Avista is not modelling wind with onsite storage or wind facilities with greater output capabilities then can be integrated on the transmission system.

Onshore winds capital costs in 2020, including AFUDC, are $1,568 per kW for Washington on-system projects, off-system projects including Oregon and Montana are $1,458 per kW, and off-shore wind is $3,569 per kW. The annual fixed O&M costs of $36.40 per kW-year for on-shore wind and $93.60 per kW-year for offshore wind. Fixed O&M does not include indirect charges to account for the inherent variation in wind generation, often referred to as wind integration. The cost of wind integration depends on the penetration of wind in Avista's balancing authority and the market price of power.

Wind capacity factors in the Northwest range between 25 and 40 percent depending on location and in the 40 to 50 percent range in Montana and offshore locations. This plan assumes Northwest wind has a 37 percent average capacity factor. A statistical method, based on regional wind studies, derives a range of annual capacity factors depending on the wind regime in each year (see stochastic modeling assumptions for details).

This IRP also estimates potential costs for offshore wind. Offshore wind has the potential for higher capacity factors (50 percent), but costs are higher. At the time of this IRP, developers have not been offering an offshore product in the Pacific Northwest. The pricing and costs are estimates based on other proposals in North America.

As discussed above, levelized costs change substantially due to capacity factor, but can change even more from tax incentives and the ownership structure of the facility. Table 9.3 shows the nominal levelized prices with different start dates for each location. These price estimates assume the facility is acquired using a 20-year PPA with a flat pricing structure, but also includes the intermittent generation integration charge for the first 100 MW to Avista's system and includes costs associated with passing the cost of the PPA to customers, excise taxes, commission fees, and uncollectables. These costs do not include the transmission costs for either capital investment or wheeling purchases. If a PPA is selected in Avista's resource strategy (Chapter 11), the model assumes the PPA will extend through the 25-year time period.

[4] In the event transmission is limited due to contractual reasons; an additional option is to buy non-firm transmission to move the power.

**Table 9.3: Levelized Wind Prices ($/MWh)**

| Year | On-System Wind | Off-System Wind | Montana Wind | Off-Shore Wind |
|---|---|---|---|---|
| 2020 | 38 | 34 | 20 | 90 |
| 2021 | 37 | 33 | 19 | 90 |
| 2022 | 42 | 38 | 25 | 97 |
| 2023 | 49 | 45 | 31 | 103 |
| 2024 | 56 | 52 | 38 | 110 |
| 2025 | 69 | 65 | 51 | 123 |
| 2026 | 70 | 67 | 51 | 125 |
| 2027 | 71 | 68 | 52 | 126 |
| 2028 | 72 | 68 | 53 | 127 |
| 2029 | 72 | 69 | 53 | 129 |
| 2030 | 73 | 70 | 54 | 130 |
| 2031 | 74 | 71 | 55 | 131 |
| 2032 | 75 | 72 | 56 | 133 |
| 2033 | 76 | 73 | 56 | 134 |
| 2034 | 77 | 75 | 58 | 136 |
| 2035 | 78 | 76 | 59 | 137 |
| 2036 | 80 | 78 | 60 | 138 |
| 2037 | 81 | 79 | 61 | 140 |
| 2038 | 83 | 81 | 63 | 141 |
| 2039 | 85 | 83 | 64 | 143 |
| 2040 | 86 | 85 | 65 | 144 |

## Photovoltaic Solar

Photovoltaic (PV) solar generation technology costs fell substantially over the last several years partly due to low-cost imports and from demand driven by renewable portfolio standards. Solar systems are now built with more generating capacity than the transmission interconnect limit to take advantage of increased energy produced throughout the year when only limited hours of the year occur when full production is produced. Some systems, also have storage connected to the system to help with integration of intermittent production, store excess energy to avoid curtailment, or shift energy to higher priced hours. Solar plus storage has an advantage, compared to other renewable systems, because storage may qualify for investment tax credits when paired with solar as long as the stored energy is from solar production. Since both systems use DC power, they can utilize the same power inverters. Other renewable resources may not benefit from this tax provision because production rather than capital spending drive the tax credits. It is possible future solar incentives will be similar to the Production Tax Credit rather than the ITC.

Avista models four potential solar systems, the first is an on-system solar facility in 25 MW (AC) increments, but modelled as a facility with at least 100 MW to take advantages of economies of scale. It is Avista's understanding the solar costs can change significantly depending on size; to address this issue, a smaller 5 MW (AC) on-system is also included. The third solar option includes a facility to be wheeled to Avista in higher solar production areas such as southern Idaho or Oregon. Although if and when Avista attempts to acquire solar energy any location is acceptable to participate in the RFP, but transmission charges and availability will be used to determine if the project(s) to move forward.

Solar capital costs have been rapidly declining, even with increasing tariffs costs. Technology improvements such as bi-facial panels make solar more efficient at delivering energy per square meter. For this IRP, larger systems assume a cost of $1,156 per kW (AC) for a single axis tracking system; by 2030, these costs are expected to rise to $1,255 per kW and $1,455 per kW by 2040. While these costs increase in nominal dollars, real solar costs are likely to fall. Smaller systems assume premium prices due to a lack of economies of scale with a price of $1,399 per kW in 2030 with similar price changes as larger systems in the future. The cost to operate solar depends on the size of the facility and location due to property taxes and lease payments; given these costs vary, Avista assumes $8 per kW-year for larger systems and $10 per kW-year for smaller systems.

Table 9.4 shows the levelized prices for 20-year flat PPA with additional costs to integrate the first 100 MW of intermittent generation, excise taxes, commission fees, and uncollectables. These costs do not include the transmission costs either for investment or wheeling purchases. The prices also assume current phase-out of federal tax credits by 2024.

**Table 9.4: Levelized Solar Prices**

| Year | On-system | Southern NW | On-system-small facility |
|---|---|---|---|
| 2020 | 38 | 34 | 50 |
| 2021 | 38 | 34 | 50 |
| 2022 | 37 | 33 | 48 |
| 2023 | 38 | 34 | 49 |
| 2024 | 48 | 43 | 63 |
| 2025 | 49 | 44 | 64 |
| 2026 | 50 | 44 | 64 |
| 2027 | 51 | 45 | 65 |
| 2028 | 51 | 45 | 66 |
| 2029 | 52 | 46 | 67 |
| 2030 | 52 | 47 | 68 |
| 2031 | 53 | 47 | 69 |
| 2032 | 54 | 48 | 69 |
| 2033 | 54 | 48 | 70 |
| 2034 | 55 | 49 | 71 |
| 2035 | 56 | 49 | 72 |
| 2036 | 56 | 50 | 73 |
| 2037 | 57 | 51 | 74 |
| 2038 | 58 | 51 | 75 |
| 2039 | 59 | 52 | 76 |
| 2040 | 59 | 53 | 76 |

## Solar Energy Storage (Lithium-ion Technology)

As previously discussed, storage paired with solar takes advantage of federal tax credits, lowers transmission costs, shifts energy deliveries, helps manage intermittent generation, uses common equipment, increases peak reliability, and prevents energy oversupply. Avista must study each potential benefit to see its value and the amount of storage duration is cost effective for each potential project. While the solar plus storage system receives tax incentives (approximately six years) it must be only supplied with solar energy. This limits the value of the storage asset due to its inability to assist with larger system variations.

Lithium-ion technology prices are falling and will likely continue to fall. Avista estimates the additional cost for more hours of storage in Table 9.5 for solar PPAs. Avista modeled one, two, and four-hour durations; although, 15 to 30 minutes will be considered if the technology is limited to assist with intermittent generation rather than reliability. Avista's experience with solar generation from its 19.2 MW Adams-Neilson PPA show significant energy variation due to cloud cover. Avista will identify in future IRPs the cost of this variability on different size projects in the event of future acquisition. For this IRP, Avista considers savings for integration and resource adequacy but due to the complexity and range of potential configurations, requires the utility to continue this analysis as Avista's system changes with less thermal resources and more intermittent resources. In addition, Avista's modeling of solar plus storage allows the storage device to use grid power as it may after six years.

### Table 9.5: Storage Cost w/ Solar System ($/kW-month)

| Year | One-Hour | Two-Hour | Four-Hour |
|---|---|---|---|
| 2020 | 9.0 | 10.3 | 12.9 |
| 2021 | 7.3 | 8.3 | 10.4 |
| 2022 | 6.9 | 7.8 | 9.8 |
| 2023 | 6.5 | 7.4 | 9.3 |
| 2024 | 7.2 | 8.2 | 10.2 |
| 2025 | 6.8 | 7.8 | 9.7 |
| 2026 | 6.4 | 7.3 | 9.1 |
| 2027 | 6.2 | 7.1 | 8.9 |
| 2028 | 6.1 | 6.9 | 8.7 |
| 2029 | 5.9 | 6.8 | 8.5 |
| 2030 | 5.8 | 6.7 | 8.3 |
| 2031 | 5.7 | 6.5 | 8.2 |
| 2032 | 5.6 | 6.4 | 8.0 |
| 2033 | 5.5 | 6.3 | 7.8 |
| 2034 | 5.4 | 6.1 | 7.7 |
| 2035 | 5.3 | 6.0 | 7.5 |
| 2036 | 5.2 | 5.9 | 7.4 |
| 2037 | 5.1 | 5.9 | 7.3 |
| 2038 | 5.1 | 5.8 | 7.2 |
| 2039 | 5.0 | 5.7 | 7.1 |
| 2040 | 4.9 | 5.6 | 7.0 |

### Stand Alone Energy Storage

Energy storage resources are gaining significant traction as a resource of choice in the western U.S., although energy storage does not create energy (it shifts it from one period to another in exchange for a portion of the energy stored). Avista is modelling several energy storage options including pumped hydro storage hydro, lithium-ion, vanadium flow, zinc bromide flow, liquid air, and hydrogen. In addition to the technology differences, Avista also considers different energy storage durations for each technology. Pricing for energy storage is also rapidly changing due to the technology advancements currently taking place. In addition to changing pricing for existing technologies, new technologies are entering the storage space. For example, iron flow batteries became a commercial technology while producing this IRP. The rapid change in pricing and new available technologies justifies the need for frequent IRP analysis on an every other year basis.

Another challenge with storage is in the pumped hydro technology where costs and storage duration can be substantially different depending on the geography of the proposed project. Storage is also gaining attention to address transmission and distribution expansion, where the technology can alleviate conductor overloading and short duration load demands rather than adding physical line/transformation capacity. Avista considers this as a benefit here, but discusses it further in Chapter 8- Transmission and Distribution Planning

The storage costs discussed in this chapter are shown as the levelized cost for the duration capability of the storage resources. This means the cost of capital and operations are levelized then divided by the duration in kilowatt-hours of the resource. Storage cannot be shown in $ per MWh as with other generation resources because they do not create energy, only store it. This analysis shows the cost differences between the technologies but does not consider the efficiency of the storage process or the cost of the energy stored. This analysis is performed in the resource selection process.

### Pumped Hydro

The most prolific energy storage technology currently in both the U.S. and the world is pumped hydro storage. This technology requires the use of two or more water reservoirs with different elevations. When prices or load are low, water is pumped up to a higher reservoir and released during higher price or load periods. Over time this technology may help with meeting system integration issues from intermittent generation resources. Currently only one of these projects exist in the northwest and several more are in various stages of the permitting process. An advantage with pumped hydro is the technology has long service lives and is technology Avista is familiar with as a hydro generating utility. The greatest disadvantages are large capital costs and long-permitting cycles.

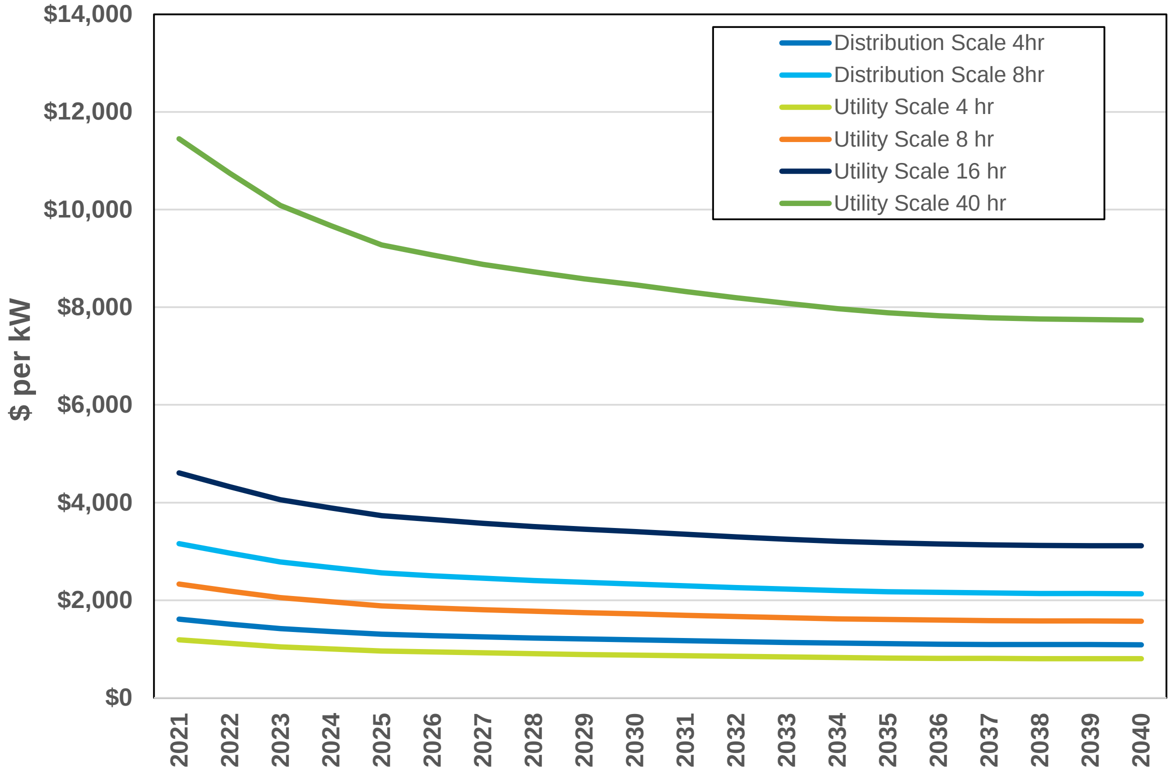
The technology has good round trip efficiency rates (Avista assumes 81 percent). When projects are developed, they are designed to utilize the amount of water storage in each reservoir and the generating/pump turbines are sized for how long the capacity needs to operate. For the IRP resource analysis, Avista models the technology with six different durations: 8 hours, 12 hours, 16 hours, 24 hours, 40 hours, and 80 hours. These durations are the amount of hours the project can run at full capacity. Modeling different duration times are required because in an energy-limited system, Avista requires resources with enough energy to provide reliable power over an extended period in addition to single hour peaks. This study uses the ELCC analysis discussed later in the chapter. Avista bases its pricing for pumped hydro using a PPA financing methodology with fixed and variable payments. The price estimate for pumped hydro is a 2020 capital cost of $2,936 per kW with $15.60 per kW of Fixed O&M per year. This results in a 2020 PPA price of $22.28 per kW-month and $5.00 per MWh of generation. These prices are generic in nature, and certain projects in the northwest have lower estimates. Avista choose to also model a lower price point of $12.50 per kW-month in the event a project has lower costs due to favorable siting or permitting. With these two price points considered, Avista believes these two price points provide enough range in pricing. A future RFP will determine pumped hydro's actual pricing and availability. Avista is conducting internal studies of the availability of pumped storage in or around its service territory. These studies may provide additional resource options in future IRPs or RFP processes.

### Lithium-ion

As discussed before, lithium-ion technology is one of the fasted growing segments of the energy storage space. When coupled with solar, both tax advantages and economies of scope can reduce the upfront pricing. This discussion focuses on using energy storage as a stand-alone resource rather than coupled with solar. Stand-alone lithium-ion assumes a utility owned asset for modeling purposes, but it could be acquired as a PPA format as well with two 10-year cycles for a 20-year life. Fixed O&M costs are included in pricing for replacements cells to maintain the storages energy conversion efficiency.

The lithium-ion technology is an advanced battery using ionized lithium atoms in the anode to separate their electrons. This technology can carry high voltages in small spaces making it a preferred technology for mobile devices, power tools, and electric vehicles. The large manufacturing sector of the technology drives prices lower and permits utility scale projects.

**Figure 9.1: Lithium-ion Capital Cost Forecast**




Avista models six conceptual stand-alone configurations for lithium-ion batteries. Two small-scale sizes (3 MW) with four and eight hour durations for modeling the potential for use on the distribution system and four larger systems (25 MW) including four and eight hour durations, but also theoretical 16 and 40 hour configurations. Pricing for this technology was set in the winter 2018/2019 using publically available pricing and forecasts, as well as review by Black & Veatch. Figure 9.1 show the forecast for each of the sizes and durations considered. Avista classifies the 4-hour battery as the standard technology with a capital cost of $1,188 per kW or $297 per kWh for 2021. Fixed O&M costs are also expected to decline; Avista assumes for the 4-hour technology an annual cost of $44.30 per kW year in 2020 and by 2030 fall to $30.70 per kW-year.

Storage technology is often displayed in many methods to illustrate the cost because it is not a traditional capacity resource. Table 9.6 below shows levelized cost per kWh for each configuration. This calculation factor levelizes the cost for the capital, O&M, and regulatory fees over 20 years divided by the capacity's duration. These costs do not consider the variable costs, such as energy purchases.

**Table 9.6: Lithium-ion Levelized Cost $/kWh**

| Year | Distribution Scale 4 hour | Distribution Scale 8 hour | Utility Scale 4 hour | Utility Scale 8 hour | Utility Scale 16 hour | Utility Scale 40 hour |
|---|---|---|---|---|---|---|
| 2020 | 287 | 563 | 212 | 415 | 822 | 2,041 |
| 2021 | 276 | 541 | 204 | 399 | 789 | 1,961 |
| 2022 | 266 | 522 | 196 | 385 | 761 | 1,891 |
| 2023 | 258 | 505 | 190 | 372 | 737 | 1,831 |
| 2024 | 251 | 493 | 185 | 363 | 719 | 1,787 |
| 2025 | 246 | 482 | 182 | 356 | 704 | 1,749 |
| 2026 | 242 | 475 | 179 | 350 | 694 | 1,723 |
| 2027 | 239 | 469 | 176 | 346 | 684 | 1,700 |
| 2028 | 237 | 464 | 174 | 342 | 677 | 1,681 |
| 2029 | 234 | 459 | 173 | 338 | 670 | 1,664 |
| 2030 | 232 | 455 | 171 | 335 | 664 | 1,649 |
| 2031 | 230 | 451 | 170 | 332 | 658 | 1,635 |
| 2032 | 228 | 447 | 168 | 330 | 653 | 1,622 |
| 2033 | 227 | 444 | 167 | 327 | 648 | 1,610 |
| 2034 | 225 | 441 | 166 | 325 | 644 | 1,600 |
| 2035 | 224 | 439 | 165 | 324 | 641 | 1,592 |
| 2036 | 223 | 437 | 164 | 322 | 638 | 1,585 |
| 2037 | 222 | 435 | 164 | 321 | 635 | 1,579 |
| 2038 | 221 | 434 | 163 | 320 | 633 | 1,573 |
| 2039 | 221 | 432 | 163 | 319 | 631 | 1,568 |
| 2040 | 220 | 431 | 162 | 318 | 629 | 1,562 |

## Flow Batteries

This IRP models two types of flow batteries, vanadium and zinc bromide. Other technologies are beginning to show up in the marketplace recently, including iron. Flow batteries have the advantage over lithium-ion as they do not degrade over time and have longer operating lives. The technology consists of two tanks of liquid solutions that flow adjacent to each other past a membrane and generate a charge by moving electrons back and forth during charging and discharging. Avista assumes acquisition size of 25 MW of capacity with 4-hours in duration for each technology.

Capital costs are $1,319 per kW for the vanadium in 2020 and costs fall 38 percent by 2030. Zinc bromide's capital cost are $1,385 per kW, in 2020 falling by 44 percent by 2030. Fixed O&M costs are $58 per kW-year for vanadium and $66 per kW-year for zinc bromide, these cost increase with inflation. Round-trip efficiency for the vanadium is 70 percent and zinc bromide is 67 percent. Given Avista's experience with vanadium flow batteries, these efficiency rates are highly dependent on the battery's state of charge and how quickly the system is charged or discharged. Table 9.7 shows the levelized cost per kWh of capacity.

**Table 9.7: Flow Battery Levelized Cost $/kWh**

| Year | Vanadium | Zinc Bromide |
|---|---|---|
| 2020 | 230 | 247 |
| 2021 | 217 | 228 |
| 2022 | 205 | 211 |
| 2023 | 205 | 197 |
| 2024 | 188 | 194 |
| 2025 | 188 | 191 |
| 2026 | 187 | 191 |
| 2027 | 186 | 191 |
| 2028 | 186 | 191 |
| 2029 | 186 | 191 |
| 2030 | 186 | 191 |
| 2031 | 186 | 192 |
| 2032 | 186 | 192 |
| 2033 | 187 | 193 |
| 2034 | 187 | 194 |
| 2035 | 188 | 195 |
| 2036 | 189 | 196 |
| 2037 | 191 | 198 |
| 2038 | 192 | 200 |
| 2039 | 194 | 202 |
| 2040 | 196 | 204 |

### Liquid Air

A new technology with promise to provide long duration and long service life is liquid air storage. This is similar to compressed air storage but rather than compressing the air, the air is cryogenically frozen and stored into a tank to increase storage duration capability. The conversion process requires a liquefier to liquefy the air for storage. It is possible to use waste heat from existing natural gas-fired turbines to increase the efficiency of liquefying the air molecules. This increases round-trip efficiencies from 65 percent to 75 percent. After the air is stored, it can be later used by pushing the air through an air turbine.

Liquid air has not been widely used in the electric sector but uses common technology from other industries requiring liquefaction of other gases. This experience in the technology gives promise as a new technology that should benefit from short commercialization periods. Avista assumes a 25 MW capacity with 400 MWh hours of storage (16 hours). Another advantage of this technology is the ability to add storage capacity by adding additional tanks and using the same turbine and liquefaction systems.

Avista estimates liquid air storage capital costs at $1,457 per kW (2020 dollars) and increasing with inflation rather than declining as the technology is not expected to reduce in real terms due to its using mature technology. Fixed O&M is $25 per kW-year and carry's a $3.00 per MWh variable charge. The levelized cost of the storage is estimated to be $215 per kWh for 2020 and future years increase with inflation.

## Hydrogen/ Fuel Cell

The idea of using hydrogen in the energy sector has been an option for the distant future for some time. Avista recognizes this technology as an avenue for long-duration energy storage with the potential to store power to continuously run for up to several days. The technology behind this storage concept is to use electric power to electrolyze water into hydrogen; the hydrogen would be stored in tanks and then converted back to power (and water) later using a fuel cell. This process would result in a 34 percent round trip efficiency. The ability to store hydrogen into tanks similar to liquid air means long duration times can be obtained. Hydrogen technologies are getting significant R&D in the transportation and other sectors and may reduce its costs or increase its efficiency. It is also possible the transportation and other sectors could utilize the electric power system to create a cleaner form hydrogen to offset gasoline, diesel, propane, or even natural gas. The concept of offsetting natural gas led Avista to engage Black and Veatch to provide Avista's Natural Gas IRP process estimates for renewable hydrogen options. The assumptions and discussion are a result of this study.

The main source of hydrogen today uses methane-reforming techniques to remove hydrogen from natural gas or coal. This technology is primarily used in the oil and gas industries, but results in similar levels of greenhouse gas emissions from the combustion of the underlying fuels. If the hydrogen could be obtained from "clean" energy through electrolysis, the amount of greenhouse gas emissions can be greatly reduced. If renewable energy prices fall and there is an available water supply the operating cost of creating hydrogen could also fall, but capital costs would remain steady.

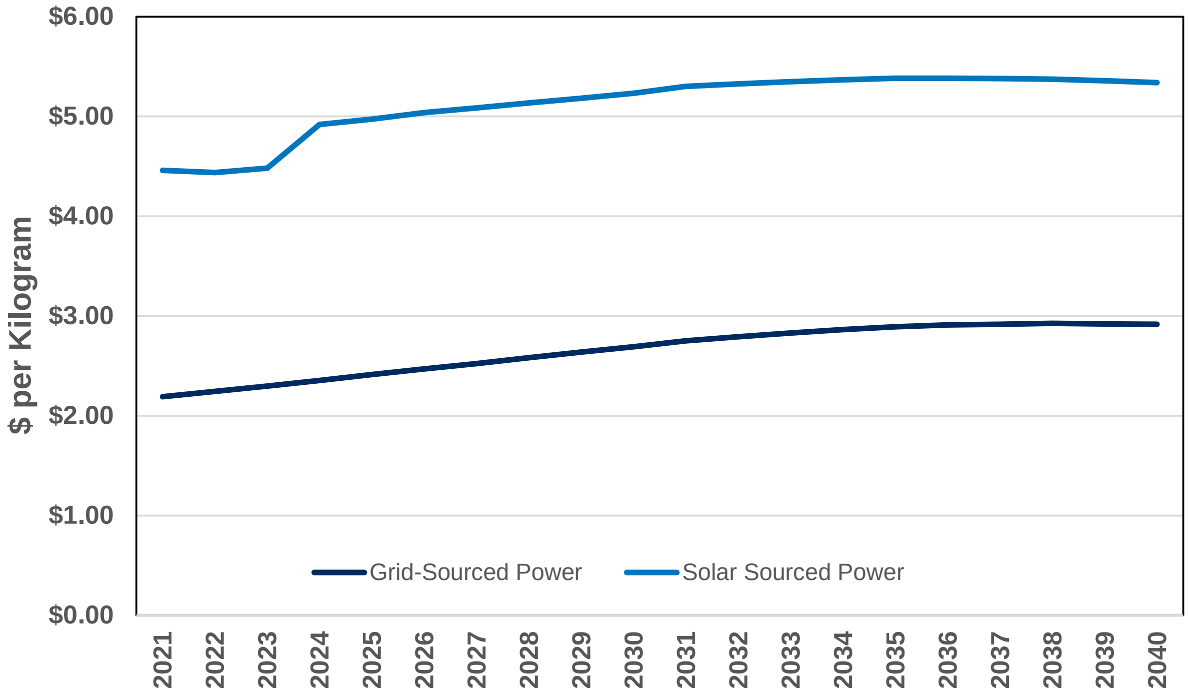
Converting hydrogen back into power would require a hydrogen fuel cell. There are many fuel cell technologies on the market. Avista started Avista Labs which was ultimately sold to Plug Power which is a fuel cell manufacturer. There are also other fuel cell technologies, which convert natural gas into power such as Bloom Energy; but Avista is not modeling this conversion cycle, but rather hydrogen to power. It is also possible to co-fire hydrogen with natural gas; although Avista is not studying this alternative in this IRP.

Estimating the cost of the hydrogen storage concept requires multiple steps. For a four-hour duration project, the first step is the cost of the electrolysis system. For modeling purposes, the system would create 5,000 kilograms of hydrogen per day and have an upfront cost of $6.7 million or $1,340 per kilogram plus cost to operate the facility would add $443,000 per year. Additional costs would be required for the power, variable O&M, excise taxes, and fees. For modeling purposes, variable O&M is $0.06 per kilogram and the energy price will depend on if the electrolizer is powered using retail power or wholesale and when the power is consumed. For example, if an independent company was using electric power to create hydrogen for another end use the buyer of electric power would be paying retail rates; but if used as an electric energy storage, it would be treated similar to other storage technologies and be fueled by wholesale market prices.

The efficiency of power to hydrogen is 50 kWh per kg in 2020, but improves to 48 kWh per kg by 2030.

Figure 9.2 shows the levelized price per kilogram of grid powered hydrogen using the efficiency and costs discussed above. These costs do not consider transportation or remarketing costs and assume power sourced from the wholesale energy market. Avista estimated the cost per kilogram would be levelized for power sourced with only solar (off grid). These costs are higher than grid power due to lower utilization factors from only producing hydrogen when the sun was out. This concept could potentially be lower cost if technology can be configured to eliminate AC transformation. Thus, creating a pure DC closed loop system.

**Figure 9.2: Wholesale Hydrogen Costs per Kilogram**




The second step in the hydrogen storage concept is to convert the hydrogen back to power. For this conversion, a 25 MW fuel cell(s) would be assembled for a utility scale needs. Approximately 40 kWh of power will be created per kilogram of hydrogen, plus the hydrogen losses from its storage. The estimated capital cost for a fuel cell is $5,470 per kW with a four-hour storage vessel plus fixed O&M at $163 per kW-year. Table 9.7 shows the all-in levelized cost of hydrogen storage including the fuel cell for 4-hour, 16-hour, and 40-hour storage lengths. Based on this analysis, the all-in cost for hydrogen storage is much higher than other options. Hydrogen likely has a future, but its likely place will be in limited applications until costs decrease, such as distributed solar with electrolysis for transportation related systems requiring frequent fueling.

### Table 9.8: Hydrogen Storage and Fuel Cell Levelized Cost $/kWh

| Year | 4-Hour | 16-Hour | 40-Hour |
|---|---|---|---|
| 2020 | 861 | 870 | 881 |
| 2021 | 864 | 872 | 883 |
| 2022 | 866 | 874 | 886 |
| 2023 | 868 | 877 | 888 |
| 2024 | 870 | 879 | 890 |
| 2025 | 873 | 882 | 893 |
| 2026 | 884 | 893 | 904 |
| 2027 | 895 | 904 | 915 |
| 2028 | 906 | 915 | 927 |
| 2029 | 918 | 927 | 938 |
| 2030 | 929 | 938 | 950 |
| 2031 | 948 | 957 | 969 |
| 2032 | 967 | 976 | 988 |
| 2033 | 986 | 996 | 1,008 |
| 2034 | 1,006 | 1,016 | 1,028 |
| 2035 | 1,026 | 1,036 | 1,048 |
| 2036 | 1,046 | 1,056 | 1,069 |
| 2037 | 1,067 | 1,078 | 1,090 |
| 2038 | 1,089 | 1,099 | 1,112 |
| 2039 | 1,110 | 1,121 | 1,134 |
| 2040 | 1,133 | 1,143 | 1,157 |

## Woody Biomass Generation

Woody biomass generation projects use waste wood from lumber mills or forest management. In the generation process, a turbine converts boiler-created steam into electricity. A substantial amount of wood fuel is required for utility-scale generation. Avista's 50 MW Kettle Falls Generation Station consumes over 350,000 tons of wood waste annually or 48 semi-truck loads of wood chips per day. It typically takes 1.5 tons of wood to make one megawatt-hour of electricity, the ratio varies with the moisture content of the fuel. The viability of another Avista biomass project depends on the availability and cost of the fuel supply. Many announced biomass projects fail due to lack of a long-term fuel source.

Based on market analysis of fuel supply and expected use of biomass facilities, a new facility could be envisioned as a wood-fired peaker. With high levels of intermittent renewable generation, a wood-fired peaker could be constructed to generate during low renewable output months or days. The capital cost for this type of facility would be $2,500 per kW plus O&M amounts of $150 per kW-year for fixed costs and $3.17 per MWh of variable costs (2020 dollars). The levelized cost per MWh is $111 per MWh for a 2020 project.

## Geothermal Generation

Geothermal energy provides predictable capacity and energy with minimal carbon dioxide emissions (zero to 200 pounds per MWh). Some forms of geothermal technology extract steam from underground sources to run through power turbines on the surface while others utilize an available hot water source to power an Organic Rankine Cycle installation. Due to the geologic conditions of Avista's service territory, no geothermal projects are likely to develop locally. Geothermal energy struggles to compete economically due to high development costs stemming from having to drill several holes thousands of feet below the earth's crust. Ongoing geothermal costs are low, but the capital required for locating and proving a viable site is significant. In Avista's last RFP, one geothermal project was bid, and this led Avista to reconsider this option as a possible resource to include in the IRP. While a project was bid, it does have the hurdles previously discussed. The IRP estimates a future geothermal PPA is $80 per MWh in 2020 at the busbar.

## Nuclear

Avista did not include nuclear plants as a resource option in prior IRPs given the uncertainty of their economics, regional political issues with the technology, U.S. nuclear waste handling policies, and Avista's modest needs relative to the size of modern nuclear plants. Nuclear resources could be in Avista's future only if other utilities in the Western Interconnect incorporate nuclear power in their resource mix and offer Avista an ownership share or if cost effective small-scale nuclear plants become commercially available.

The viability of nuclear power could change as national policy priorities focus attention on decarbonizing the nation's energy supply. The limited amount of recent nuclear construction experience in the U.S. makes estimating construction costs difficult. Cost projections in the IRP are from industry studies, recent nuclear plant license proposals, and the small number of projects currently under development. Modular nuclear design could increase the potential for nuclear generation by shortening the permitting and construction phase, and making these traditionally large projects a better fit the needs of smaller utilities. Given this possibility, Avista included an option for small scale nuclear power. The estimated cost for nuclear per MWh on a levelized basis in 2030 is $123 per MWh assuming capital costs of $4,518 per kW (2020 dollars) as a PPA.

## Other Generation Resource Options

Resources not specifically included as options in this IRP include cogeneration, landfill gas, anaerobic digesters, and central heating districts. This plan does not model these resource options explicitly but continues to monitor their availability, cost, and operating characteristics to determine if state policies change or the technology becomes more economically available.

Exclusion from the PRS analysis does not necessarily exclude non-modeled technologies from Avista's future portfolio. The non-modeled resources can compete with resources identified in the PRS through competitive acquisition processes. Competitive acquisition processes identify technologies to displace resources otherwise included in the IRP strategy. Another possibility is acquisition through PURPA. PURPA provides developers the ability to sell qualifying power to Avista at set prices and terms.[5]

[5] Rates, terms, and conditions are available at www.avistautilities.com under Schedule 62.

## Landfill Gas Generation

Landfill gas projects generally use reciprocating engines to burn methane gas collected at landfills. The Northwest has developed many landfill gas resources. The costs of a landfill gas project depend on the site specifics of a landfill. The Spokane area had a project on one of its landfills, but it was retired after the fuel source depleted to an unsustainable level. Much of the Spokane area no longer landfills its waste and instead uses the Spokane Waste to Energy Plant. Nearby in Kootenai County, Idaho, the Kootenai Electric Cooperative developed the 3.2 MW Fighting Creek Project. Using publically available costs and the NPCC estimates, landfill gas resources are economically promising, but are limited in their size, quantity, and location. Many landfills are considering cleaning the landfill gas to create pipeline quality gas due to falling wholesale electric market prices. This form of renewable gas has become an option for natural gas utilities to offer a renewable gas alternative to customers. This form of gas and the duration of the supply depends on the on-going disposal of trash, otherwise the methane could be depleted in seven to ten years.

## Anaerobic Digesters (Manure or Wastewater Treatment)

The number of anaerobic digesters is increasing in the Northwest. These plants typically capture methane from agricultural waste, such as manure or plant residuals, and burn the gas in reciprocating engines to power generators. These facilities tend to be significantly smaller than most utility-scale generation projects, at less than five megawatts. Most facilities are located at large dairies and cattle feedlots. A survey of Avista's service territory found no large-scale livestock operations capable of implementing this technology.

Wastewater treatment facilities can host anaerobic digesting technology. Digesters installed when a facility is initially constructed helps the economics of a project significantly, although costs range greatly depending on system configuration. Retrofits to existing wastewater treatment facilities are possible but tend to have higher costs. Many projects offset energy needs of the facility, so there may be little, if any, surplus generation capability. Avista currently has a 260 kW wastewater system under a PURPA contract with a Spokane County wastewater facility. Anaerobic digesters may opt to clean the gas to make to pipeline quality to offer a clean gas alternative.

## Small Cogeneration

Avista has few industrial customers with loads significantly large enough to support a cogeneration project. If an interested customer was inclined to develop a small cogeneration project, it could provide benefits including reduced transmission and distribution losses, shared fuel, capital, and emissions costs, and credit toward Washington's EIA efficiency targets.

Another potentially promising option is natural gas pipeline cogeneration. This technology uses waste-heat from large natural gas pipeline compressor stations. Few compressor stations exist in Avista's service territory, but the existing compressors in our service territory have potential for this generation technology. Avista has discussed adding cogeneration with pipeline owners, but no project has been determined feasible.

A big challenge in developing any new cogeneration project is aligning the needs of the cogenerator with the utility need for power. The optimal time to add cogeneration is during the retrofit or creation of an industrial process, but the retrofit may not occur when the utility needs new capacity. Another challenge to cogeneration within an IRP is estimating costs when host operations drive costs for a particular project. The best method for the utility to acquire this technology is through the PURPA process or in a future RFP.

### Coal

The coal generation industry is at a crossroads. In many states, like Washington, new coal-fired plants are extremely unlikely due to emission performance standards and the shortage of utility scale carbon capture and storage projects. The risks associated with future carbon legislation and projected low natural gas and renewables costs make investments in this technology highly unlikely. It is possible in the future there with be permanent carbon sequestration technology at price points to compete with alternative fuels. Avista will continue to monitor this development for future IRPs.

### Heating Districts

Historically heating districts were preferred options to heat city centers. This concept relies on a central facility to either create steam or hot water then distribute via a pipeline to buildings to provide heat for their end use of space and water heating. Historically, Avista provided steam for downtown Spokane using a coal-fired steam plant. This concept is still used in many cities in the U.S. and Europe including Seattle, WA. Developing new heating districts requires the right circumstances, partners, and long-term vision.

These requirements recently came together in a new concept of central heating districts being tested by a partnership between Avista and McKinstry in the Spokane University District called the Eco-District. The Hub facility will contain a central energy plant. It can generate, store, and share thermal and electrical energy with a combination of heat pumps, boilers, chillers, thermal, and electrical storage. The Hub will control all electric consumption for the campus and balance this against the needs of both the development and the grid. Future buildings within the district will be served by the Hub's central energy plant, expanding the district's shared energy footprint. A part of the Eco-District development will involve studying the costs and benefits of this configuration. The success of the district will determine how it will be implemented in the future for Avista's customers.

### Bonneville Power Administration

For many years, Avista received power from the Bonneville Power Administration (BPA) through long-term contract as part of the settlement from WNP-3. Most of the BPA's power is sold to preference customers or in the short-term market. Avista does not have access to power held for preference customers but does engage BPA on the short-term market. Avista has two other options for procuring BPA power. The first is using the New Resource NR rate. BPA's power tariff outlines a process for utilities to acquire power from BPA using this rate for one year at a time. As of the publishing of this IRP, the NR rate is

$79.80 per MWh[6]. Since this offering is short-term and variable, Avista does not consider it as a viable long-term option for planning purposes, but it is a viable alternative for short-run capacity needs. The other option to acquire power from BPA is to solicit an offer. BPA is willing to provide prices for periods of time when it believes it has excess power or capacity. This process would likely parallel an RFP process for future capacity needs.

### Existing Resources Owned by Others

Avista purchased long-term energy and capacity from regional utilities in the past, specifically the Public Utility Districts in Mid-Columbia region. Avista contracts are currently discussed in Chapter 4, but extensions or new agreements could be formed. It is also possible in the event other utilities are long on capacity to develop agreements to strengthen Avista's capacity versus load positon. Since these potential agreements are based on existing assets, prices depend on future markets. Avista is modeling for this IRP the possibility of an up to 75 MW extension of existing agreements, but the cost and actual quantities available are unknown. Avista could acquire or contract for energy and capacity of other existing facilities without long term agreements. Avista anticipates these resources will be offered into future RFPs.

### Renewable Natural Gas

Avista did not model the option to use renewable natural gas (RNG) for electric generation in this IRP. RNG is methane gas sourced from waste produced by dairies, landfills, wastewater treatment plants and other facilities. The amount of RNG is limited by the output of the available processes. The amount of greenhouse gas emissions the RNG offsets differs depending upon the source of the gas and the duration of the methane abatement used. Avista considers the cost-effective use of this fuel type in its Natural Gas IRP and believes its best use is to reduce emissions from the direct use of natural gas rather than use it as a fuel in natural gas-fired turbines due to higher efficiency in end use in customer's homes.

## Hydroelectric Project Upgrades and Options

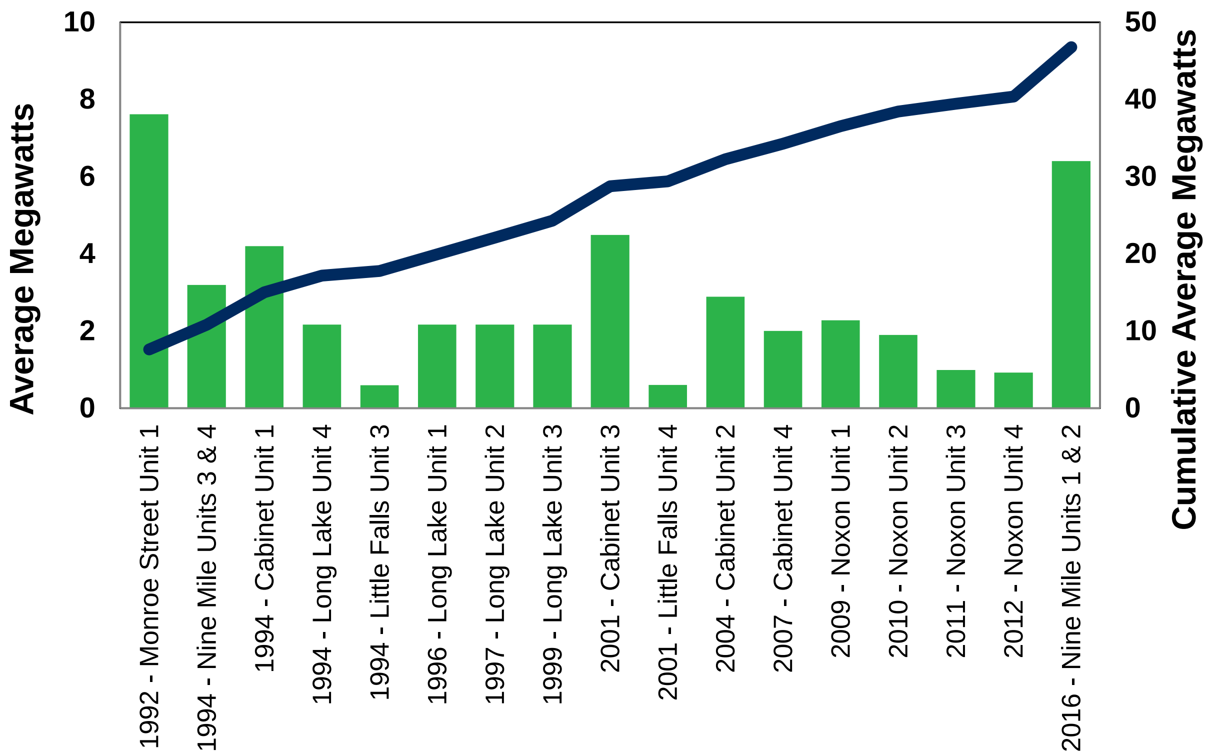
Avista continues to upgrade its hydroelectric facilities as shown in Figure 9.3. The latest hydroelectric upgrade added ten megawatts to the Nine Mile Falls Development in 2016. Avista added 46.8 aMW of incremental hydroelectric energy between 1992 and 2016. Upgrades completed after 1999 can qualify for the EIA, thereby reducing the need for additional renewable energy options. Further, any upgrade can qualify for CETA if it meets the requirements as a clean energy resource.

Construction of the Spokane River hydroelectric project occurred in the late 1800s and early 1900s, when the priority was to meet then-current loads. The developments therefore do not capture a majority of river flows. In 2012, Avista reassessed its Spokane River Project to evaluate opportunities to capture more of the streamflow. The goal was to develop a long-term strategy and prioritize potential facility upgrades. Avista evaluated five of the six Spokane River developments and estimated costs for generation upgrade options. Each upgrade option should qualify for the EIA renewable energy goal. These

[6] https://www.bpa.gov/Finance/RateInformation/Pages/Current-Power-Rates.aspx.

studies were part of the 2011 and 2013 IRP Action Plans and results appear below. Each of these upgrades are major engineering projects, taking several years to complete and requiring major changes to the FERC licenses and the project's non-consumptive water rights. The upgrades will compete against other renewable options when more renewables are required or developed as Avista considers the most effective management plans for these existing projects.

Figure 9.3: Historical and Planned Hydro Upgrades




## Post Falls

At the time of publishing the 2017 IRP, the Post Falls project was undergoing an analysis to determine the best course of action to maintain the facility. Two primary options were proposed. The first option is to replace existing equipment with similar size. The second option is to increase the capacity of the project by eight megawatts. Within this IRP modeling process, the PRiSM model can choose to upgrade the facility in 2027. Upgrading the facility would increase generating capacity by 4.5 aMW and increase winter peak generation by 3.8 MW for an additional cost above replacing with in-kind equipment.

## Long Lake Second Powerhouse

Avista studied adding a second powerhouse at Long Lake over 30 years ago by using the small arch or saddle dam located on the south end of the project site. This project would be a major undertaking and require several years to complete, including major changes to the Spokane River FERC license and water rights. In addition to providing customers with a clean energy source, this project could help reduce total dissolved gas levels by reducing spill at the project and providing incremental capacity to meet peak load growth.

The 2012 study considered three alternatives. The first replaces the existing four-unit powerhouse with four larger units totaling 120 MW, increasing capacity by 32 MW. The other two alternatives develop a second powerhouse with a penstock beginning from a new intake structure downstream of the existing saddle dam. One powerhouse option was a single 68 MW turbine project. The second was a two-unit 152 MW project. The best alternative in the study was to add the single 68 MW unit. Table 9.9 shows upgrade costs and characteristics. Avista will need to refine this study for future analysis as the existing machinery in the powerhouse approach their end of life.

### Monroe Street/Upper Falls Second Power House

Avista replaced the powerhouse at its Monroe Street development on the Spokane River in 1992. There are three options to increase its capacity. Each would be a major undertaking requiring substantial cooperation with the City of Spokane to mitigate disruption in Riverfront and Huntington parks and downtown Spokane during construction. The upgrade could increase plant capacity by up to 80 MW. To minimize impacts on the downtown area and the park, a tunnel drilled on the east side of Canada Island could avoid excavation of the south channel to increase streamflow to the new powerhouse. A smaller option would add a second 40 MW Upper Falls powerhouse, but this option would require south channel excavation. A final option would add a second Monroe Street powerhouse for 44 MW. All project options were removed for this IRP due to the disruption to the Riverfront Park and the downtown area. Avista may reconsider this analysis in future partnership with the City of Spokane.

### Cabinet Gorge Second Powerhouse

Avista is exploring the addition of a second powerhouse at the Cabinet Gorge development site to mitigate total dissolved gas and produce additional electricity. A new 110 MW underground powerhouse would benefit from an existing diversion tunnel around the dam built during original construction. This resource does not add any peak capacity credit due to the water right limitations of the license. The resource only creates additional energy during spring runoff.

**Table 9.9: Hydroelectric Upgrade Options**

| Resource | Monroe Street/Upper Falls | Long Lake | Cabinet Gorge |
|---|---|---|---|
| Incremental Capacity (MW) | 80 | 68 | 110 |
| Incremental Energy (MWh) | 237,352 | 202,592 | 161,571 |
| Incremental Energy (aMW) | 27.1 | 23.1 | 9.2 |
| Peak Credit (Winter/ Summer) | 31/0 | 100/100 | 0/0 |
| Capital Cost ($2020 Millions) | $171 | $165 | $260 |
| Levelized Energy Cost ($2020/MWh) | $92 | $84 | $196 |

## Thermal Resource Upgrade Options

For the last several IRPs, Avista investigated opportunities to add capacity at existing facilities. These projects have been implemented when cost effective. Avista is modeling three potential options at Rathdrum CT and an option at Kettle Falls Generating State. No costs are presented in this section, as pricing is sensitive to third-party suppliers, but presents an overview of the concepts. Estimated cost are including the portfolio modeling discussed in Chapter 11.

### Rathdrum CT Supplemental Compression

Supplemental compression is a new technology developed by PowerPhase LLC that increases airflow through a CT compressor increasing machine output. This upgrade could increase Rathdrum CT capacity by 24 MW.

### Rathdrum CT 2055 Uprates

By upgrading certain combustion and turbine components, the firing temperature can increase to 2,055 degrees from 2,020 degrees corresponding to a five MW increase in output.

### Rathdrum CT Inlet Evaporation

Installing a new inlet evaporation system will increase the Rathdrum CT capacity by 17 MW on a peak summer day, but no additional energy is expected during winter months.

### Kettle Falls Turbine Generator Upgrade

The Kettle Falls plant began operation in 1983. In 2025, the generator and turbine will be 42 years old and at the end of its expected life. At this time, Avista could spend additional capital and upgrade the unit by 12 megawatts rather than replace it with in-kind technology.

## Intermittent Generation Costs

Intermittent generation resources such as wind and solar require other resources to help balance the unpredictable energy supply. This materializes in a cost by changing otherwise more efficient operations. For Avista this is challenging because the cost could be the difference of running stored water hours later compared to now. Avista began studying these costs on its system in 2007. This analysis created the methodology the ADSS model now uses to not only study the costs of the intermittent resources, but also better equips our real-time operations team in managing when to dispatch resources. For this IRP, wind will add approximately $5 per MWh in operating cost inefficiencies and solar $1.80 per MWh based on the 2007 study. Avista’s 2007 study is still relevant due to scenario analysis performed including pricing similar to prices of today along with a similar resource portfolio. With an EIM in place, Avista expects these costs to lower by 40 percent, this result was also part of the 2007 analysis when shorter trading blocks were studied. Avista believes these costs will increase with additional generation on the system and will need to study these issues in future IRPs when tools with sub-hourly modeling of Avista’s unique system are completed.

Another cost to consider when adding intermittent generation is the capacity value for reliability. Intermittent resources add additional load following requirements when operating in the event the resource loses power. For this additional requirement, Avista's ELCC studies require a 10 percent increase in held reserves of the produced energy each hour.

## Ancillary Services Values

Many of the resources discussed in this chapter may provide benefits to the electrical system beyond traditional energy and capacity (for reliability). Some resources can provide reserve products such as Frequency Response or Contingency Reserves. Avista is required to hold generating reserves of 3 percent of load and 3 percent of on-line generation. This means resources need to be able to respond in 10 minutes in the event of other resources outages on the system. Within the reserve requirement, 22 MW must be held as frequency response to provide instantaneous response to correct system frequency variations. In addition to these requirements, Avista must also hold capacity to help control intermittent resources and load variance, this is referred to as load following and regulation. The shorter time steps minute-to-minute is regulation and longer time steps such as hour-to-hour is load following. Together these benefits consist of Ancillary Services for the purposes of this IRP.

Many types of resources can help with these requirements, specifically storage projects, natural gas peakers, and hydroelectric generation. The benefits these projects bring to the system greatly depend on many external factors including other "capacity" resources within the system, the amount of variation of both load and generation, market prices, market organization (i.e. EIM), and hydro conditions. Internal factors also play a role; these include the ability for the resource to respond in speed and quantity. Avista conducted a study on its Turner Energy Storage project along with the Pacific Northwest National Lab to clarify the operating restrictions of the technology. For example, if the battery is quickly discharged, the efficiency lowers and depending on the current state of charge the efficiency is also affected. These nuances make it more difficult to model in software systems.

Further, Avista needs to continue studying the benefits of energy storage by modeling additional scenarios including price, water year, and level of renewable penetration. It will also need to study the benefits of using a sub-hourly model. Avista is still developing the ADSS model to provide this complete analysis. In the fifth TAC meeting, Avista presented results from two studies regarding the potential analysis with the ADSS system. These analyses were completed using existing markets and showed the potential to provide benefits. Although, as Avista enters a future with additional on-system renewables and an EIM, these estimates will need to be revised. With this in mind, Table 9.10 outlines the assumed values for Ancillary Service benefits for new construction projects.

**Table 9.10: Ancillary Services Value Estimates (2020 dollars)**

| Resource | $/kW-yr |
|---|---|
| Natural gas-fired CT/reciprocating engine | 1.04 |
| Lithium-ion battery | 4.93 |
| Lithium-ion battery connect to solar | 1.50 |
| Pumped hydro | 4.93 |
| Flow battery | 1.56 |
| Liquid Air | 0.52 |

## Resource ELCC Analysis

Avista conducted substantial research and time in studying the impact of resources effect on resource adequacy. Throughout this process, Avista learned that the quantity, location, and mixture of resources has a substantial effect on the benefit each resource can provide. For example, 4-hour duration storage can provide high levels of resource adequacy in small quantities because it has other resources to assist in its re-charging; but as its proportion gets larger, there is not enough energy to refill the storage device for later dispatch as shown in the E3 study for resource adequacy[7]. When coupled with renewable energy storage the combined resources may increase our resource adequacy, but this depends on how much energy can be stored and the amount produced in critical periods. Higher levels of penetrations for renewables may lower their effect on resource adequacy.

Avista used 1,000 simulations of Avista hydro, load, wind, and forced outage rates to estimate the contribution for different types of resources available to meet its peak. This is measured by the resources ability to lower Loss of Load Probability (LOLP) using the Avista Reliability Assessment Model (ARAM). The model is first simulated using a reliable system with a set of new natural gas-fired CTs to meet future load obligations. Then the gas turbines are removed and replaced with each of the resources in Table 9.11. The percentage shown in the table is the percent of natural gas turbines assumed the replacement resource would offset. After PRiSM selects the PRS, the specific resource selection is studied for LOLP. If not meeting the 5 percent LOLP metric due to intra reaction between the resources, the resulting/effective planning margin increases and a new strategy selected for comparison to the reliability metric.

[7] Appendix F, Resource Adequacy in the Pacific Northwest, page 54.

**Table 9.11: Peak Credit**

| Resource | Peak Credit (percent) |
|---|---|
| Solar | 2 |
| Northwest wind | 5 |
| Montana wind[8] | 36 |
| Hydro w/ storage | 100 |
| Hydro run-of-river | 31[9] |
| Storage 4 hr duration | 15 |
| Storage 8 hr duration | 30 |
| Storage 12 hr duration | 58 |
| Storage 16 hr duration | 60 |
| Storage 24 hr duration | 65 |
| Storage 40 hr duration | 75 |
| Storage 80 hr duration | 95 |
| Demand response | 60 |
| Solar + 4 hr Storage[10] | 15 |
| Solar + 2 hr Storage[11] | 13 |

# Other Environmental Considerations

## Natural Gas Production and Transportation Greenhouse Gas Emissions

All generating resources have an associated emissions profile, either when it produces energy or when it was constructed. For this IRP Avista models associated emissions with the production of energy. Future IRPs may consider the emissions associated with the manufacturing and construction of the facility. Other potential studies could be from the indirect greenhouse gas emissions from biomass and coal production.

The only indirect greenhouse gas emissions resource studied in this plan is natural gas. Natural gas is assumed to emit 119 pounds of greenhouse gas emissions equivalent per dekatherm when including the other gases within the supply. In addition to those emissions, there could be upstream emissions from the drilling process and the transportation of the fuel to the plant also known as fugitive emissions. The Washington State customer's share of generation includes these potential emissions priced at the social cost of carbon for resource optimization. The additional emissions are 0.829

[8] Net of transmission losses.
[9] Based on Monroe Street 2nd Powerhouse.
[10] This resource assumes the storage resource may only charge with solar, this specific option was not modeled within the PRS and is shown as a reference only. Avista only modelled solar plus storage where the storage resource could be charged with non-solar as well to reflect long-term utility operations
[11] Avista limited solar plus storage to these two scenarios; many other options are likely including different durations and storage to solar ratios. Specific configurations would need to be studied to validate peak credits for those configurations

percent[12]. Avista sources its natural gas for power generation from the province of Alberta via the GTN pipeline and the province tracks these emissions. To account for these emissions, Avista is using a set of official reports as accounted for by the Canadian and United States governments. These 2017 reports were submitted to the National Energy Board (NEB) in Canada and PHMSA (Pipeline and Hazardous Materials Safety Administration) in the U.S. The reports carry penalties for falsehoods and are subject to review and audit.

There are three pipelines carrying natural gas from the Canadian production areas to the U.S. demand markets. The first is Nova Gas Transmission (NGTL) and it is the largest set of pipelines connected to the production fields bringing over eight billion dekatherms of energy to the market in 2017. Its carbon equivalent fugitive emissions are roughly five million tons or 0.767% of the overall energy produced. Foothills pipeline delivers 1.5 billion dekatherms of energy with a reported 0.678% fugitive emissions rate. Finally, Gas Transmission Northwest (GTN) is the backbone of supply of natural gas to our generation facilities and in 2017 alone delivered nearly eight hundred million dekatherms of volume with an emissions rate of 1.758%. As a system the overall emissions for 2017 is 1.164% and includes $CO_2$, $CH_4$ and $N_2O$ emissions all converted to metric tons of carbon dioxide equivalents using 100-year Global Warming Potentials as found by the Intergovernmental Panel on Climate Change (IPCC). The IPCC is the United Nations body for assessing the science related to climate change. A summary of these figures and their sources can be found in Table 9.12:

**Table 9.12: Natural Gas Fugitive Emissions**

| 2017 | Volume reported, Dth | Conversion of volume to tonnes $CO_2$ equivalent | Emissions reported, tonnes $CO_2$ equivalent | Percent |
|---|---|---|---|---|
| Nova Gas Transmission, NGTL[13] | 8,202,460,151 | 435,430,053 | 3,341,551 | 0.767% |
| Foothills Pipeline, AB & SK[14] | 1,527,266,974 | 81,075,425 | 549,489 | 0.678% |
| Gas Transmission Northwest, GTN[15] | 794,764,490 | 42,190,311 | 741,635 | 1.758% |
| | 10,524,491,615 | 558,695,789 | 4,632,676 | 0.829% |

## Greenhouse Gas Emissions for Storage Resources

Avista considers emissions from the acquisition of market power. As outlined in Chapter 10, the greenhouse gas emissions associated with power purchases is the average emission rate for the northwest area for this IRP. Avista conducted additional analysis to

[12] The IRP analysis included 0.783 percent for these emissions from Avista's draft analysis; the 0.829 percent number represents the final estimate.
[13] Volume: National Energy Board (NEB) Pipeline profiles data, neb-one.gc.ca; Emissions: Canadian GHG reporting program (GHGRP), climate-change.canada.ca.
[14] Volume: National Energy Board (NEB) Pipeline profiles data, neb-one.gc.ca; Emissions: Canadian GHG reporting program (GHGRP), climate-change.canada.ca.
[15] Volume: 2017 annual report to PHMSA, form 7100.2-1 (rev 10-2014), Part C, phmsa.dot.gov; Emissions: 2017 submission to EPA, epa.gov.

estimate the emissions associated with market purchases for energy storage resources. When power is stored from market power, it may have associated greenhouse gas emissions. Many other IRPs assume power stored is emission free, where its emissions are based on the source of the power stored. In a future where market purchases are used to store the power, the power will likely be assigned emissions from the market's emission intensity. Although the intensity of those emissions will differ from the market as the storage resources is only charging in certain periods. To understand this difference, Avista modeled the hourly emissions intensity of the northwest energy supply and matched those hours when a storage device was charging[16]. The results show when suppling a storage facility with market power will ultimately have lower emissions profiles than the overall energy market, this is because the market typically charges in lower price periods when more renewables are available. The amount of reduction as compared to the market depends on the duration of the storage resource, but on average storage emissions are 30 percent less than average market emission rates after 2030.

### Other Environmental Considerations

There are other environmental factors involved when siting and operating power plants. Avista considers these cost in the siting process. For example, new hydroelectric projects or modifications to existing facilities must be made in accordance with their operating license, and if new facilities require operations outside this license, the license would reopen. When siting solar and wind facilities, developers must have approvals from local governing boards to make sure all laws and regulations are kept.

If Avista sites a new natural gas facility, it will have to meet state and local air requirements for its air permit. These requirements are at levels these governing bodies find fitting for their communities. At this time, Avista is not evaluating emissions costs outside of these considerations.

[16] This analysis uses the deterministic version of the expected cases market analysis.

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