# Appendix M. Supply-side options

This appendix provides information summarizing the operational and cost attributes of various power generation and storage technologies. The technologies considered include onshore and offshore wind, solar photovoltaic, battery and pumped hydroelectric energy storage, hydrogen production and storage, geothermal, biomass, nuclear powered generation, and various natural gas-fueled resources including a combined-cycle combustion turbine with carbon sequestration.

## M.1 Sources of information

### M.1.1 Resource costs and operating parameters

The National Renewable Energy Laboratory produces the Annual Technology Baseline (NREL ATB) to "develop and document transparent, normalized technology cost and performance assumptions" for typical generating resources in the United States. The Energy Information Administration (EIA) commissioned Sargent & Lundy to "evaluate the overnight capital cost and performance characteristics for 25 electric generator types" to reflect these generators in the Annual Energy Outlook 2020 (EIA AEO).[500] Resource capital and operating expenditures, as well as operating parameters, are sourced from the ATB and AEO unless otherwise noted (**Table 139** and **Table 140**). Where information needed for PGE's models is not provided in the ATB or AEO, PGE relies on information from other publicly available sources, including supply-side options studies prepared in support of past IRPs. Historical inflation rates were applied to escalate from the EIA and NREL study values.

Note that in tables containing numerical values, the totals may not add due to rounding.

NREL defines capital expenditures as generally including costs in the following categories:[501]

---

[500] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy. Available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf
[501] NREL 2021 Electricity ATB. Available at: https://atb.nrel.gov/electricity/2021/definitions

**Table 139. Capital expenditure details**

| Capital expenditure components | Description |
|---|---|
| **Balance of system/balance of plant** | All other major plant components within the facility fence line are necessary to deliver electricity to the bulk power system. |
| **Electrical infrastructure and interconnection (electrical interconnection, electronic, electrical infrastructure, electrical)** | • Internal and control connections<br>• Onsite electrical equipment (e.g., switchyard)<br>• Power electronics<br>• Transmission substation upgrades |
| **Generation equipment and infrastructure (civil works, generation equipment, other equipment, support structure)** | • Plant construction<br>• Power plant equipment |
| **Installation and indirect** | • Distributable labor and materials<br>• Engineering<br>• Start-up and commissioning |
| **Owners' costs** | • Development costs<br>• Environmental studies and permitting<br>• Insurance<br>• Legal fees<br>• Preliminary feasibility and engineering studies<br>• Property taxes during construction |
| **Site costs** | • Access roads<br>• Buildings for operation and maintenance<br>• Fencing<br>• Land acquisition<br>• Site preparation<br>• Transformers<br>• Underground utilities |

NREL defines operational expenditures as generally including costs in the following categories:[502]

**Table 140. Operational expenditure details**

| Operational expenditure components | Description |
|---|---|
| **Fixed costs** | • Administrative fees<br>• Administrative labor<br>• Insurance<br>• Land lease payments<br>• Legal fees<br>• Operating labor<br>• Other<br>• Property taxes<br>• Site security<br>• Taxes |
| **Fixed costs components** | Project management |
| **Maintenance costs** | • General maintenance<br>• Scheduled maintenance over technical life<br>• Unscheduled maintenance over technical life |
| **Variable cost components** | • Consumables (e.g., water, chemicals, catalysts, etc.)<br>• Waste disposal (e.g., ash, slag, process wastes, process byproducts that are not otherwise sold, etc.) |
| **Maintenance components** | Transformers |
| **Replacement costs** | Annualized present value of large component replacement over technical life |

[502] *Id.*

# M.2 Renewable resources

## M.2.1 Onshore wind

### Technology description

Wind turbine generators convert kinetic wind energy into electrical power. The horizontal-axis three-bladed design is the most ubiquitous type of wind turbine used for electric power generation. Lift is generated when wind flows around the turbine blades, resulting in rotation. The blades are connected to a central hub and drivetrain that turns a generator inside the nacelle, which is the housing positioned atop the wind turbine tower.

### Commercial status

Installed wind capacity has grown by more than 50 percent in the United States since 2017. At the end of 2021, wind generating capacity in the country totaled nearly 136 GW.[503] Key aspects of wind turbine generator designs continue to grow as well. The average rated capacity of new turbines in 2021 was 3.0 MW, 9 percent more than the year prior. Likewise, the blade rotor diameter of new turbine installations grew 2 percent to 127.5 meters and hub heights rose to nearly 94 meters or 4 percent higher than the prior year's average.[504]

### Operational characteristics

Three PNW sites, and one Wyoming location, are modeled with identical turbine specifications and layouts, shown in **Table 141**:

**Table 141. Summary of Oregon onshore wind operational characteristics 2026 COD**

| Site | Lat. | Long. | IRP CF% |
|---|---|---|---|
| **Oregon Gorge** | 45.65 | -120.63 | 44.4% |
| **Central Montana** | 46.35 | -110.34 | 42.3% |
| **Southeast Washington** | 46.41 | -117.84 | 42.0% |
| **Casper Wyoming** | 43.04 | -105.56 | 44.1% |

503 Lawrence Berkeley National Laboratory. "Land-based Wind Market Report: 2022 Edition," available at: https://emp.lbl.gov/publications/land-based-wind-market-report-2022

504 *Id.*

3.5 MW turbines are modeled in System Advisor Model (SAM) using eight years of weather data, as mentioned previously. The Hub height is 105 meters, and rotor diameter is 136 meters. These parameters are consistent with those specified for a NW wind resource in PGE's most recent IRP. Maintaining a consistent resource configuration at the three sites focuses any analysis on wind resource variations rather than attempting to optimize each site's design. It is expected that developers in the marketplace will use their expertise to design an optimal solar PV resource for any specific location. Each site employs 87 turbines to provide approximately 300 MW of generating capacity. The default layout in SAM arranges the turbines in three rows of 29 turbines with eight-rotor diameter spacing. The "Simple Wake Model" estimates the interactive effects on downwind turbines. According to NREL, this model "uses a thrust coefficient to calculate the wind speed deficit at each turbine due to wake effects of the upwind turbines."[505]

An hourly generation profile is simulated for each year of weather data for each site listed in the previous table. These hourly generation profiles are produced using SAM. The profiles are used as inputs to Sequoia. The hourly shape for the representative year is used as input to Aurora for energy modeling.

## Operational expenditures

Operational expenditures for the representative onshore wind resource are derived from the EIA AEO 2020 study, shown in **Table 142**. The general categories of costs included in operational expenditures are listed earlier.

**Table 142. Summary of Oregon onshore wind operational expenditures**

| Operational expenditures, onshore wind | | | | |
|---|---|---|---|---|
| **2019$** | **Oregon Gorge** | **Southeast Washington** | **Central Montana** | **Casper Wyoming** |
| **Fixed O&M ($/kW-year)** | $26.34 | $26.34 | $26.34 | $26.34 |
| **Less: Land Lease** | $2.80 | $2.80 | $2.80 | $2.80 |
| **Fixed O&M Ex-Land Lease** | $23.54 | $23.54 | $23.54 | $23.54 |

[505] SAM Version 2021.12.02 Help System. NREL. https://sam.nrel.gov/images/web_page_files/sam-help-2021-12-02.pdf

| Operational expenditures, onshore wind | | | | |
|---|---|---|---|---|
| **Variable O&M ($/MWh)** | $0 | $0 | $0 | $0 |
| **Variable Land Lease ($/MWh)** | $1.70 | $1.70 | $1.70 | $1.70 |

## Capital expenditures

Cost information is derived from the EIA AEO 2020 study. The general categories of costs included in capital expenditures are listed earlier. The EIA transmission line costs are removed, and PGE estimated values are used in the revenue requirements modeling process. A locational cost adjustment is applied based on the EIA study's resource location and the adjustment factors. The factors from the EIA study correspond to an average of Portland, Spokane, and Boise factors for the Oregon Gorge resource, an average of Spokane and Boise factors for the Southeast Washington resource, and Great Falls for the Montana resource (**Table 143**). Capital expenditures for the Casper, Wyoming, resource mirror the Central Montana location.

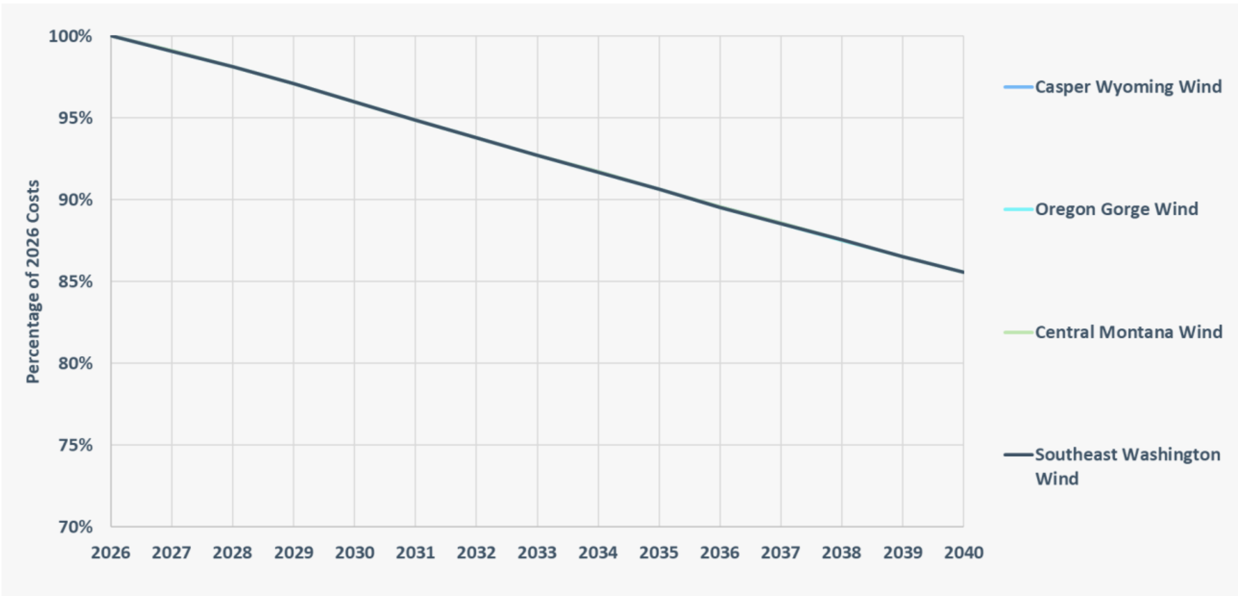
**Table 143. Summary of Oregon onshore wind capital expenditures**

| Capital expenditures, onshore wind | | | | |
|---|---|---|---|---|
| **2019 $/kW** | Oregon Gorge | Southeast Washington | Central Montana | Casper Wyoming |
| **Overnight capital** | $1,265 | $1,265 | $1,265 | $1,265 |
| **Less: Transmission Line Cost** | $6 | $6 | $6 | $6 |
| **Overnight EPC Capital Cost -Ex Interconnect Cost** | $1,259 | $1,259 | $1,259 | $1,259 |
| **Location Adjustment** | 1.02 | 1.02 | 0.99 | 0.99 |
| **Location-adjusted Overnight Capital Cost** | $1,288 | $1,278 | $1,246 | $1,246 |

## Forward capital cost curve

EIA onshore resources share a common forward capital cost trajectory across the various sites. The EIA AEO 2020 projection of future capital costs for the Reference Case scenario are presented in **Figure 157**.

**Figure 157. Onshore wind capital cost trajectory**




# M.2.2 Offshore wind

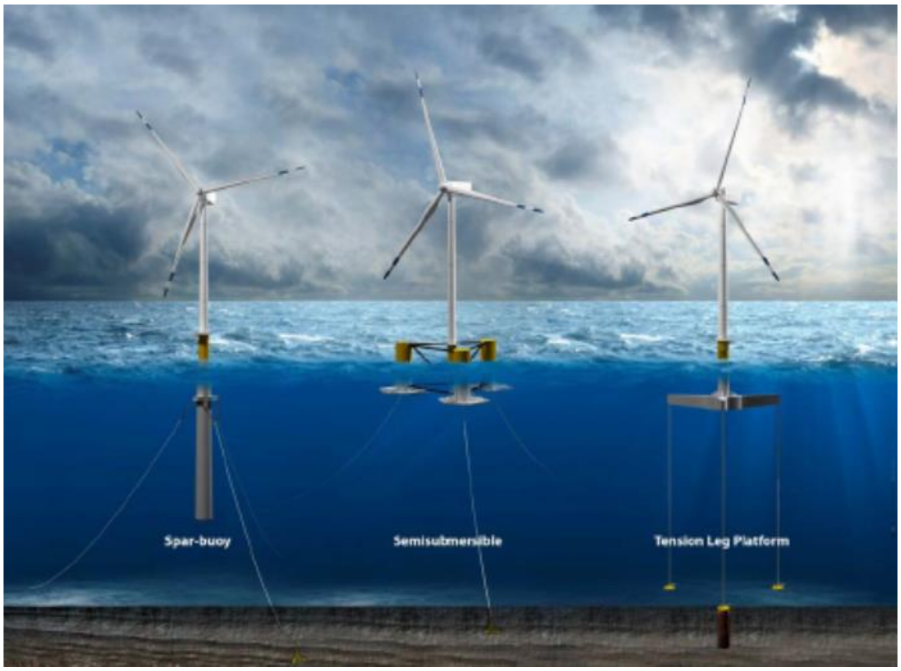
## Technology description

Electricity generation from offshore wind is conceptually similar to that of onshore wind. The primary difference is that the wind plant is in offshore waters allowing access to a potentially diverse and more energetic wind resource. The offshore wind technology is generally described by the structure that suspends the turbine: "fixed-bottom" resources are those with a tower attached directly to the seabed; "floating" installations do not anchor the tower directly to the ground, but rather employ a structure that floats in the water and is anchored to the seabed (**Figure 158**). The application of fixed bottom vs. floating technology is generally dictated by the depth of the water, with water in excess of 60 meters typically requiring the use of a floating structure. According to NREL research, water depths are greater than 60 meters in 97 percent of the water on the Outer Continental Shelf (OCS – administered by the federal government) off the Oregon coast, dictating the use of a floating technology as opposed to fixed-bottom.

The structure further defines the technology: spar-buoy, semi-submersible, tension leg platform.

Each design offers certain advantages and disadvantages relative to the others. For example, the semi-submersible design has a shallower draft (the distance the structure occupies under the water surface) than the spar-buoy type, requiring less water depth for assembly. Companies are Innovating structure designs to optimize costs and performance. According to NREL, the semi-submersible structure is dominant in the conditions expected for Oregon offshore wind development and is the basis for cost estimates.

**Figure 158. Floating offshore wind platforms**




The assumption for a project online in 2032 makes use of semi-submersible platforms employing turbines rated at 15 MW with 248-meter rotor diameters at hub heights of 150 meters. These specifications are equivalent to those proposed by NREL for the 2032 reference technology. Turbine power curve data are also consistent with those used by NREL, as updated for 2021.[506]

[506] Musial, Walter, Patrick Duffy, Donna Heimiller, and Philipp Beiter. 2021. Updated Oregon Floating Offshore Wind Cost Modeling. Available at: nrel.gov/docs/fy22osti/80908.pdf.

## Commercial status

European deployments of offshore wind vastly outpace those of the United States. According to WindEurope, an industry advocacy group, total offshore wind capacity in Europe totaled more than 28 GW at 2021year-end. This capacity is expected to almost double in the period 2022–2026. More than 3 GW was added in 2021 alone.

The Biden Administration has stated a goal of 30 GW of offshore wind by 2030. The state of California has established a goal of 2-5 GW of offshore wind capacity by 2030 and 25 GW by 2045.[507] State and federal goals for offshore wind development In the United States, offshore wind development in federal waters is overseen by the Bureau of Ocean Energy Management (BOEM). The areas under BOEM's responsibility include the submerged lands on the OCS, which begins approximately three nautical miles offshore and extends to 200 nautical miles marking the exclusive economic zone boundary. BOEM controls the process for issuing leases and approving offshore wind projects on the OCS. The leasing process includes stakeholder engagement and numerous opportunities for review and approval. This process may extend many years from the lease initiation to the approval of a construction and operations plan preceding construction. BOEM plans to review 16 offshore wind projects, more than 22 GW, by 2025.

As of mid-2021, two offshore wind projects were operating in waters off the east coast of the US: Block Island Wind Farm (approximately 30 MW off the coast of Rhode Island) and the Coastal Virginia Offshore Wind pilot project (12 MW off the Virginia coast). Additionally, the 800 MW Vineyard Wind project off the Massachusetts coast is fully permitted and expected to be operational in 2024, while the 130 MW South Fork project off the coast of Rhode Island was approved in 2022 and may reach COD in 2023.

The 2022 New York Bright auction for offshore wind leases saw six developers win leases on six areas representing more than 488,000 acres. The winning bids totaled $4.37 billion, or an average of nearly $9,000 per acre.

Two BOEM wind energy areas are off the California coast (Morro Bay and Humboldt). The results of the lease sale for these sites were released December 7, 2022.[508] Five leases were sold through the auction. The sites comprise more than 370,000 acres with an average price of approximately $2,000 per acre. BOEM reports that development of these lease areas could potentially support 4.6 GW of generating capacity.

[507] California Energy Commission. Offshore Wind Energy Development off the California Coast. August 2022. https://www.energy.ca.gov/filebrowser/download/4361#page=63&zoom=100,0,0

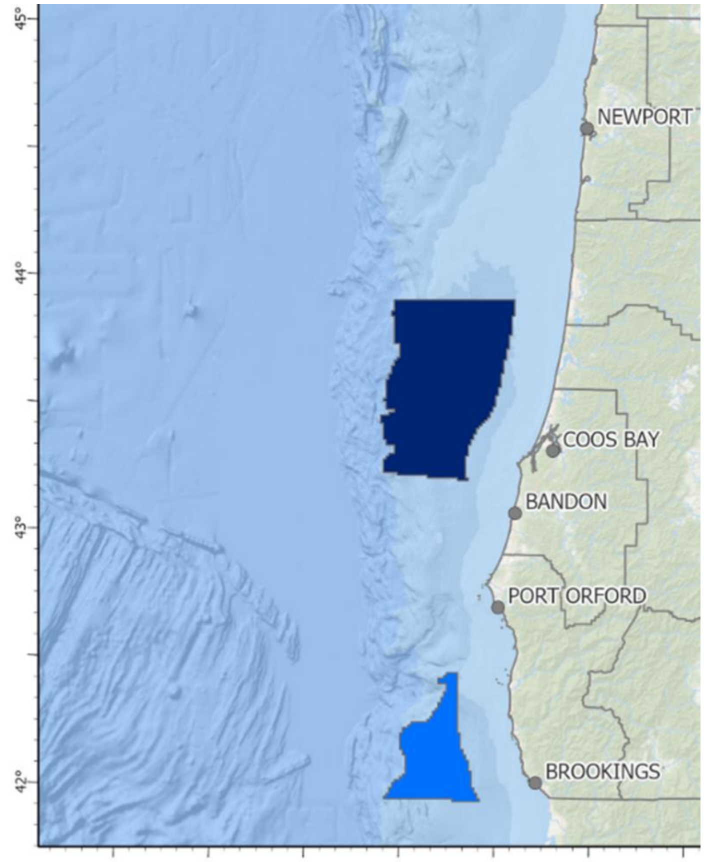
[508] US Department of the Interior. Biden-Harris Administration Announces Winners of California Offshore Wind Energy Auction. https://doi.gov/pressreleases/biden-harris-administration-announces-winners-california-offshore-wind-energy-auction

## Oregon offshore developments

In HB 3375, Oregon's Legislative Assembly identifies several potential benefits and roles that offshore wind could bring to the utility/electricity sector and regional economy. The legislation requires the Oregon Department of Energy to explore the "benefits and challenges of integrating up to three gigawatts of floating offshore wind energy into Oregon's electric grid by 2030."

On April 27, 2022, the BOEM issued a Call for Information and Nominations regarding the potential for wind energy leases in federal waters off the south-central and southern Oregon coast (**Figure 159**). The two areas identified (Call Areas) comprise approximately 1,800 square miles. The Coos Bay Call Area represents over 1,300 square miles with water depths ranging from 400 to 700 feet. The southern Brookings Call Area is more than 400 square miles in depths of 400 to 1,100 feet.

**Figure 159. Coos Bay and Brookings call areas**[509]




The areas potentially leased for commercial development will be a subset of the Call Areas. The initial BOEM leases could result in up to 3 GW of offshore wind capacity, per published statements. The total potential offshore wind capacity in the Call Areas is roughly 14 GW according to BOEM's assessment (assumes 3 MW / square kilometer).

NREL analysis finds the potential for up to 2.6 GW of wind nameplate capacity, or nearly 2.2 GW, at the assumed points of interconnect (POIs) along the Oregon coast. The findings are summarized in **Table 144** (note that the difference between the "Max Capacity" and "Max Injected" values is explained by assumed losses between the plant and POI). These values arise from NREL's attempt to determine the "maximum possible penetration of offshore wind without trans-coastal transmission infrastructure upgrades." Per NREL, the analytical process is as follows:

[509]Coos Bay and Brookings call areas, available at: https://www.boem.gov/sites/default/files/images/or_callareas_april2022.jpg

> *"We started by scaling the maximum power output of offshore wind at each of the five points of interconnection to match the summer trans-coastal line limit for the associated evacuation line. The summer limits were verified in consultation with BPA; however, there is uncertainty regarding the exact limits on these lines. Then, we ran the full-year model and checked for congestion of the trans-coastal lines. If a particular line did not exhibit congestion during the entire year, we increased the capacity of its associated offshore wind generation by the available capacity in its highest use hour (i.e., the maximum flow subtracted from the line limit). If a line exhibited congestion, we first checked that the congestion occurred simultaneously with the curtailment of its associated offshore wind generation. We then reduced the offshore generation capacity to eliminate the congestion. We repeated this process several times until the trans-coastal transmission was fully utilized with minimal congestion and with no study site experiencing more than 1 percent annual curtailment."*

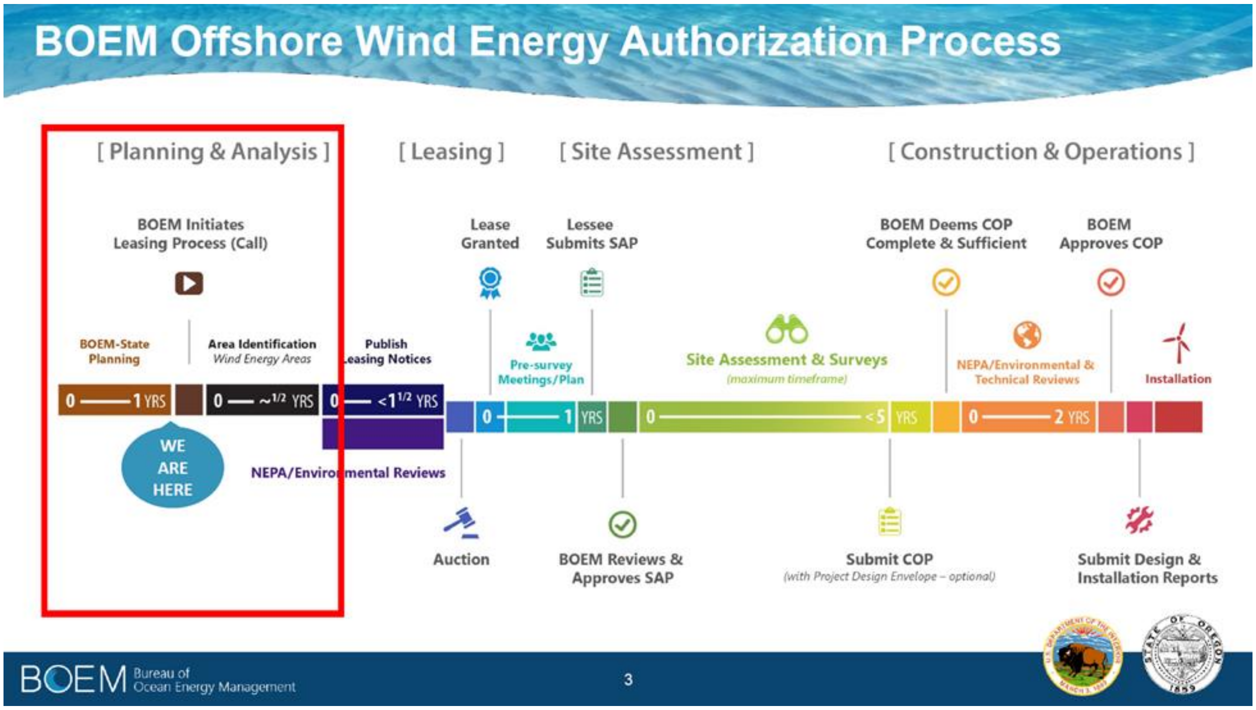
**Table 144. NREL Oregon offshore wind interconnection potential**

| Offshore Wind Point of Interconnection | Max Capacity (MW) | Max Injected Power (MW) |
|---|---|---|
| **1 – Clatsop** | 361 | 301 |
| **2 – Tillamook** | 553 | 461 |
| **3 -Toledo** | 156 | 130 |
| **4 - Wendson** | 613 | 512 |
| **5 - Fairview** | 941 | 7852 |
| **Total** | 2625 | 2189 |

The NREL authors note, "Detailed power flow analysis is needed to refine the distribution of offshore wind, the total offshore wind capacity, and identify small upgrades to the trans-coastal system to enable or increase the 2.6 GW finding."

Lengthy lead time gave the BOEM lease auction process and regulatory requirements (Site Assessment Plan – SAP, Construction and Operations Plan – COP) preceding the construction phase. The following timeline from BOEM's Oregon offshore wind process is still relatively near the beginning (**Figure 160**). Current expectations are a COD for the first Oregon offshore wind project in 2032.

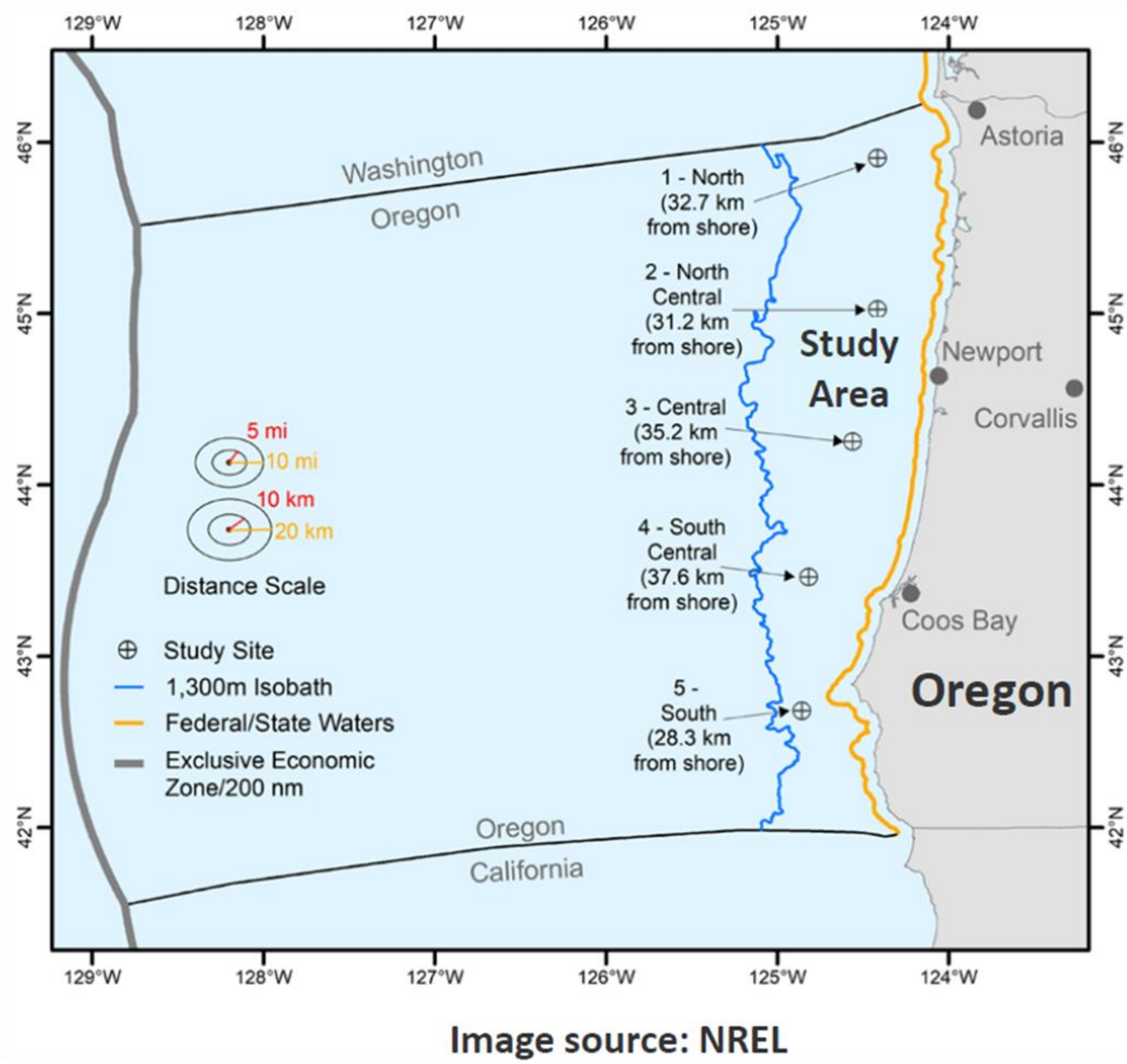
**Figure 160. BOEM offshore wind development process**



## Operational characteristics

**Figure 161** shows NREL research which presents five potential sites for Oregon offshore wind:

**Figure 161. NREL Oregon offshore sites**




Study Site "4 – South Central" in the NREL graphic is approximately equivalent to a location within the Coos Bay Call Area, while Study Site "5 – South" aligns with Brookings Call Area.

PGE focuses on the southernmost site to model an offshore wind resource. This site produces the highest capacity factors based on analysis of the historical weather data.

PGE's analysis of the wind resource utilizes an NREL dataset covering the 20 years 2000 through 2019 ("OR-WA20" dataset).

The generic offshore wind resource in the IRP is modeled as a semi-submersible platform 15 MW turbine with a 248-meter rotor diameter at a hub height of 150 meters (**Table 145**). These specifications are equivalent to those proposed by NREL for the 2032 reference technology. Sixty-four turbines are used to provide approximately 960 MW of generating capacity. The turbine arrangement is based on a seven-rotor diameter spacing per NREL. The default layout in SAM arranges the turbines in eight rows of eight turbines. As with the onshore wind analysis, the "Simple Wake Model" estimates the interactive effects on downwind turbines. PGE's energy modeling analysis uses the NREL published power curve for a 15 MW turbine, including revisions to the cut-out speed as detailed in the 2021 update.[510]

**Table 145. Oregon offshore wind operational characteristics**

| Site | Lat. | Long. | Hub Height (m) | Rotor Diameter (m) | Turbine Rating (MW) | IRP CF (%) |
|---|---|---|---|---|---|---|
| **Oregon South** | 42.69 | -124.84 | 150 | 248 | 15 | 55.2% |

## Operational expenditures

Estimates for offshore wind operational expenditures use NREL's Oregon site-specific research to 2032 COD (**Table 146**). Beyond 2032, cost trajectories follow those provided in the NREL 2021 ATB.

**Table 146. Summary of Oregon offshore wind operational expenditures**

| Operational Expenditures, offshore wind | |
|---|---|
| **2019$** | Oregon South |
| **Fixed O&M ($/kW-year)** | $97 |
| **Variable O&M ($/MWh)** | $0 |

[510] Musial, Walter, Patrick Duffy, Donna Heimiller, and Philipp Beiter. 2021. Updated Oregon Floating Offshore Wind Cost Modeling, available at: nrel.gov/docs/fy22osti/80908.pdf.

## Capital expenditures

NREL's Oregon site-specific research shows that capital expenditures are based on 2032 COD (2021 Update). Beyond 2032, cost trajectories follow NREL ATB. The NREL capital costs are adjusted to PGE's definition of overnight capital by removing the estimated decommissioning costs and financing costs during the construction period (AFUDC). Estimated decommissioning costs are included in the fixed lifetime cost of resource ownership as discussed in the details regarding PGE's fixed revenue requirements model, LUCAS (See **Appendix H, 2023 IRP modeling details**). The overnight capital cost for the earliest published year (2022) is detailed in **Table 147**.

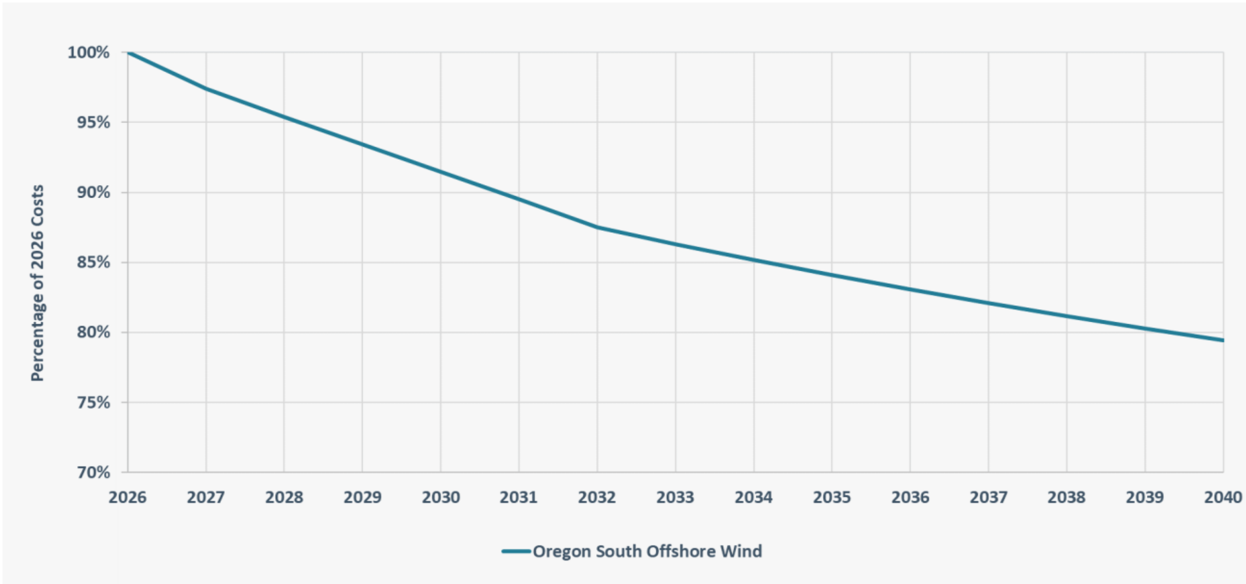
**Table 147. Summary of Oregon offshore wind capital expenditures**

| Capital Expenditures, offshore wind | |
|---|---|
| **2019 $/kW** | Oregon South |
| **Stated Capital Cost** | $3,522 |
| **Less: Decommissioning** | $34 |
| **Less: AFUDC** | $142 |
| **Overnight Capital Cost** | $3,346 |

## Forward capital cost curve

Beginning with the earliest relevant year published by NREL, the overnight capital costs align with NREL's research to 2032 (**Figure 162**). Beyond 2032, cost curves developed by HDR for PGE's 2019 IRP are used.

**Figure 162. Offshore wind capital cost trajectory**




# M.2.3 Solar photovoltaic

## Technology description

Solar photovoltaic (solar PV) converts light from the sun into electrical energy. Cells generate direct current (DC) electrical energy. This conversion occurs within a cell; multiple cells are connected within a module. The total quantity of modules is the array. The power rating of the array is the DC capacity of the resource. The modules in the array can be either fixed at a given angle or tilted in one or two directions to track the sun. The orientation of the modules is typically defined with respect to azimuth (e.g., zero (0) if facing north, 180 if facing south).

Given that the array generates in DC, inverters are used to output AC electricity to the grid. The array's DC capacity related to the inverter's AC rating is referred to as the inverter load ratio (ILR). For example, an ILR of 2.0 means that the DC capacity of the array is twice the AC rating of the inverter. With this relationship, there will be periods when the array will have the potential to generate at levels higher than the inverter's rating. The inverter will limit the total output, and this excess energy from the array will be lost or "clipped."

## Commercial status

Solar installations overall represented 45 percent of new generating capacity in 2021, up from 30 percent in 2017. The capacity installed in 2021 alone totaled approximately

18.9GWAC.[511] According to EIA data, approximately 60 GW of solar PV capacity was operational in the United States at the end of 2021.[512] Photovoltaic (PV) module efficiency has increased considerably over the past decade. An average standard monocrystalline module installed in 2021 was 20 percent efficient compared to approximately 14 percent in 2010.[513] National Renewable Energy Laboratory (NREL) reports recent increases in the share of bifacial modules installed, particularly in larger non-residential applications.[514] The median inverter loading ratio ("ILR" is the ratio of DC-to-AC capacity) for tracking solar PV projects installed in 2020 and 2021 was 1.34 and 1.33, respectively.[515] This value has been largely unchanged over the past five years. Solar PV installation with tracking continue to be preferred to fixed-tilt configurations. The trend towards tracking has grown significantly in the past eight years: in 2014, more solar PV capacity with fixed-tilt was installed than with tracking, by 2021, new tracking capacity additions represented nearly eight-times the capacity of fixed-tilt.[516]

## Operational characteristics

Three Oregon locations are used to represent solar photovoltaic (PV) resources in the IRP: one central Oregon (east of Cascades) location near Christmas Valley, one location with a similar longitude (east of Cascades) but farther north near Wasco, and one location with a similar latitude as Wasco but in the Willamette Valley (west of the Cascades) near McMinnville (**Table 148**). A solar PV resource near Mead, Nevada, which will be accessed via incremental transmission action is included in PGE's analysis as well.

[511] Lawrence Berkeley National Laboratory. "Utility-Scale Solar, 2022 Edition" available at: https://emp.lbl.gov/utility-scale-solar
[512] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only). https://www.eia.gov/electricity/data/eia860/
[513] National Renewable Energy Laboratory (NREL). Spring 2022 Solar Industry Update. April 23, 2022. available at: https://www.nrel.gov/docs/fy22osti/82854.pdf
[514] *Id.*
[515] Lawrence Berkeley National Laboratory. "Utility-Scale Solar, 2022 Edition" available at: https://emp.lbl.gov/utility-scale-solar
[516] *Id.*

**Table 148. Summary of solar PV operational characteristics 2026 COD**

| Site | Lat. | Long. | IRP CF% |
|---|---|---|---|
| **Central Oregon (Christmas Valley)** | 43.25 | -120.62 | 26.7% |
| **Oregon Gorge (Wasco)** | 45.61 | -120.7 | 25.3% |
| **Willamette Valley (McMinnville)** | 45.21 | -123.18 | 21.1% |
| **Nevada (Mead)** | 35.89 | -114.98 | 31.6% |

Solar PV resources utilize single-axis tracking. Energy estimates are created in SAM using crystalline silicon modules with 21 percent nominal efficiency and inverter efficiency of 98 percent.[517] The ILR is 1.34, consistent with the assumptions in the NREL ATB.

Similar to the rationale for onshore wind, resource configurations remain constant across the four Solar PV sites. This focuses any analysis on solar resource variations rather than attempting to optimize each site's design. It is expected that developers in the marketplace will employ their expertise to design an optimal solar PV resource for any specific location. An hourly generation profile is simulated for each year of weather data for each site listed in **Table 148**. These hourly generation profiles are produced using SAM. The profiles are used as inputs to Sequoia. The hourly shape for the representative year is used as input to Aurora for energy modeling. Consistent with the NREL ATB assumption, annual degradation of 0.5 percent is applied to arrive at the IRP capacity factor listed in **Table 148**.

## Operational expenditures

Operational expenditures for the representative solar PV plant are sourced from the NREL 2021 ATB as well (**Table 149**). The general categories of costs included in operational expenditures are listed earlier.

[517] Feldman, David, Vignesh Ramasamy, Ran Fu, Ashwin Ramdas, Jal Desai, and Robert Margolis. 2021. U.S. Solar Photovoltaic System Cost Benchmark: Q1 2020. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-77324. https://www.nrel.gov/docs/fy21osti/77324.pdf#page=66

**Table 149. Summary of solar PV operational expenditures**

| Operational Expenditures, solar photovoltaic | | | | |
|---|---|---|---|---|
| **2019$** | Central Oregon | Oregon Gorge | Willamette Valley | Mead, Nevada |
| **Fixed O&M ($/kW-year)** | $23 | $23 | $23 | $23 |
| **Variable O&M ($/MWh)** | $0 | $0 | $0 | $0 |

## Capital expenditures

Capital expenditures for the representative solar PV plant are sourced from the NREL 2021 ATB as well (**Table 150**). The general categories of costs included in capital expenditures are listed earlier.

**Table 150. Summary of solar PV capital expenditures**

| Capital Expenditures, solar photovoltaic | | | | |
|---|---|---|---|---|
| **2019 $/kWac** | **Central Oregon** | **Oregon Gorge** | **Willamette Valley** | **Mead, Nevada** |
| **Overnight capital** | $1,347 | $1,347 | $1,347 | $1,347 |
| **Less: Transmission Line Cost** | $71 | $71 | $71 | $71 |
| **Overnight EPC Capital Cost -Ex Interconnect Cost** | $1,277 | $1,277 | $1,277 | $1,277 |

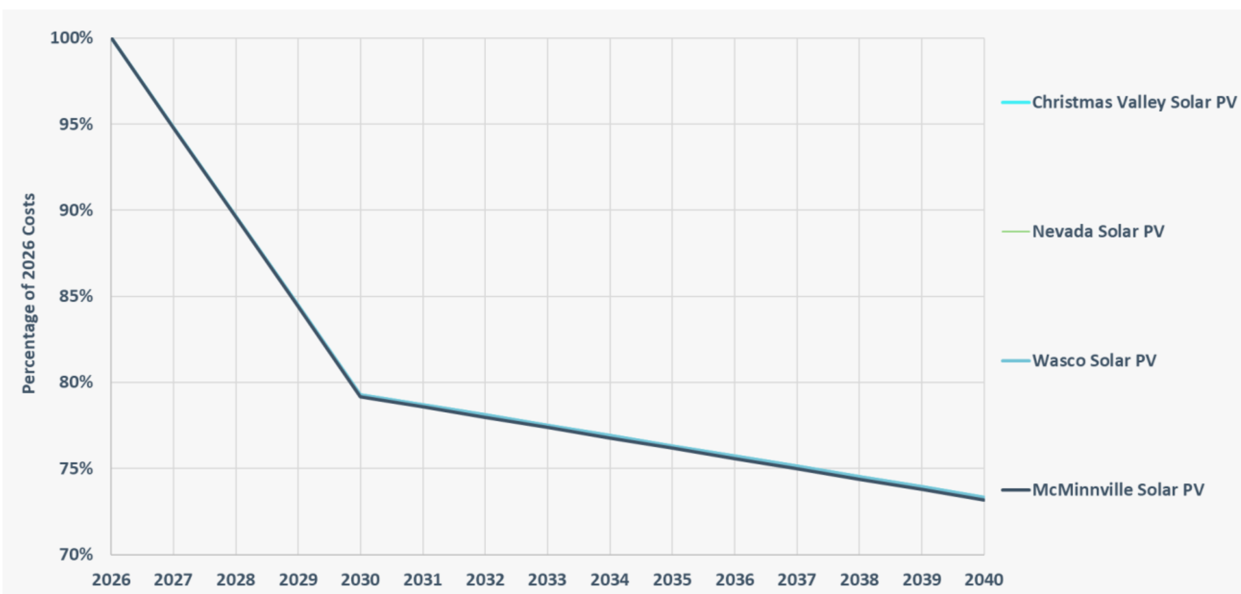
| Capital Expenditures, solar photovoltaic | | | | |
|---|---|---|---|---|
| **Location Adjustment** | 1 | 1 | 1.05 | 1 |
| **Location-adjusted Overnight Capital Cost** | $1,277 | $1,277 | $1,340 | $1,277 |

Costs are presented in units of $/kWAC based on the aggregated inverter rating. The locational adjustments applied to Central Oregon and Oregon Gorge resources are based on an average of the EIA factors for Portland, Boise, and Spokane. The location adjustment factor for the Willamette Valley resource corresponds to the EIA factor for Portland. Note that NREL documentation includes land acquisition costs as a capital expenditure component.

## Forward capital cost curve

The solar PV resources at different locations share a common forward capital cost trajectory. The NREL 2021 ATB projection of future capital costs for the Reference Case scenario are shown in **Figure 163**.

**Figure 163. Solar PV capital cost trajectory**



# M.2.4 Geothermal

## Technology description

Geothermal energy is the heat contained in the Earth's interior. This heat is typically accessed for electricity generation by the drilling of injection and production wells. Various technologies are used to harness the energy in a particular location depending on the nature of that specific resource, generally described by the temperature. Geothermal energy can also be employed for purposes aside from electricity generation; these so-called "direct use" cases include building and district heating, and recreation/therapeutic bathing.

Heat recovery generally generates electricity from geothermal resources in the form of hot water or steam via a well drilled into the earth. Resources are broadly categorized as either hydrothermal or enhanced geothermal systems (EGS) depending on the groundwater and subsurface rock structure characteristics.

Hydrothermal resources are those where the naturally occurring rock structure and groundwater flow are sufficient to support energy recovery. These may be referred to as "conventional" geothermal resources.

In contrast, EGS resources have sufficient heat but lack the groundwater or rock structure, allowing for efficient energy recovery. These resources require engineering techniques to introduce liquid or allow liquid flow within the rock structure.

EGS resources can be further classified based on their location with respect to existing conventional hydrothermal resources. When EGS techniques are applied within existing hydrothermal developments the resource is referred to as "in-field" EGS. This might happen to promote the recovery of energy from an otherwise non-productive well, for example. "Near-field" EGS occurs beyond the geological boundaries of a conventional resource where applying EGS engineering techniques can expand the development of cost-effective resources. "Deep" EGS refers to developing geothermal resources beyond those relying on hydrothermal fields. Areas of sufficient temperature would be identified and then accessed via drilled wells at depths of up to 7 km. The use of engineering techniques to introduce liquid and fracture the rock structure could allow for the recovery of vast amounts of energy.

In general, geothermal energy generates electricity by using the hot water or steam produced from within the Earth to turn a turbine and generator. The condensed liquid is then injected back into the ground. The technology to utilize that hot water or steam is generally dictated by the operating temperature of the specific resource.

Flash power plants are used at resources with relatively higher temperatures, generally exceeding 200 degrees Celsius. In this application, the heated fluid directly drives the turbine.

Binary power plants employ a heat exchanger to extract energy from the heated fluid and operate the turbine via a Rankine cycle (fluid movement through a system arising from temperature differences). This technology is generally used at resources with temperatures in the range of 100 – 200 degrees Celsius.

All else equal, it's expected that flash plants result in lower capital expenditures and higher operating efficiencies than binary plants.

Pairing resource descriptions and the technology options arising from the characteristics of a given resource results in the following six resource and technology categories:

(1) Hydrothermal Flash or (2) Hydrothermal Binary.

(3) Near-field EGS Flash or (3) Near-field EGS Binary.

(5) Deep EGS Flash or (6) Deep EGS Binary.

## Commercial status

Nationally, according to EIA data, nearly 4 GW of geothermal generating capacity was operable at the end of 2021.[518] More than 3 GW are currently operating in the WECC. However, only one commercial project operates in Oregon, representing approximately 29 MW. The majority, over 95 percent, of regional geothermal capacity is in California and Nevada, representing 67 percent and 30 percent, respectively. Roughly 30 percent of California's geothermal capacity is at Calpine's nearly 700 MW The Geysers project is north of Santa Rosa.[519]

The only commercial geothermal project currently operating in Oregon is the Neal Hot Springs plant near Vale in eastern Oregon. The 28.5 MW project, which began operation in 2012, is jointly owned by Ormat and Enbridge; Idaho Power is the off-taker.

## Operational characteristics

The representative geothermal plant in the RFP uses resource cost characteristics consistent with a hydrothermal flash resource from the NREL ATB.

[518] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)
[519] S&P Global Market Intelligence (work paper)

## Operational expenditures

Fixed and variable operating expenditures are sourced from the NREL ATB. These costs represent the average annual expenditures for operations and maintenance over the resource's life (**Table 151**). These include the costs of plant and well-field components.

**Table 151. Summary of geothermal flash operational expenditures**

| Operational Expenditures, geothermal flash | |
|---|---|
| **2019$** | **Oregon** |
| **Fixed O&M ($/kW-year)** | $137 |
| **Variable O&M ($/MWh)** | $0 |

## Capital expenditures

Capital expenditures for the representative geothermal plant are sourced from the NREL 2021 ATB as well (**Table 152**). In addition to the general cost categories listed earlier, geothermal-specific costs include: "exploration, confirmation drilling, well field development, reservoir stimulation (EGS), plant equipment" and "plant construction, power plant equipment, well-field equipment, and components for wells (including dry/noncommercial wells)."[520]

**Table 152. Summary of geothermal flash capital expenditures**

| Capital Expenditures, geothermal flash | |
|---|---|
| **2019 $/kW** | **Oregon** |
| **Overnight capital** | $4,440 |
| **Less: Transmission Line Cost** | $30 |
| **Overnight EPC Capital Cost -Ex Interconnect Cost** | $4,410 |
| **Location Adjustment** | 1.04 |
| **Location-adjusted Overnight Capital Cost** | $4,601 |

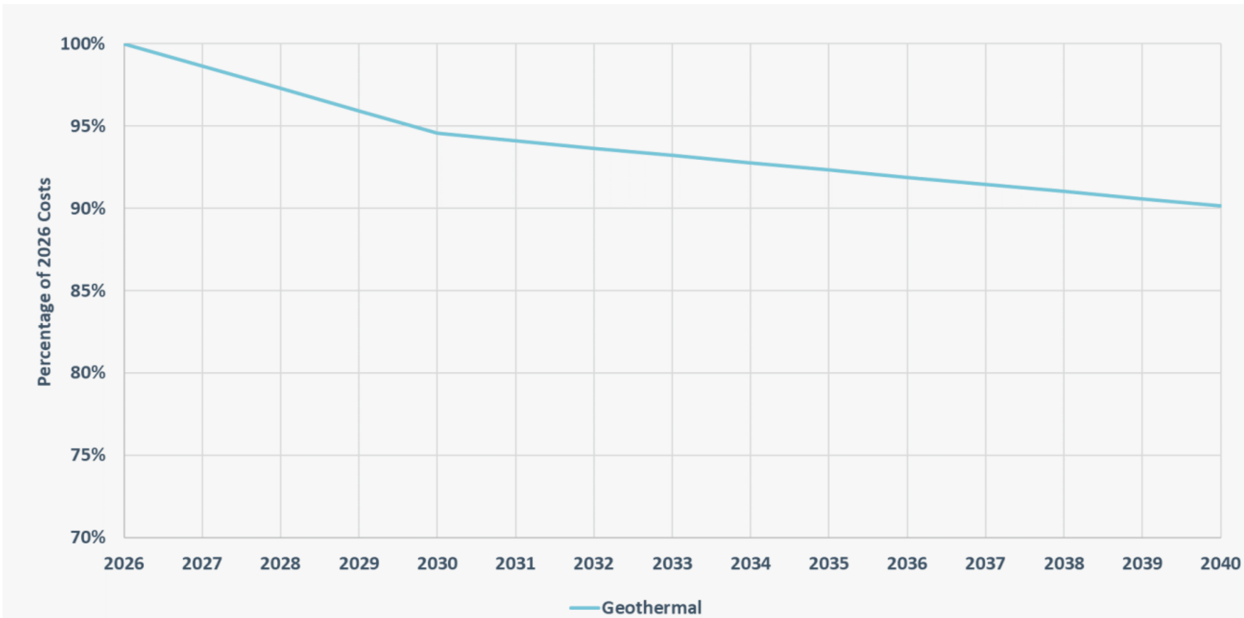
The locational adjustment is based on an average of the EIA factors provided by Portland, Boise, and Spokane.

[520] NREL 2021 Electricity ATB. Available at: https://atb.nrel.gov/electricity/2021/geothermal

### Forward capital cost curve

The NREL 2021 ATB projection of future capital costs for the Reference Case scenario are presented in **Figure 164**:

**Figure 164. Geothermal capital cost trajectory**




# M.3 Energy storage resources

## M.3.1 Battery energy storage

### Technology description

PGE's IRP uses lithium-ion technology for analysis of battery energy storage systems (BESS) in this IRP. The cost and performance of storage durations ranging from 2-24 hours are evaluated.

### Commercial status

According to EIA data, at the end of 2021, nearly 5 GW of battery energy storage capacity was operable in the United States. More than 3 GW of that total came online in 2021 alone.[521]

[521] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

## Operational characteristics

The representative battery energy storage systems (BESS) costs and performance characteristics are now based on lithium-ion technology. These data are sourced from the NREL ATB for durations up to eight hours; IRP cost assumptions for longer durations apply the NREL ATB methodology and are derived from the same energy and power cost estimates.

## Operational expenditures

The NREL ATB derives fixed operational expenditures as a percentage (2.5 percent) of the overnight capital for BESS. As a result, these expenditures vary with by battery duration as summarized in **Table 153**. Fixed operational expenditures are inclusive of amounts required to compensate for degradation to enable the battery system to have a constant capacity throughout its life.[522]

**Table 153. Summary of BESS operational expenditures**

| Operational Expenditures, battery energy storage system | | | | | | |
|---|---|---|---|---|---|---|
| **2019$** | **2 Hour** | **4 Hour** | **6 Hour** | **8 Hour** | **16 Hour** | **24 Hour** |
| **Fixed O&M ($/kW-year)** | $20 | $34 | $48 | $62 | $117 | $172 |
| **Variable O&M ($/MWh)** | $0 | $0 | $0 | $0 | $0 | $0 |

## Capital expenditures

The capital expenditures for BESS are sourced from the NREL 2021 ATB (**Table 154**). The general categories of costs included in capital expenditures are listed earlier. The capital expenditures for BESS are a function of energy and power capacities:

Total system cost ($/kW) = Battery Energy Cost ($/kWh) * Storage Duration (hr.) + Battery Power Cost ($/kW)

[522] NREL 2021 Electricity ATB. Available at: https://atb.nrel.gov/electricity/2021/utility-scale_battery_storage

**Table 154. Summary of BESS capital expenditures**

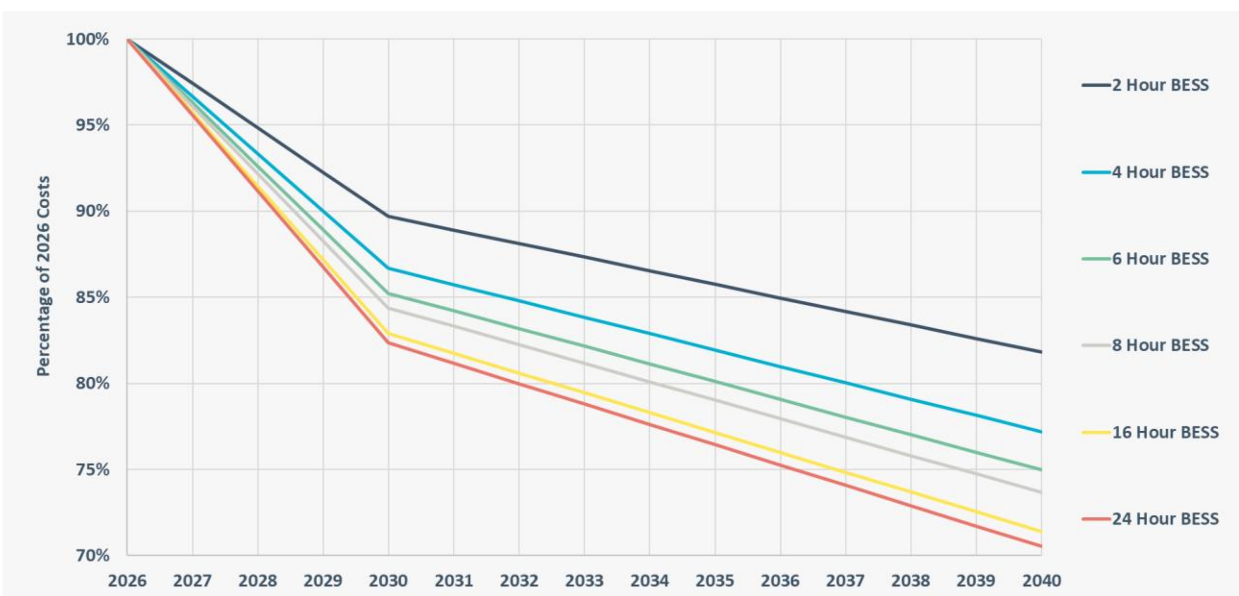
| Capital Expenditures, battery energy storage system | | | | | | |
|---|---|---|---|---|---|---|
| **2019 $/kWac** | **2 Hour** | **4 Hour** | **6 Hour** | **8 Hour** | **16 Hour** | **24 Hour** |
| **Overnight capital** | $792 | $1,331 | $1,870 | $2,410 | $4,567 | $6,724 |
| **Location Adjustment** | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 |
| **Location-adjusted Overnight Capital Cost** | $810 | $1,362 | $1,914 | $2,466 | $4,674 | $6,881 |

The location adjustment is based on an average of the EIA factors provided by Portland, Boise, and Spokane.

## Forward capital cost curve

Given that total capital costs are a function of the energy (weighted by duration) and power components, the trajectory of future capital costs for various durations depends on the developments assumed for these components. The NREL 2021 ATB future capital costs project a more rapid decline in energy component-related costs than power component-related costs. The result is that capital costs for longer-duration BESS decline more quickly than shorter duration. The Reference Case scenario is presented in **Figure 165.**

**Figure 165. Battery energy storage system capital cost trajectory**



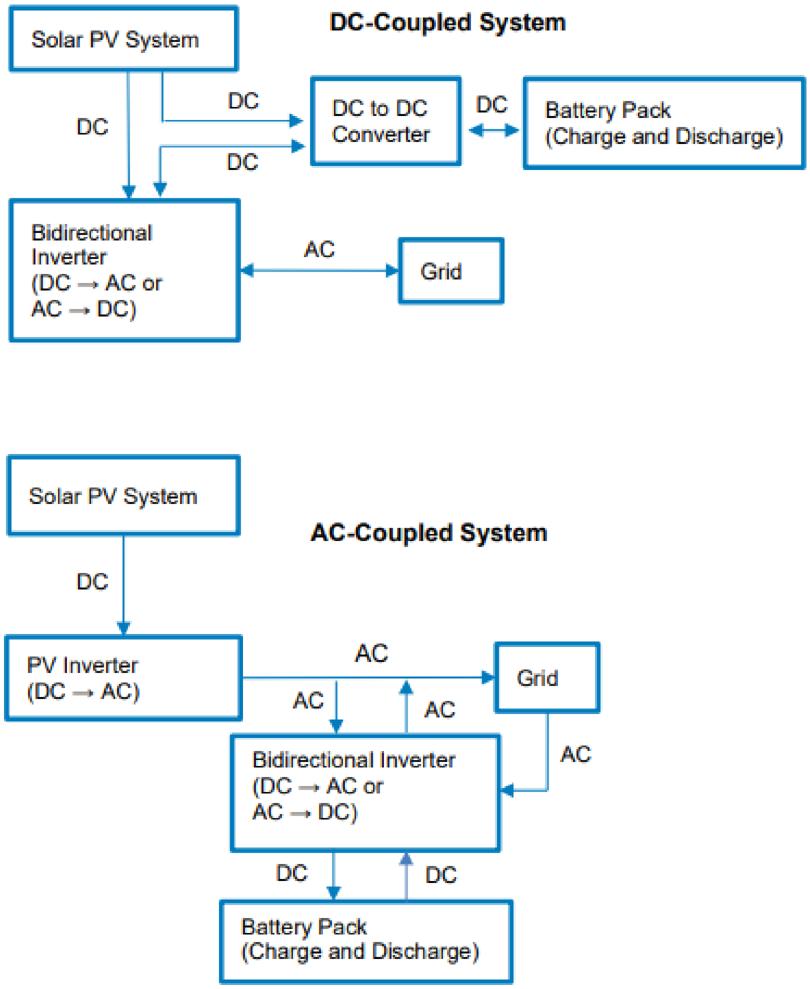
## M.3.2 Hybrid solar photovoltaic + battery energy storage

### Technology description

"Hybrid" resources pair renewable and storage resources behind a single interconnection. Hybrid resources could include solar PV with energy storage, wind with energy storage, and wind and solar PV with energy storage (such as PGE's Wheatridge Renewable Energy Facility), among others. In this 2023 IRP, PGE models solar PV with battery energy storage hybrid resources. Multiple elements are required when describing a solar + BESS resource, including resource coupling (AC- or DC-coupled), solar-to-storage ratio, solar-to-inverter ratio ("inverter loading ratio" as described previously), and storage duration. The solar and BESS components could be coupled on the AC side of the inverters (AC-coupled) or the DC side of the inverter (DC-coupled). When AC-coupled, the battery, and solar resources use separate inverters. The IRP assumption of DC coupling is consistent with the NREL ATB. **Figure 166** illustrates the basic elements of these two configurations.[523]

[523] Feldman, David, Vignesh Ramasamy, Ran Fu, Ashwin Ramdas, Jal Desai, and Robert Margolis. 2021. U.S. Solar Photovoltaic System Cost Benchmark: Q1 2020. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-77324. https://www.nrel.gov/docs/fy21osti/77324.pdf.

**Figure 166. Illustrative DC- and AC-coupled solar + BESS**




## Commercial status

Hybrid solar and storage were the dominant form of hybrid resources by the end of 2021. Solar and storage hybrids also saw a significant installed capacity increase; nearly 90 percent of all hybrid solar and storage resources came online in 2021 (when measured on a storage capacity basis, or ~77 percent when viewed on a generation capacity basis).[524]

[524] U.S. Department of Energy. "Land-based Wind Market Report: 2022 Edition." Available at: https://emp.lbl.gov/sites/default/files/2022_land_based_wind_market_report.pdf

## Operational characteristics

Given the large number of hybrid resource permutations that would arise from investigating sensitivities around each design element, the IRP simplifies the analysis to include two representative solar and BESS hybrid resources at two locations (**Table 155**). At each location these two hybrid resources:

- Employ a DC-coupled configuration.
- Differ in the ratio of solar-to-storage capacity. The two representative hybrid resources tested in this IRP are differentiated by this ratio, with one resource featuring a storage power capacity equivalent to the inverter rating (1.0) and one resource with a storage power capacity equal to one-half of the inverter rating (0.5).
- Utilize the Christmas Valley and McMinnville solar locations discussed previously; however, the solar resources differ regarding the inverter loading ratio. While the standalone solar resource is modeled with an ILR of 1.34, the hybrid solar resource has an ILR of 1.50.
- Use BESS with a four-hour storage duration.

**Table 155. Summary of hybrid solar PV + BESS operational characteristics**

| Hybrid PV + BESS | | | | |
|---|---|---|---|---|
| **Description** | Christmas Valley Solar w/ 4 Hour Li-Ion (0.5) | Christmas Valley Solar w/ 4 Hour Li-Ion (1.0) | McMinnville Solar w/ 4 Hour Li-Ion (0.5) | McMinnville Solar w/ 4 Hour Li-Ion (1.0) |
| **Location (Lat., Long.)** | 43.25, -120.62 | 43.25, -120.62 | 43.25, -120.62 | 43.25, -120.62 |
| **Capacity (MWac)** | 75 | 75 | 75 | 75 |
| **Duration (hours)** | 4 | 4 | 4 | 4 |
| **Round-Trip Efficiency** | 86% | 86% | 86% | 86% |
| **Solar Capacity Factor**[525] | 28.6% | 28.6% | 23.0% | 23.0% |
| **Solar ILR** | 1.50 | 1.50 | 1.50 | 1.50 |

525 Lifetime capacity factor inclusive of 0.5 percent annual degradation; does not account for battery storage of clipped energy.

| Hybrid PV + BESS | | | | |
|---|---|---|---|---|
| **Solar Capacity (MWdc)** | 112.5 | 112.5 | 112.5 | 112.5 |
| **Storage Ratio** | 1:2 | 1:1 | 1:2 | 1:1 |
| **Storage Capacity (MW)** | 37.5 | 75 | 37.5 | 75 |

## Operational expenditures

Solar PV and BESS values from the NREL 2021 ATB are the basis for the operational expenditures for the hybrid resources (**Table 156**).

**Table 156. Summary of hybrid solar PV + BESS operational expenditures**

| Operational Expenditures | | | Hybrid PV + BESS | |
|---|---|---|---|---|
| **2019$** | Christmas Valley Solar w/ 4 Hour Li-Ion (0.5) | Christmas Valley Solar w/ 4 Hour Li-Ion (1.0) | McMinnville Solar w/ 4 Hour Li-Ion (0.5) | McMinnville Solar w/ 4 Hour Li-Ion (1.0) |
| **Fixed O&M ($/kW-year)** | $40 | $53 | $41 | $54 |
| **Variable O&M ($/MWh)** | $0 | $0 | $0 | $0 |

## Capital expenditures

The capital expenditures for the hybrid resources are sourced from the NREL 2021 ATB and cited NREL research (**Table 157**). The ILR of the solar resource in the hybrid configuration differs slightly from the standalone solar PV resource. The PV module and balance of system costs were scaled based on relationships from NREL research to approximate the difference in ILR.[526] Additionally, costs were scaled to estimate the two storage-to-inverter ratios mentioned previously. The general categories of costs included in capital expenditures are listed earlier.

**Table 157. Summary of hybrid solar PV + BESS capital expenditures**

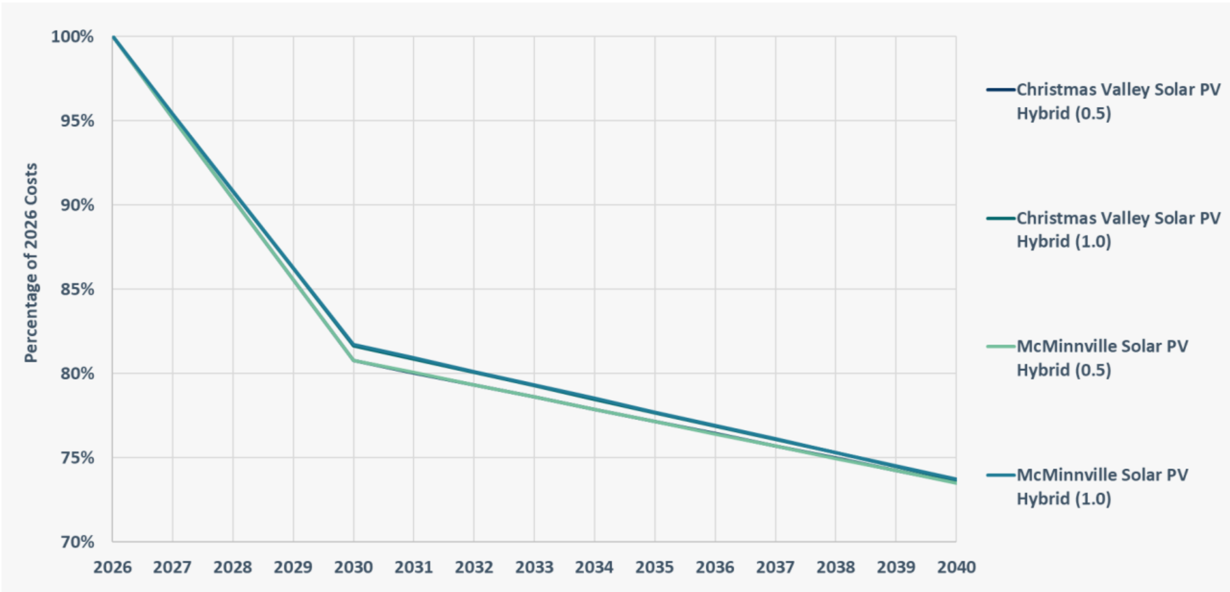
| Capital Expenditures, hybrid PV + BESS | | | | |
|---|---|---|---|---|
| **2019 $/kWac** | Christmas Valley Solar w/ 4 Hour Li-Ion (0.5) | Christmas Valley Solar w/ 4 Hour Li-Ion (1.0) | McMinnville Solar w/ 4 Hour Li-Ion (0.5) | McMinnville Solar w/ 4 Hour Li-Ion (1.0) |
| **O/N Capital Cost ($/kW)** | $1,931 | $2,558 | $1,995 | $2,622 |
| **O/N Capital Cost ($/kWh)** | $483 | $640 | $499 | $655 |

## Forward capital cost curve

The hybrid capital costs are a function of the solar PV and BESS components. As such, the trajectory of future capital costs for various durations depends on the developments assumed for those components. The NREL 2021 ATB future capital costs project a slightly faster decline in solar PV costs than BESS costs. The result is that capital costs for the hybrid pairings with relatively more solar than BESS (those with lower storage-to-inverter ratios) decline more quickly. The Reference Case scenario is presented in the following figure (**Figure 167**):

[526] NREL 2021 Electricity ATB. Available at: https://atb.nrel.gov/electricity/2021/utility-scale_pv-plus-battery#comparison_with_alternate_configurations

**Figure 167. Reference case cost curve**




## M.3.3 Pumped hydroelectric energy storage

### Technology description

Pumped hydropower energy storage resources generally employ two reservoirs at different locations. Water is pumped to the higher-elevation reservoir and stored, which converts electrical energy to operate the pumps into potential energy (charging). When the water is released from the reservoir it flows through a turbine, generating electricity (discharging).[527]

### Commercial status

According to EIA data, approximately 22 GW of pumped hydropower capacity was operable in the United States at the end of 2021. However, no new capacity has come online in nearly a decade, with 370 MW of new capacity operable since 1995.[528]

[527] Portland General Electric. "THERMAL AND PUMPED STORAGE GENERATION OPTIONS." Prepared by HDR, Inc. as External Study D to 2019 Integrated Resource Plan. https://downloads.ctfassets.net/416ywc1laqmd/6KTPcOKFlLvXpf18xKNseh/271b9b966c913703a5126b2e7bbbc37a/2019-Integrated-Resource-Plan.pdf#page=556
[528] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

## Operational characteristics

The pumped-storage hydropower resource is a 600 MW closed-loop system (water is pumped between two reservoirs and is not connected to a water system) providing 10 hours of energy storage. The availability of this resource is geographically limited. Costs and performance attributes of this representative resource are based on an average of six proposed regional closed-loop projects gathered from information published by the Northwest Power and Conservation Council.

## Operational expenditures

Operational expenditures for a representative pumped hydropower storage project in the pacific northwest are sourced from data published by the Northwest Power and Conservation Council in support of the 2021 Northwest Power Plan (**Table 158**).

**Table 158. Summary of pumped hydropower storage operational expenditures**

| Operational Expenditures, pumped hydropower storage | |
|---|---|
| **2019$** | PNW |
| **Fixed O&M ($/kW-year)** | $17 |
| **Variable O&M ($/MWh)** | $0 |

## Capital expenditures

The capital cost for a representative pumped hydropower storage project in the pacific northwest is sourced from data published by the Northwest Power and Conservation Council in support of the 2021 Northwest Power Plan. The developer capital cost reported in **Table 159** is an average of the closed-loop system's data. To this cost, an allowance for the owner's expense is applied. The 20 percent owner's cost allowance compares with the 20 percent used by in other regional IRPs[529] on very similar data and approximately 25 percent used by PGE in the 2019 IRP based on data furnished by HDR, Inc. (**Table 159**).

[529] PacifiCorp. "2020 Renewable Resources Assessment." Revision 1, August 2020. https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/2021-irp-support-and-studies/2020-10-01_PacifiCorp_2020_Renewable_Resource_Study_Report_FINAL.pdf#PAGE=44

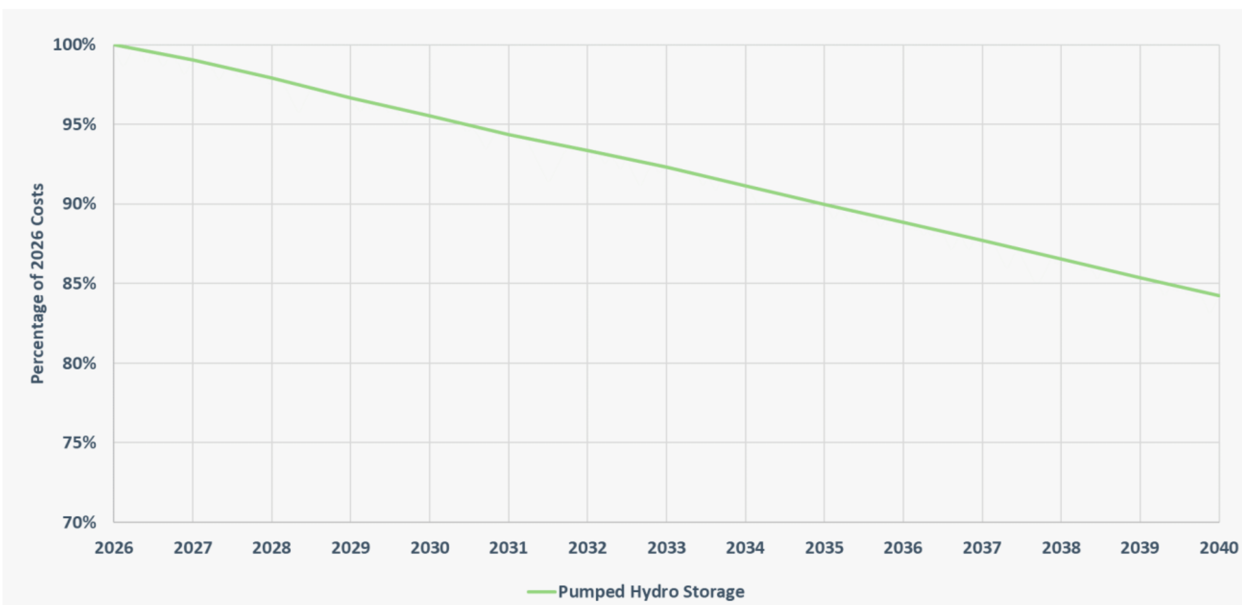
**Table 159. Summary of pumped hydropower storage capital expenditures**

| Capital expenditures, pumped hydropower storage | |
|---|---|
| **2019 $/kW** | PNW |
| **Developer Capital Cost** | $2,135 |
| **Owner's Cost Allowance %** | 20% |
| **Owner's Cost Allowance $/kW** | $427 |
| **Overnight Capital Cost** | $2,562 |

## Forward capital cost curve

The HDR, Inc., projection of future capital costs for the Reference Case scenario are presented in **Figure 168**.[530]

**Figure 168. Pumped hydropower storage capital cost trajectory:**




[530] Portland General Electric. "THERMAL AND PUMPED STORAGE GENERATION OPTIONS." Prepared by HDR, Inc. as External Study D to 2019 Integrated Resource Plan. https://downloads.ctfassets.net/416ywc1laqmd/6KTPcOKFlLvXpf18xKNseh/271b9b966c913703a5126b2e7bbbc37a/2019-Integrated-Resource-Plan.pdf#page=522

## M.3.4 Hydrogen-fueled CCCT with production and storage

### Technology description

This resource is representative of a renewable ("green") hydrogen-fueled combined-cycle combustion turbine (CCCT) with hydrogen fuel production and storage. An electrolyzer uses electricity to produce hydrogen from water. The hydrogen (H2) is then compressed and stored in underground pipes; storage is sufficient to provide 24 hours of fuel supply. Where available, geologic formations (e.g., salt caverns) present an alternative means of fuel storage. The hydrogen fuel feeds the CCCT to generate electricity.

### Commercial status

In June 2022, the U.S. Department of Energy (DOE) issued a loan guarantee in excess of $500 million to support the development of a hydrogen production and energy storage facility in Delta, Utah. 220 MW of electrolyzer capacity will produce hydrogen for storage in salt caverns. The hydrogen will then be available to fuel an 840 MW CCCT at the Intermountain Power Project.[531] The CCCT is expected to begin operation with blended hydrogen and natural gas fuel in 2025.[532] DOE states that the "scale of deployed electrolyzers as well as the use of salt caverns to store hydrogen are both significant innovations."[533]

### Operational characteristics

For modeling purposes, the CCCT is consistent with the natural gas-fired resource described in **Section M.5 Natural gas-fueled resources**. Cost and performance parameters for this resource's hydrogen production and storage components are based on the research and analyses of Mongrid and Hunter.[534,535] The CCCT is paired with an equivalent electrolyzer capacity. As illustrated in the capital expenditure as shown in **Table 162**, the electrolyzer may be the primary capital expenditure on the H2 production side of the resource; reducing the electrolyzer capacity will lower costs but will result in longer H2 production (charging) times. The 1:1 pairing produces approximately seven metric tons of H2 per hour or approximately

---

[531] https://www.energy.gov/lpo/advanced-clean-energy-storage
[532] S&P Global Market Intelligence
[533] https://www.energy.gov/lpo/advanced-clean-energy-storage
[534] Mongrid et al., "2020 Grid Energy Storage Technology Cost and Performance Assessment." Pacific Northwest National Laboratory. December 2020. Retrieved from: https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf
[535] Hunter et al., "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high variable renewable energy grids." Retrieved from: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769

38 percent of the fuel needed to operate the CCCT at full load for one hour. Consistent with the research, electrolyzer efficiency is assumed to be 72.5 percent. The CCCT is approximately 52 percent efficient (based on a perfect heat rate of 3,412 Btu/kWh and a CCCT lifetime heat rate of 6,561 Btu/kWh).

**Table 160. Summary of CCCT w/ H2 operational characteristics**

| Operational Characteristics, combined-cycle CT (1 x 1) w/ H2 production/storage | |
|---|---|
| **Capacity (MW average lifetime)** | 407 |
| **Heat Rate (Btu/kWh average lifetime)** | 6,561 |
| **Storage Duration (Hours)** | 24 |
| **Electrolyzer Efficiency (%)** | 72.50% |
| **Planned outage rate** | 3.88% |
| **Forced outage rate** | 2.19% |

## Operational expenditures

The $H_2$ production and storage operational costs are derived from Mongrid and Hunter and combined with the generation operational expenditures associated with the natural gas-fired CCCT (**Table 161**) discussed in **Appendix M.5.2, Combined-cycle combustion turbine**.[536,537]

**Table 161. Summary of CCCT w/ H2 operational expenditures**

| Operational Expenditures, combined-cycle CT (1 x 1) w/ H2 production/storage | |
|---|---|
| **2019$** | |
| **Fixed O&M ($/kW-year)** | $27 |
| **Variable O&M ($/MWh)** | $4 |

[536] Mongrid, et al., "2020 Grid Energy Storage Technology Cost and Performance Assessment." Pacific Northwest National Laboratory. December 2020. Retrieved from: https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf

[537] Hunter, et al., "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high variable renewable energy grids." Retrieved from: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769

## Capital expenditures

The $H_2$ production and storage component costs are derived from Mongrid and Hunter and summarized in **Table 162**.[538,539] Values are in 2019 dollars, and production costs are based on energy input to the system. These costs represent the components necessary to produce and store hydrogen for later combustion in an H-class CCCT.

**Table 162. Summary of CCCT w/ H2 capital expenditures**

| Capital Expenditures, combined-cycle CT (1 x 1) w/ H2 production/storage | |
|---|---|
| **2019 $kW** | |
| **PEM Electrolyzer (kW input)** | $1,534 |
| **Rectifier (kW input)** | $133 |
| **Compressor (kW input)** | $40 |
| **Controls & Integration (kW input)** | $20 |
| **Total Production (kW input)** | $1,728 |
| **Pipe Storage (24 hours)** | $710 |
| **Owner's Costs** | $306 |
| **Total Production + Storage** | $2,745 |

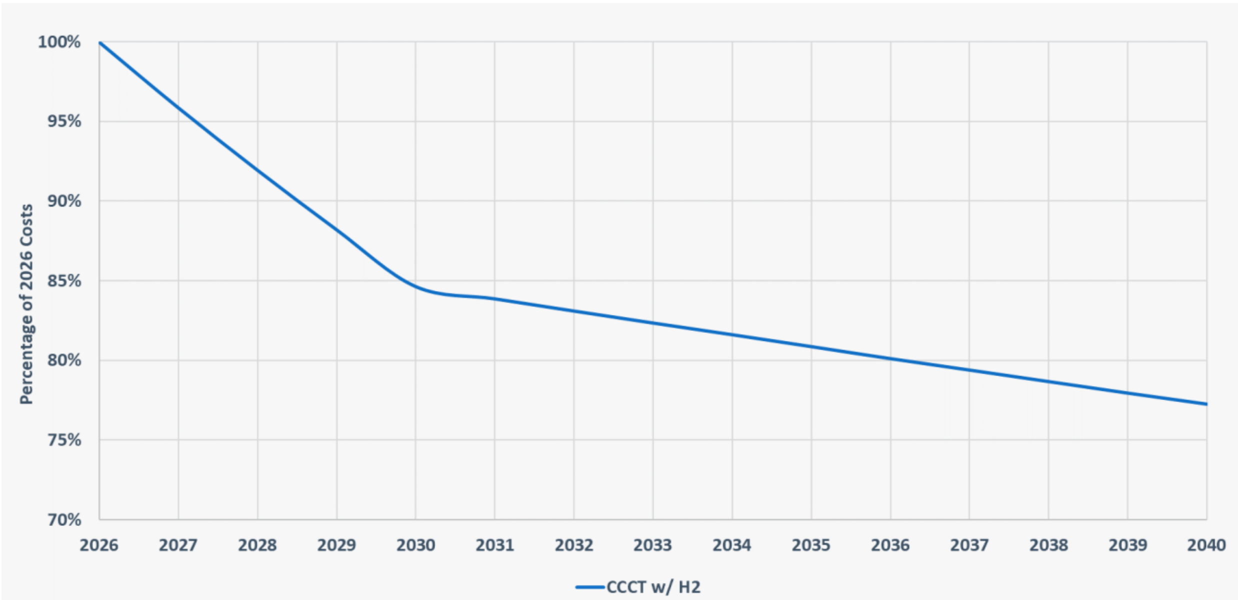
The owner's cost allowance of 12.5 percent (owner's cost in EIA research applicable to hydrogen fuel cell resource) is added to the production and storage values.[540]

Costs associated with the CCCT are based on the H-class CCCT detailed in **Appendix M.5.2, Combined-cycle combustion turbine**.

538 Mongrid, et al., "2020 Grid Energy Storage Technology Cost and Performance Assessment." Pacific Northwest National Laboratory. December 2020. Retrieved from: https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf
539 Hunter, et al., "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high variable renewable energy grids." Retrieved from: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769
540 EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy.

### Forward capital cost curve

**Figure 169. Hydrogen production/storage/CCCT capital cost trajectory**




# M.4 Dispatchable resources

## M.4.1 Biomass

### Technology description

Power production using biomass fuel is similar to other solid fuel power plants in that a boiler is used to combust fuel and generate steam to drive a turbine and produce electricity. The representative biomass-fueled resource uses a bubbling fluidized bed (BFB) design to combust wood chips. NOx emissions are controlled in-furnace using over-fire air (OFA), and with a high dust selective catalytic reduction (SCR) system, SO2 emissions from wood firing are inherently low and therefore are uncontrolled. Particulate matter is controlled using a pulse jet fabric filter baghouse."[541]

[541] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy.

## Commercial status

According to EIA data, at the end of 2021, wood and wood waste biomass capacity in the United States totaled more than 9 GW.[542]

## Operational characteristics

**Table 163. summary of biomass operational characteristics**

| Operational Characteristics, biomass | |
|---|---|
| **2019$** | BFB |
| **Capacity (MW average lifetime)** | 50 |
| **Heat Rate (Btu/kWh average lifetime)** | 13,300 |
| **Planned outage rate** | 3.07% |
| **Forced outage rate** | 6.03% |

## Operational expenditures

**Table 164. Summary of biomass operational expenditures**

| Operational Expenditures, biomass | |
|---|---|
| **2019$** | BFB |
| **Fixed O&M ($/kW-year)** | $126 |
| **Variable O&M ($/MWh)** | $5 |

[542] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

## Capital expenditures

**Table 165. Summary of biomass capital expenditures**

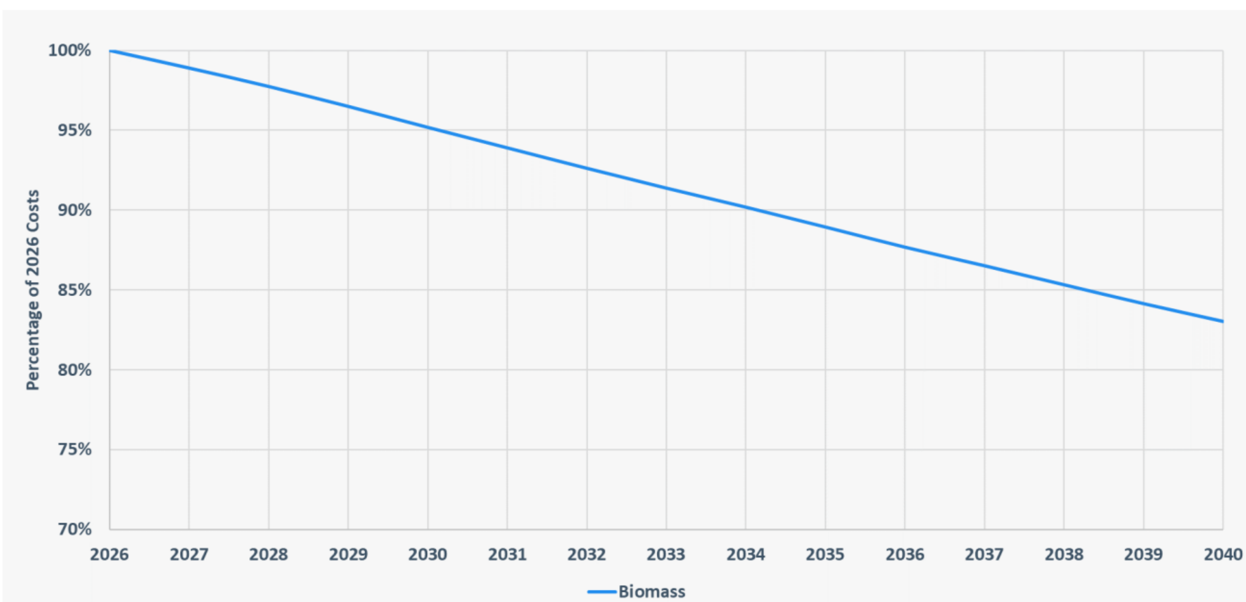
| Capital Expenditures, biomass | |
|---|---|
| **2019 $/kW** | BFB |
| **Overnight capital** | $4,097 |
| **Transmission Line Cost** | $24 |
| **Overnight EPC Capital Cost -Ex Interconnect Cost** | $4,073 |
| **Location Adjustment** | 1.09 |
| **Location-adjusted Overnight Capital Cost** | $4,453 |

The location adjustment is based on an average of the EIA factors provided by Portland, Boise, and Spokane.

## Forward capital cost curve

The EIA 2020 AEO projection of future capital costs for the Reference Case scenario are presented in **Figure 170**.

**Figure 170. Biomass capital cost trajectory**



## M.4.2 Nuclear

### Technology description

The AP1000 advanced passive design and a representative small modular reactor (SMR) design are considered two nuclear-fueled generating options. This description is excerpted from EIA:

"The AP1000 improves on previous nuclear designs by simplifying the design to decrease the number of components, including piping, wiring, and valves. The AP1000 design is standardized as much as possible to reduce engineering and procurement costs. The AP1000 component reductions from previous designs are approximately:

- 50 percent fewer valves
- 35 percent fewer pumps
- 80 percent less pipe
- 45 percent less seismic building volume
- 85 percent less cable

The AP1000 design uses an improved passive nuclear safety system that requires no operator intervention or external power to remove heat for up to 72 hours.

The AP1000 uses a traditional steam cycle similar to other generating facilities such as coal or CC units. The primary difference is that the AP1000 uses enriched uranium as fuel instead of coal or gas as the heat source to generate steam. The enriched uranium is contained inside the pressurized water reactor. The AP1000 uses a two-loop system in which the heat generated by the fuel is released into the surrounding pressurized reactor cooling water. The pressurization allows the cooling water to absorb the released heat without boiling. The cooling water then flows through a steam generator that provides steam to the turbine for electrical generation."[543]

The SMR resource is based on a representative design of 12 reactor modules, each representing 50 MW or 600 MW in total. "The mechanical systems of an SMR are much smaller than those of a traditional nuclear plant. The mechanical systems are similar to that of an advanced nuclear power plant. Each reactor module comprises a nuclear core and steam generator within a reactor vessel, enclosed within a containment vessel in a vertical

[543] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy. Available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

orientation. The nuclear core is located at the module's base, with the steam generator located in the upper half of the module. Feedwater enters, and steam exits through the top of the vessel towards the steam turbine. The entire containment vessel sits within a water-filled pool that provides cooling and passive protection in a loss of power event. All 12 reactor modules sit within the same water-filled pool housed within a typical reactor building.

Each SMR module uses a pressurized water reactor design to achieve a high level of safety and reduce the number of components required. To improve licensing and construction times, each reactor is prefabricated at the OEM's facility and shipped to the site for assembly. The compact integral design allows each reactor to be shipped by rail, truck, or barge.

Each module has a dedicated balance of plant (BOP) system for power generation. Steam from the reactor module is pumped through a steam turbine connected to a generator for electrical generation. Each BOP system is fully independent, containing a steam turbine and all necessary pumps, tanks, heat exchangers, electrical equipment, and controls for operation. This allows for the independent operation of each reactor module. Each reactor module's independent operation provides greater efficiencies at lower operating loads when dispatched capacity is reduced.

Additionally, the modular design of the reactors allows for refueling and maintenance of the individual reactors without requiring an outage of the entire facility. An extra reactor bay includes the pool housed with the reactor building. This extra bay allows for removing individual reactors for maintenance without impacting the remaining reactors."[544]

## Commercial status

At the end of 2021, nearly 100 GW of nuclear capacity was operable in the United States, according to EIA data. Watts Bar Unit 2, which came online in 2016, is the most recent nuclear resource addition. Nearly 3 GW are currently proposed to come online between 2023 and year-end 2030, including six SMR units planned for Utah Associated Municipal Power Systems at the Department of Energy (DOE) Idaho National Laboratory.[545]

[544] *Id.*
[545] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

## Operational characteristics

**Table 166. Summary of nuclear-powered generating resource operational characteristics**

| Operational Characteristics | Nuclear | |
|---|---|---|
| | SMR | AP1000 |
| **Capacity (MW average lifetime)** | 600 | 2,156 |
| **Heat Rate (Btu/kWh average lifetime)** | 10,046 | 10,608 |
| **Planned outage rate** | 5.00% | 5.00% |
| **Forced outage rate** | 5.00% | 5.00% |

## Operational expenditures

The EIA 2020 AEO provides the operational expenditures estimates for the nuclear-powered generation options in **Table 167**.

**Table 167. Summary of nuclear-powered generating resource operating expenditures**

| Operational Expenditures, nuclear | | |
|---|---|---|
| **2019$** | SMR | AP1000 |
| **Fixed O&M ($/kW-year)** | $95 | $122 |
| **Variable O&M ($/MWh)** | $3 | $2 |

## Capital expenditures

EIA 2020 AEO research provides the basis for capital expenditure estimates in **Table 168**.

**Table 168. Summary of nuclear-powered generating resource capital expenditures**

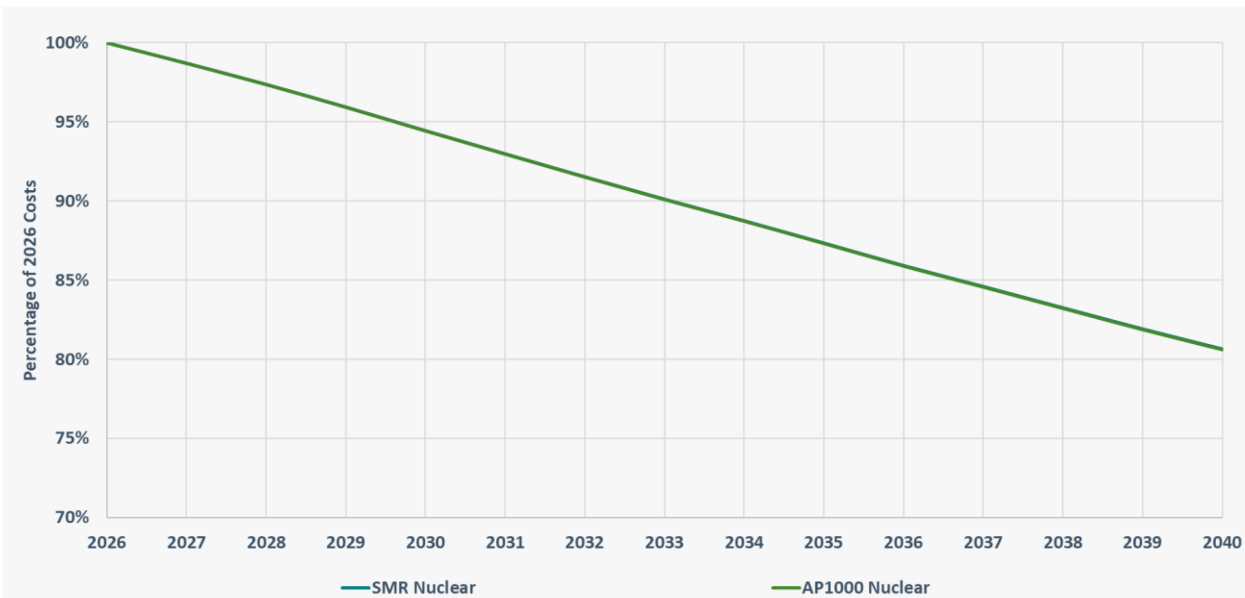
| Capital Expenditures, nuclear | | |
|---|---|---|
| **2019 $/kW** | SMR | AP1000 |
| **Overnight capital** | $6,191 | $6,041 |
| **Transmission Line Cost** | $4 | $1 |
| **Overnight EPC Capital Cost -Ex Interconnect Cost** | $6,187 | $6,040 |

| Capital Expenditures, nuclear | | |
|---|---|---|
| **Location Adjustment** | 1.06 | 1.08 |
| **Location-adjusted Overnight Capital Cost** | $6,579 | $6,524 |

## Forward capital cost curve

The EIA 2020 AEO projection of future capital costs for the Reference Case scenario are presented in **Figure 171**.

**Figure 171. Nuclear-powered generator capital cost trajectory**



# M.5 Natural gas-fueled resources

## M.5.1 Simple-cycle combustion turbine

### Technology description

The simple-cycle combustion turbine (SCCT) is based on "one industrial frame Model F dual fuel CT in simple-cycle configuration with a nominal output of 237.2 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 232.6 MW. The inlet air duct for the CT is equipped with an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT output. The CT is also equipped with burners designed to reduce the CT's NOX emission."[546] Selective catalytic reduction (SCR) and CO catalysts are not included.

### Commercial status

Research in PGE's recent IRPs indicates that resources employing natural gas-fired combustion turbine generators are "well-proven and commercially available technologies for power generation."[547]

### Operational characteristics

**Table 169. Summary of SCCT operational characteristics**

| Operational characteristics | SCCT F-Class |
|---|---|
| **Capacity (MW average lifetime)** | 227 |
| **Heat Rate (Btu/kWh average lifetime)** | 10,042 |
| **Planned outage rate** | 2.38% |
| **Forced outage rate** | 1.73% |

[546] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy. Available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf
[547] *Id.*

## Operational expenditures

Fixed O&M includes the fixed portion of a long-term service agreement.

"Variable O&M costs include consumable commodities, such as water, lubricants, and chemicals. Also included is the average annual cost of the planned maintenance events for the CT over the long-term maintenance cycle. Planned maintenance costs for the CT in a given year are based on the number of equivalent starts the CT has accumulated. A significant overhaul is performed for this type of CT every 900 equivalent starts, and a major overhaul is performed every 2,400 equivalent starts. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of [equivalent operating hours] EOH)."[548]

The SCCT is assumed to use a starts-based schedule, and the effective cost per start is shown in **Table 170** and included in the dispatch modeling for this resource.

**Table 170. Summary of SCCT operational expenditures**

| Operational expenditures, SCCT | |
|---|---|
| **2019 $** | F-Class |
| **Fixed O&M ($/kW-year)** | $7 |
| **Variable O&M ($/MWh)** | $1 |

## Capital expenditures

EIA 2020 AEO research provides the basis for capital expenditure estimates, shown in **Table 171**.

**Table 171. Summary of SCCT capital expenditures**

| Capital Expenditures, SCCT | |
|---|---|
| **2019 $/kW** | F-Class |
| **Overnight capital** | $713 |
| **Less: Transmission Line Cost** | $5 |
| **Less: Gas Interconnection Cost** | $19 |
| **Overnight EPC Capital Cost -Ex Interconnect Cost** | $688 |

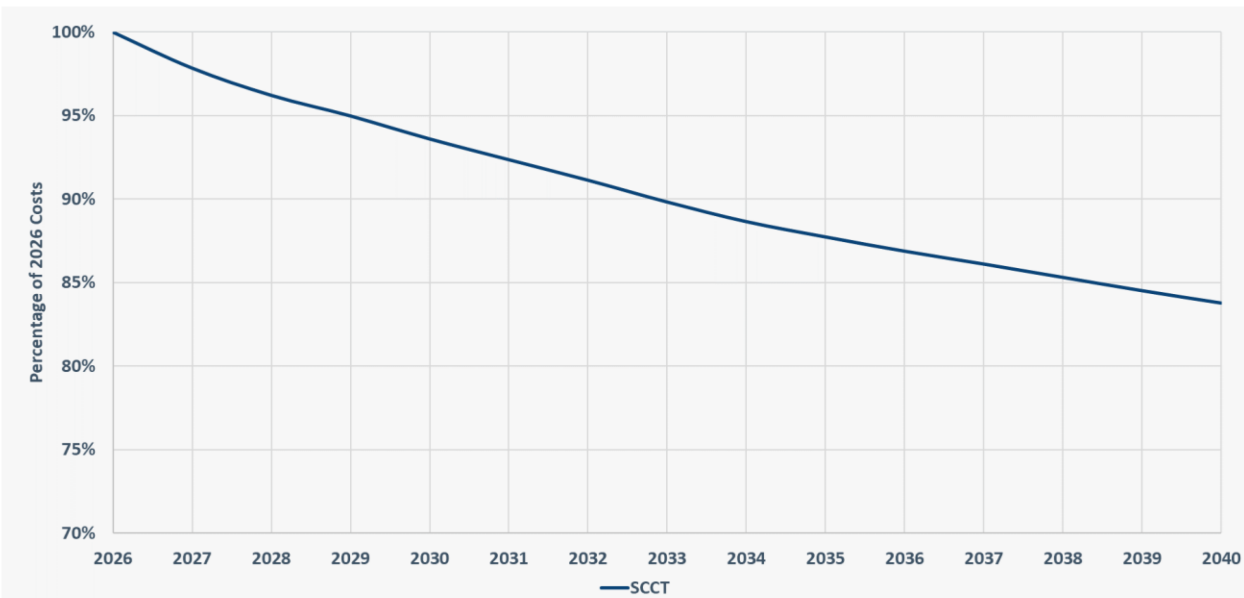
[548] *Id.*

| Capital Expenditures, SCCT | |
|---|---|
| **Location Adjustment** | 1.05 |
| **Location-adjusted Overnight Capital Cost** | $721 |

## Forward capital cost curve

The EIA AEO projection of future capital costs for the Reference Case scenario are presented in **Figure 172**.

**Figure 172. Simple-cycle combustion turbine capital cost trajectory**




# M.5.2 Combined-cycle combustion turbine

## Technology description

The combined-cycle combustion turbine (CCCT) resource comprises one Model H "advanced technology" combustion turbine (CT), one steam turbine generator (STG), and one electric generator that is common to the CT and the STG.

Emissions controls include burners to reduce NOX emissions, an SCR to reduce NOX emissions, and a CO catalyst to reduce CO emissions. "The inlet air duct for the CT is equipped with an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT and plant output…"

The CT is categorized as Model H industrial frame type CT with an advanced technology design since it incorporates in the design the following features:

- High-firing temperatures (~2900°F)
- Advanced materials of construction
- Advanced thermal barrier coatings"[549]

## Commercial status

Research in PGE's recent IRPs indicates that resources employing natural gas-fired combustion turbine generators are "well-proven and commercially available technologies for power generation."

## Operational characteristics

**Table 172. Summary of CCCT operational characteristics**

| Operational characteristics | CCCT H-Class |
|---|---|
| **Capacity (MW average lifetime)** | 407 |
| **Heat Rate (Btu/kWh average lifetime)** | 6,561 |
| **Planned outage rate** | 3.88% |
| **Forced outage rate** | 2.19% |

## Operational expenditures

Fixed O&M includes the fixed portion of a long-term service agreement (**Table 173**).

"Variable O&M costs include consumable commodities such as water, lubricants, and chemicals and periodic costs to change out the SCR and CO catalysts. The variable O&M costs also include the average annual cost of the planned maintenance events for the CT and the STG over the long-term maintenance cycle. Planned maintenance costs for the CT in a given year are based on the number of EOHs the CT has run. A significant overhaul is typically performed for this type of CT every 25,000 EOH, and a major overhaul is performed

[549] *Id.*

every 50,000 EOH. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH)."[550]

The CCCT is assumed to require an EOH-based maintenance schedule for the CT. The STG requires less frequent major outage maintenance.

**Table 173. Summary of CCCT operational expenditures**

| Operational Expenditures | CCCT |
|---|---|
| **2019$** | H-Class |
| **Fixed O&M ($/kW-year)** | $14 |
| **Variable O&M ($/MWh)** | $3 |

## Capital expenditures

EIA 2020 AEO research provides the basis for capital expenditure estimates (**Table 174**).

**Table 174. Summary of CCCT capital expenditures**

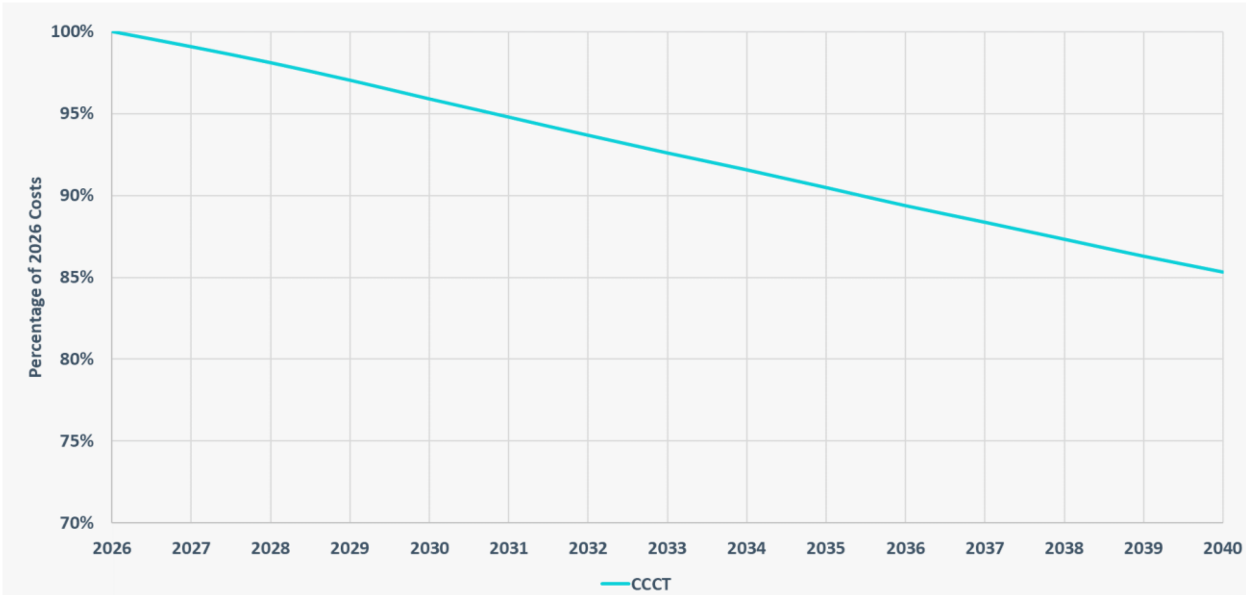
| Capital expenditures | CCCT |
|---|---|
| **2019 $/kW** | H-Class |
| **Overnight capital** | $1,084 |
| **Transmission Line Cost** | $4 |
| **Gas Interconnection Cost** | $14 |
| **Overnight EPC Capital Cost -Ex Interconnect Cost** | $1,066 |
| **Location Adjustment** | 1.08 |
| **Location-adjusted Overnight Capital Cost** | $1,154 |

## Forward capital cost curve

The EIA AEO projection of future capital costs for the Reference Case scenario are presented in **Figure 173**.

[550] *Id.*

**Figure 173. Combined-cycle combustion turbine capital cost trajectory**




# M.5.3 Combined-cycle combustion turbine with $CO_2$ capture system

## Technology description

The H-class combined-cycle unit is similar in configuration and specification to the traditional resource previously described. In addition to the CCCT, the resource includes an amine-based $CO_2$ capture system designed to remove 90 percent of the $CO_2$ from exhaust gases. The resource configuration as described in the EIA research include:

"[T]o obtain 90 percent $CO_2$ removal from the flue gas generated from the CT, [t]he full flue gas path must be treated. The flue gas generated from natural gas-fired CT combustions results in a much lower $CO_2$ concentration in the flue gas than flue gas from a coal-fired facility. As such, the flue gas absorber and quencher would be much larger in scale on a per ton of $CO_2$ treated basis than with a coal facility. However, the stripper and compression system would scale directly with the mass rate of $CO_2$ captured.

In this scenario, it is not practical to increase the CT or STG size to account for the steam extraction and added auxiliary power required by the $CO_2$ capture system. The net power output in the $CO_2$ capture case is significantly less than in Case 8.

The flue gas path differs from the base case (Case 8) in that 100 percent of the gas is directed to the carbon capture system downstream of the preheater section of the HRSG. The SCR and CO catalysts would operate the same, and the flue gas mass flows would be the same. Rather than exiting a stack, the flue gases would be ducted to a set of booster fans that would feed the $CO_2$ absorber column. The total gross power generated from the CT is approximately the same as Case 8, with no carbon capture.

Steam for the $CO_2$ stripper is to be extracted from the intermediate-pressure turbine to the low-pressure turbine crossover line; however, the steam must be attemporated to meet the requirements of the carbon capture system. The total steam required for the carbon capture system is approximately 306,000 pounds per hour. As a result of the steam extraction, the gross STG generation outlet decreases from 133 MW to 112 MW."[551]

## Commercial status

Research in PGE's recent IRPs indicates that resources employing natural gas-fired combustion turbine generators are "well-proven and commercially available technologies for power generation." Carbon capture and sequestration, however, has substantially fewer examples deployed in operation.

## Operational characteristics

The CCCT described previously serves as the basis for this resource. The configuration and auxiliary power requirements for the operation of the $CO_2$ capture system, however, result in an approximately 40 MW decrease in the net capacity of this resource as described previously. Similarly, the resource is less efficient, resulting in a higher heat rate than the CCCT without $CO_2$ capture (**Table 175**).

**Table 175. Summary of CCCT w/ CCS operational characteristics**

| Operational characteristics | CCCT w/ CCS |
|---|---|
| **Capacity (MW average lifetime)** | 367 |
| **Heat Rate (Btu/kWh average lifetime)** | 7,271 |
| **Planned outage rate** | 3.88% |
| **Forced outage rate** | 2.19% |

[551] *Id.*

## Operational expenditures

"Variable O&M costs include consumable commodities such as water, lubricants, chemicals, solvent makeup, and periodic costs to change out the SCR and CO catalysts. The variable O&M costs also include the average annual cost of the planned maintenance events for the CT and the STG over the long-term maintenance cycle. Planned maintenance costs for the CT in a given year are based on the number of EOHs the CT has run. A significant overhaul is typically performed for this type of CT every 25,000 EOH, and a major overhaul is performed every 50,000 EOH. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH)." The CCCT with $CO_2$ capture system is assumed to require an EOH-based maintenance schedule for the CT. The STG requires less frequent major outage maintenance.

"For the $CO_2$ capture system, variable costs include solvent makeup and disposal costs (usually offsite disposal; the spent solvent may be considered hazardous waste), additional wastewater treatment costs (predominantly CT blowdown treatment), and additional demineralized makeup water costs."[552]

The costs of $CO_2$ storage are not included in the EIA cost estimates; as such, these costs are derived from Hunter[553] to form a representative estimate of the total resource variable cost (**Table 176**).

**Table 176. Summary of CCCT w/ CCS operational expenditures**

| Operational expenditures | CCCT w/ CCS |
|---|---|
| **2019$** | H-Class |
| **Fixed O&M ($/kW-year)** | $28 |
| **Variable O&M ($/MWh)** | $6 |
| **Sequestration Cost ($/MWh)** | $15 |
| **Total Variable O&M ($/MWh)** | $21 |

[552] *Id.*
[553] Hunter et al., "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high variable renewable energy grids." Retrieved from: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769

## Capital expenditures

EIA 2020 AEO research provides the basis for capital expenditure estimates, shown in **Table 177**.

**Table 177. Summary of CCCT w/ CCS capital expenditures**

| Capital expenditures | CCCT w/ CCS |
|---|---|
| **2019 $/kW** | H-Class |
| **Overnight capital** | $2,481 |
| **Transmission Line Cost** | $5 |
| **Gas Interconnection Cost** | $16 |
| **Overnight EPC Capital Cost -Ex Interconnect Cost** | $2,461 |
| **Location Adjustment** | 1.08 |
| **Location-adjusted Overnight Capital Cost** | $2,666 |

## Forward capital cost curve

The EIA AEO projection of future capital costs for the Reference Case scenario are presented in **Figure 174**.

**Figure 174. Combined-cycle combustion turbine w/ CCS capital cost trajectory**