FINAL

CHARACTERIZATION OF SUPPLY-SIDE OPTIONS (2017)

B&V PROJECT NO. 196332
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PREPARED FOR

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BLACK & VEATCH

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Legal Notice

1.0 Introduction

Black & Veatch has prepared this report characterizing supply-side options (SSOs) to be considered in upcoming Integrated Resource Planning (IRP) activities to be conducted by Portland General Electric (PGE). The SSOs requested by PGE include the following:

- 1x0 GE 7F.05 CTG.
- 6x0 Wartsila 18V50SG Reciprocating Engines (RICE).
- 1x1 GE 7HA.01 Combined Cycle (CCCT).
- Biomass Combustion (35 MW Bubbling Fluidized Bed).
- Geothermal (35 MW Binary System).
- Battery Storage (50 MW, 100 MWh Lithium Ion Battery).
- Battery Storage (10 MW, 60 MWh Redox Flow Battery).

Each of these technology options is described in the following sections, including a brief technology overview and characterization of the performance and cost parameters. A full matrix of cost and performance parameters for the 7 requested SSOs is provided as Appendix A. Expenditure patterns for each SSO are provided in Appendix B. A Technology Maturity Outlook for each SSO, described further in Subsection 2.5.4 is included in Appendix C.

2.0 Design Basis and General Assumptions

2.1 DESIGN BASIS FOR SUPPLY-SIDE OPTIONS

To develop technical performance and cost characteristics, Black & Veatch worked with PGE to establish design basis parameters for each of the SSOs under consideration. The design basis parameters are summarized in Table 2-1.

Table 2-1 Design Basis for Supply-Side Options

SUPPLY-SIDE OPTION	MAJOR EQUIPMENT	DUTY	NET CAPACITY (MW)	CAPACITY FACTOR (PERCENT)	PRIMARY FUEL
1x0 GE 7F.05	Combustion Turbine: GE 7F.05 Emissions Control: SCR, CO Catalyst	Peaking	230	11	Natural Gas
6x0 Wartsila 18V50SG	Recip. Engine: Wartsila 18V50SG Heat Rejection: Wet Cooling Tower Emissions Control: SCR, CO Catalyst	Peaking	110	25	Natural Gas
1x1 GE 7HA.01	Combustion Turbine: GE 7HA.01 Duct Firing: None Emissions Control: SCR, CO Catalyst Heat Rejection: Wet Cooling Tower	Intermediate	400	70	Natural Gas
Biomass Combustion	Boiler: Bubbling Fluidized Bed Emissions Control: Selective Non-Catalytic Reduction (SNCR), Fabric Filter Heat Rejection: Wet Cooling Tower	Baseload	35	85	Wood
Geothermal – Binary	System: Binary Geothermal System Heat Rejection: Air-Cooled Condenser	Baseload	35	84	N/A
Battery Storage	Battery: Lithium Ion Discharge Duration: 2 hours	Storage	50	N/A	N/A
Battery Storage	Battery: Redox Flow Discharge Duration: 6 hours	Storage	10	N/A	N/A

2.2 GENERAL SITE ASSUMPTIONS

In addition to the design basis parameters shown in Table 2-1, Black & Veatch worked with PGE to establish the following general site assumptions for the SSOs:

- For 1x0 GE 7F.05 and 6x0 Wartsila 18V50SG options, units are assumed to be installed as additions at existing combined cycle or thermal plant sites. All other options are assumed to be installed at greenfield sites.
- The site has sufficient area available to accommodate construction activities including, but not limited to, office trailers, lay-down, and staging.
- The plant will not be located on environmentally or culturally sensitive lands. The project site will require neither mitigation nor remediation.
- Pilings are assumed under major equipment, and spread footings are assumed for all other equipment foundations.

- All buildings will be preengineered unless otherwise specified.
- Construction power is available at the boundary of the site.
- Potable, service, and fire water will be supplied from the local water utility.
- Wastewater disposal will utilize local sewer systems.
- Cooling water, if required, will be treated sewage effluent or groundwater. Allowances for pipeline costs are included in the Owner's cost.
- Costs for transmission lines and switching stations are included as part of the Owner's cost estimate.

2.3 CAPITAL COST ESTIMATING ASSUMPTIONS

Black & Veatch worked with PGE to establish the following capital cost estimating assumptions for the SSOs:

- Capital cost estimates were developed on an engineering, procurement, and construction (EPC) basis. The EPC capital cost estimates presented in this document include both direct and indirect costs.
- All capital cost estimates are presented in 2017 dollars.
- EPC capital cost estimates are presented as "overnight" costs and do not include any allowances for escalation, financing fees, interest, or other general Owner's cost items.
- Separately from the EPC capital cost estimates, a recommended allowance for Owner's costs has been provided for each technology. Potential Owner's costs are listed in Table 2-2.

Table 2-2 Potential Owner's Costs for Power Generation/Storage Projects

Project Development • Site selection study • Land purchase/rezoning for greenfield sites • Transmission/gas pipeline right-of-way • Road modifications/upgrades • Demolition • Environmental permitting/offsets • Public relations/community development • Legal assistance • Provision of project management	**Owner's Contingency** • Owner's uncertainty and costs pending final negotiation • Unidentified project scope increases • Unidentified project requirements • Costs pending final agreements (i.e., interconnection contract costs) **Owner's Project Management** • Preparation of bid documents and the selection of contractors and suppliers • Performance of engineering due diligence • Provision of personnel for site construction management
Spare Parts and Plant Equipment • Combustion turbine and reciprocating engine materials, gas compressors, supplies, and parts • Steam turbine materials, supplies, and parts • Boiler materials, supplies, and parts • Balance-of-plant equipment/tools • Rolling stock • Plant furnishings and supplies	**Taxes/Advisory Fees/Legal** • Taxes • Market and environmental consultants • Owner's legal expenses • Interconnect agreements • Contracts (procurement and construction) • Property
Plant Startup/Construction Support • Owner's site mobilization • Operations and Maintenance (O&M) staff training • Initial test fluids and lubricants • Initial inventory of chemicals and reagents • Consumables • Cost of fuel not recovered in power sales • Auxiliary power purchases • Acceptance testing • Construction all-risk insurance	**Utility Interconnections** • Natural gas service • Gas system upgrades • Electrical transmission • Water supply • Wastewater/sewer **Financing (included in fixed charge rate)** • Financial advisor, lender's legal, market analyst, and engineer • Loan administration and commitment fees • Debt service reserve fund

2.3.1 Direct Cost Assumptions

Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services. Assumptions regarding direct costs within the capital cost estimates include the following:

- Construction costs are based on a turnkey EPC contracting philosophy.
- Permitting and licensing are excluded from EPC costs. These items should be included in the Owner's cost estimate.

2.3.2 Indirect Cost Assumptions

Indirect costs within the capital cost estimates are assumed to include the following:

- General indirect costs, including all necessary services required for checkout, testing, and commissioning.
- Insurance, including builder's risk, general liability, and liability insurance for equipment and tools.
- Engineering and related services.
- Field construction management services including field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct cost construction contracts, safety and medical services, guards and other security services, insurance premiums, and performance bonds.
- Contractor's contingency and profit.
- Transportation costs for delivery to the jobsite.
- Startup and commissioning spare parts.

Indirect costs are assumed to exclude the following:

- Initial inventory of spare parts for use during operation. These items are assumed to be included in the Owner's costs.
- Allowance for funds used during construction and financing fees. These costs should be included in the Owner's overall cost estimate.

2.4 OPERATION AND MAINTENANCE COST ESTIMATING ASSUMPTIONS

Assumptions associated with operations and maintenance (O&M) cost estimates developed by Black & Veatch include the following:

- O&M cost estimates were developed as representative estimates based on (1) previous Black & Veatch experience with projects of similar design and scale, and (2) relevant vendor information available to Black & Veatch.

- For gas-fired combustion turbine options, the annual number of starts may affect maintenance patterns. For gas-fired reciprocating engines, the number of starts does not affect maintenance patterns. Annual starts were assumed as follows:
  - 1x0 GE 7F.05: 120 starts/year
  - 6x0 Wartsila 18V50SG: 350 starts/year
  - 1x1 GE 7HA.01: 12 starts per year
- O&M cost estimates were categorized into fixed O&M and nonfuel variable O&M components. Nonfuel variable O&M costs exclude the cost of fuel (e.g., natural gas or woody biomass). Depending upon the SSO, fuel may or may not be required.
  - Fixed O&M costs include labor (operations, maintenance, technical services, and administration), routine maintenance (major equipment and systems, including contracted services) and other expenses (training, office and administrative expenses, bonus and incentives, and miscellaneous). Options assumed to operate as peaking units have minimal staff, assumed to be shared with staffing at an existing, adjacent facility. Costs are presented in $/kW-year.
  - For labor costs, the average burdened wage rate is assumed to be $61/hr.
  - Nonfuel variable O&M costs include outage maintenance, parts and materials, water usage, chemical usage and equipment. Costs are presented in $/MWh.
- Nonfuel variable wear and tear costs and nonfuel startup variable O&M costs are presented as sub-categories of nonfuel variable O&M costs and are defined as follows:
  - Nonfuel variable wear and tear costs include annualized estimated variable maintenance costs on the turbines, generators, HRSG when applicable, and SCR catalysts. Costs are presented in $/MWh.
  - Nonfuel startup variable O&M costs assume an average start and include makeup water and chemicals. This estimate does not include fuel or electricity. Costs are presented in $/start.
- All nonfuel O&M cost estimates are presented in 2017 dollars.
- Additionally, Black & Veatch provided estimates of fuel startup variable O&M Usage presented in million British thermal units (MMBtu)-HHV/start.

2.5 ADDITIONAL PARAMETER ASSUMPTIONS

In addition to capital and O&M cost parameters, PGE requested characterization of the other financial parameters, including overnight total cost standard deviation, capital expenditures and maintenance accruals, decommissioning costs, and a technical maturity outlook. A brief description of the methodology applied for each of these financial parameters is described in the following subsections.

2.5.1 Overnight Total Cost Standard Deviation

One standard deviation accounts for approximately 68.2 percent of the data points for a given data set, assuming a normal distribution. Given the planning level of this IRP study, Black & Veatch assumed a normal distribution and estimated the standard deviation by comparing the technology options on a relative basis. The standard deviation estimates are based on expert judgment and were based on Black & Veatch project experience with units of similar size and type, where possible.

2.5.2 Capital Expenditures/Maintenance Accruals

Operation of certain SSOs requires periodic replacement of specific systems or equipment (either dependent upon number of years in service or hours of operation). For example, the operation of a geothermal facility typically requires the drilling of new supply wells at regular intervals during the lifetime of the power project, and depending on the extent of charge/discharge cycling, battery energy storage systems may require periodic replacement of batteries.

Typically, Black & Veatch does not provide estimates of the costs associated with these activities as capital expenditures or maintenance accruals separately from other O&M costs. In instances where these periodic costs are necessary (for the SSOs under consideration in this report, excluding battery energy storage systems), these costs have been included in the relevant O&M costs associated with specific technology options. For these SSOs, the periodic system/equipment replacement requirements are noted in the technology-specific assumptions.

2.5.3 Decommissioning Costs

The total estimated decommissioning cost is presented in 2017 USD based on a percentage of the total overnight capital cost. Relative percentages are based on recent decommissioning cost estimates for a similar scope of decommissioning for similar assets and Black & Veatch expert judgment. Values are net of salvage.

Typically, a fixed amount of money is accrued each year over the book life of the asset to cover the cost of decommissioning the asset. For all SSOs, it is assumed the site would be returned to a brownfield condition at the end of its book life.

2.5.4 Technology Maturity Outlook

To provide an outlook on technology maturity and the potential for reductions in future capital costs, Black & Veatch employed a methodology for estimating future costs associated with each of the SSOs considered in this study. To provide this technology maturity outlook, Black & Veatch employed data developed by the US Department of Energy (US DOE) Energy Information Administration (EIA) in the Annual Energy Outlook (AEO) 2017 and applied these data to the present-day capital costs for each SSO. For the data developed for the AEO 2017, EIA employs the National Energy Modeling System (NEMS). Black & Veatch has provided estimates of total capital cost from 2017 to 2037. All estimates of future capital costs are presented on a constant dollar basis (i.e., in 2017 dollars).

2.5.4.1 NEMS Attributes

Relative strengths of the NEMS estimates of future capital costs for generation technologies include the following:

- NEMS was first developed in 1993 and has been employed by the EIA since then to provide a basis for the AEO. The model employs an analytical methodology; is well-documented, and has been peer reviewed over the course of time.
- NEMS is one of the more commonly used methods for future capital cost forecasting.
- The forecast data provided by NEMS provide technology-specific forecasts for the majority of technologies of interest, and forecast data is provided on a year-by-year basis from 2017 to 2050, which is consistent with the time horizon considered in this study.
- Within the NEMS model, future cost forecasts are developed and updated annually, rather than on cycles of multiple years (i.e., 2 to 5 years).
- The estimates are developed by the US DOE rather than national laboratories and technology-specific advocacy groups. In many cases, the national laboratories advocacy groups have a specific area of technical focus. The estimates developed by US DOE utilize information provided by the laboratories and other groups but are considered to have less technology bias than estimates developed by others.

Relative weaknesses of these estimates include the following:

- NEMS is a model of the energy market within the United States, and no model is able to fully integrate and consider all factors that affect costs of generation assets. The model may not predict short-term market effects. For example, the NEMS model did not forecast the increase in capital costs of all generation facilities in the 2005 to 2009 time period, which was attributed to (1) short-term shortage in craft labor supply and (2) short-term increases in commodity prices. While virtually all forecast models are limited in their ability to predict these short-term variations, the NEMS model is considered to provide a general indication of price trends over the long term.
- The NEMS model assumes continual development for all technologies, which may not be the case, particularly for technologies that are mature from a technical perspective. For example, coal fired boiler, simple cycle turbine and reciprocating engine technologies are unlikely to see significant reductions in cost.

Given these considerations, the NEMS forecast of future capital cost is useful as a means to quantify general capital cost trends for the disparate set of generation options available to utilities. These trends provide a reasonable base case for future capital costs, and variations for specific technologies may be considered via sensitivity analysis, if necessary. For example, for emerging technologies such as battery energy storage, analysis of variations in forecasts may be beneficial.

2.5.4.2 Estimated Future Capital Costs for PGE IRP 2016

As part of the NEMS data within the AEO 2017, EIA developed forecasts of capital cost (over the 2017 to 2050 time period) for technologies as listed in Table 2-3. Black & Veatch requested data associated with these forecasts, and EIA provided the data via email in June 2017. The data provided by EIA includes the overnight capital costs for these technologies presented in 2016 dollars (on a $/kW basis). Based on notes from EIA, these data represents the "cost of new plants, including contingencies, excluding regional multipliers, excluding tax credits."

Table 2-3 Technologies Included in NEMS Data Provided by EIA

CONVENTIONAL TECHNOLOGIES	RENEWABLE TECHNOLOGIES	DISTRIBUTED GENERATION TECHNOLOGIES
Coal with 30% CCS	Biomass	Distributed Generation Base
Coal with 90% CCS	Landfill Gas	Distributed Generation Peak
Combustion Turbine	Hydroelectric	
Advanced Comb. Turbine	Wind (Onshore)	
Combined Cycle	Offshore Wind	
Advanced Combined Cycle	Solar Thermal	
Adv. CC w/ Sequestration	Solar Photovoltaic (PV)	
Fuel Cell		
Nuclear		
Hydroelectric		

Maintaining a constant dollar basis, Black & Veatch developed a set of "forecast factors," and normalized these factors to 2017 values for each technology presented in the NEMS overnight capital cost data. The resulting forecast factors for conventional technologies, including nuclear, are illustrated in Figure 2-1. The forecast factors for renewable technologies, including fuel cell and distributed generation technologies, are illustrated in Figure 2-2. A table of these NEMS-based forecast factors for conventional and renewable technologies is presented in Appendix C.

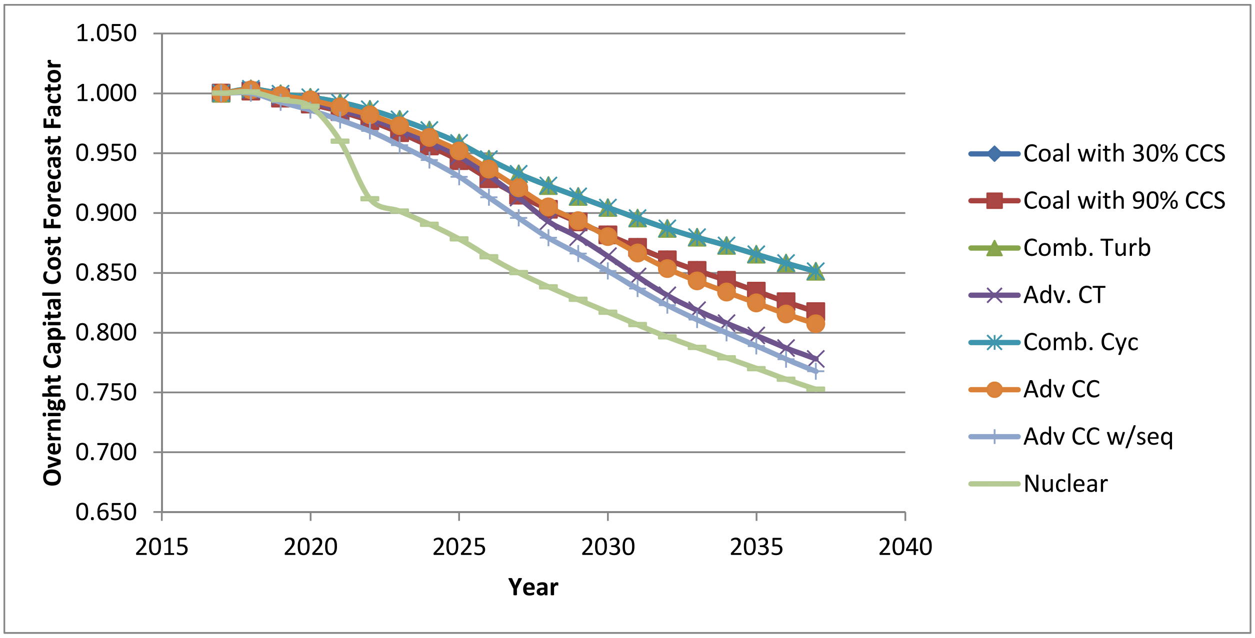


Figure 2-1 **Overnight Capital Cost Forecast Factors for Conventional Technologies**

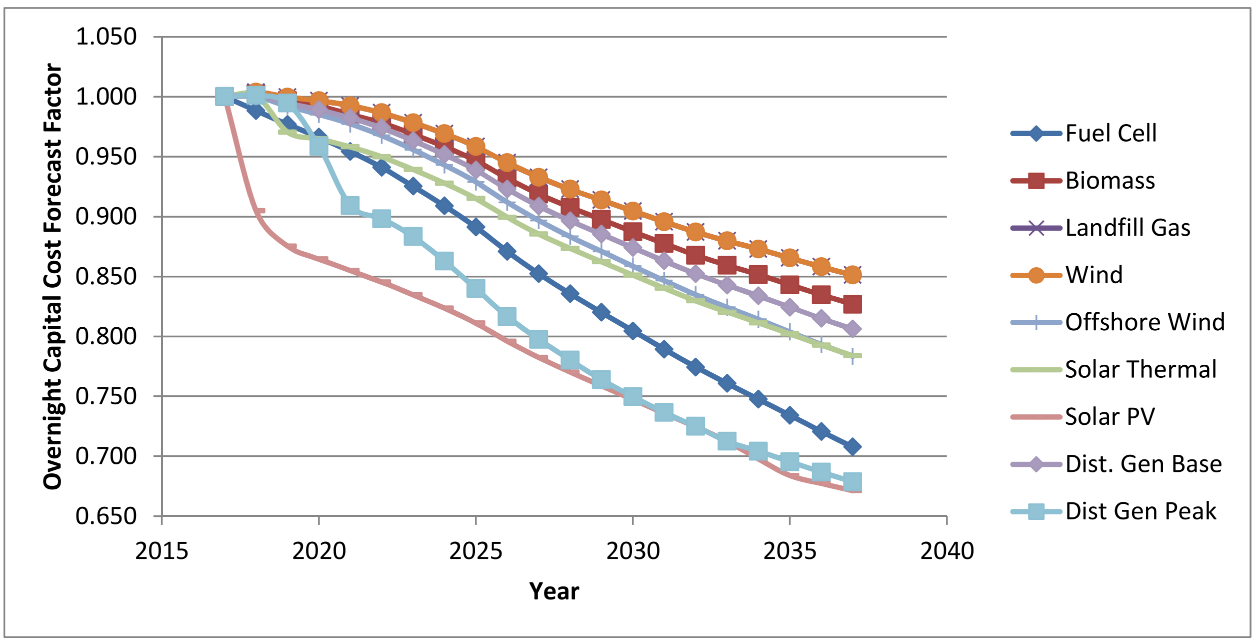


Figure 2-2 **Overnight Capital Cost Forecast Factors for Renewable Technologies**

For the SSOs considered in this IRP study, the estimates of future capital costs were based on the corresponding technology forecast factors (based on NEMS data). The future capital cost for each SSO was estimated by multiplying the present-day total overnight capital cost by the appropriate technology forecast factor. For example, the future capital costs of the simple cycle GE 7F.05 SSO were based on the set of forecast factors associated with the NEMS data for combustion turbine technologies. To estimate the total capital cost in a specific year (in 2017 dollars), the present-day capital cost (in 2017 dollars) was multiplied by the combustion turbine forecast factor associated with the specified year. The NEMS technology forecast factors applied for each SSO are identified in Table 2-4.

Table 2-4 Technology-Specific Forecast Data Employed for Supply-Side Options

SUPPLY-SIDE OPTION	EIA NEMS TECHNOLOGY FORECAST EMPLOYED
1x0 GE 7F.05	Combustion Turbine
6x0 Wartsila 18V50SG	Combustion Turbine
1x1 GE 7HA.01	Advanced Combined Cycle
Biomass Combustion	Biomass
Geothermal – Binary	Biomass[1]
Battery Storage – Li-Ion	Not Applicable[2]
Battery Storage – Redox Flow	Not Applicable[2]

Notes:
1. For Geothermal SSOs, Black & Veatch considered these to be technologically mature renewable options, similar in terms of future capital cost outlook to Biomass SSOs.
2. Expected trends for battery energy storage options are not consistent with any of the technology forecasts provided within the EIA data. Therefore, for battery storage applications, Black & Veatch developed a separate estimate of future capital costs.

2.5.4.3 Other NEMS Characteristics

Regarding the NEMS technology data applied to each SSO, Black & Veatch notes the following:

- While the NEMS data included geothermal and hydroelectric cost data, Black & Veatch notes that this data was not presented in the same fashion as other technologies within the data provided by EIA. The costs for geothermal and hydroelectric provided by EIA had significant fluctuations from year to year. According to EIA staff, capital costs for geothermal and hydroelectric technologies were determined by selecting projects from within a database of existing sites with site-specific costs.[1]

- Because the NEMS capital cost data for geothermal and hydroelectric technologies did follow a consistent trend, Black & Veatch did not apply these forecasts to geothermal and hydroelectric options considered in this study.
- Because both geothermal and pumped storage hydroelectric are considered technologically mature renewable/storage options, Black & Veatch applied forecast factors associated with Biomass technologies, which are also considered to be a technologically mature renewable technologies.

- For utility-scale battery energy storage technologies, none of the technologies included in the NEMS data were considered consistent with anticipated capital costs over the next 25 years. Therefore, Black & Veatch reviewed past and present battery price data to develop capital cost forecast factors for battery energy storage technologies, as shown in Figure 2-3. Projections are based on industry-wide learning curve data for battery cells, packs, and stacks published in July 2017.[2]
  - Black & Veatch anticipates that capital costs associated with battery energy storage facilities may decrease to 0.72 of the 2017 basis cost by 2020 (on a constant dollar basis).
  - By 2025 capital costs may further decrease to 0.50 of the 2017 basis cost (on a constant dollar basis).
  - By 2030 capital costs may further decrease to 0.45 of the 2017 basis cost, leveling off thereafter (on a constant dollar basis)
  - The estimates of future costs for utility-scale battery are consistent with industry learning curve price reductions that have been tracked since 2010.

[1] In an email to Black & Veatch, Laura Martin of the Electricity Analysis Team at EIA stated: “Reflected in the [geothermal and hydroelectric technology] costs I provided you are just the least-cost plants available each year, based on the model results in that scenario. Within the model we develop a supply curve of capacity and costs for the technology, and pass the electricity model information about the most economic sites (looking at total operating costs, not just capital costs) and the model makes decisions about whether or not to build. As sites are chosen, the supply curves are readjusted each year, and the overnight costs associated with the cheapest ‘total cost’ site may jump around.”

[2] Schmidt, E. et al, “The future cost of electrical energy storage based on experience rates,” *Nature Energy* (2) 17110, 2017.

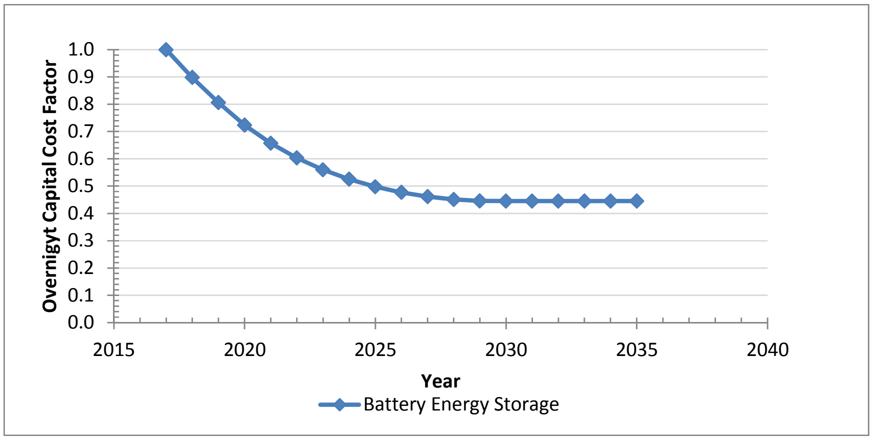


Figure 2-3 Overnight Capital Cost Forecast Factors for Battery Energy Storage Supply-Side Options

3.0 Conventional Generation Options

Three conventional generation SSOs were considered:

- 1x0 GE 7F.05 CTG.
- 6x0 Wartsila 18V50SG RICE.
- 1x1 GE 7HA.01 CCCT.

These conventional SSOs and their performance and cost characteristics are defined in the following subsections.

3.1 1X0 GE 7F.05

3.1.1 Technology Overview

The 7F.05 is an air cooled heavy frame CTG with a single shaft, 14-stage axial compressor, 3-stage axial turbine, and 14-can-annular dry low NO_x (DLN) combustors. The 7F.05 is GE's fifth-generation 7F machine with the latest advancements including a redesigned compressor and three variable stator stages and a variable inlet guide vane for improved turndown capabilities. GE's 7F fleet of over 800 units has over 33 million operating hours.

Key attributes of the GE 7F.05 include the following:

- High availability.
- 40 MW/min ramp rate.
- Start to 200 MW in 10 minutes, full load in 11 minutes.
- Natural gas interface pressure requirement of only 435 psig.
- Dual fuel capable.
- DLN combustion with CTG NOx emissions of 9 ppm on natural gas.
- Water injected combustion with CTG NOx emissions of 42 ppm on diesel fuel.
- High exhaust temperature makes it difficult to implement post-combustion NOx emissions controls.

3.1.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for a simple cycle natural gas-fired GE 7F.05 combustion turbine facility. Relevant assumptions employed in the development of performance and cost parameters for the 7F.05 facility include the following:

- The power plant would consist of a single GE 7F.05 CTG, located outdoors in a weather-proof enclosure.
- To reduce NOx and CO emissions, a SCR system with oxidation catalyst would be utilized. The SCR system would include purge/tempering air for startup and to reduce CTG exhaust temperature to within the operational limits of the SCR catalyst.
- A generation building would house electrical equipment, engine controls, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- No natural gas compression has been assumed for this option.

3.2 6X0 WARTSILA 18V50SG

3.2.1 Technology Overview

The 18V50SG is a turbocharged, four-stroke spark-ignited natural gas engine. Unlike dual fuel reciprocating engines, the SG does not require liquid pilot fuel during startup and to maintain combustion. The 18V50SG utilizes 18 cylinders in a "V" configuration. Each cylinder has a bore diameter of 500 millimeters (19-11/16 inches) and a stroke of 580 millimeters (22-13/16 inches). Each engine operates at a shaft speed of 514 revolutions per minute. Individual cylinder computer controls and knock sensors provide precise control of the combustion process, enabling the engine to operate more efficiently while minimizing emissions. There have been at least 62 18V50SG engines sold to date with initial commercial operations starting in 2013.

For this characterization, it is assumed that engine heat is rejected to the atmosphere by way of a mechanical draft cooling tower. In locations with limited water resources, an air-cooled heat exchanger may be employed as an alternative to a mechanical draft cooling tower. An 18V50SG power plant utilizing air cooled heat exchangers would require very little makeup water as the engines do not typically utilize inlet cooling for power augmentation or water injection for NO_x reduction.

Key attributes of the Wartsila 18V50SG include the following:

- High full- and part-load efficiency.
- Minimal performance impact at hot-day conditions.
- 10 minutes to full power.
- Minimal power plant footprint.
- Low starting electrical load demand.
- Ability to cycle on and off without impact of maintenance costs or schedule.
- Natural gas interface pressure requirement of 75 psig.
- Not dual fuel capable.

While the 18V50SG does not provide dual fuel capability, the diesel variation of the engine, the 18V50DF model, does provide dual fuel capability. In diesel mode, the main diesel injection valve injects the total amount of light fuel oil as necessary for proper operation. In gas mode, the combustion air and the fuel gas are mixed in the inlet port of the combustion chamber, and ignition is provided by injecting a small amount of light fuel oil (less than one percent by heat input). The injected light fuel oil ignites instantly, which then ignites the air/fuel gas mixture in the combustion chamber. During startup, the 18V50DF must operate in diesel mode until the engine is up to speed; once up to speed, the unit may operate in gas mode.

Wartsila offers a standard, pre-engineered six-engine configuration for the 18V50SG and the 18V50DF, sometimes referred to as a "6-Pack". The 6-Pack configuration has a net generation output of approximately 110 MW and ties the six engines to a single bus and step-up transformer. This configuration provides economies of scale associated with the balance of plant systems (e.g., step-up transformer and associated switchgear) and reduced engineering costs.

3.2.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for a simple cycle (6x0) natural gas-fired Wartsila 18V50SG reciprocating engine facility. Relevant assumptions employed in the development of performance and cost parameters for the 18V50SG facility include the following:

- The facility would consist of six Wartsila 18V50SG reciprocating engines, arranged as slide along units and co-located in a common engine hall.
- The engine hall would be one of a number of rooms within a generation building. The generation building would also include space for water treatment, electrical equipment, engine controls, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- An SCR system with oxidation catalyst would be utilized to minimize NOx and CO emissions.
- Engine heat is rejected to atmosphere by way of a common wet mechanical draft cooling tower.

3.3 1X1 GE 7HA.01

3.3.1 Technology Overview

The GE 7HA.01 is an air cooled heavy frame CTG with a single shaft, 14-stage axial compressor, 4-stage axial turbine, and 12-can-annular DLN combustors. The 7HA.01 has a single inlet guide vane stage and three variable stator vain stages to vary compressor geometry for part load operation. The 7HA.01, along with the scaled-up 7HA.02 and 50 Hertz versions, the 9HA.01 and 9HA.02, represent the largest and most advanced heavy frame CTG technologies from GE. The compressor design is scaled from GE’s 7F.05 and 6F.01 (formally 6C) designs. The 7HA.01 will use a DLN 2.6+ AFS (Axial Fuel Staged) fuel staging combustion system which allows for high firing temperatures and improved gas turbine turndown while maintaining emissions guarantees, stable operations, and allows for increased fuel variability. 7HA.01 first shipments are expected to begin in 2016. GE has 16 orders of its HA CTG technology to date.

This option would also employ a triple-pressure HRSG, reheat condensing STG, wet surface condenser, and wet mechanical draft counterflow cooling tower. The STG would likely employ a single axial flow exhaust.

Key attributes of the GE 7HA.01 include the following:

- High availability.
- CTG 50 MW/min ramp rate.
- Combined cycle start times dependent on bottoming cycle, HRSG, and STG design. A nominal hot start time of 60 minutes is typical.
- Natural gas interface pressure requirement of about 500 psig.
- Dual fuel capable.
- DLN combustion with CTG NOx emissions of 25 ppm on natural gas.

3.3.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for a combined cycle natural gas-fired GE HA.01 CTG-based facility. Relevant assumptions employed in the development of performance and cost parameters include the following:

- The power plant would consist of a single GE 7HA.01 CTG, located outdoors in a weather-proof enclosure with close-coupled three-pressure HRSG.
- An axial flow reheat condensing steam turbine would accept steam from the HRSG at three pressure levels. The steam turbine would be located within a building.
- A wet surface condenser and mechanical draft counterflow cooling tower would reject STG exhaust heat to atmosphere.
- To reduce NOx and CO emissions, a SCR system with oxidation catalyst would be utilized. The SCR system would be located within the HRSG in a temperature region conducive to the SCR catalyst.
- A generation building would house electrical equipment, engine controls, water treatment equipment, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- Natural gas compression has been assumed for this option.

3.4 TECHNICAL AND FINANCIAL PARAMETERS

Technical parameters for conventional energy options considered for PGE are summarized in Table 3-1, while cost and financial parameters for conventional energy options considered for PGE are summarized in Table 3-1 and Table 3-2.

Table 3-1 Technical Parameters for Conventional Generation Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)[1]	AVERAGE DESIGN LIFE NET CAPACITY, INCLUDING DEGRADATION (MW)	CAPACITY FACTOR (PERCENT)	LAND REQUIRED (ACRES/ MW)[2]	NET PLANT HEAT RATE (BTU/ kWh-HHV)	AVERAGE DESIGN LIFE NET PLANT HEAT RATE, INCLUDING DEGRADATION (BTU/kWh-HHV)	FUEL CONSUMPTION VERSUS OUTPUT (MMBtu/h-[HHV] VERSUS KW-NET, NEW AND CLEAN)[3]	MINIMUM TURNDOWN CAPACITY (PERCENT)[4]	RAMP RATE (MW/MIN)	MINIMUM RUN/ DOWN TIMES (HOURS)	START TIME TO FULL LOAD (MINS)[5]	WATER CONSUMPTION (MGD)	SCHEDULED MAINTENANCE (WEEKS/YR)[6]	EQUIVALENT FORCED OUTAGE RATE – DEMAND (PERCENT)	EPC PERIOD (MONTHS)[7]
1x0 GE 7F.05	231	218	11	0.04	9,830	10,170	$y = 1.657E-08x^2 + 1.883E-03x + 9.521E+02$	43	40	0.5 / 0.5	11	0.0	1.8	4.0	24
6x0 Wartsila 18V50SG	110	107	25	0.06	8,300	8,470	$y = -3.336E-09x^2 + 7.875E-03x + 8.800E+01$	25	84	0.5 / 0.5	5	0.36	0.9	2.2	24
1x1 GE 7HA.01	424	400	70	0.04	6,290	6,450	$y = 1.638E-09x^2 + 4.583E-03x + 4.283E+02$	33	55	2.0 / 1.0	Hot:60 Warm:100 Cold:210	1.9	3.9	2.9	30

Notes:

1. Performance parameters assume International Organization for Standardization (ISO) conditions (59° F, 60% relative humidity, and sea level elevation). Net capacity is defined as the nameplate (or gross) unit capacity minus any auxiliary losses.
2. Typical value; actual value is specific to project, location, and owner's requirements.
3. For combustion turbines and reciprocating engines, heat rate is a function of output as well as fuel consumption. In Black & Veatch's experience, providing a curve showing fuel consumption as a function of output provides a more accurate result. The curve provided is fuel consumption versus output (MMBtu-HHV versus kW-net, new and clean). Heat rate can be further determined by dividing fuel consumption by output.
4. While maintaining emissions compliance for combustion turbine and reciprocating engine based option.
5. Start times exclude purge time. Combined cycle start time definitions: Hot start is defined as a start after an 8 hour shutdown (generally considered 8 hours or less). Warm start is defined as a start after a 48 hour shutdown (generally considered 8 to 48 hours). Cold start is defined as a start when the steam turbine rotor temperature is at or near atmospheric temperature (generally considered greater than 48 hours).
6. Maintenance values are annual averages based on prime mover (combustion turbine or reciprocating engine) manufacturer recommended maintenance.
7. The project duration period starts with EPC contractor notice to proceed (NTP) and ends at the commercial operation date (COD). Some excluded activities are permitting and EPC specification development.

Table 3-2 Financial Parameters for Conventional Generation Options

SUPPLY-SIDE OPTION	BOOK LIFE (YEARS)	EXPENDITURE PATTERN (BY MONTH)	OVERNIGHT EPC CAPITAL COST ($000, 2017$)	OWNER'S COST ALLOWANCE (PERCENT)[8]	OVERNIGHT TOTAL CAPITAL COST ($000, 2017$)	OVERNIGHT TOTAL CAPITAL COST STANDARD DEVIATION, 1σ ($000, 2017$)	FIXED O&M COSTS ($/kW-YEAR)[9]	NONFUEL VARIABLE O&M COST (2017$/MWh)[9]	NONFUEL VARIABLE WEAR AND TEAR COSTS (2017$/MWh)[10]	CAPITAL ADDITIONS/ MAINTENANCE ACCRUAL (2017$/YEAR)	NONFUEL STARTUP VARIABLE O&M COSTS (2017$/ START)[11]	STARTUP FUEL CONSUMPTION (MMBTU-HHV/ START)[12]	DECOMMISSIONING COST ($000, 2017$)[13]
1x0 GE 7F.05	30	Refer to Appendix B	115,000	25	143,750	10,800	6.7	6.9	6.7	Refer to Note 14	4	295	1,380
6x0 Wartsila 18V50SG	30	Refer to Appendix B	116,000	25	145,000	10,900	11.0	7.2	6.3	Refer to Note 14	11	72	1,260
1x1 GE 7HA.01	30	Refer to Appendix B	449,000	25	561,250	56,200	7.4	3.3	2.7	Refer to Note 14	370	950	9,770

Notes (continued from Table 3-1):

8. Owner's cost allowance includes costs associated with project development, operating spare parts and plant equipment, owner's contingencies and project management, utility interconnections, taxes, and legal fees. The owner's cost allowance can vary widely.
9. Estimates expressed in terms of new and clean condition.
10. Estimated wear and tear costs include annualized estimated variable maintenance costs on the turbines, generators, HRSG, and SCR catalysts, as applicable.
11. Assumes average start. Includes makeup water and chemicals. Does not include fuel or electricity.
12. Startup fuel consumption for achieving CTG/RICE full load operation.
13. Decommissioning costs are typically accrued annually over the design life of the asset to decommission the facility. Total project decommissioning costs, net of salvage, are provided in 2017 USD. Assumes the site would be returned to a brownfield condition at the end of its design life.
14. Operation of certain SSOs requires periodic replacement of specific systems or equipment (either dependent upon number of years in service or hours of operation). In instances where these periodic costs are necessary, these costs have been included in the relevant O&M costs associated with specific technology options.

4.0 Renewable Generation Options

Renewable SSOs considered include the following:

- Biomass Combustion (35 MW Bubbling Fluidized Bed).
- Geothermal (35 MW Binary System).

These renewable SSOs and their performance and cost characteristics are defined in the following sections.

4.1 BIOMASS COMBUSTION

4.1.1 Technology Overview

Direct biomass combustion power plants in operation today use the same steam Rankine cycle that was introduced commercially over 100 years ago. In many respects, biomass power plants are similar to coal plants. When burning biomass, pressurized steam is generated in a boiler and then expanded through a turbine to produce electricity. Prior to its combustion in the boiler, the biomass fuel may require processing to improve the physical and chemical properties of the feedstock. Boiler systems used in biomass combustion include stoker fired, suspension fired, fluidized bed, cyclone, and pile burners. Newly constructed biomass-fired generation facilities likely employ either a stoker boiler or a fluidized bed boiler. Advanced technologies, such as integrated biomass gasification combined cycle and biomass pyrolysis, are under development but have not achieved widespread commercial operation at utility scales.

Although wood is the most common biomass fuel, other biomass fuels include agricultural residues such as bagasse (sugar cane residues), dried manure and sewage sludge, black liquor from pulp mills, and dedicated fuel crops such as fast growing grasses and eucalyptus.

Biomass plants usually have a capacity of less than 50 MW because of the dispersed nature of the feedstock and the large quantities of fuel required. As a result of the smaller scale of the plants and lower heating values of the fuels, biomass plants are less efficient than modern fossil fuel plants. These factors usually limit the use of direct-fired biomass technology to inexpensive or waste biomass sources.

Biomass power projects must maintain a careful balance to ensure long-term sustainability with minimal environmental impact. Most biomass projects target the use of biomass waste material for energy production, saving valuable landfill space. Biomass projects that burn forestry or agricultural products must ensure that both fuel harvesting and collection practices are sustainable and do not adversely affect the environment. Biomass projects that collect thinning from forests to reduce the risk of forest fires are increasingly seen as a way to restore a positive balance to forest ecosystems while avoiding catastrophic and polluting uncontrolled forest fires.

Unlike coal or natural gas, biomass may be viewed as a carbon-neutral power generation fuel. While carbon dioxide (CO_2) is emitted during biomass combustion, a nearly equal amount of CO_2 is absorbed from the atmosphere during the biomass growth phase. Furthermore, biomass fuels contain little sulfur compared to coal and, therefore, produce less sulfur dioxide (SO_2). Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as mercury (Hg), cadmium, and lead.

While biomass fuels offer certain emissions benefits relative to coal and natural gas, biomass combustion facilities typically require technologies to control emissions of NO_x, particulate matter (PM), and CO to meet state and or federal regulatory requirements.

4.1.2 Technology-Specific Assumptions

For this PGE IRP effort, Black & Veatch developed performance and cost parameters for a biomass facility employing a Bubbling Fluidized Bed (BFB) boiler, with a net generation output of 35 MW-net. Relevant assumptions employed in the development of performance and cost parameters for the 35 MW-net biomass energy facility include the following:

- The primary fuel for the biomass facility will be woody biomass, with an average moisture content of 40 percent and an as-received heating value of 5,100 Btu/lb (HHV).
- The facility will have an average annual capacity factor of 85 percent. It is estimated that the facility would produce approximately 260,600 MWh per year of electricity.
- The facility will have a wood fuel yard sufficiently sized to store 30 days of woody biomass fuel.
- Air quality control equipment includes SCR systems for NOx control, sorbent injection for acid gas control, and a fabric filter for PM control.

4.2 GEOTHERMAL

4.2.1 Technology Overview

Geothermal power is produced by using steam or a secondary working fluid in a Rankine Cycle to produce electricity. Geothermal energy was first used to make electricity at the beginning of the 20th century. In 1904, Prince Piero Conti, owner of the Larderello fields in Italy, attached a generator to a natural-steam-driven engine which lit four light bulbs. This experiment led to the installation of the world's first geothermal power plant in 1911, with a capacity of 250 kilowatts. The government of New Zealand was the first significant producer of geothermal electricity, with the ~150-MW Wairakei power plant, which began operating in 1958. Shortly thereafter, the first power plants were installed at The Geysers in California, USA. By 1975, the Larderello fields were capable of producing about 400 MW of power. By the mid-1980s, The Geysers' output had peaked at about 1,600 MW, after which it declined to its present output at about 850 MW.[3] Today, roughly 70 geothermal power facilities are in operation in over 20 countries around the world, generating approximately 13.3 GW as of January 2016.[4]. There is a natural concentration of geothermal

[3] Sanyal, S. K. (2011) Fifty Years of Power Generation at The Geysers - The Lessons Learned. Proceedings, Thirty-sixth Workshop on Geothermal Reservoir Engineering, Stanford University, January 31 - February 2, 2011, SGP-TR-191.

[4] B. Matek, (2016). 2016 Annual US and Global Geothermal Power Production Report. Geothermal Energy Association. Washington, DC, USA.

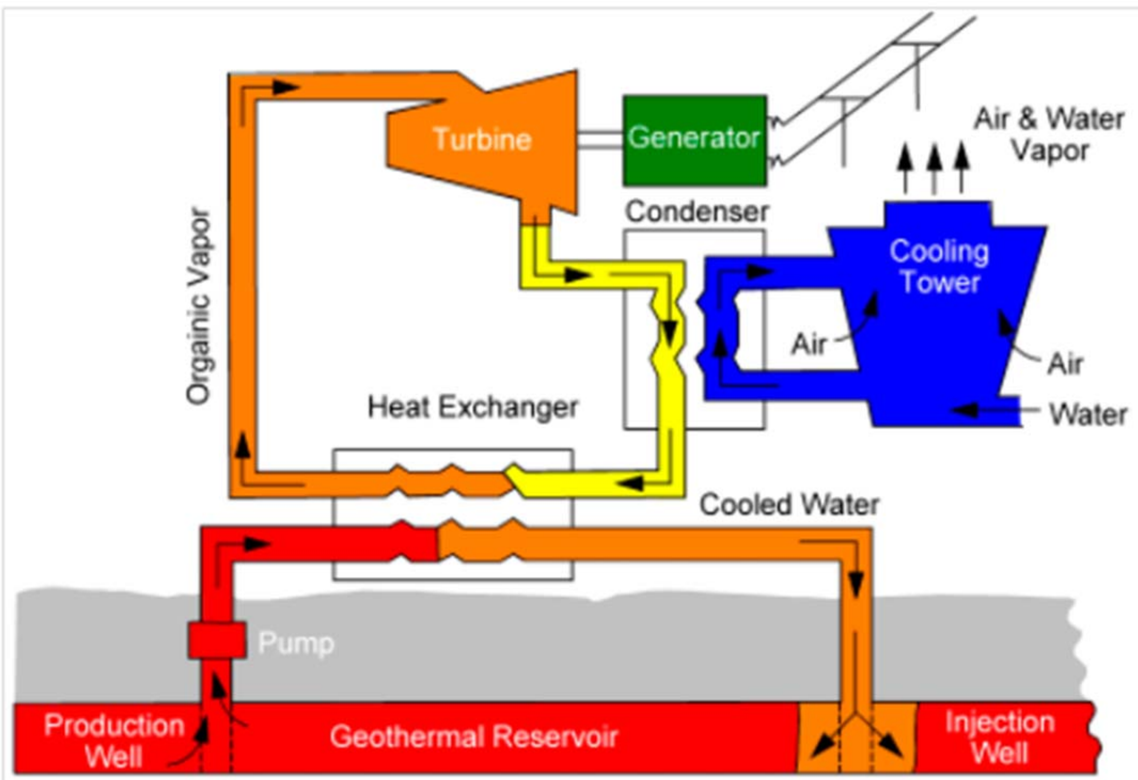
resources in regions characterized by volcanism, active tectonism, or both. For example, Indonesia and The Philippines have many large, high-temperature geothermal resources.

The most commonly used power generation technologies are direct steam (or dry steam), single-flash, dual-flash, and binary systems. In addition, efforts are underway to develop "enhanced geothermal" projects. The choice of technology is driven primarily by the temperature and quality of the steam/liquid extracted from the geothermal resource area. These geothermal technologies are classified as follows:

- Direct steam: For geothermal resources that provide slightly superheated steam, direct-steam technologies may be employed. Superheated steam (with temperatures exceeding 350° F [177° C]) is gathered from the geothermal reservoir (via production wells) to drive a condensing steam turbine-generator. Following expansion in the steam turbine, the brine is scrubbed as necessary to remove acid gases and other contaminants, and re-injection wells are employed to return the geothermal brine to the geothermal reservoir.
- Single-Flash or Double-Flash: Flash systems are used in high temperature (i.e., greater than 350° F [177° C]) liquid-dominated geothermal reservoirs. Upon extraction from the geothermal reservoir, the geothermal fluid is a pressurized two-phase mixture of liquid brine and steam. This two-phase mixture is routed to a separator, where the pressure of the mixture is reduced, causing the fluid to flash into steam. This steam is then expanded in steam turbine generator. Double-flash systems flash the separated brine a second time. In double-flash systems, the lower temperature steam may be expanded through a separate steam turbine, or the steam may be introduced into the high-pressure turbine through a second admission port. As in direct steam systems, the spent brine is scrubbed and re-injected into the geothermal reservoir.
- Binary: Binary cycle systems are employed for development of liquid-dominated geothermal reservoirs that do not have temperatures sufficiently high enough to flash steam (i.e., less than 350° F [177° C]). In a binary system, a secondary fluid is employed to capture thermal energy of the brine and operate within a Rankine Cycle. Additional details regarding binary geothermal systems are discussed below.
- Enhanced geothermal (or "hot dry rock"): For geologic formations with high temperatures but without the necessary subsurface fluids or permeability, fluid may be injected to develop geothermal resources. Typically, the geologic structure must be hydraulically fractured to achieve a functional geothermal resource. While enhanced geothermal projects are currently being demonstrated around the world (including the Newberry Volcano EGS demonstration near Bend, Oregon), this technology is not yet considered commercial.

Considering the temperatures associated with geothermal resource areas located in Oregon, it is anticipated that geothermal developments would utilize either binary geothermal systems or enhanced geothermal systems. Because of the technical and cost uncertainty associated with enhanced geothermal systems, Black & Veatch has selected binary geothermal options for this characterization and has developed performance and cost parameters for a 35 MW-net binary geothermal facility.

In a binary plant, the thermal energy in the geothermal brine is transferred in a heat exchanger to a secondary working fluid for use in a fairly conventional Rankine cycle, as shown in Figure 4-1. The brine itself does not contact moving parts of the power plant, thus minimizing the potential of equipment fouling (e.g., scaling, corrosion or erosion). Binary plants may be especially advantageous for low brine temperatures (i.e., less than about 350°F [177°C])) or for brines with high dissolved gases or high corrosion or scaling potential.



Source: Colorado Department of Natural Resources

Figure 4-1 Binary Geothermal System

Most binary plants operate on pumped wells and geothermal fluid remains in the liquid phase throughout the plant, from production wells through the heat exchangers to the injection wells. Dry cooling is typically used with a binary plant to avoid the necessity for make-up water required for a wet cooling system. Dry cooling systems generally add 5 to 10 percent to the cost of the power plant compared to wet cooling systems. Because of chemical impurities, the waste geothermal fluid is not generally suitable for cooling tower make-up. There is a wide range of candidate working fluids for the closed power cycle. The working fluid of the binary system is generally selected to achieve good thermodynamic match to the particular geothermal temperature. The optimal fluid would provide high utilization efficiency with safe and economical operation.

4.2.2 Technology-Specific Assumptions

Relevant assumptions employed in the development of performance and cost parameters for the 35 MW-net geothermal energy facility include the following:

- The geothermal energy facility would employ a binary geothermal system with dry cooling methods (rather than a wet cooling tower) to minimize water requirements.
- The facility will have an average annual capacity factor of 85 percent.
- To extract and re-inject geothermal brine, the facility would utilize 5 supply wells and 5 return wells.
  - Capital costs estimated by Black & Veatch include the cost of well development.
  - Variable O&M costs estimated by Black & Veatch include costs associated with development of 1 new supply well every 5 years. When drilling replacement wells, it is assumed that 1 out of every 5 supply wells is dry (i.e., does not provide sufficient flow and is unusable), and well replacement costs include costs associated with drilling of dry wells.
- The geothermal project would require 35 acres of land, and this land would be leased for the lifetime of the project. Land lease costs for the geothermal facility are included in the Variable O&M costs estimated by Black & Veatch.

4.3 TECHNICAL AND FINANCIAL PARAMETERS

Technical parameters for renewable energy options considered for PGE are summarized in Table 4-1, while cost and financial parameters for renewable energy options considered for PGE are summarized in Table 4-2.

Table 4-1 Technical Parameters for Renewable Generation Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)[1]	AVERAGE DESIGN LIFE NET CAPACITY, INCLUDING DEGRADATION (MW)	CAPACITY FACTOR (PERCENT)	LAND REQUIRED (ACRES/ MW)[2]	NET PLANT HEAT RATE (BTU/ kWh-HHV)	AVERAGE DESIGN LIFE NET PLANT HEAT RATE, INCLUDING DEGRADATION (BTU/kWh-HHV)	FUEL CONSUMPTION VERSUS OUTPUT (MMBtu-HHV VERSUS KW-NET, NEW AND CLEAN)[3]	MINIMUM TURNDOWN CAPACITY (PERCENT)[4]	RAMP RATE (MW/MIN)	MINIMUM RUN/ DOWN TIMES (HOURS)	START TIME TO FULL LOAD (MINS)[5]	WATER CONSUMPTION (MGD)	SCHEDULED MAINTENANCE (WEEKS/YR)[6]	EQUIVALENT FORCED OUTAGE RATE – DEMAND (PERCENT)	EPC PERIOD (MONTHS)[7]
Biomass Combustion	35	35	85	1.0	13,000	13,350	N/A	25	1.75	8.0 / 8.0	180	1.0	3.83	7.5	36
Geothermal -- Binary	35	N/A	85	1.0	N/A	See Note (8)	N/A	50	4.5	0.5 / 0.5	10	0.2	3.83	6.0	24[(9)]

Notes:

1. Performance parameters assume International Organization for Standardization (ISO) conditions (59° F, 60% relative humidity, and sea level elevation). Net capacity is defined as the nameplate (or gross) unit capacity minus any auxiliary losses.
2. Typical value; actual value is specific to project, location, and owner's requirements.
3. For combustion turbines and reciprocating engines, heat rate is a function of output as well as fuel consumption. In Black & Veatch's experience, providing a curve showing fuel consumption as a function of output provides a more accurate result. The curve provided is fuel consumption versus output (MMBtu-HHV versus kW-net, new and clean). Heat rate can be further determined by dividing fuel consumption by output.
4. While maintaining emissions compliance for combustion turbine and reciprocating engine based option.
5. Start times exclude purge time. Combined cycle start time definitions: Hot start is defined as a start after an 8 hour shutdown (generally considered 8 hours or less). Warm start is defined as a start after a 48 hour shutdown (generally considered 8 to 48 hours). Cold start is defined as a start when the steam turbine rotor temperature is at or near atmospheric temperature (generally considered greater than 48 hours).
6. Maintenance values are annual averages based on prime mover (combustion turbine or reciprocating engine) manufacturer recommended maintenance.
7. The project duration period starts with EPC contractor notice to proceed (NTP) and ends at the commercial operation date (COD). Some excluded activities are permitting and EPC specification development.
8. Geothermal resources typically degrade at about 1.5°F per year. This is typically accounted for via decrease in net power output, which may be mitigated somewhat by additional well that is drilled once per five years.
9. EPC period for geothermal projects is considered 24 months for construction of generation systems. Project development, including drilling of test wells and associated well development activities, is assumed to require 24 months, but development is assumed to be conducted prior to the EPC period.

Table 4-2 Financial Parameters for Renewable Generation Options

SUPPLY-SIDE OPTION	BOOK LIFE (YEARS)	EXPENDITURE PATTERN (BY MONTH)	OVERNIGHT EPC CAPITAL COST ($000, 2017$)	OWNER'S COST ALLOWANCE (PERCENT)[10]	OVERNIGHT TOTAL CAPITAL COST ($000, 2017$)	OVERNIGHT TOTAL CAPITAL COST STANDARD DEVIATION, 1σ ($000, 2017$)	FIXED O&M COSTS ($/kW-YEAR)[11]	NONFUEL VARIABLE O&M COST (2017$/MWh)[11]	NONFUEL VARIABLE WEAR AND TEAR COSTS (2017$/MWh)[12]	CAPITAL ADDITIONS/ MAINTENANCE ACCRUAL (2017$/YEAR)	NONFUEL STARTUP VARIABLE O&M COSTS (2017$/ START)[13]	STARTUP FUEL CONSUMPTION (MMBTU-HHV/ START)[14]	DECOMMISSIONING COST ($000, 2017$)[15]
Biomass Combustion	40	Refer to Appendix B	170,800	25	213,500	32,000	145	9.6	N/A	See Note (16)	N/A	N/A	2,080
Geothermal -- Binary	30	Refer to Appendix B	235,700	25	282,800	70,700	110	16.8	N/A	See Note (16)	N/A	N/A	3,940

Notes (continued from Table 4-1):

10. Owner's cost allowance includes costs associated with project development, operating spare parts and plant equipment, owner's contingencies and project management, utility interconnections, taxes, and legal fees. The owner's cost allowance can vary widely.
11. Estimates expressed in terms of new and clean condition.
12. Estimated wear and tear costs include annualized estimated variable maintenance costs on the turbines, generators, HRSG, and SCR catalysts, as applicable.
13. Assumes average start. Includes makeup water and chemicals. Does not include fuel or electricity.
14. Startup fuel consumption for achieving CTG/RICE full load operation.
15. Decommissioning costs are typically accrued annually over the design life of the asset to decommission the facility. Total project decommissioning costs, net of salvage, are provided in 2017 USD. Assumes the site would be returned to a brownfield condition at the end of its design life.
16. Operation of certain SSOs requires periodic replacement of specific systems or equipment (either dependent upon number of years in service or hours of operation). In instances where these periodic costs are necessary (for the SSOs under consideration in this report), these costs have been included in the relevant O&M costs associated with specific technology options.

5.0 Energy Storage Options

Energy Storage SSOs considered include the following:

- Battery Storage (50 MW, 100 MWh Lithium Ion Battery).
- Battery Storage (10 MW, 60 MWh Redox Flow Battery).

These energy storage options and their performance and cost characteristics are defined in the following subsections.

5.1 BATTERY ENERGY STORAGE

5.1.1 Technology Overview

Batteries are electrochemical cells that convert chemical energy into electrical energy. This conversion is achieved via electrochemical oxidation-reduction (redox) reactions occurring at the electrodes of the batteries. The batteries of interest for this report are secondary batteries that can be recharged (i.e., the redox reaction can be reversed). The main components of a battery are the positive electrode (cathode), the negative electrode (anode) and the electrolyte. The resulting potential, or voltage, of the battery is based on the composition of the electrodes and the redox reactions that occur at the electrodes.[5]

Battery energy storage systems employ multiple (up to several thousand) batteries and are charged via an external source of electrical energy. The battery energy storage system discharges this stored energy to provide a specific electrical function. Examples of these functions, as defined by the Energy Storage Association (ESA), are as follows:

- Spinning Reserve: the use of energy storage to supply generation capacity that is online and dispatchable within 10 minutes.
- Non-Spinning Reserve: a resource that follows spinning reserve dispatch during loss of generation or transmission events and usually required to respond within 10 to 15 minutes.
- Capacity Firming: the use of energy storage to fill in capacity (power) when variable energy resources, such as solar and wind, fall below their rated output.
- Voltage Support: the use of energy storage to manage and supply reactive power on the grid at or near a power factor of 1.
- Frequency Regulation: the use energy storage to maintain grid system frequency with a resource that is capable of responding within seconds.
- Ramping Service: using energy storage ramping to offset excessive ramping of other generating facilities, often variable energy resources such as solar or wind.

[5] Linden's Handbook of Batteries. Edited by Thomas B. Reddy.

The size of a battery energy storage system is based on two parameters: power, usually in kW or MW, and energy, usually in kWh or MWh. The energy storage capacity of a battery designates how long a given energy storage system can discharge at a given power. Other parameters relevant for energy storage systems are:

- Ramp-rate: how quickly an energy storage system can change its power output, typically in MW/ min.
- Response time: how quickly an energy storage system can reach its rated power (constrained by power conversion system [PCS]).
- Round-trip efficiency: the amount of energy discharged from an energy storage system relative to the amount required for charging.
- Discharge duration: how long a battery can be discharged at a given power.
- Charge/Discharge rate (C-rate): how quickly the battery can charge or discharge relative to a one-hour charge or discharge (for example, a 2C rate charges or discharges in 30 minutes).

Operational parameters associated with battery energy storage technologies include:

- State-of-charge (SOC): how much energy is stored in an energy storage system relative to the maximum energy storage capacity. In general, maximum lifetime of battery systems occurs when the SOC is maintained between 10 and 90 percent.
- Depth of discharge (DoD): how discharged an energy storage system is relative to the maximum energy storage capacity.
- Cycles-to-failure (CtF): the number of cycles at 100 percent DoD until the battery's energy storage capacity is degraded to 80 percent of its original capacity.

Battery types employed within battery energy storage systems include lithium-ion (Li-ion), lead-acid and flow batteries. This section will focus on two commonly deployed utility scale battery technologies, namely, Li-ion battery and Redox Flow battery technologies.

5.1.1.1 Lithium Ion Batteries

Lithium ion batteries are a form of energy storage where all the energy is stored electrochemically within each cell. During charging or discharging, lithium ions are created and are the mechanism for charge transfer through the electrolyte of the battery. In general, these systems vary from vendor to vendor by the composition of the cathode or the anode. Some examples of cathode and anode combinations are shown in Figure 5-1.

The battery cells are integrated to form modules. These modules are then strung together in series/ parallel to achieve the appropriate power and energy rating to be coupled to the PCS.

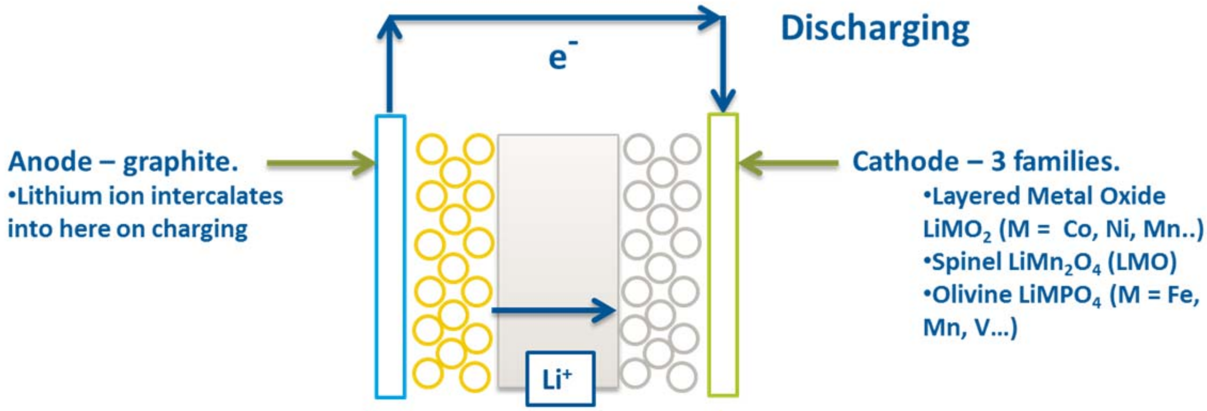


Figure 5-1 Lithium Ion Battery Showing Different Electrode Configurations

Lithium ion battery storage systems are typically used for both power and energy applications. One strength of lithium ion batteries is their strong cycle life. For shallow, frequent cycles, which are quite common for power applications, lithium ion systems demonstrate good cycle life characteristics. Additionally, lithium ion systems demonstrate good cycle life characteristics for deeper discharges common for energy applications. Overall, this technology offers the following benefits:

- Excellent Cycle Life: Lithium ion technologies have superior cycling ability to other battery technologies such as lead acid.
- Fast Response Time: Lithium ion technologies have a fast response time which is typically less than 100 milliseconds.
- High Round Trip Efficiency: Lithium ion energy conversion is efficient and has a 90 percent round trip efficiency (DC-DC).
- Versatility: Lithium ion solutions can provide many relevant operating functions.
- Commercial Availability: Dozens of strong lithium ion vendors.
- Energy Density: Lithium ion solutions have a high energy density to meet space constraints.

An image of a sample lithium ion BESS can be found in Figure 5-2.

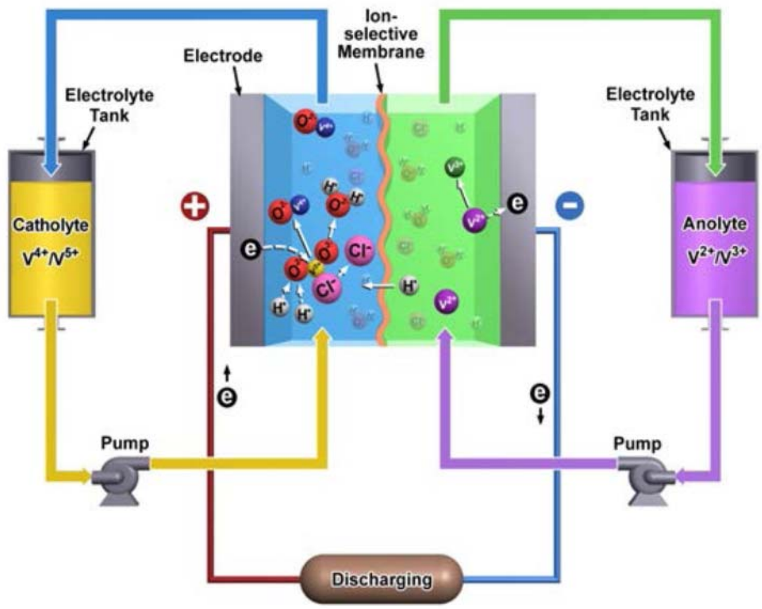
Figure 5-2 Lithium Ion Battery Energy Storage System located at the Black & Veatch Headquarters

Various Li-ion battery systems are installed around the world, including projects in the United States. The 30 MW/ 120 MWh Escondido Li-ion energy storage project owned by SDG&E is currently the largest installed. PGE also employs a 5 MW Li-Ion system at the Salem Smart Power Center (SSPC) as part of the Pacific Northwest Smart Grid Demonstration. According to the DOE Energy Storage Database, the United States installed (or under construction) capacity of Li-ion is about 334 MW.[6]

5.1.1.2 Redox Flow Batteries

Redox flow batteries are another form of electrochemical storage. Redox flow batteries are the most commercially developed technology of the various flow battery technologies. In this technology, the energy for these systems is stored within a liquid electrolyte stored in tanks. The volume of electrolyte can be scaled to produce the desired energy storage capacity; the power cells (where the reactions happen) can be scaled to produce the desired power output. A diagram of a redox flow battery can be found on Figure 5-3.

[6] DOE Energy Storage Database (beta). Sadia National Laboratories. http://www.energystorageexchange.org/, does not include unverified projects



Source: DOE/Electric Power Research Institute [EPRI] 2013 Electricity Storage Handbook.

Figure 5-3 Diagram of Vanadium Redox Flow Battery

This technology is also integrated with a PCS to form the overall BESS. Redox batteries are more typically used for energy applications, as they can more effectively be scaled to longer discharge periods than lithium ion batteries. However, one drawback with flow batteries is the space requirements for these systems relative to other battery technologies. The Redox flow batteries require more space for the installation than lithium ion batteries. Redox BESS can be modular, as shown on Figure 5-4, and containerized systems, as shown on Figure 5-5.

Source: Prudent Energy

Figure 5-4 Redox Flow Battery

Source: UniEnergy.

Figure 5-5 Containerized Flow Battery

Various Flow battery systems are installed around the world, including projects in the United States. The 600 kW Gills Onions Project in California, the 1 MW Avista Project in Washington, and other projects in Japan and China employ Flow batteries. According to the DOE Energy Storage Database, the United States installed (or under construction) capacity of Flow battery is about 4 MW.[7]

A summary of representative performance parameters for battery energy storage systems employing Li-ion and Flow batteries is provided in Table 5-1.

5.1.2 Technology-Specific Assumptions

Black & Veatch developed performance and cost parameters for 50-MW and 10-MW battery energy storage systems, capable of discharging at their rated power for 2 and 6 hours, respectively. Relevant assumptions employed in the development of these performance and cost parameters include the following:

- The battery storage system is assumed to have a 20 year service lifetime. Assuming one (complete) discharge of the battery energy per day, it is anticipated that the battery energy storage modules employed within the system will provide 20 years of operation. No capacity additions (i.e., periodic battery replacement) were included in estimates of either capital costs or O&M costs.
- Service contracts for long-term battery maintenance (provided by the OEM) are included in the fixed O&M costs.

[7] DOE Energy Storage Database (beta). Sandia National Laboratories. http://www.energystorageexchange.org/

Table 5-1 Representative Performance Parameters for Lithium Ion and Redox Flow Energy Storage Systems

PARAMETER	LI-ION	REDOX FLOW
Commercial Availability	Commercial	Commercial
Facility Power Rating, MW	0.005 to 32	0.05 to 5
Module Power Rating, MW	0.005 to 4	0.005 to 0.25
Facility Energy Capacity, MWh	0.005 to 120	0.2 to 10
Module Energy Capacity, MWh	0.1 to 2	0.03 to 0.5
Ramp Rate, MW/min	Note[1]	Note[1]
Response Time[2]	< 100 ms	< 100 ms
Round-Trip Efficiency, percent	75 to 90	65 to 75
Discharge Duration, hours	0.25 to 4	3 to 8
Charge/Discharge Rate, C[3]	C/4 to 4C	C/8 to C/3

Notes:
1. Li-ion and Redox Flow systems are able to ramp up from an idle status to full rated capacity in less than 1 second.
2. Amount of time system takes to reach rated power.
3. Charge/discharge rate is conventionally expressed in terms of “C-rate”. Under this convention, a system with a charge/discharge rate of 2C could be fully charged or discharged in 30 minutes (1/2 hour), while a system with a charge/discharge rate of 6C could be fully charged or discharged in 10 minutes (1/6 hour).

5.2 TECHNICAL AND FINANCIAL PARAMETERS

Technical parameters for energy storage options considered for PGE are summarized in Table 5-2, while cost and financial parameters for energy storage options considered for PGE are summarized in Table 5-3. Additional parameters specific to energy storage options are shown in Table 5-4.

Table 5-2 Technical Parameters for Energy Storage Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)[1]	AVERAGE DESIGN LIFE NET CAPACITY, INCLUDING DEGRADATION (MW)	CAPACITY FACTOR (PERCENT)	LAND REQUIRED (ACRES/MW)[2]	NET PLANT HEAT RATE (BTU/ kWh-HHV)	AVERAGE DESIGN LIFE NET PLANT HEAT RATE, INCLUDING DEGRADATION (BTU/kWh-HHV)	HEAT RATE VERSUS OUTPUT (BTU/KWh-HHV VERSUS KW-NET, NEW AND CLEAN)	MINIMUM TURNDOWN CAPACITY (PERCENT)	RAMP RATE (MW/MIN)	MINIMUM RUN/ DOWN TIME (HOURS)	START TIME TO FULL LOAD (MINS)	WATER CONSUMPTION (MGD)	SCHEDULED MAINTENANCE (WEEKS/YR)	EQUIVALENT FORCED OUTAGE RATE – DEMAND (PERCENT)	EPC PERIOD (MONTHS)[3]
Battery Storage – Lithium Ion	50	N/A	N/A	0.04[(4)]	N/A	N/A	N/A	0	Refer to Note 5	N/A	N/A	N/A	2	N/A	12 to 15
Battery Storage – Redox Flow	10	N/A	N/A	0.16[(4)]	N/A	N/A	N/A	0	Refer to Note 5	N/A	N/A	N/A	2	N/A	12 to 15

Notes:

1. Performance parameters assume ISO conditions (59° F, 60% relative humidity, and sea level elevation). Net capacity is defined as the nameplate (or gross) unit capacity minus any auxiliary losses.
2. Typical value; actual value is specific to project, location, and owner's requirements.
3. The project duration period starts with EPC contractor NTP and ends at the COD. Some excluded activities are permitting and EPC specification development.
4. For battery energy storage systems (BESS), 1 acre can accommodate approximately 40 to 60 MWh of energy storage capacity. Therefore, a 50 MW|100 MWh system would require approximately 2 acres and a 10 MW|40 MWh system would require approximately 1 acre.
5. BESS are able to ramp up from an idle status to full rated capacity in less than 1 second.

Table 5-3 Financial Parameters for Energy Storage Options

SUPPLY-SIDE OPTION	BOOK LIFE (YEARS)	EXPENDITURE PATTERN (BY QUARTER)	OVERNIGHT EPC CAPITAL COST ($000, 2017$)	OWNER'S COST ALLOWANCE (PERCENT)[6]	OVERNIGHT TOTAL CAPITAL COST ($000, 2017$)	OVERNIGHT TOTAL CAPITAL COST STANDARD DEVIATION, 1σ ($000, 2017$)	FIXED O&M COSTS ($/kW-YEAR)[7]	NONFUEL VARIABLE O&M COST (2017$/MWh)[7]	NONFUEL VARIABLE WEAR AND TEAR COSTS (2017$/MWh)[8]	CAPITAL ADDITIONS/ MAINTENANCE ACCRUAL (2017$/YEAR)	NONFUEL STARTUP VARIABLE O&M COSTS (2015$/ START)	FUEL STARTUP VARIABLE O&M COSTS (MMBTU-HHV/ START)	DECOMMISSIONING COST ($000, 2017$)[9]
Battery Storage	20	Refer to Appendix B	71,000	12	79,500	9,900	12	N/A	N/A	200,000[(10)]	N/A	N/A	1,240
Battery Storage	20	Refer to Appendix B	36,700	12	41,100	5,100	30	N/A	N/A	45,000[(10)]	N/A	N/A	640

Notes (continued from Table 5-2):

6. Owner's cost allowance includes costs associated with project development, operating spare parts and plant equipment, owner's contingencies and project management, utility interconnections, taxes, and legal fees. The owner's cost allowance can vary widely.
7. Estimates expressed in terms of new and clean condition.
8. Estimated wear and tear costs include annualized estimated variable maintenance costs on the turbines, generators, and batteries.
9. Decommissioning costs are typically accrued annually over the design life of the asset to decommission the facility. Total project decommissioning costs, net of salvage, are provided in 2015 USD. For all SSOs except Pumped Storage Hydro, the site would be returned to a brownfield condition at the end of its design life. For Pumped Storage Hydro, it is assumed that powerhouse equipment would be decommissioned and salvaged, and the facility/reservoirs would be retired in place, with the site secured as appropriate (e.g., reservoirs drained, additional security fencing installed, and signs posted).
10. The cost per year presented here assumes 365 cycles per year at 80% depth of discharge (DoD) for both technologies. For lithium ion, the degradation per year is approximately 1.8%. For vanadium redox, the degradation is less than 1% per year.

Table 5-4 Additional Parameters for Energy Storage Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)	ENERGY CAPACITY (MWh)	ROUND TRIP EFFICIENCY (PERCENT)
Battery Storage – Lithium Ion	50	100	85
Battery Storage – Redox Flow	10	60	75

Appendix A. Supply-Side Option Parameters (Full Table)

		Design Basis Parameters							Technical/Performance Parameters												
No.	Supply-Side Option	Option Design Basis	Duty	Net Capacity (MW)[1]	Average Design Life Net Capacity, Including Degradation (MW)	Capacity Factor (%)	Primary Fuel	Land Required (acres/MW)[2]	Net Plant Heat Rate (Btu/kWh-HHV)	Average Design Life Net Plant Heat Rate, Including Degradation (Btu/kWh-HHV)	Heat Rate vs Output (Btu/kWh versus kW-net, New and Clean)	Fuel Consumption versus Output (MMBtu/hr-HHV versus kW-net, New and Clean)[3]	Minimum Turndown Capacity (%)[4]	Ramp Rate (MW/min)	Minimum Run/Down Times (hours)	Start Time to Full Load (mins)[5]	Water Consumption (MGD)	Scheduled Maintenance (weeks/yr)[6]	Equivalent Forced Outage Rate - Demand (%)	EPC Period[7] (months)
1	1x0 GE 7F.05	Combustion Turbine: GE 7F.05 Emissions Control: SCR, CO catalyst	Peaking	231	218	11%	Natural Gas	0.04	9,830	10,170	See Next Column	$y = 1.657E\text{-}08x^2 + 1.883E\text{-}03x + 9.521E{+}02$	43%	40	0.5 / 0.5	11	0	1.80	4.0%	24
2	6x0 Wartsila 18V50SG	Recip. Engine: Wartsila 18V50SG Heat Rejection: Wet Cooling Tower Emissions Control: SCR, CO catalyst	Peaking	110	107	25%	Natural Gas	0.06	8,300	8,470	See Next Column	$y = -3.336E\text{-}09x^2 + 7.875E\text{-}03x + 8.800E{+}01$	25%	84	0.5 / 0.5	10	0.36	0.90	2.2%	24
3	1x1 GE 7HA.01	Combustion Turbine: GE 7HA.01 Duct Firing: None Emissions Control: SCR, CO catalyst Heat Rejection: Wet Cooling Tower	Intermediate	424	400	70%	Natural Gas	0.04	6,290	6,450	See Next Column	$y = 1.638E\text{-}09x^2 + 4.583E\text{-}03x + 4.283E{+}02$	33%	55	1.5 / 1.5	Hot: 60 Warm: 100 Cold: 210	1.90	3.90	2.9%	30
4	Biomass Combustion	Boiler: Bubbling Fluidized Bed Emissions Control: SNCR, Fabric Filter Heat Rejection: Wet Cooling Tower	Baseload	35	35	85%	Wood	1.0	13,000	13,350	$y = 3.918E\text{-}06x^2 - 0.3086x + 19{,}000$	n/a	25%	1.75	8.0 / 8.0	180	1.0	3.83	7.5%	36
5	Geothermal -- Binary	System: Binary Geothermal System Heat Rejection: Air-Cooled Condenser	Baseload	35	n/a	85%	n/a	1.0	n/a	n/a	Refer to Note 21	n/a	50%	4.5	0.5 / 0.5	10	0.20	3.83	6.0%	24[16]
6	Battery Storage -- Lithium Ion	Battery: Lithium Ion Discharge Duration: 2 hrs	Storage	50	n/a	n/a	n/a	0.04[14]	n/a	n/a	n/a	n/a	0%	Refer to Note 15	n/a	n/a	n/a	2	n/a	12 to 15
7	Battery Storage -- Redox Flow	Battery: Redox Flow Discharge Duration: 6 hrs	Storage	10	n/a	n/a	n/a	0.16[14]	n/a	n/a	n/a	n/a	0%	Refer to Note 15	n/a	n/a	n/a	2	n/a	12 to 15

NOTES:

(1) Performance parameters assume ISO conditions (59° F, 60% relative humidity, and sea level elevation). Net capacity is defined as the nameplate (or gross) unit capacity, minus any auxiliary losses.

(2) Typical value; actual value is specific to project, location, and owner's requirements.

(3) For combustion turbines and reciprocating engines, heat rate is a function of output as well as fuel consumption. In Black & Veatch's experience, providing a curve showing fuel consumption as a function of output provides a more accurate result. The curve provided is Fuel Consumption versus Output (MMBtu-HHV versus kW-net, New and Clean). Heat rate can be further determined by dividing fuel consumption by output.

(4) While maintaining emissions compliance for Options 1 through 7.

(5) Start times exclude purge time. Combined cycle start time definitions: Hot start is defined as a start after an 8 hour shutdown (generally considered 8 hours or less). Warm start is defined as a start after a 48 hour shutdown (generally considered 8 to 48 hours). Cold start is defined as a start when the steam turbine rotor temperature is at or near atmospheric temperature (generally considered greater than 48 hours).

(6) Natural gas fueled option maintenance values are annual averages based on prime mover (combustion turbine or reciprocating engine) manufacturer recommended maintenance, excluding annual outages. Renewable option maintenance based on industry norms

(7) The project duration period starts with EPC contractor notice to proceed (NTP) and ends at the commercial operation date (COD). Some excluded activities are permitting and EPC specification development

(8) Owner's cost allowance includes costs associated with project development, operating spare parts and plant equipment, owner's contingencies and project management, utility interconnections, taxes, and legal fees. The owner's cost allowance can vary widely

(9) Estimates expressed in terms of new and clean condition.

(10) Estimated wear and tear costs include annualized estimated variable maintenance costs on the turbines, generators,steam generator, batteries, and SCR catalysts, as applicable

(11) Assumes average start. Includes makeup water and chemicals. Does not include fuel or electricity

(12) Startup fuel consumption for achieving CTG/RICE full load operation.

(13) Decommissioning costs are typically accrued annually over the design life of the asset to decommission the facility. Total project decommissioning costs are provided in 2017 USD. For all SSOs, the site would be returned to a brownfield condition at the end of its design life.

(14) For battery energy storage systems (BESS), 1 acre can accommodate approximately 40 to 60 MWh of energy storage capacity. Therefore, a 50 MW|100 MWh system would require approximately 2 acres and a 10 MW|40 MWh system would require approximately 1 acre

(15) BESS are able to ramp up from an idle status to full rated capacity in less than 1 second

(16) EPC period for geothermal projects is considered 24 months for construction of generation systems. Project development, including drilling of test wells and associated well development activities, is assumed to require 24 months, but development is assumed to be conducted prior to the EPC period

(17) Design life for battery energy storage options is consistent with the warranties/guarantees provided by battery OEMs and is consistent with the capacity maintenance costs listed in the Table

(18) Operation of certain SSOs requires periodic replacement of specific systems or equipment (either dependent upon number of years in service or hours of operation). In instances where these periodic costs are necessary (for the SSOs under consideration in this report), these costs have been included in the relevant O&M costs associated with specific technology options

(19) The cost per year presented here assumes 365 cycles per year at 80% depth of discharge (DoD) for both technologies. For lithium ion, the degradation per year is approximately 1.8%. For vanadium redox, the degradation is less than 1% per year.

(20) Daily storage based on the 8 hours of discharge per day.

(21) Geothermal resources typically degrade at about -1.5degF per year. This is typically accounted for via decrease in net power output, which may be mitigated somewhat by additional well that is drilled once per five years

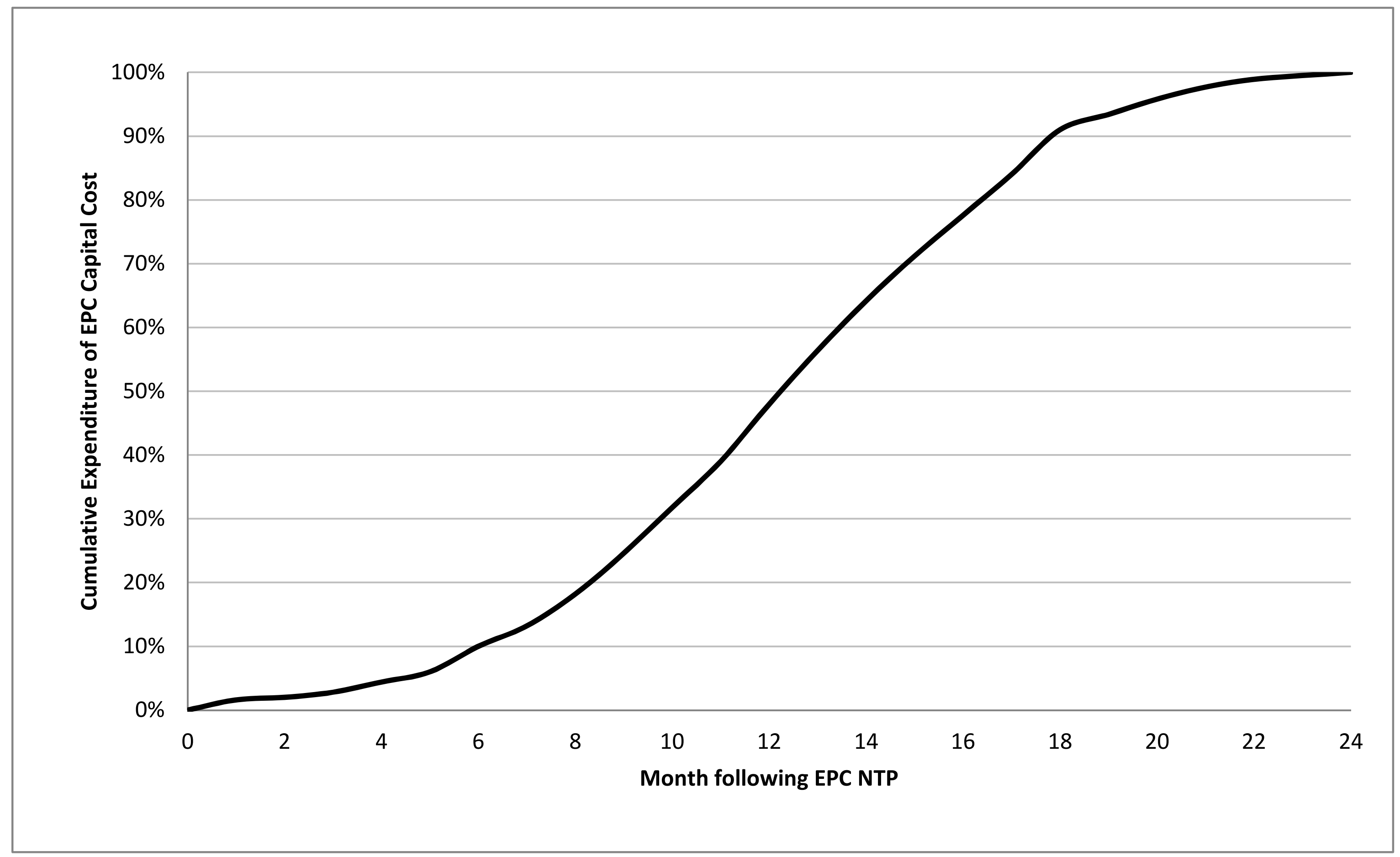
		Financial Parameters													Energy Storage Parameters	
No.	Supply-Side Option	Book Life (years)	Expenditure Pattern (by month/qtr)	Overnight EPC Capital Cost ($000, 2017$)	Owner's Cost Allowance [8] (%)	Overnight Total Capital Cost ($000, 2017$)	Overnight Total Capital Cost Standard Deviation, 1σ ($,000, 2017$)	Fixed O&M Cost (2017$/kW-year)[9]	Nonfuel Variable O&M Cost (2017$/MWh) [9]	Nonfuel Variable Wear and Tear Costs (2017$/MWh)[10]	Capital Additions/ Maintenance Accrual (2017$/yr)	Nonfuel Startup Variable O&M Costs (2017$/start)[11]	Fuel Startup Variable O&M Usage (MMBtu-HHV/start)[12]	Decommissioning Cost ($000, 2017$)[13]	Energy Capacity (MWh)	Round Trip Efficiency (%)
2	1x0 GE 7F.05	30	Refer to Appendix B	115,000	25%	143,750	10,800	6.7	6.9	6.7	Refer to Note 18	4	295	1,380	n/a	n/a
3	6x0 Wartsila 18V50SG	30	Refer to Appendix B	116,000	25%	145,000	10,900	11.0	7.2	6.3	Refer to Note 18	11	72	1,260	n/a	n/a
5	1x1 GE 7HA.01	30	Refer to Appendix B	449,000	25%	561,250	56,200	7.4	3.3	2.7	Refer to Note 18	370	950	9,770	n/a	n/a
7	Biomass Combustion	40	Refer to Appendix B	170,800	25%	213,500	32,000	145	9.60	n/a	Refer to Note 18	n/a	n/a	2,080	n/a	n/a
8	Geothermal -- Binary	30	Refer to Appendix B	235,700	20%	282,800	70,700	110	16.8	n/a	Refer to Note 18	n/a	n/a	3,940	n/a	n/a
10	Battery Storage -- Lithium Ion	20[17]	Refer to Appendix B	71,000	12%	79,500	9,900	12	n/a	n/a	200,000[19]	n/a	n/a	1,240	100	85
11	Battery Storage -- Redox Flow	20[17]	Refer to Appendix B	36,700	12%	41,100	5,100	30	n/a	n/a	45,000[19]	n/a	n/a	640	60	75

Appendix B. SSO Expenditure Patterns

Expenditure Pattern for EPC Capital Cost

Supply Side Option: 1x0 MW GE 7F.05

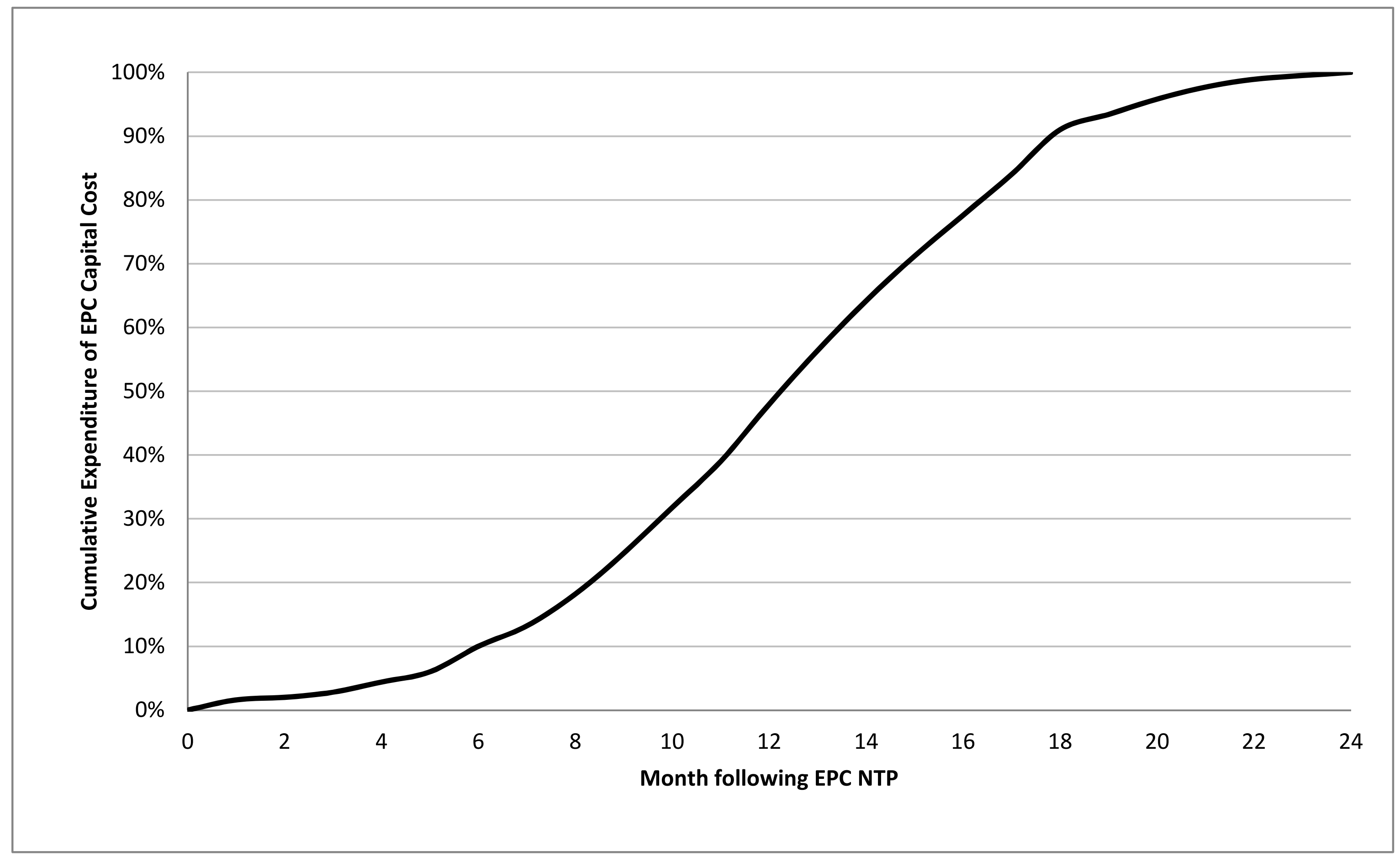
Year	Month	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	1.6%	1.6%
1	2	2	0.4%	2.0%
1	3	3	0.8%	2.8%
1	4	4	1.6%	4.4%
1	5	5	1.6%	6.0%
1	6	6	4.0%	10.0%
1	7	7	3.2%	13.2%
1	8	8	5.0%	18.2%
1	9	9	6.4%	24.6%
1	10	10	7.2%	31.8%
1	11	11	7.2%	39.0%
1	12	12	9.0%	48.0%
2	1	13	8.4%	56.4%
2	2	14	7.8%	64.2%
2	3	15	7.0%	71.2%
2	4	16	6.4%	77.6%
2	5	17	6.4%	84.0%
2	6	18	7.0%	91.0%
2	7	19	2.4%	93.4%
2	8	20	2.4%	95.8%
2	9	21	1.9%	97.7%
2	10	22	1.2%	98.9%
2	11	23	0.6%	99.5%
2	12	24	0.5%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 6x0 Wartsila 18V50SG

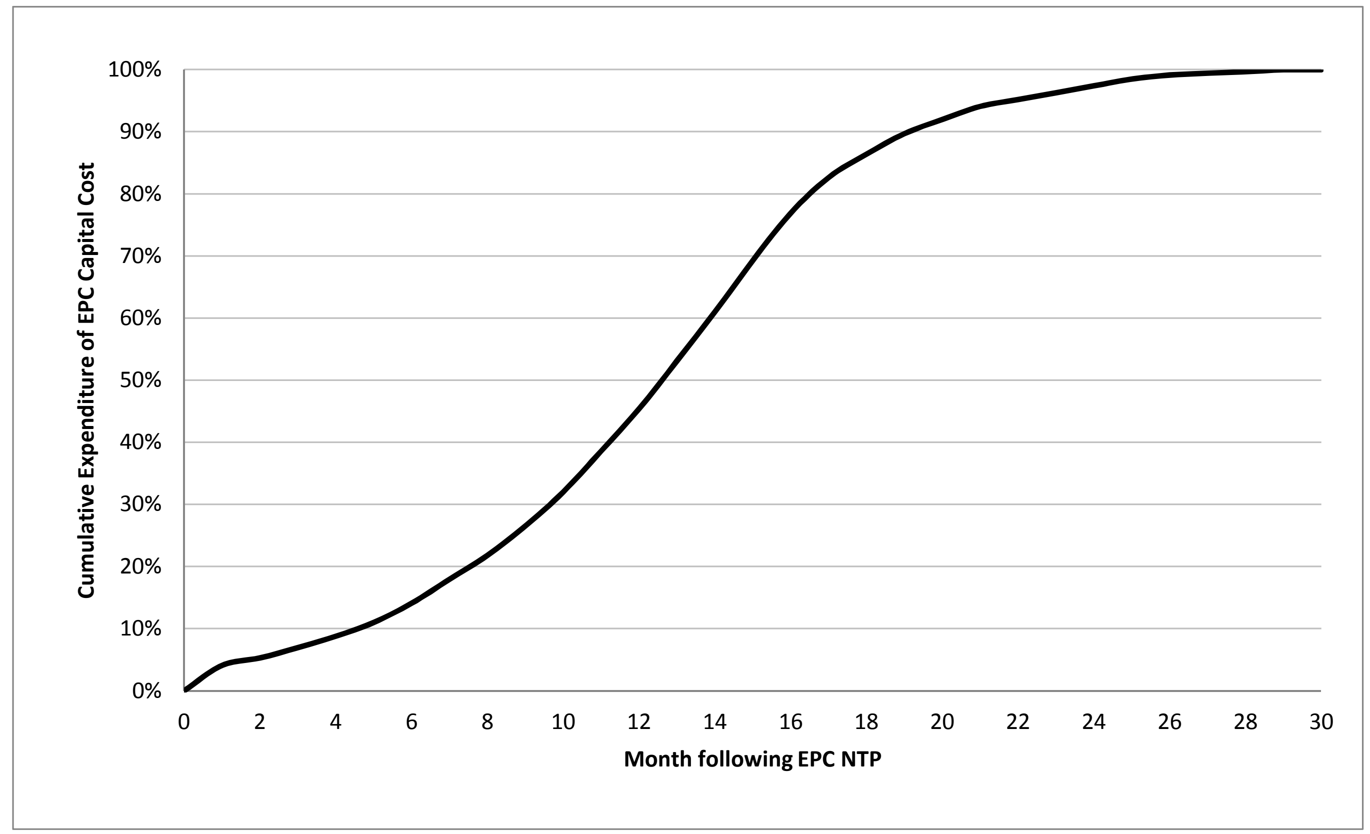
Year	Month	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	1.6%	1.6%
1	2	2	0.4%	2.0%
1	3	3	0.8%	2.8%
1	4	4	1.6%	4.4%
1	5	5	1.6%	6.0%
1	6	6	4.0%	10.0%
1	7	7	3.2%	13.2%
1	8	8	5.0%	18.2%
1	9	9	6.4%	24.6%
1	10	10	7.2%	31.8%
1	11	11	7.2%	39.0%
1	12	12	9.0%	48.0%
2	1	13	8.4%	56.4%
2	2	14	7.8%	64.2%
2	3	15	7.0%	71.2%
2	4	16	6.4%	77.6%
2	5	17	6.4%	84.0%
2	6	18	7.0%	91.0%
2	7	19	2.4%	93.4%
2	8	20	2.4%	95.8%
2	9	21	1.9%	97.7%
2	10	22	1.2%	98.9%
2	11	23	0.6%	99.5%
2	12	24	0.5%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 1x1 GE 7HA.01

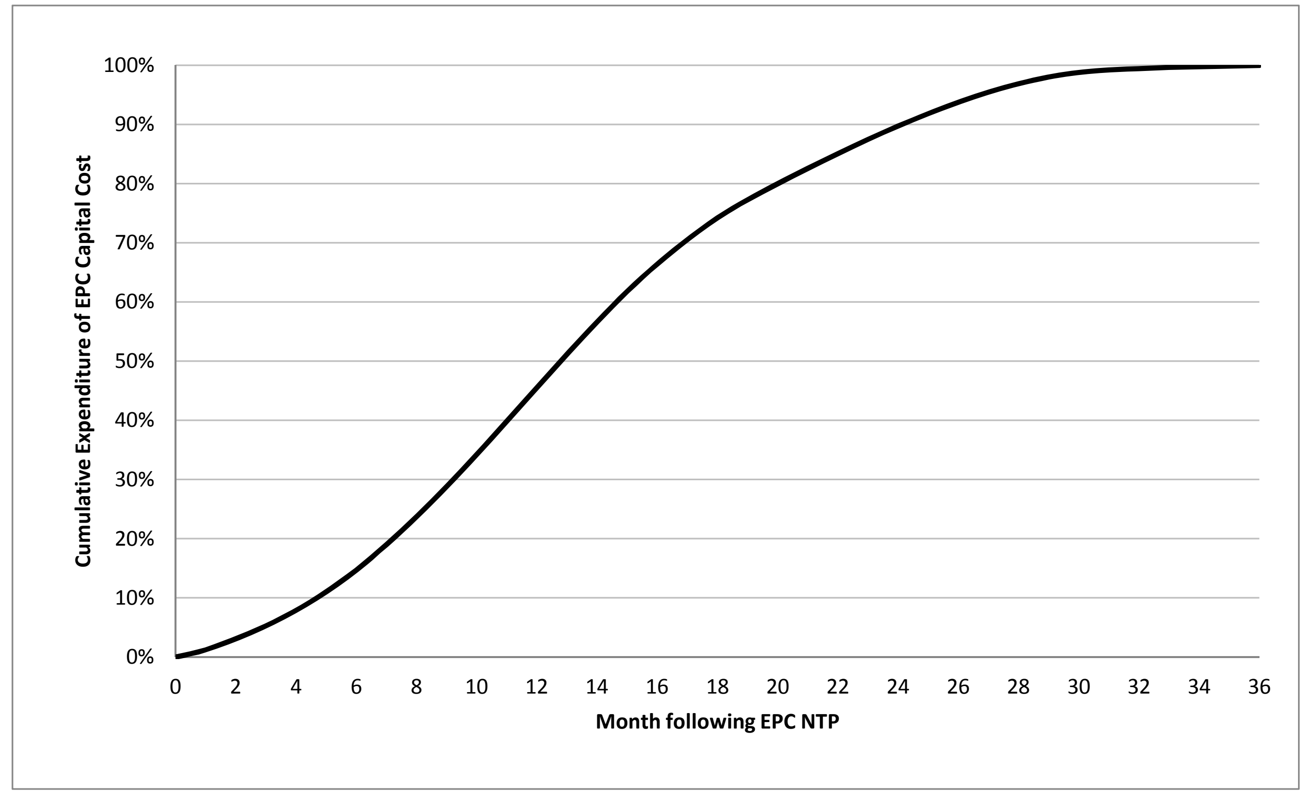
Year	Month	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	4.1%	4.1%
1	2	2	1.2%	5.3%
1	3	3	1.7%	7.0%
1	4	4	1.9%	8.8%
1	5	5	2.2%	11.0%
1	6	6	3.1%	14.1%
1	7	7	3.9%	18.0%
1	8	8	3.9%	21.8%
1	9	9	4.8%	26.6%
1	10	10	5.5%	32.0%
1	11	11	6.6%	38.6%
1	12	12	6.8%	45.4%
2	1	13	7.7%	53.1%
2	2	14	7.9%	61.0%
2	3	15	8.3%	69.3%
2	4	16	7.7%	76.9%
2	5	17	5.8%	82.7%
2	6	18	3.8%	86.4%
2	7	19	3.3%	89.7%
2	8	20	2.3%	92.0%
2	9	21	2.1%	94.1%
2	10	22	1.1%	95.2%
2	11	23	1.1%	96.3%
2	12	24	1.1%	97.4%
3	1	25	1.1%	98.5%
3	2	26	0.7%	99.2%
3	3	27	0.3%	99.4%
3	4	28	0.3%	99.7%
3	5	29	0.3%	100.0%
3	6	30	0.0%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 35 MW Biomass Combustion (BFB)

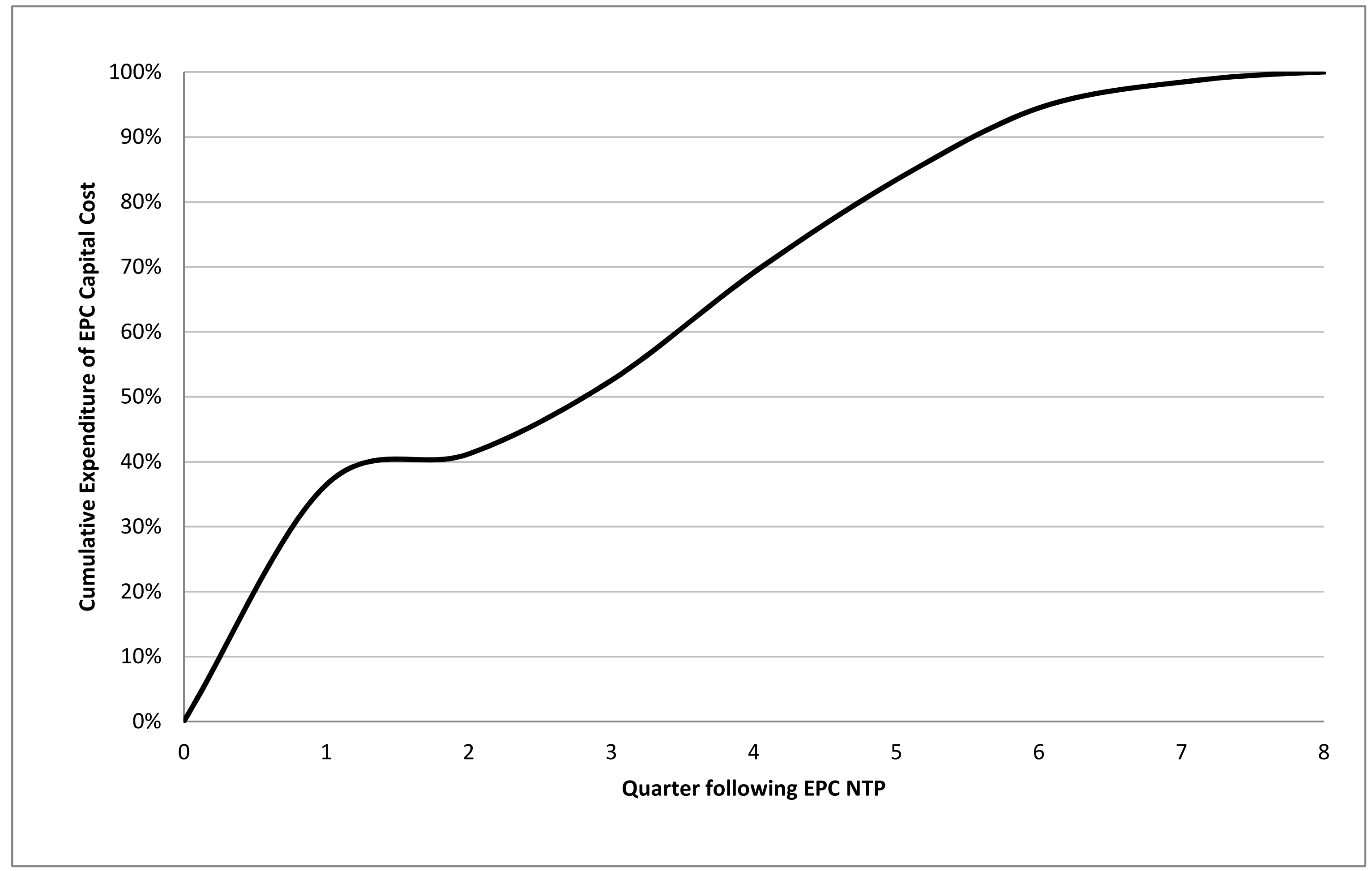
Year	Quarter	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	1.2%	1.2%
1	2	2	1.9%	3.1%
1	3	3	2.2%	5.3%
1	4	4	2.6%	7.9%
1	5	5	3.2%	11.0%
1	6	6	3.7%	14.7%
1	7	7	4.3%	19.0%
1	8	8	4.7%	23.7%
1	9	9	5.1%	28.8%
1	10	10	5.4%	34.2%
1	11	11	5.6%	39.8%
1	12	12	5.7%	45.5%
2	1	13	5.6%	51.2%
2	2	14	5.5%	56.6%
2	3	15	5.2%	61.8%
2	4	16	4.6%	66.4%
2	5	17	4.1%	70.5%
2	6	18	3.7%	74.2%
2	7	19	3.0%	77.3%
2	8	20	2.7%	80.0%
2	9	21	2.6%	82.6%
2	10	22	2.5%	85.1%
2	11	23	2.4%	87.5%
2	12	24	2.2%	89.7%
3	1	25	2.1%	91.8%
3	2	26	1.9%	93.8%
3	3	27	1.7%	95.5%
3	4	28	1.4%	96.9%
3	5	29	1.1%	98.0%
3	6	30	0.8%	98.8%
3	7	31	0.4%	99.2%
3	8	32	0.2%	99.5%
3	9	33	0.2%	99.6%
3	10	34	0.1%	99.8%
3	11	35	0.1%	99.9%
3	12	36	0.1%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 35 MW Geothermal

Year	Quarter	Cumulative Quarter	Quarterly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	36.5%	36.5%
1	2	2	4.7%	41.2%
1	3	3	11.3%	52.5%
1	4	4	16.6%	69.1%
2	1	5	14.3%	83.4%
2	2	6	11.1%	94.5%
2	3	7	4.0%	98.5%
2	4	8	1.5%	100.0%
3	1	9	0.0%	100.0%
3	2	10	0.0%	100.0%
3	3	11	0.0%	100.0%
3	4	12	0.0%	100.0%
4	1	13	0.0%	100.0%
4	2	14	0.0%	100.0%
4	3	15	0.0%	100.0%
4	4	16	0.0%	100.0%
5	1	17	0.0%	100.0%
5	2	18	0.0%	100.0%
5	3	19	0.0%	100.0%
5	4	20	0.0%	0.0%



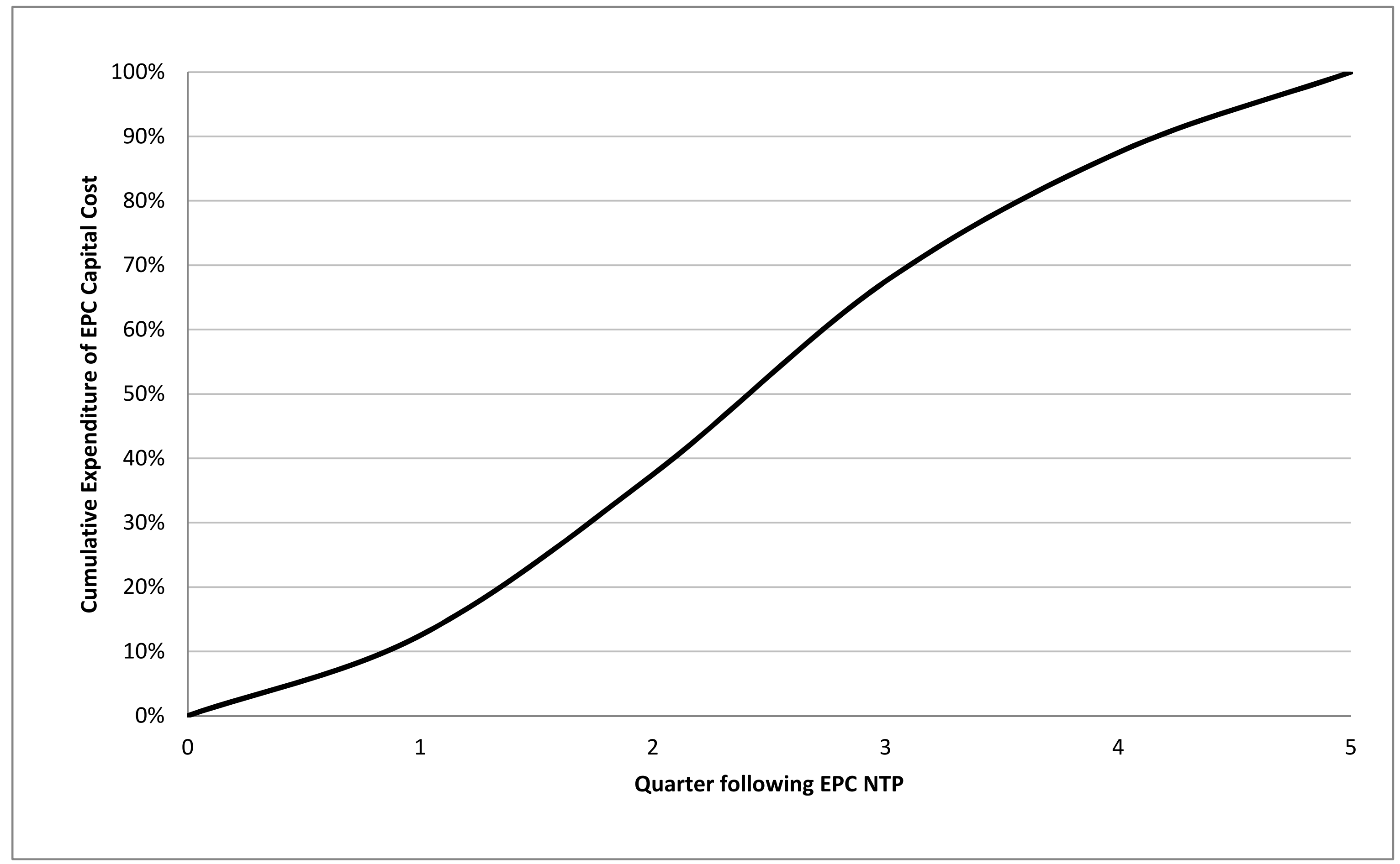
Note:

(1) Geothermal expenditure pattern assumes project development (including well field development) represents roughly one-third of project cost. It is assumed that PGE would buy the project at the beginning of the EPC contract, and all development costs would be re-imbursed to the project developer during Month 1 of the EPC period.

Expenditure Pattern for EPC Capital Cost

Supply Side Option: 50 MW Li-Ion Battery Energy Storage

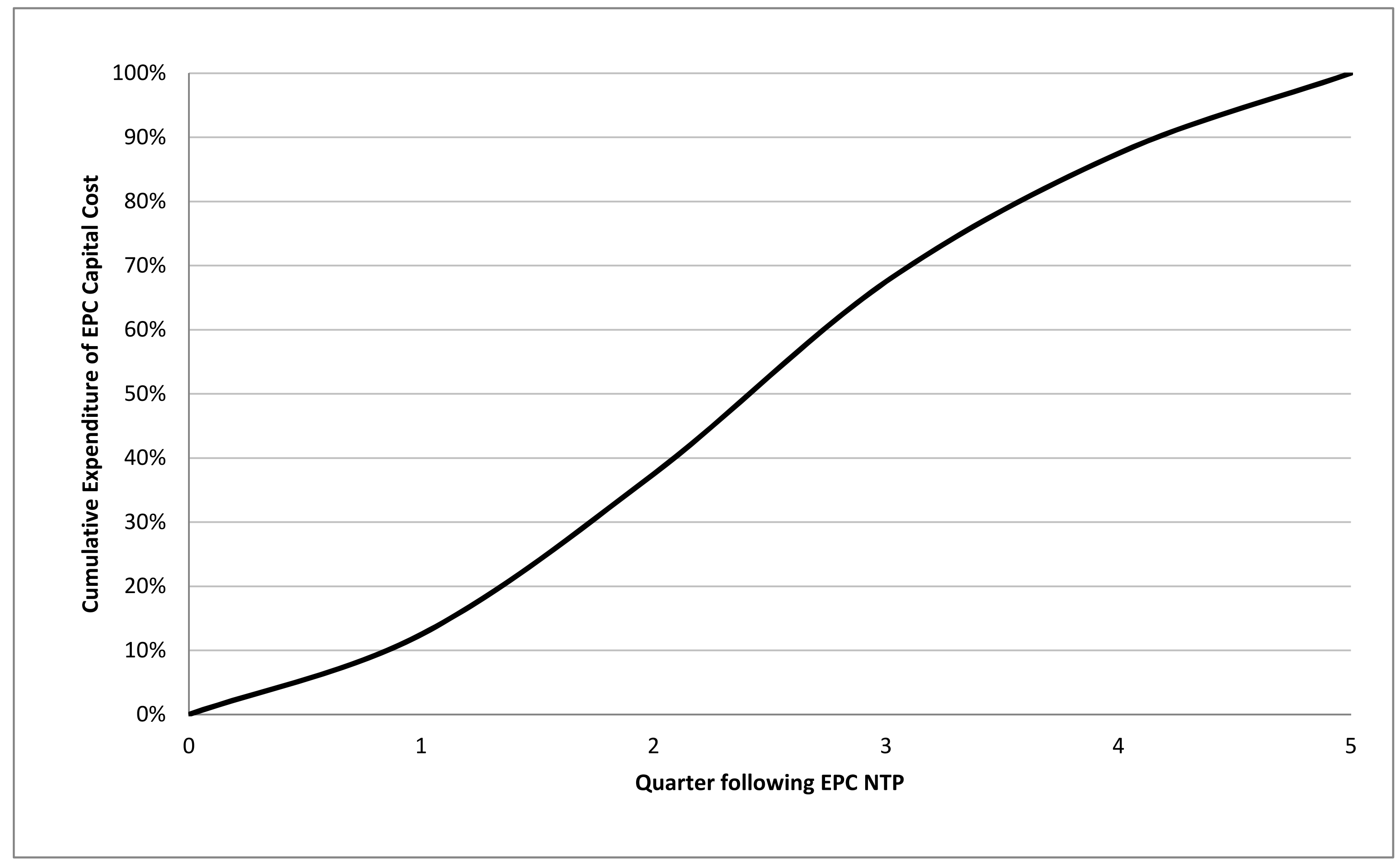
Year	Quarter	Cumulative Quarter	Quarterly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	12.5%	12.5%
1	2	2	25.0%	37.5%
1	3	3	30.0%	67.5%
1	4	4	20.0%	87.5%
2	1	5	12.5%	100.0%
2	2	6	0.0%	100.0%
2	3	7	0.0%	100.0%
2	4	8	0.0%	100.0%
3	1	9	0.0%	100.0%
3	2	10	0.0%	100.0%
3	3	11	0.0%	100.0%
3	4	12	0.0%	100.0%
4	1	13	0.0%	100.0%
4	2	14	0.0%	100.0%
4	3	15	0.0%	100.0%
4	4	16	0.0%	100.0%
5	1	17	0.0%	100.0%
5	2	18	0.0%	100.0%
5	3	19	0.0%	100.0%
5	4	20	0.0%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 10 MW Redox Flow Battery Energy Storage

Year	Quarter	Cumulative Quarter	Quarterly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	12.5%	12.5%
1	2	2	25.0%	37.5%
1	3	3	30.0%	67.5%
1	4	4	20.0%	87.5%
2	1	5	12.5%	100.0%
2	2	6	0.0%	100.0%
2	3	7	0.0%	100.0%
2	4	8	0.0%	100.0%
3	1	9	0.0%	100.0%
3	2	10	0.0%	100.0%
3	3	11	0.0%	100.0%
3	4	12	0.0%	100.0%
4	1	13	0.0%	100.0%
4	2	14	0.0%	100.0%
4	3	15	0.0%	100.0%
4	4	16	0.0%	100.0%
5	1	17	0.0%	100.0%
5	2	18	0.0%	100.0%
5	3	19	0.0%	100.0%
5	4	20	0.0%	100.0%



Appendix C. Technology Maturity Outlook

Table C-1 Total Capital Cost Forecast Factors by Technology (Constant Dollar Basis)

TECHNOLOGY	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Coal with 30% CCS	1.000	1.002	0.996	0.991	0.985	0.977	0.967	0.956	0.944	0.928	0.915	0.903	0.892	0.882	0.871	0.861	0.852	0.844	0.835	0.826	0.817
Coal with 90% CCS	1.000	1.002	0.996	0.991	0.985	0.977	0.967	0.956	0.944	0.928	0.915	0.903	0.892	0.882	0.871	0.861	0.852	0.844	0.835	0.826	0.817
Combustion Turbine	1.000	1.004	1.000	0.997	0.992	0.987	0.978	0.969	0.958	0.945	0.933	0.923	0.914	0.905	0.896	0.887	0.880	0.873	0.865	0.858	0.851
Advanced Comb. Turbine	1.000	1.002	0.997	0.993	0.986	0.979	0.969	0.959	0.947	0.931	0.913	0.893	0.880	0.864	0.847	0.831	0.819	0.808	0.798	0.787	0.778
Combined Cycle	1.000	1.004	1.000	0.997	0.992	0.987	0.978	0.969	0.958	0.945	0.933	0.923	0.914	0.905	0.896	0.887	0.880	0.873	0.865	0.858	0.851
Advanced Combined Cycle	1.000	1.003	0.998	0.994	0.988	0.982	0.973	0.963	0.952	0.937	0.921	0.905	0.893	0.880	0.866	0.853	0.843	0.834	0.825	0.815	0.807
Adv. CC w/ Sequestration	1.000	1.000	0.993	0.986	0.978	0.968	0.957	0.944	0.930	0.913	0.896	0.879	0.866	0.851	0.837	0.823	0.811	0.800	0.789	0.778	0.768
Fuel Cell	1.000	0.988	0.977	0.966	0.954	0.941	0.925	0.909	0.891	0.871	0.852	0.836	0.820	0.804	0.789	0.774	0.761	0.748	0.734	0.721	0.708
Nuclear	1.000	1.001	0.995	0.989	0.960	0.912	0.901	0.891	0.878	0.863	0.850	0.838	0.828	0.817	0.807	0.796	0.787	0.779	0.770	0.761	0.753
Biomass	1.000	1.002	0.997	0.992	0.985	0.978	0.969	0.958	0.947	0.932	0.919	0.908	0.898	0.887	0.877	0.868	0.859	0.851	0.843	0.835	0.827
Landfill Gas	1.000	1.004	1.000	0.997	0.992	0.987	0.978	0.969	0.958	0.945	0.933	0.923	0.914	0.905	0.896	0.887	0.880	0.873	0.865	0.858	0.851
Wind (Onshore)	1.000	1.004	1.000	0.997	0.992	0.987	0.978	0.969	0.958	0.945	0.933	0.923	0.914	0.905	0.896	0.887	0.880	0.873	0.865	0.858	0.851
Offshore Wind	1.000	1.000	0.992	0.985	0.977	0.968	0.956	0.943	0.929	0.912	0.897	0.883	0.871	0.859	0.846	0.835	0.824	0.814	0.804	0.793	0.783
Solar Thermal	1.000	1.001	0.970	0.965	0.958	0.950	0.939	0.928	0.915	0.899	0.885	0.873	0.862	0.851	0.840	0.830	0.820	0.811	0.802	0.793	0.784
Solar PV	1.000	0.905	0.875	0.864	0.855	0.845	0.835	0.823	0.811	0.796	0.782	0.770	0.759	0.747	0.736	0.725	0.712	0.698	0.684	0.677	0.671
Distributed Gen Base	1.000	1.001	0.995	0.989	0.982	0.974	0.963	0.952	0.939	0.923	0.909	0.896	0.885	0.874	0.863	0.852	0.843	0.834	0.824	0.815	0.806
Distributed Gen Peak	1.000	1.001	0.995	0.959	0.909	0.898	0.883	0.863	0.840	0.816	0.798	0.780	0.764	0.750	0.736	0.725	0.712	0.704	0.695	0.687	0.679

Source: U.S. Department of Energy, Energy Information Administration, National Energy Modeling System (NEMS). Data developed as part of Annual Energy Outlook 2017 (AEO2017).