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1.0 Executive Summary

Black & Veatch was commissioned by Portland General Electric (PGE) to assess the potential deployment of solar and other distributed generation (DG) technologies, given technical, financial and other achievability criteria. This report examines the potential of three classes of non-solar DG for electricity-only applications: battery energy storage systems (BESS), fuel cells, and microturbines. The assessment covered various technologies within each class that are most practical for behind-the-meter, customer-sited applications for commercial customers. These technologies include the following:

1. Battery Energy Storage Systems (BESS)
    a. Lithium ion
    b. Vanadium redox flow battery
2. Fuel Cells (Natural Gas)
    a. Solid oxide fuel cells (SOFC)
    b. Molten carbonate fuel cells (MCFC)
    c. Phosphoric acid fuel cells (PAFC)
3. Microturbines (Natural Gas)

While there are other technologies that exist, they were not included because either they are not suitable for stationary applications or they are still in relatively early stages of commercialization. Black & Veatch also focused on the potential for using natural gas as the fuel input, as biogas utilization would be highly site-specific and would pose additional issues around maintenance for these technologies. Combined heat and power (CHP) applications were not included in the scope of this study, as they require customer and site specific evaluations

1.1 TECHNOLOGY CHARACTERISTICS AND COSTS

The study first considered the technical characteristics, the status of each of the technologies, and current and forecasted costs of the various technologies. A summary of the system characteristics and status of deployment for the various technologies is provided in Table 1-1 and Table 1-2. For BESS, the round trip efficiency reflects the overall efficiency losses incurred during both charging and discharging of the system.

Table 1-1 BESS Technical Characteristics

	COMMERCIAL STATUS	APPLICATION	SYSTEM SIZING (KWH)	ROUND TRIP EFFICIENCY
BESS				
Lithium Ion	Advanced	Peak Shaving/Load Shifting	5 to 32,000	75 to 90 percent
Vanadium Redox	Emerging	Peak Shaving/Load Shifting	200 to 8,000	65 to 75 percent
kWh - kilowatt-hour				

Table 1-2 Fuel Cells and Microturbines Technical Characteristics

	COMMERCIAL STATUS	APPLICATION	MINIMUM UNIT SIZE (KW)	ELECTRICAL EFFICIENCY (HHV), %
Fuel Cells				
SOFC	Emerging	Baseload	210-262.5	47 to 54
MCFC	Advanced	Baseload	300-1400	43
PAFC	Advanced	Baseload	400	42
Microturbines	Mature	Baseload/ Dispatchable (limited)	65	25

kW - kilowatt
HHV - higher heating value

As far as technical feasibility, all of these technologies have already been deployed in some capacity nationally and internationally, so they are technically feasible, and their potential are not limited by resource availability, as is the case with solar and wind resources. The greater constraints are associated with the economics of the systems.

The cost assumptions used for the various technologies are shown in Table 1-3 and Table 1-4. It should be noted that dramatic cost declines are assumed for all technologies between 2016 and 2035, except for microturbines. While there is considerable uncertainty whether these technologies can achieve those lower cost levels, Black & Veatch wanted to test whether these systems would be financially viable at those lower levels.

Table 1-3 Technical and Financial Assumptions - BESS (2014$)

		2016			2035		
TECHNOLOGY	SIZE (KWH)	CAPITAL COST ($/KW)	FIXED O&M ($/KW-YR)	ROUND-TRIP EFFICIENCY (%)	CAPITAL COST ($/KW)	FIXED O&M ($/KW-YR)	ROUND-TRIP EFFICIENCY (%)
BESS	10	1500	20	87	400	20	87

$/kW - dollars per kilowatt-hour
O&M - operations and maintenance

Table 1-4 Technical and Financial Assumptions - Fuel Cells and Microturbines (2014$)

		2016			2035		
TECHNOLOGY	SIZE (KW)	CAPITAL COST ($/KW)	FIXED O&M ($/KW-YR)	HEAT RATE (BTU/KWH)	CAPITAL COST ($/KW)	FIXED O&M ($/KW-YR)	HEAT RATE (BTU/KWH)
SOFC	210	8000	1000	7000	1500	150	5600
MCFC	300	4000	300	8000	1500	150	8000
PAFC	400	6000	150	9000	1500	150	9000
Microturbine	65	4000	170	13400	4000	170	13400
Btu/kWh - British thermal unit per kilowatt-hour							

1.2 FINANCIAL ASSESSMENT

To understand project financials, Black & Veatch modeled each of the technologies for a number of commercial customer types using a modified scripting of the National Renewable Energy Laboratory (NREL) System Advisor Model (SAM) software. The model incorporates technical performance parameters, system capital and O&M costs, project financing and taxes, incentives, and utility rate data, together with customer load data, to produce a suite of results including net present value (NPV), payback period, levelized cost of energy (LCOE), annual cash flow, and annual energy savings. Black & Veatch modeled scenarios for 2016 and 2035 for all technologies and customer types. For BESS, the system was tested with and without solar photovoltaic (PV). Also, it was important to use different customer types to understand how different load shapes may benefit through electricity bill reductions for both demand and energy charges, under each of their respective rate classes. For each customer type, each of the technologies was also sized to meet either the customer load or minimum technology unit size. For both the 2016 and 2035 cases, Black & Veatch also tested two utility rates escalating two ways: at the Consumer Price Index (CPI) of 2 percent, and at CPI plus 1 percent (CPI + 1). Additionally, fuel cells and microturbines were tested under base and low gas price scenarios.

In general, none of the BESS options evaluated are financially viable in the 2016 time frame, defined as payback of fewer than 20 years, given estimated costs, performance, available incentives, and utility rates. Aside from cost of the systems, an examination of PGE's commercial retail rates showed that there is little or no benefit in load shifting between peak and off-peak hours, as the round-trip efficiency of BESS washes out the time of use (TOU) price differential between peak and off-peak hours. Thus, demand charge reduction is the only source of bill savings, and PGE demand charges for commercial customers are somewhat low compared to other parts of the country where BESS are being deployed. By 2035, assuming dramatic installed cost declines, BESS options do appear to become financially viable. The paybacks for the customers range from 5 to 10 years for most customers. Refer to Figure 1-1.

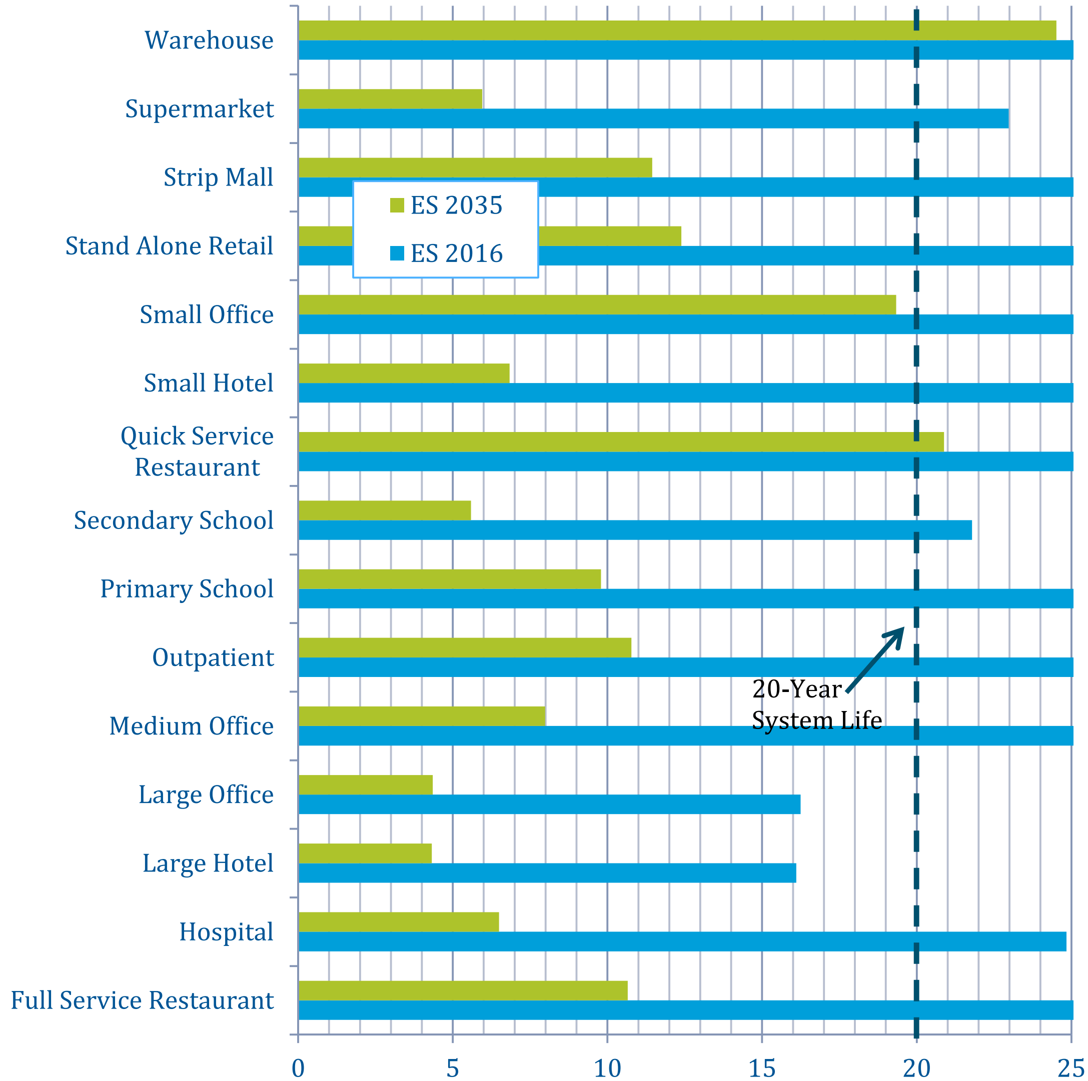

Figure 1-1 BESS Only Payback by Customer Type

The analysis of fuel cells and microturbines in all cases, including low natural gas price cases, showed that none of these technologies result in paybacks less than the life of the project. One exception is the case for secondary schools in 2035 deploying SOFC, under a low natural gas price scenario with rates that increase at CPI + 1, results in a payback period less than the life of the project. However, this assumes that the installed system and O&M costs drop substantially and efficiency gains are achieved for the technology, which is highly uncertain given the technology status today. Aside from capital and O&M cost, the financials of these technologies relative to utility-supplied power are penalized in two ways: higher heat rates compared to PGE's system heat rate and natural gas priced at retail rates. These drawbacks are unlikely to change under any condition. Refer to Table 1-5 for the levelized cost of energy.

Table 1-5 Summary of Levelized Cost of Energy for Fuel Cells and Microturbines (2014$/kWh)

YEAR	NATURAL GAS CASE	SOFC	MCFC	PAFC	MICROTURBINE
2016	Base	$0.24	$0.13	$0.13	$0.16
	Low	$0.23	$0.12	$0.12	$0.14
2035	Base	$0.08	$0.10	$0.11	$0.18
	Low	$0.07	$0.09	$0.10	$0.15

1.3 ACHIEVABLE POTENTIAL

Developing estimates of achievable potential for the DG technologies examined in this study is challenging in that these technologies are not financially viable in the near-term under current financial conditions, and the long-term cost outlook is quite uncertain for many of these technologies. Another added complexity is that appropriately sizing of the systems, matched to a customer's load shape, really drives the financials. In order for the technologies to be financially viable, technology costs would need to drop substantially, additional policies and incentives would need to be put in place, and changes in rate structure are needed to promote adoption. Absent those conditions, Black & Veatch forecasts minimal adoption of these technologies over the study period. If any adoption occurs, it would be towards the latter decade (2026 to 2035) of the analysis period when better clarity on costs is available. The one major caveat in this study is that Black & Veatch focused on the impact of these systems on customer electricity bills but did not account for the value of reliability and power quality to the customer. These factors are much more difficult to value and could vary widely by customer type. PGE may want to consider studying these values to customers further in future analysis.

As discussed in the financial assessment section, only BESS technology makes some financial sense by 2035. Black & Veatch estimates that during the 2025 to 2035 time frame, approximately 2.6 to 5.1 MW per year of energy storage installations may be possible if costs do fall to forecasted levels and the financially optimal system size is 10 kWh per customer. Adoption may be higher if certain customer types, such as critical facilities (hospitals, schools, etc.), place some value on reliability and power quality associated with installing BESS and, thus, install larger systems and/or have wider adoption despite poor paybacks. However, this metric was not studied in this analysis.

Table 1-6 Forecasted Annual BESS Adoption

BESS CAPACITY (MW/MWH)	2016 TO 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low Adoption	0	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2
High Adoption	0	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4

For the BESS plus solar PV cases, it was determined that the addition of BESS to a solar installation does not improve the financials of the combined system, and, in fact, in the 2016 cases, BESS causes payback to increase. Therefore, in the near-term, given that solar PV installations are able to net meter, there is no incremental benefit to deploying an energy storage system with PV until net metering is no longer available. By 2035, BESS costs will have fallen enough that BESS installations, combined with solar PV, would not alter the payback significantly compared to solar PV alone. However, this also implies that a customer would be ambivalent to installing a BESS with its solar PV system, unless net metering policy changes in the future. If net metering is replaced with other policies, the deployment of BESS as part of a solar PV system may become financially viable but will depend on the rules around the alternative rate structures.

As noted previously, electricity-only applications for fuel cells and microturbines are not financially viable in almost all cases. These technologies could be configured to provide combined heat-and-power to help with the financials of the systems. While CHP may improve these technologies' financials over electricity-only operation, CHP applications are limited to specific customers that can utilize both the energy and heat. Additional studies examining specific customer load would be needed to assess the potential of fuel cells and microturbines for CHP applications.

2.0 Introduction

Black & Veatch was commissioned by Portland General Electric (PGE) to assess the potential deployment of solar and other distributed generation (DG) technologies, given technical, financial and other achievability criteria. This report examines the potential of three classes of non-solar DG for electricity-only applications: battery energy storage systems (BESS), fuel cells, and microturbines. The assessment covered various technologies within each class that are most practical for behind-the-meter, customer-sited applications for commercial customers. These technologies include the following:

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3.0 Technical Characteristics and Costs

This section covers the technical characteristics of the various DG technologies that were reviewed and their typical operating modes. Current estimated costs are also presented for each of the DG technologies based on Black & Veatch's engineering, procurement, and construction (EPC) experience, industry surveys, and/or installed cost data from publicly available sources. Since many of these technologies do not have a large installed base, the number of data points may be limited.

3.1 BATTERY ENERGY STORAGE SYSTEMS

BESS are becoming a more prevalent grid resource option in recent years as the need for more flexible capacity is emerging, both at the transmission as well as the distribution level. New policies in a number of states, such as California, New York, and Hawaii, are driving growth in this sector through incentives or state requirements. Companies, such as Tesla, an electric vehicle company, are seeking ways to mass produce batteries in order to drive costs down for both transportation and stationary applications. This section covers the technical characteristics and costs associated with the BESS technologies that were reviewed, current costs, and forecasted costs.

Since the focus of this report is on behind-the-meter, stationary customer applications, lithium ion and vanadium redox flow batteries are two practical technologies to consider for stationary energy storage.

3.1.1 Technical Characteristics

Although it is not a generation resource, energy storage can perform many of the same applications as a traditional generator by using stored energy from the grid or from other distributed generation resources. These applications range from traditional uses such as providing capacity or ancillary services to more unique applications such as microgrids or renewable integration applications. A snapshot of various energy storage applications across the electric utility system can be found on Figure 3-1.

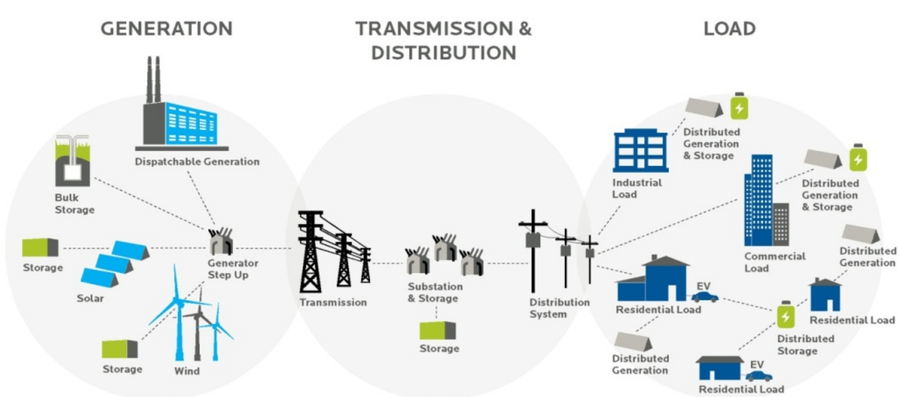

Figure 3-1 Energy Storage Applications Across the Electric Utility System

Generally speaking, energy storage can serve a number of roles:

- **Time of Use (TOU) Energy Management (Electrical Energy Time-Shift):** Energy storage can charge energy when electricity prices are low and discharge to supply load when electricity prices are high.
- **Demand Charge Management:** Energy storage can discharge during expensive peak demand times to reduce a customer's monthly demand charges.
- **Electric Service Reliability:** Energy storage can improve the reliability of a customer's electric service and help reduce the number of outages for customers. This application can include emergency backup power.
- **Power Quality:** Energy storage can protect loads against short duration events (i.e., voltage flickers, frequency deviations) that affect the quality of power delivered to the load.
- **Frequency Regulation:** Energy storage can be used to mitigate load and generation imbalances on the second to minute interval to maintain grid frequency.
- **Voltage Support:** The energy storage converter can provide reactive power for voltage support and respond to voltage control signals from the grid.
- **Variable Energy Resource Capacity Firming:** Energy storage can be used to firm energy generation of a variable energy resource so that output reaches a specified level at certain times of the day.
- **Variable Energy Resource Ramp Rate Control:** Ramp rate control can be used to limit the ramp rate of a variable energy resource to limit the impact to the grid.

Energy storage applications can be grouped into either power or energy applications. Power applications are generally shorter duration (approximately 30 minutes to 1 hour) applications that may involve frequent rapid responses or cycles. Frequency regulation or other renewable integration applications such as ramp rate control/smoothing are good examples of power applications. Energy applications generally require longer duration (approximately 2 hours or more) energy storage systems.

For the purposes of this report, Black & Veatch focused on customer-sited storage that is connected behind the electricity meter for commercial and industrial customers (also called behind-the-meter energy storage). The applications specifically related to behind-the-meter energy storage are a subset of all the potential applications storage systems can perform.

The primary purpose of the energy storage devices considered in this report would be to provide TOU energy management and demand charge management, which would be primarily an energy application. TOU energy management and demand charge management together can be called end-user bill management applications. While the storage systems are versatile and can perform other applications, the end-user bill management applications are the most common applications performed by behind-the-meter energy storage systems seen today. This is because avoiding expensive demand charges (that can vary by region and utility) can provide reasonable value to the customer. More detailed analysis on end-user bill management can be found in later sections of this report. The other applications can be performed by behind-the-meter energy storage, but often valuing these particular applications is difficult and is highly site and market-specific.

A fully operational BESS comprises an energy storage system that is combined with a bidirectional converter (also called a power conversion system). The BESS also contains a battery management system (BMS) and site or BESS controller (Table 3-1).

Table 3-1 BESS Components

COMPONENT	DEFINITION
Energy Storage System (ESS)	The ESS consists of the battery modules or components as well as the racking, mechanical components, and electrical connections between the various components.
Power Conversion System (PCS)	The PCS is a bidirectional converter that converts alternating current (ac) to direct current (dc) and dc to ac. The PCS also communicates with the BMS and BESS controller.
Battery Management System (BMS)	The BMS can be composed of various BMS units at the cell, module, and system level. The BMS monitors and manages the battery state of change (SOC) and charge and discharge of the ESS.
BESS/Site Controller	The BESS controller communicates with all the components and is also the utility communication interface. Most of the advanced algorithms and control of the BESS resides in the BESS/site controller.

When considering different energy storage technologies, there are a number of key performance parameters to understand:

- **Power Rating:** The rated power output (MW) of the entire energy storage system.
- **Energy Rating:** The energy storage capacity (MWh) of the entire energy storage system.
- **Discharge Duration:** The typical duration that the BESS can discharge at its power rating.
- **Response Time:** How quickly an ESS can reach its power rating (typically in milliseconds).
- **Charge/Discharge Rate (C-rate):** A measure of the rate at which the ESS can charge/discharge relative to the rate at which it will completely charge/discharge the battery in 1 hour. A 1 hour charge/discharge rate is a 1C rate. Furthermore, a 2C rate completely charges/discharges the ESS in 30 minutes.
- **Round Trip Efficiency (RTE):** The amount of energy that can be discharged from an ESS relative to the amount of energy that went into the battery during charging (as a percentage). Typically stated at the point of interconnection and includes the ESS, PCS, and transformer efficiencies.
- **Depth of Discharge (DoD):** The amount of energy discharged as a percentage of its overall energy rating.
- **State of Charge (SOC):** The amount of energy an energy storage resource has charged relative to its energy rating, noted as a percentage.
- **Cycle Life:** These are reported at 80 percent and 10 percent of DoD and correlate to the number of cycles the ESS can undergo before the energy storage system degrades to 80 percent of its initial energy rating (kWh). The cycle life can vary for various DoDs.

Since the focus of this report is on behind-the-meter, stationary customer applications, lithium ion and vanadium redox flow batteries are two practical technologies to consider for stationary energy storage. Most of the stationary energy storage activity in the industry is currently based on the lithium ion battery technology. Lithium ion batteries are the dominant player in battery energy storage, and their demonstrated experience is growing. According to the Department of Energy (DOE) Global Energy Storage Database, over 80 MW of lithium ion installations are operational in the United States. Lithium ion batteries are projected to be a major industry player in the years to come and are well suited for both power and cycling applications as well as some energy applications.

Vanadium redox flow battery installations are more limited, but worldwide installations total over 17 MW, including installations currently being verified.[1] Vanadium redox flow batteries are also projected to likely have a considerable market share for large stationary applications in the future and are best suited for energy applications that require longer durations of discharge.

A basic description of these two technologies is provided in the following sections.

3.1.1.1 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 on Figure 3-2.

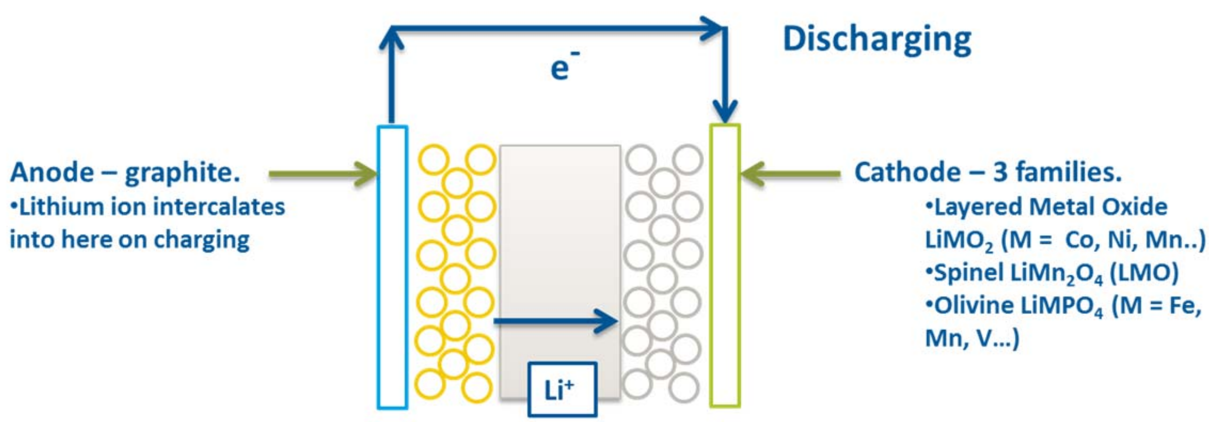

Figure 3-2 Lithium Ion Battery Showing Different Electrode Configurations

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

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[1] DOE Global Energy Storage Database, http://www.energystorageexchange.org/.

An image of an example lithium ion BESS can be found on Figure 3-3.

Figure 3-3 Lithium Ion Battery Energy Storage System Located at Black & Veatch HQ

Lithium ion battery storage systems can be used for both power and energy applications. One key strength of lithium ion batteries is their strong cycle life (refer to Table 3-2). For shallow, frequent cycles, which are quite common for power applications, lithium ion systems demonstrate excellent 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 a cycling ability superior to other battery technologies such as lead acid.
- **Fast Response Time**: Lithium ion technologies have a fast response time that is typically less than 100 milliseconds.
- **High Round Trip Efficiency**: Lithium ion energy conversion is efficient and has up to a 90 percent round trip efficiency (dc-dc).
- **Versatility**: Lithium ion solutions can provide many relevant operating functions.
- **Commercial Availability**: There are dozens of lithium ion battery manufacturers.
- **Energy Density**: Lithium ion solutions have a high energy density to meet space constraints.

Table 3-2 Typical Lithium Ion Battery Performance Parameters

PARAMETER	LITHIUM ION BATTERY
Power rating, MW	0.005 to 32
Energy rating, MWh	0.005 to 32
Discharge duration, hours	0.25 to 4
Response time, milliseconds	< 100
Round trip efficiency (ac-ac), %	75 to 90
Cycle life, cycles at 80 % DoD	1,200 to 4,000
Cycle life, cycles at 10 % DoD	60,000 to 200,000

3.1.1.2 Vanadium Redox Flow Batteries

Vanadium redox flow batteries are another form of electrochemical storage. Vanadium 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 that is typically stored in large tanks. The 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 vanadium redox flow battery can be found on Figure 3-4.

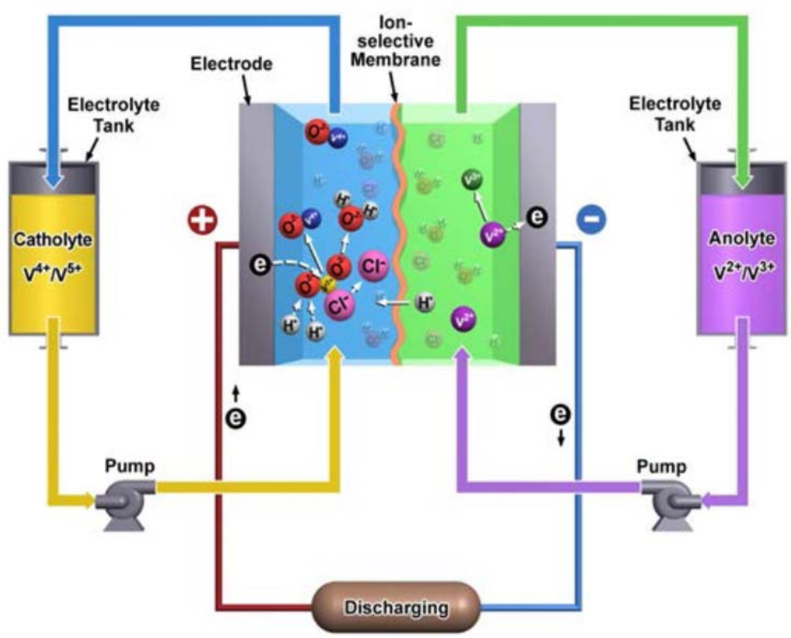

Figure 3-4 Diagram of Vanadium Redox Flow Battery (Source: DOE/Electric Power Research Institute [EPRI] 2013 Electricity Storage Handbook in Collaboration with National Rural Electric Cooperative Association [NRECA])

This technology is also integrated with a PCS to form the overall BESS. Vanadium 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. The vanadium redox flow batteries require more space for the installation than lithium ion batteries. Vanadium redox BESS can be modular, as shown on Figure 3-5, and containerized systems, as shown on Figure 3-6.

Figure 3-5 Vanadium Redox Flow Battery (Source: Prudent Energy brochure)

Figure 3-6 Containerized Flow Battery (Source: UniEnergy)

A comparison of lithium ion and flow battery technologies is provided in Table 3-3. Compared to lithium ion batteries, flow batteries are better suited to providing longer discharge durations and have a longer cycle life at 80 percent of DoD. On the other hand, vanadium redox flow batteries suffer from lower round trip efficiencies. Additionally, flow batteries do not perform as well at shallow 10 percent DoD cycles. While the electrolyte in flow batteries does not degrade, manufacturer information indicates that the power cell component of the battery may need to be replaced after 5 to 10 years.

Table 3-3 Vanadium Redox Flow Battery Versus Lithium Ion Battery

PARAMETER	LITHIUM ION BATTERY	VANADIUM REDOX FLOW BATTERY
Power rating, MW	0.005 to 32	0.050 to 4
Energy rating, MWh	0.005 to 32	0.200 to 8
Discharge duration, hours	0.25 to 4	3 to 8
Response time, milliseconds	< 100	< 100
Round trip efficiency, %	75 to 90	65 to 75
Cycle life, cycles at 80 % DoD	1,200 to 4,000	10,000 to 15,000 (not DoD dependent)
Cycle life, cycles at 10% DoD	60,000 to 200,000	10,000 to 15,000 (not DoD dependent)

3.1.2 BESS Costs

Black & Veatch leveraged its experience in the energy storage industry and deep vendor knowledge to provide high-level costs for the two technologies of interest.

In addition to this, Black & Veatch reviewed Sandia National Laboratory's report titled "DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA," which includes costs gathered through extensive surveys of a number of vendors.[2] Black & Veatch also reviewed the DOE Global Energy Storage Database, which is a compilation of many existing energy storage projects.[3] Furthermore, historical data from the California Self-Generation Incentive Program (SGIP) was also reviewed. SGIP program data show costs have declined significantly since 2009-2010 but have been generally flat between 2011 and 2014 (Figure 3-7).

[2] DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA, http://www.sandia.gov/ess/handbook.php.
[3] DOE Global Energy Storage Database, http://www.energystorageexchange.org/.

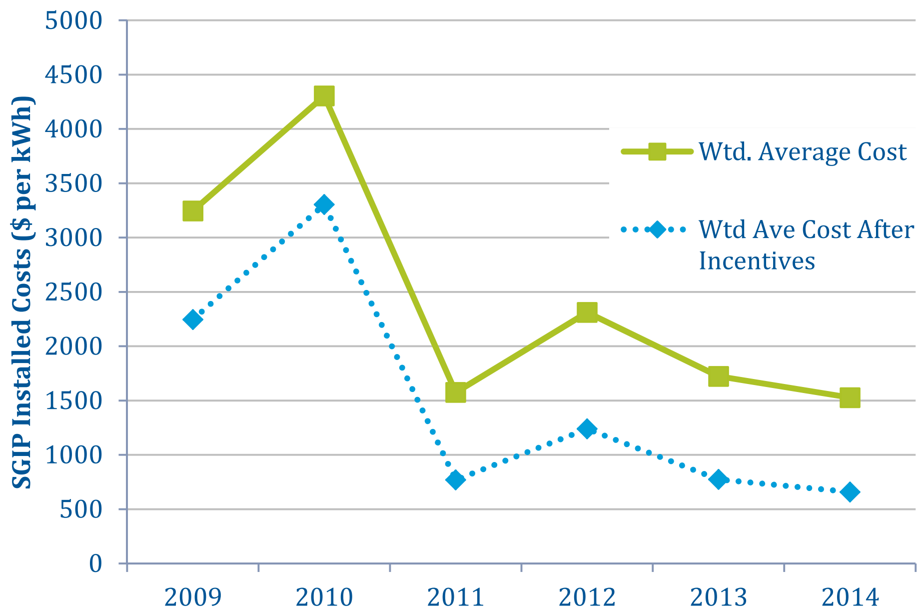

Figure 3-7 California SGIP Historical Energy Storage Costs ($ per kWh) (Source: SGIP Database)

3.1.2.1 Current Energy Storage Costs

Reported costs of energy storage systems can vary widely, depending on size and unique site conditions, and are often reported inconsistently. Costs may be reported for the batteries alone or for total installed cost. Furthermore, installed costs for BESS may be reported in cost per kW (power) or cost per kWh (energy). Since the applications considered in this analysis are primarily energy applications, costs are presented on a dollars per kWh basis.

Current reported equipment pricing for lithium ion batteries alone range from $500 to $750 per kWh and total installed costs ranging from $700 to $3000 per kWh, with smaller behind-the-meter systems at the higher end.[4] Vanadium redox flow batteries are far more integrated systems, so costs are typically reported as total installed cost.

Black & Veatch developed a range of installed costs that include the following components:

- Battery modules.
- PCS.
- BMS.
- Controller.

[4] "The Value of Distributed Electricity Storage in Texas," Brattle Group, 2014. http://www.brattle.com/system/news/pdfs/000/000/749/original/The_Value_of_Distributed_Electricity_Storage_in_Texas.pdf?1415631708.

- Balance-of-systems, including interconnecting electrical equipment, racking, and wiring.
- Engineering and design, including necessary permitting and construction management.
- Installation, including labor.
- Contractor margin.

Various sizes of energy storage systems are shown in Table 3-4 that represent a reasonable range of sizes for the storage systems studied in this report. The costs are presented in terms of dollars per installed kWh based on the energy storage ability, which is what will be used in the modeling exercise presented later in this study.

Table 3-4 Energy Storage System Conceptual EPC Costs for 2015 (2014$)

TECHNOLOGY	POWER, KW	ENERGY, KWH	INSTALLED COST, $/KWH	FIXED O&M, $/KW-YR	VARIABLE O&M, $/KWH
Lithium ion battery	5	10	1,500 – 2,000	20-25	0.0010 – 0.0015
	100	400	1,250 – 1,750	20 –25	0.0010 – 0.0015
	1,000	4,000	1,000 – 1,300	8 –10	0.0010 – 0.0015
Vanadium redox flow battery	200	700	1,400 – 1,600	15-20	0.0015 – 0.0020
	1,200	4,000	900 – 1,100	7-9	0.0015 – 0.0020

Fixed and variable operations and maintenance (O&M) costs for lithium ion and flow batteries are also presented in Table 3-4. Fixed O&M includes routine maintenance on the equipment and electronics, and variable O&M depends on how much the storage system is used throughout the course of its operation. Since the O&M is dependent on the expected operation, the operation of these systems is assumed to be one full charge and discharge daily for 365 days of the year. This is a reasonable assumption for the expected applications considered in this report. The O&M costs do not include battery replacements or component replacements over time. Furthermore, the number of cycles in operation will determine their overall life, which is estimated to be approximately 10 years if cycled daily, and proportionately longer if the system is not cycled daily.

3.1.2.2 Forecasted Energy Storage Costs

Based on industry workshops, the DOE has established goals of reducing the installed system capital cost for BESS in the near-term (by 2019) to $250 per kWh. [5] Additionally, the DOE has a longer term 2024 goal of $150 per kWh. Other industry reports project battery-alone costs to drop to $100 to $250 per kWh in the near-term (5 to 10 years) and total installed costs to be as low as $350 per kWh by 2020, which is more reasonable than the DOE goals. In all cases, these costs are for larger utility-scale installations.

For smaller-scale systems being considered for behind-the-meter applications, Black & Veatch believes these targets are overly optimistic for complete BESS installations. Therefore, for the

[5] Grid Energy Storage, U.S. Department of Energy, December 2013 (http://energy.gov/oe/downloads/grid-energy-storage-december-2013).

10 year horizon, Black & Veatch expects a total installed cost to be more in the range of $400 to $500 per kWh in 2014$ and then costs to decline more slowly beyond that time frame.

3.2 FUEL CELLS

Fuel cells convert hydrogen directly to electricity through an electrochemical reaction, as shown on Figure 3-8. Hydrogen-rich fuels such as natural gas or digester gas may be transformed into hydrogen in a process called reforming prior to use in certain types of fuel cells. Fuel cell technologies have a number of operational advantages including relatively high conversion efficiency (i.e., greater than 40 percent), low emissions, and quiet operation. Utilization of heat recovery for combined heat and power operations can increase the overall efficiency to more than 80 percent. However, fuel cells currently suffer from a number of shortcomings including high capital cost, short fuel cell stack life of 3 to 5 years (which increases O&M costs), and corrosion and breakdown of cell components, resulting in performance degradation over time. Due to the long startup times for fuel cells, they also operate mostly as baseload generation and cannot be dispatched to follow load.

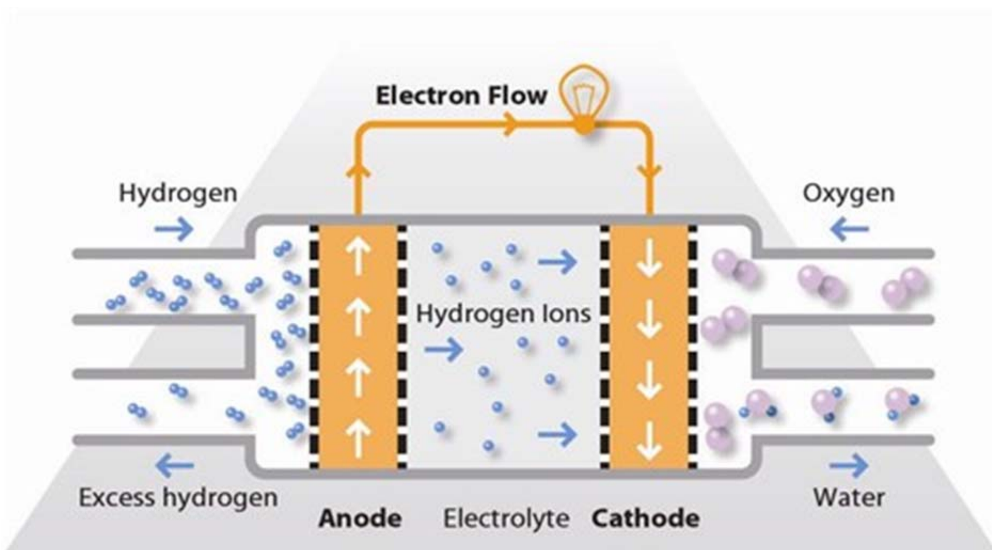

Figure 3-8 Schematic of a Hydrogen-Fueled Fuel Cell (Source: www.fuelcelltoday.com)

The discussion in this section focuses on stationary fuel cells for electricity-only applications. The technologies that are reviewed include:

- SOFC
- MCFC
- PAFC

Only a handful of manufacturers supply these technologies, so the key suppliers are discussed in this section. It is important to note that none of the fuel cell suppliers are profitable today, and as will be shown in the cost discussion, fuel cell costs have not shown any decline in the past 10 years.

3.2.1 Technical Characteristics

Fuel cells are composed of two electrodes separated by an electrolyte. The specific reactions that occur at the electrode depend on the type of electrolyte employed within the fuel cell. However, in general, ions are created at either the anode or cathode, then pass through the electrolyte; simultaneously, electrons flow between the electrodes through an external circuit, producing an electrical current. Catalysts are often employed to speed up the reactions at the electrodes.

There are six prominent types of fuel cells, typically distinguished by the material that serves as the electrolyte within the fuel cell:

- SOFC
- MCFC
- PAFC
- Proton exchange membrane fuel cells (PEMFC)
- Direct methanol fuel cells (DMFC)
- Alkaline fuel cells (AFC)

Distinguishing features for these technologies are listed in Table 3-5.

Table 3-5 Distinguishing Features of Fuel Cell Technologies

FUEL CELL TECHNOLOGY	ELECTROLYTE	ELECTRODE CATALYST	MOBILE ION	OPERATING TEMPERATURE (°C)	POTENTIAL FUELS
PEMFC	Water-based, acidic polymer membrane	Platinum	H+	< 100	Hydrogen
DMFC	Polymer membrane	Platinum-Ruthenium	H+	60 to 130	Methanol
AFC	Potassium hydroxide in water	Nickel	OH-	70 to 100	Hydrogen
PAFC	Phosphoric acid in silicon carbide structure	Platinum	H+	180	Hydrogen
MCFC	Liquid carbonate salt suspended in porous ceramic	None	CO32-	650	Hydrogen, natural gas, biogas
SOFC	Solid ceramic (e.g., zirconium oxide/ yttrium oxide)	None	O2-	800 to 1,000	Hydrogen, natural gas, biogas

Source: Fuel Cell Today (www.fuelcelltoday.com).

As shown in Table 3-5, PEMFC and DMFC technologies are typically employed for portable and transportation applications, while MCFC, PAFC, and SOFC technologies are employed for behind-the-meter, stationary power generation applications. While there are some cases of PEMFC used in stationary applications, the technology requires very pure hydrogen to minimize contamination, which would be challenging for customer-sited projects. Therefore, in the remainder of this discussion regarding fuel cells, Black & Veatch has focused on MCFC, PAFC, and SOFC technologies. Note that MCFC and SOFC technologies are also more practical for stationary applications because they are able to use natural gas directly as the input fuel, rather than hydrogen.

Table 3-6 Typical Applications for Fuel Cells

	PORTABLE APPLICATIONS	STATIONARY APPLICATIONS	TRANSPORTATION APPLICATIONS
Typical Power Range, kW	0.005 to 20	0.5 to 400	1 to 100
Potential Fuel Cell Technology	PEMFC DMFC	MCFC PAFC SOFC	PEMFC DMFC
Examples	Personal electronics; military applications	Power generation; uninterrupted power supplies (UPS)	Material handling vehicles; automobiles, trucks, and buses
Source: Fuel Cell Today, Fuel Cell Industry Review 2013.			

Hydrogen-rich fuels such as natural gas or digester gas may be transformed into hydrogen in a process called reforming. A common method of reforming introduces steam to the fuel stream; the chemical formula of this reforming reaction for natural gas composed primarily of methane (CH_4) is as follows:

$$CH_4 + 2\ H_2O \Rightarrow CO_2 + 4\ H_2$$

MCFC and SOFC technologies operate at high temperatures (650 °C and higher) and, therefore, are able to reform gaseous fuels internally. Lower temperature fuel cells, such as PAFC, require an external reformer, which adds to the system cost. When fuel gases (e.g., natural gas or digester gas) are used, certain constituents in the fuel gas (e.g., moisture, hydrogen sulfide (H_2S), and siloxanes) must be removed before the gas is used in fuel cells to avoid damage to internal components of the fuel cells.

After reforming, hydrogen is supplied to the fuel cell stack. A “stack” is a group of fuel cells (each consisting of an anode and a cathode separated by an ion-conducting electrolyte) that are connected in series within the fuel cell module. The number of fuel cells in the stack determines the total voltage, and the surface area of each cell determines the total current. Multiplying the voltage by the current yields the total electrical power generated. The electricity produced is in the form of dc, which is converted to ac by an inverter.

This overall process, including the reformation of natural gas and generation of electricity, is illustrated on Figure 3-9.

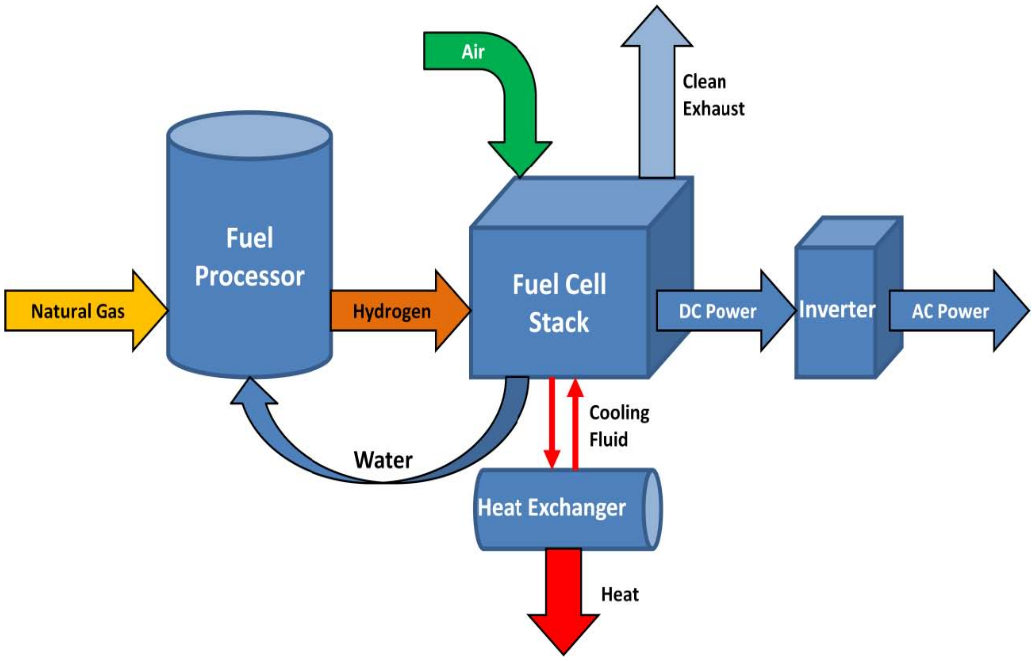

Figure 3-9 Fuel Cell Flow Diagram

Operational advantages of fuel cell technologies include high efficiency (i.e., greater than 40 percent), low emissions, and quiet operation. The higher efficiencies are achievable because the fuel cell process does not involve combustion and is, therefore, not limited by Carnot cycle efficiency. In addition, fuel cells can sustain high efficiency operations even under partial load conditions (generally constant above 60 percent of maximum load). Utilization of heat recovery for combined heat and power (CHP) operations can increase the overall efficiency to more than 80 percent. As a result of these high operating efficiencies and the lack of combustion, fuel cells emit fewer greenhouse gases per unit of power generated than other DG technologies such as internal combustion engines and microturbines. The combustion-free process also produces fewer byproducts than the other alternatives, which reduces criteria air pollutant emissions (notably nitrogen oxides [NO_x] and sulfur oxides [SO_x]).

Disadvantages of fuel cells vary by type. High capital cost, long startup time, a short fuel cell stack life of 3 to 5 years (which increases O&M costs), low power density, and performance degradation over time resulting from corrosion and breakdown of cell components are the primary disadvantages of fuel cell systems and are the focus of research and development.

Depending on the type of fuel cell employed and the nature of the fuel gas, fuel cells require maintenance, including the following:

- Replacing the contaminant adsorbents in the pretreatment module two to four times annually.
- Conducting an annual shutdown for replacement of filters and for servicing other components such as blowers.
- Replacing fuel cell stacks every 3 to 10 years, depending on the type.
- Overhauling the fuel processor after 5 to 10 years of use.

3.2.1.1 Solid Oxide

SOFC utilize a solid, nonporous ceramic metal oxide electrolyte, typically Yttria Stabilized Zirconia (YSZ). SOFC operate at relatively high temperatures (500 to 1000 °C) and can achieve electrical efficiencies in the range of 60 percent. When used on larger scales, the expelled heat can be utilized to generate additional energy. The resulting CHP efficiency may be between 70 and 80 percent.

The higher operating temperatures allow for internal reforming of a wide range of fuels, including natural gas and other hydrocarbon renewable and fossil fuels, without the use of a reforming catalyst. The absence of a catalyst eliminates the need for precious metals (such as platinum group metals) in their construction. Conversely, the higher operating temperatures present engineering and design challenges. To date, SOFC operational life is usually limited to approximately 25,000 hours because of durability issues associated with the material tolerances to temperature, particularly when used in a cyclical application. Because of the shorter life span, cell replacement is necessary on a more frequent basis and O&M costs associated with SOFC are estimated to be high, approximately $1000/kW-yr, based on reported extended warranty costs.[6]

Current SOFC development efforts are focused on reducing operating temperatures through the use of a different or improved electrolyte and electrodes, while maintaining high efficiency. Lower operating temperatures should provide extended operational life and allow the use of less expensive materials in the stack construction and electrical interconnections. Such achievements could effectively reduce both capital and O&M costs.

SOFC Technology Supplier: Bloom Energy

Bloom Energy, based in Sunnyvale, California, provides modular SOFC systems for electricity-only applications. The company was founded in 2001, growing from the work of company founder Dr. K.R. Sridhar for the National Aeronautics and Space Administration (NASA) Mars program. Bloom acknowledges the challenges associated with SOFC and claims to have solved those challenges with breakthroughs in material science and system design. Bloom Energy's products are named "Energy Servers" and are available at nameplate capacities of 210 and 262.5 kW (models ES-5700 and ES-5710, respectively).

Under California's SGIP program, Bloom systems have accounted for over 100 MW of capacity in the state since 2007, with individual systems ranging in size from 210 kW to 4.2 MW. Bloom has supplied its systems to several Fortune 500 companies, banks, and data centers. In July 2014

[6] GreenTech Media, "Stat of the Day: Fuel Cell Costs From Bloom and UTC" May 13, 2013. Available online at: http://www.greentechmedia.com/articles/read/Stat-of-the-Day-Fuel-Cell-Costs-From-Bloom-and-UTC.

Bloom partnered with Excelon to develop 21 MW of fuel cell projects to supply power to customers throughout the United States.

Performance characteristics of the Bloom Energy Servers are shown in Table 3-7.

Table 3-7 Performance Characteristics of Bloom Energy Fuel Cell Systems

	BLOOM ENERGY: ES-5700	BLOOM ENERGY: ES-5710
Unit Ratings		
Gross Power Output, kW	210	262.5
Output Voltage, V	480	480
Operating Parameters		
System Efficiency(1)		
Heat Rate (HHV), Btu/kWh	6,925-7,990	6,925-7,990
Electrical Efficiency (HHV net AC), %	47-54	47-54
Emission Rates		
Carbon Dioxide, lb/MWh	735-849	735-849
Nitrogen Oxides, lb/MWh	<0.01	<0.01
Sulfur Oxides, lb/MWh	Negligible	Negligible
Volatile Organic Compounds (VOCs)	<0.02	<0.02
Carbon Monoxide, lb/MWh	<0.10	<0.10
Particulate Matter (PM_{10}), lb/MWh	NA	NA

Source: Bloom Energy
Notes:
1. Heat rate and electrical efficiency are estimated over project life.

3.2.1.2 Molten Carbonate

MCFC operate at temperatures near 650 °C, providing balance between the electrolyte conductivity and a temperature range suitable for lower cost metals. The electrolyte in an MCFC is a molten carbonate salt mixture, suspended in a porous ceramic. The higher operating temperatures allow for internal reforming of a range of fuels, including natural gas and coal syngas. MCFC achieve electrical efficiencies in the range of 45 to 50 percent. Often, MCFCs are deployed in CHP applications, where even further energy recovery from the system is accomplished, achieving upwards of 85 percent overall energy efficiency. Modern commercial MCFC stacks have life spans estimated around 40,000 hours, with O&M costs of approximately $300/kW-yr.

The use of nonprecious metals and the ability to internally reform the fuel both reduce the cost of MCFC. While MCFC run cooler than SOFC, the high operating temperatures still lead to some durability challenges and reduced operating life span. In the case of the MCFC, the corrosive property of the electrolyte has been seen to further decrease cell life. Current research and development (R&D) efforts in the field of MCFC are focused on increased cell and stack life through electrolyte advances and the use of more robust electrode materials.

MCFC Technology Supplier: FuelCell Energy

FuelCell Energy, originally founded in 1969 as Energy Research Corporation, has been producing MCFC since the 1980s, with the first commercial plant installed in 2003 utilizing its 250 kW stack. The company's production facility is located in Torrington, Connecticut, and, as of 2012, it produces 56 MW of MCFC annually. In 2013, the company installed a 59 MW facility in South Korea, currently the largest fuel cell plant in the world. According to the company's website, FuelCell Energy has "more than 300 MW of power generation capacity installed or in backlog," and the company's power generation facilities have generated more than 2.5 billion kilowatt-hours of electricity.

FuelCell Energy provides three products in its Direct FuelCell (DFC) line: the 2.8 MW DFC3000, the 1.4 MW DFC1500, and the 300 kW DFC300. The company also provides its "Multi-MW DFC-ERG" (Direct FuelCell Energy Recovery Generation) system, which couples a gas expansion turbine utilizing the natural gas pipeline pressure to drive the turbine prior to supplying the fuel cells. In this configuration, the system increases its electrical efficiency from 43 percent (HHV, DFC3000 and DFC1500) to 55 percent or higher.

Performance characteristics of FuelCell Energy systems are listed in Table 3-8.

3.2.1.3 Phosphoric Acid (PAFC)

PAFC is a long-established fuel cell technology with many years of development and operational history. This type of fuel cell utilizes a liquid phosphoric acid electrolyte and carbon paper anodes with a platinum-based catalyst. PAFC have an electrical efficiency of 40 to 50 percent, though they are typically utilized in CHP applications, accomplishing a combined electrical and thermal efficiency as high as 80 to 90 percent. Due to relatively low operating temperatures, around 200 °C, cell corrosion and degradation is limited, and PAFC have demonstrated long operating life spans as high as 80,000 hours. However, the use of expensive catalyst material and stack design results in a relatively high cost for this technology.

Current PAFC development efforts are focused on increased catalyst performance and lower cost materials. Both of these goals would lead to lower costs on a $/kW basis for PAFC systems. Currently, commercial PAFC systems operate on lifespans around 60,000 hours. Due to the longer stack life compared to MCFC and SOFC, O&M costs for commercial PAFC systems are estimated to be approximately $150/kW-yr.

PAFC Technology Supplier: Doosan Fuel Cell America, Inc.

Doosan Fuel Cell, based in South Windsor, Connecticut, is a well-established commercial provider of PAFC systems. Doosan acquired ClearEdge Power, after it filed for bankruptcy, and its PureCell fuel cell in July 2014. Prior to that, ClearEdge had purchased UTC Power in 2013; UTC was originally founded in 1958 and provided fuel cells to early NASA missions.

Table 3-8 Performance Characteristics of FuelCell Energy Fuel Cell Systems

	FUELCELL ENERGY: DFC3000	FUELCELL ENERGY: DFC1500
Unit Ratings		
Gross Power Output, kW	300	1,400
Output Voltage, V	480	480
Operating Parameters		
Fuel and Water Consumption/Discharge		
Natural Gas Consumption, scfm	39	181
Natural Gas Consumption(1), MMBtu/h (HHV)	2.39	11.1
Water Consumption (average), gpm	0.9	4.5
Water Discharge (average), gpm	0.45	2.25
System Efficiency(2)		
Heat Rate (HHV), Btu/kWh	7,950	7,950
Electrical Efficiency, %	43	43
Emission Rates		
Carbon Dioxide (electricity only), lb/MWh	980	980
Nitrogen Oxides, lb/MWh	0.01	0.01
Sulfur Oxides, lb/MWh	0.001	0.0001
Particulate Matter (PM_{10}), lb/MWh	0.00002	0.00002

Source: FuelCell Energy
Notes:
1. Assumes HHV of natural gas of 1,023 British thermal unit per standard cubic foot (Btu/scf).
2. System efficiency assumes electricity-only operation (i.e., no waste heat recovery or CHP operation).

scmf - standard cubic feet per minute
MMBtu/h - million British thermal units per hour
gpm - gallons per minute

The PureCell Model 400 is a 400 kW PAFC system consisting of a fuel reformer, the PAFC stack, and a power conditioner to supply AC power. Process heat is also available and, when combined with electricity generation, the PureCell achieves an overall efficiency of 90 percent. The PureCell is marketed toward and utilized primarily in CHP applications to maximize the system's total energy product. Doosan states that the PureCell product line has over 11 million fleet operating hours, with the Model 400 (introduced in 2012) recently surpassing 1 million fleet operating hours.

Performance characteristics of the PureCell are shown in Table 3-9.

Table 3-9 Performance Characteristics of Doosan PureCell Model 400

	PURECELL MODEL 400
Unit Ratings	
Gross Power Output, kW	400
Output Voltage, V	480
Operating Parameters(1)	
Fuel and Water Consumption/Discharge	
Natural Gas Consumption, scfm	58.6
Natural Gas Consumption, MMBtu/h (HHV)	3.6
Water Consumption (average), gpm	None
Water Discharge (average), gpm	None
System Efficiency(2,3)	
Heat Rate (HHV), Btu/kWh	9,000
Electrical Efficiency, %	42
Emission Rates(4)	
Carbon Dioxide (electricity only), lb/MWh	1,049
Nitrogen Oxides, lb/MWh	0.01
Sulfur Oxides, lb/MWh	Negligible
Particulate Matter (PM_{10}), lb/MWh	Negligible

Source: Doosan Fuel Cell

Notes:

1. Average performance during first year of operation.
2. Assumes HHV of natural gas of 1,025 Btu/scf.
3. System efficiency assumes electricity-only operation (i.e., no waste heat recovery or CHP operation).
4. Performance and emissions based on 400 kW operation.

3.2.2 Fuel Cell Costs

Upon reviewing various sources of data for fuel cell costs, Black & Veatch determined that the best source of current fuel cell costs come from the Self-Generation Incentive Program (SGIP) offered by the state of California, which has funded a significant portion of the fuel cell installations in the United States.

Figure 3-10 illustrates historical SGIP data on fuel cell costs compiled by the NREL.[7] The cost data have been normalized for all years to 2010 dollars. This figure shows that the installed cost of fuel cells increased (in 2010 dollars) over the period from 2003 to 2013, which would seem to indicate that economies of scale have not yet been achieved by any of the fuel cell technologies described previously. This trend appeared in all size categories (i.e., less than 500 kW, 500 to 1,000 kW, and greater than 1,000 kW).

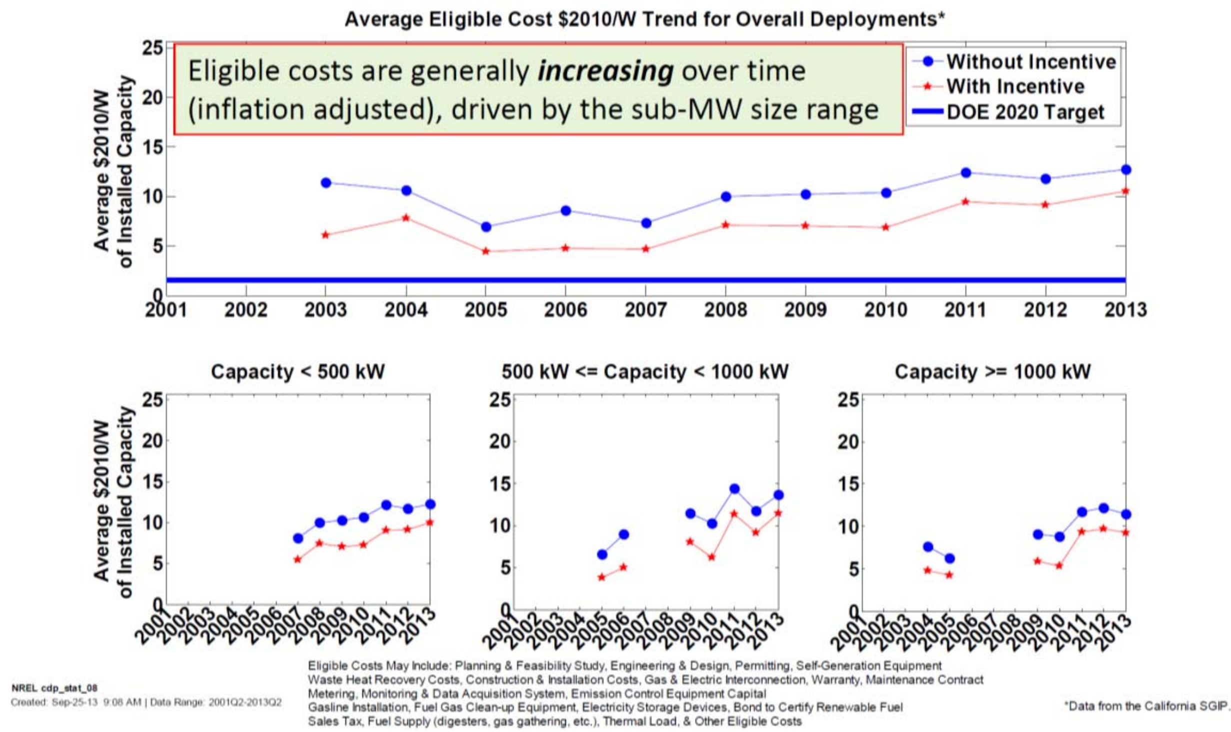

Figure 3-10 Stationary Fuel Cell Installed Cost (with and without incentives) – 2003 to 2013 (Source: NREL)

[7] Wilpe, et al. "Evaluation of Stationary Fuel Cell Deployments, Costs and Fuels," 2013 Fuel Cell Seminar and Energy Exposition, Columbus, Ohio, October 23, 2013.

3.2.2.1 Current Costs

The California Public Utilities Commission (CPUC) publishes eligible projects costs information by project.[8] Eligible costs include a variety of project costs: engineering costs, permitting costs, cost of equipment and installation, and interconnection costs.

Within the SGIP database, there are 143 fuel cell projects that applied for SGIP funding in 2012, 2013, and 2014.[9] The vast majority of these 2012 to 2014 projects (i.e., 130 projects) are electricity-only projects employing fuel cells supplied by Bloom. The remainder of these projects are CHP projects employing fuel cells supplied by Doosan (11 projects under the ClearEdge and UTC brand names) or FuelCell Energy (2 projects). Capital costs for these projects, based on the total eligible costs listed in the SGIP database, are summarized in Table 3-10.

Table 3-10 Fuel Cell Projects Applying for SGIP Funding in 2012 to 2014

TECHNOLOGY	SUPPLIER	APPLICATION	NUMBER OF PROJECTS(1)	TOTAL INSTALLED CAPACITY (MW)	AVERAGE PROJECT SIZE (KW)	AVERAGE PROJECT COST(2) ($/KW)
SOFC	Bloom	Electricity-only	130	52	400	12,000
PAFC (small-scale)(3)	Doosan(4)	CHP	6	0.18	30	17,400
PAFC (large-scale)(3)	Doosan(4)	CHP	5	4.0	800	9,200
MCFC	FuelCell Energy	CHP	2	2.8	1,400	6,200

Source: CPUC, SGIP Quarterly Projects Report (http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/).

Notes:

1. Number of projects identifies projects that have applied for SGIP funding in 2012, 2013, and 2014 (excluding projects with status of “canceled” or “suspended.”)
2. Average project cost is based on total eligible costs listed in SGIP database.
3. Because of significant variations in scales, PAFC projects are split into two categories: small-scale projects ranging in size from 15 to 80 kW and large-scale projects ranging in size from 400 to 1,200 kW.
4. Doosan includes projects supplied by UTC and ClearEdge.

[8] California Public Utility Commission, Self-Generation Incentive Program, http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/.

[9] This total excludes projects that have either been canceled or are currently suspended.

For Bloom's electricity-only SOFC projects, rated capacities of the projects ranged from 210 kW to 1,050 kW, with most projects reporting costs between $11,000/kW and $13,000/kW. Project costs for PAFC systems were split into two categories: smaller scale (i.e., less than 100 kW) and larger scale (i.e., greater than 400 kW). These projects are defined as CHP projects within the SGIP database. Total eligible costs for the smaller scale category average $17,400/kW, while total eligible costs for the larger scale category average $9,200.

Project costs for MCFC systems are based on two projects identified as CHP projects. The eligible costs for these two projects (each rated at 1,400 kW) were reported as $5,700/kW and $6,700/kW, respectively.

Based on the information summarized in Table 3-10, the capital cost of SOFC systems are greater than those of PAFC and MCFC. This is true even though the SOFC systems provide only electricity, while PAFC and MCFC projects listed in the SGIP database have CHP applications.

While the SGIP data represent installed system costs, Black & Veatch considers these values to be somewhat inflated in order to maximize investment tax credit (ITC) payment. Fuel cells are eligible for an ITC payment of 30 percent of system costs, up to $3,000/kW, effectively allowing the full 30 percent credit for system costs up to $10,000/kW. For example, the SGIP data for SOFC projects show system costs ranging from approximately $11,000/kW to $13,000/kW, while Bloom's published system quotes are around $8,000/kW[10]. Balance-of-system costs are acknowledged to account for some of that gap. Further complicating the estimation of actual fuel cell system costs are statements from major fuel cell suppliers, including Bloom and FuelCell Energy, implying negative profitability to date. The lack of cost transparency adds significant uncertainty to current and forecasted fuel cell cost estimates.

3.2.2.2 Forecasted Costs

Current capital costs greatly exceed targets for fuel cells identified by the DOE, which set 2020 targets at $1,500/kW for operation on natural gas.[11]

Several technical gaps have been identified as areas for significant cost reductions, and recent historical cost trends indicate that it will require a dramatic near-term reduction in cost for fuel cell suppliers to achieve DOE cost targets. Although not commercially available, Redox Power, a SOFC manufacturer who is currently working to commercialize its technology with Microsoft under a DOE grant, claims to have achieved a breakthrough design, lowering costs to about 10 percent of current commercial SOFC costs[12],[13]. Several other manufacturers including Toyota, Mitsubishi, and Honda are currently developing their own SOFC technologies. This market momentum may reduce system costs for SOFC and, in turn, drive down costs for MCFC and PAFC. While fuel cell cost forecasts are uncertain, and even current costs are considered to be vague (as discussed in Subsection 3.2.2.1), Black & Veatch has concluded that fuel cell system costs reported by SGIP are somewhat inflated and, therefore, has assumed for analysis purposes that 2016 costs are about one-third lower than SGIP reports. To test whether a dramatic drop in costs would be financially viable, Black & Veatch assumed that the market goal of $1500/kW would be met for all fuel cell

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[10] http://www.seattle.gov/light/news/issues/irp/docs/dbg_538_app_i_5.pdf.

[11] U.S. DOE, Fuel Cell Technologies Office Multi-Year Research, Development, and Demonstration Plan (2012).

[12] http://www.technologyreview.com/news/518516/an-inexpensive-fuel-cell-generator/.

[13] http://www.dailytech.com/Microsofts+New+Fuel+Cell+Partner+is+Ready+to+Blow+Away+the+Bloom+Box/article36118.htm.

technologies by 2035. This cost forecast is not necessarily supported by the recent historical market trends; however, without a significant cost reduction, these technologies will not be financially feasible in DG applications such as those considered in this assessment.

3.3 MICROTURBINES

Microturbines are small combustion turbines that operate at very high speeds (i.e., more than 40,000 revolutions per minute [rpm] and up to 100,000 rpm). Microturbines, as shown on Figure 3-11, are typically rated at less than 250 kW, but multiple units can be installed in parallel for higher capacity. They are available as modular packaged units that include the combustor, the turbine, the generator, and the cooling and heat recovery equipment. Because of the small system footprints, microturbine units are attractive for small- to medium-sized applications.

3.3.1 Technical Characteristics

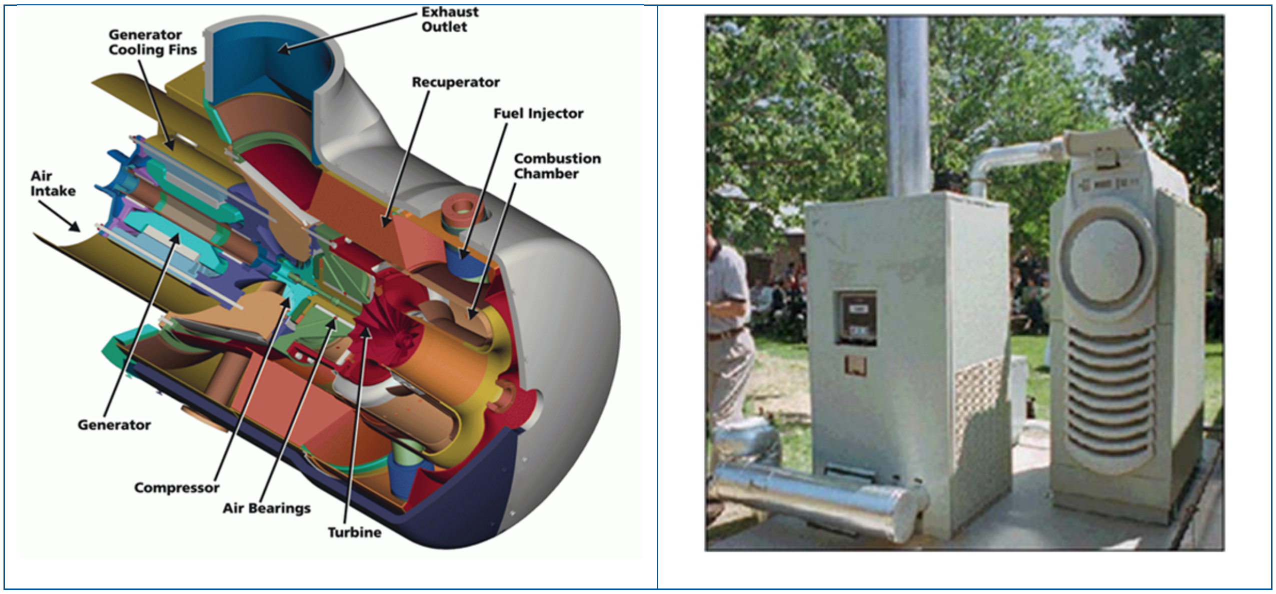

Figure 3-11 Cut-Away of Microturbine (left) and Typical Microturbine Installation (right) with Heat Recovery Module

Within a microturbine, the fuel gas is compressed and mixed with air in the combustor; combustion of the fuel/air mixture generates heat that causes the gases to expand. The expanding gases drive the turbine, which in turn drives a generator producing electricity. Heat from the turbine exhaust is recovered in a recuperator and is used to preheat incoming combustion air. This helps improve the overall operating efficiency of the unit.

Compared to reciprocating engines and engine-driven equipment, microturbines have the following operating characteristics:

- Lower efficiencies.
- Lower emissions.
- Greater inlet gas pressure requirements (ranging from 75 to 100 pounds per square inch gauge [psig]).
- Greater fuel gas treatment requirements (e.g., H_2S content must be reduced to less than 5000 parts per million volumetric [ppmv]).

The thermal efficiency of microturbine units is in the range of 25 to 30 percent (on a lower heat value [LHV] basis), depending on the manufacturer, ambient conditions, and the need for fuel compression. Similar to combustion turbines, efficiencies are reduced to some extent when operating at higher ambient temperatures (as the mass flow of combustion is reduced at higher ambient temperatures).

Microturbines are best operated continuously at full load as frequent start/stop cycles increase the frequency of periodic maintenance and reduce availability. These machines can operate at partial loads, although part-load operation negatively affects efficiency. For example, operation at 50 percent load would result in a thermal efficiency reduction to 25 percent (relative to 30 percent efficiency at full load).

Capstone C65 System

At present, there are two primary vendors for microturbine systems: Capstone Turbine Corporation and FlexEnergy. For the purposes of this characterization, Black & Veatch will provide information on Capstone's C65 system, which has a rated output of 65 kW. Performance of this machine is summarized in Table 3-11.

Regarding O&M costs, Capstone offers service packages at various levels of service (up to and including complete parts and labor for all maintenance activities). Lump sum fees for this service are paid on an annual basis. The annual fee for the complete O&M service package is equivalent to approximately $170/kW-yr.

Table 3-11 Performance Characteristics of Capstone C65 Microturbine

	CAPSTONE C65 MICROTURBINE
Unit Ratings	
Gross Power Output, kW	65
Output Voltage, V	480
Operating Parameters	
Fuel and Water Consumption/Discharge	
Natural Gas Consumption, scfm	14.2
Natural Gas Consumption, MMBtu/h (HHV)	0.87
Water Consumption (average), gpm	None
Water Discharge (average), gpm	None
System Efficiency(1)(2)	
Heat Rate (HHV), Btu/kWh	13,400
Electrical Efficiency, %	25
Emission Rates	
Carbon Dioxide (electricity only), lb/MWh	1,375
Nitrogen Oxides, lb/MWh	0.05
Sulfur Oxides, lb/MWh	Negligible
Particulate Matter (PM10), lb/MWh	Negligible

Source: Capstone Turbine Corporation
Notes:
1. Assumes HHV of natural gas of 1,025 Btu/scf.
2. System efficiency assumes electricity-only operation (i.e., no waste heat recovery or CHP operation).

3.3.2 Microturbine Costs

In the period from 2011 to 2014, only 8 microturbine projects were funded through SGIP. These projects are summarized in Table 3-12.

Table 3-12 Microturbine Projects Applying for SGIP Funding in 2011 to 2014

TECHNOLOGY	SUPPLIER	YEAR OF APPLICATION	RATED CAPACITY (KW)	ELIGIBLE PROJECT COST(1) ($)	ELIGIBLE PROJECT COST(1) ($/KW)
Microturbine	FlexEnergy	2011	726	2,831,300	3,900
Microturbine	Capstone	2012	65	504,200	7,750
Microturbine	Capstone	2012	65	504,200	7,750
Microturbine	Capstone	2012	585	2,510,100	4,290
Microturbine	Capstone	2012	600	1,129,600	1,880
Microturbine	Flex Energy	2012	750	3,310,500	4,410
Microturbine	Capstone	2012	1,000	4,541,300	4,540
Microturbine	Capstone	2013	1,000	3,067,100	3,070

Source: CPUC, SGIP Quarterly Projects Report (http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/).
Notes:
1. Eligible project cost is based on total eligible costs listed in SGIP database.

For the Capstone installations of 65 kW, costs were reported to be $7,750 per kW in 2012, while larger systems (greater than 500 kW) ranged from $3,000 to $4,500 per kW, with the exception of the 600 kW Capstone system with a reported cost of $1,880 per kW.

Based on recent price quotations obtained by Black & Veatch for microturbines and ancillary equipment, equipment costs are approximately $2,500 per kW to $3,000 per kW. Therefore, when adding project development and installation costs, the reported costs from SGIP would be consistent with these recent equipment quotations and be representative of current installed costs.

3.3.2.1 Forecasted Costs

Because of the relatively mature state of microturbine technology, Black & Veatch does not foresee significant cost reductions in microturbine project costs over the long term. Therefore, these project costs are anticipated to be flat over the modeled project period in real dollars.

4.0 Financial Assessment

To model project financials, Black & Veatch modeled each of the technologies for a number of commercial customer types using a modified scripting of NREL's SAM software. The model incorporates technical performance parameters, system capital and O&M costs, project financing and taxes, incentives, and utility rate data, together with customer load data, to produce a suite of results including net present value (NPV), payback period, levelized cost of energy (LCOE), annual cash flow, and annual energy savings. Black & Veatch modeled scenarios for 2016 and 2035 for all technologies and customer types. For BESS, the system was tested with and without solar PV. Also, it was important to use different customer types to understand how different load shapes may benefit through electricity bill reductions for both demand and energy charges, under each of their respective rate classes. For each customer type, each of the technologies was also sized to meet either the customer load or minimum technology unit size. For both the 2016 and 2035 cases, Black & Veatch also tested two utility rates escalating two ways: at the CPI of 2 percent, and at CPI plus 1 percent (CPI + 1). Additionally, fuel cells and microturbines were tested under base and low gas price scenarios.

4.1 MODEL ASSUMPTIONS

Black & Veatch developed technical and financial assumptions to be input into the SAM model for each scenario, many of which were derived from the technical characteristics discussed in Section 3.0. These inputs are summarized in the following section.

4.1.1 Technical and Cost Assumptions

For this analysis, Black & Veatch used as input the technical parameters and cost forecasts developed in Section 3 for the various technologies.

Table 4-1 and Table 4-2 summarize the technical and cost inputs to the financial assessment. For BESS, Black & Veatch opted to model lithium ion technology only, as the technology has better round-trip efficiency than flow batteries and are more practical at a small scale.

Table 4-1 Technical and Financial Assumptions - BESS (2014$)

		2016			2035		
TECHNOLOGY	SIZE (KWH)	CAPITAL COST ($/KWH)	FIXED O&M ($/KW-YR)	ROUND-TRIP EFFICIENCY (%)	CAPITAL COST ($/KWH)	FIXED O&M ($/KW-YR)	ROUND-TRIP EFFICIENCY (%)
BESS	10	1500	20	87	400	20	87

For the 2035 case, the improvements in fixed cost for fuel cells and BESS were assumed as discussed in Section 3.0. In the case of SOFC, a heat rate improvement on the order of 20 percent higher than that of current commercial systems was assumed. This assumption is based on the gap between existing commercial systems and the technically achievable efficiency for SOFC. Other commercial fuel cell technologies (MCFC, PAFC) and microturbines currently perform near their technical potential; thus, no heat rate improvement is applied. Similarly, no improvement is assumed for BESS round-trip efficiency in the 2035 case.

Table 4-2 Technical and Financial Assumptions - Fuel Cells and Microturbines (2014$)

TECHNOLOGY	SIZE (KW)	2016			2035		
		CAPITAL COST ($/KW)	FIXED O&M ($/KW-YR)	HEAT RATE (BTU/KWH)	CAPITAL COST ($/KW)	FIXED O&M ($/KW-YR)	HEAT RATE (BTU/KWH)
SOFC	210	8000	1000	7000	1500	150	5600
MCFC	300	4000	300	8000	1500	150	8000
PAFC	400	6000	150	9000	1500	150	9000
Microturbine	65	4000	170	13400	4000	170	13400

Table 4-3 shows the gross-to-net loss assumptions applied to fuel cells, microturbines, and BESS. In the case of fuel cells, rather than apply a percentage year-to-year degradation, an overall system de-rate was applied to better represent the stack replacement under the assumed O&M practices for commercial systems. Black & Veatch has assumed that fuel cell technologies will improve through advances identified in Section 3.2, hence this de-rate is reduced for the 2035 scenarios.

Table 4-3 System Loss Summary for Fuel Cells and Microturbines

LOSS CATEGORY	LOSS (%)
Nameplate Losses	99
Availability	98
De-rate for Stack Degradation – 2016 (Fuel Cell Only)	90
De-rate for Stack Degradation – 2035 (Fuel Cell Only)	95

Fuel cells and microturbines are modeled as fueled by natural gas. Both technologies are capable of running on biogas, but such a project would require a unique location, for example a food processing plant, landfill, or wastewater treatment facility. Black & Veatch has assumed for the purposes of this analysis that the evaluated commercial customer types would likely not have the ability to utilize biogas for this reason. Such operation would also add to the capital and O&M costs and, in some cases, reduce life span of some system components. The natural gas prices used are based on current published commercial rates from NW Natural, the gas utility serving Portland, and escalated at the growth rate calculated from base and low wholesale price forecasts provided by PGE,[14] as shown on Figure 4-1 and in Table 4-4.

[14] NW Natural Summary of Monthly Sales Service Billing Rates: https://www.nwnatural.com/uploadedFiles/Oregon_Billing_Rate_Summaries.pdf.

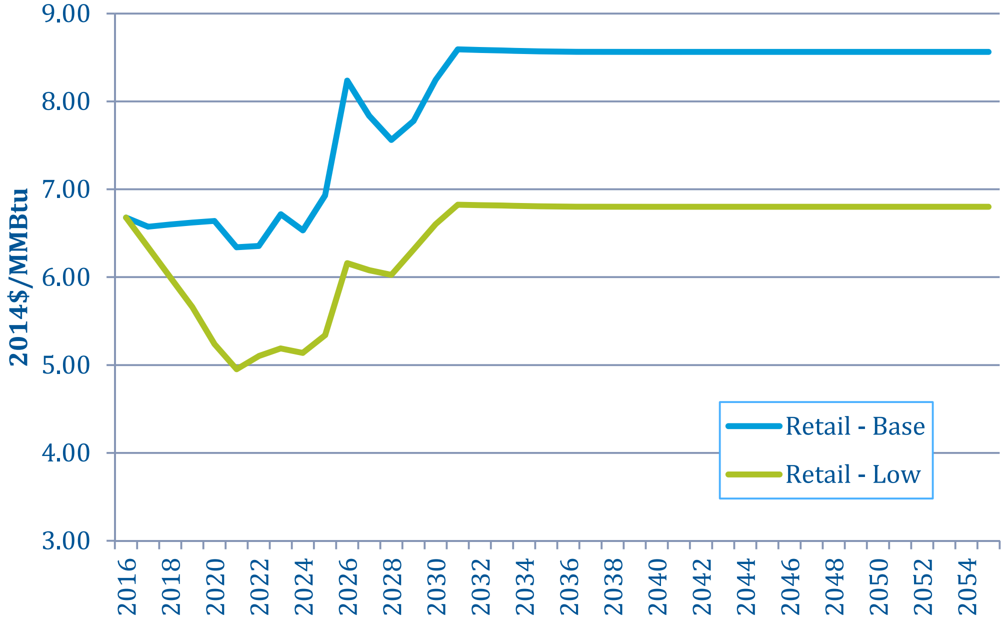

Figure 4-1 Retail Natural Gas Forecast, Base and Low Cases (2014$)

Table 4-4 Natural Gas Wholesale and Retail Commercial Forecast (2014$)

	2014$/MMBTU			
	PGE FORECASTED WHOLESALE PRICES		ESTIMATED RETAIL PRICES	
	BASE	LOW	BASE	LOW
2016	3.86	3.86	6.68	6.68
2017	3.80	3.67	6.57	6.34
2018	3.82	3.47	6.60	6.00
2019	3.83	3.28	6.62	5.66
2020	3.84	3.03	6.64	5.24
2021	3.67	2.87	6.34	4.95
2022	3.68	2.95	6.35	5.10
2023	3.89	3.00	6.72	5.19
2024	3.78	2.97	6.53	5.14
2025	4.01	3.09	6.93	5.34
2026	4.77	3.56	8.24	6.16
2027	4.53	3.52	7.83	6.08
2028	4.38	3.49	7.56	6.03
2029	4.50	3.65	7.78	6.31
2030	4.77	3.82	8.25	6.60
2031	4.97	3.95	8.59	6.82
2032	4.97	3.95	8.59	6.82
2033	4.96	3.94	8.58	6.81
2034	4.96	3.94	8.57	6.81
2035	4.96	3.94	8.57	6.80

4.1.2 Financial and Incentive Assumptions

The following are incentives that were reviewed for the analysis and matched to eligible technologies. Each incentive was applied to the eligible technologies for the various 2016 modeling scenarios:

- **Federal ITC:** A tax credit equal to 30 percent of eligible project costs for fuel cells and 10 percent of eligible costs for microturbines.
- **Federal Modified Accelerated Cost Recovery System (MACRS):** Five years for fuel cells, microturbines, and energy storage.
- **Oregon State Renewable Energy Systems Property Tax Exemption:** Of the technologies considered in this analysis, only fuel cells are explicitly included, although it has been assumed that the exemption is available to microturbines and energy storage.
- **Energy Trust of Oregon (ETO):** 50 percent grants for a number of renewable energy technologies including fuel cells; however, eligibility is limited to those projects using a renewable fuel. The Black & Veatch assessment considers only natural gas as a fuel, so fuel cells are not eligible.
- **ETO Solar Incentive:** Similar to the assumptions for Black & Veatch's Solar Market Study, it was assumed that the solar portion of the solar PV and BESS system would be eligible. Table 4-5 summarizes the incentives applied in the financial assessment.
- **Oregon State Net Energy Metering (NEM)**: PGE customers are credited at their utility rate schedule for excess generation, rolling over from month-to-month. Any excess generation remaining at the end of the year is not credited to the customer. This effectively caps a project under NEM at the customer's total annual consumption. Fuel cells running on natural gas are eligible, but microturbines and BESS are not. Black & Veatch has assumed a solar PV plus BESS system would be eligible for net metering.

Table 4-5 Available Financial Incentives in 2016 Cases

TECHNOLOGY	FEDERAL ITC	FEDERAL MACRS	PROPERTY TAX EXEMPTION	ETO	NET METERING
SOFC	30%	Eligible	Eligible	Not Eligible	Eligible
MCFC	30%	Eligible	Eligible	Not Eligible	Eligible
PAFC	30%	Eligible	Eligible	Not Eligible	Eligible
Microturbine	10%	Eligible	Eligible	Not Eligible	Not Eligible
BESS	Not Eligible	Eligible	Eligible	Not Eligible	Not Eligible
BESS + Solar PV	Solar Portion Only	Eligible	Eligible	Solar Portion Only	Eligible

For the 2035 cases, incentives are assumed not to be available, except for the 5-year MACRS.

The analysis period for all projects has been set to 20 years. As discussed in Section 3.0, the estimated project life spans for some technologies may be significantly less than 20 years, particularly in the case of fuel cells. However, O&M cost data have been estimated based on full-service warranties and is correspondingly high for those technologies with short life spans to account for frequent fuel cell, turbine, or other component replacement. In the case of energy storage, as discussed in Subsection 3.1.1, full daily cycling may result in a life span of approximately 10 years. Black & Veatch has assumed that the battery system will be cycling daily but not necessarily at full discharge, so should be able to operate for the 20 year test period.

All projects are assumed to be customer-owned with no debt financing. Table 4-6 summarizes the financial modeling assumptions, though schools were modeled as tax-exempt entities. It is important to note that the payback calculation reduces "energy savings" for tax-paying entities by their tax rates because they would have otherwise have been able to expense their electric bill as a tax-deductible item. The impact of this calculation between tax-paying and tax-exempt customers is significant on payback calculations, even though tax-paying commercial customers do benefit from MACRS and are able to deduct the asset as a capital expense.

Table 4-6 Financial Modeling Assumptions

FINANCIAL ASSUMPTIONS	
Analysis Period (Years)	20
Federal Income Tax (%)	35.0
State Income Tax (%)	7.6

4.1.3 Customer Load

It was important to use different customer types to understand how different load shapes may benefit through electricity bill reductions for both demand and energy charges, under each of their respective rate classes. Customer load profiles (hourly electricity demand) were obtained from DOE data compiled for all Typical Meteorological Year 3 (TMY3) locations in the United States, using the DOE commercial reference building model[15]. The dataset corresponding to the Portland International Airport TMY3 location was used for this analysis. Commercial customer types are presented in Table 4-7 together with summary statistics. PGE rate schedules used in the analysis are summarized in Table 4-8.

[15] US DOE Commercial and Residential Hourly Load Profiles, openEI.org : http://en.openei.org/datasets/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states.

Table 4-7 Commercial Customer Type Load Summary

COMMERCIAL CUSTOMER TYPE	ENERGY USE (MWH)	AVERAGE DEMAND (KW)	PEAK DEMAND (KW)	MINIMUM DEMAND (KW)	LOAD FACTOR (%)	ASSIGNED PGE RATE SCHEDULE
Full Service Restaurant	301	34	64	15	54	83
Hospital	8770	1001	1387	632	72	85
Large Hotel	2331	266	421	124	63	85
Large Office	5698	650	1718	211	38	85
Medium Office	682	78	270	19	29	85
Outpatient	1228	140	307	36	46	85
Primary School[1]	810	92	273	40	34	85
Quick Service Restaurant	186	21	37	9	58	83
Secondary School[1]	2488	284	908	87	31	85
Small Hotel	549	63	126	32	50	83
Small Office	61	7	19	2	37	32
Stand-Alone Retail	290	33	90	4	37	83
Strip Mall	270	31	84	3	37	83
Supermarket	1614	184	357	76	52	85
Warehouse	238	27	85	6	32	83

(1)Primary and secondary schools are tax-exempt customer types and are modeled as such.

Table 4-8 PGE Commercial Rate Schedule Summary (2014 Rates)

SCHEDULE	PEAK DEMAND (KW)	OFF-PEAK RATE ($/KWH)	PEAK RATE ($/KWH)	DEMAND CHARGE ($/KW)
32	0 to 30	0.0827	0.0827	0
83	31 to 200	0.0728	0.0831	5.6753
85	201 to 4000	0.0639	0.0742	5.0573
89	> 4000	0.0594	0.0697	3.8522

Results for the various technologies are presented in the following sections.

4.2 ENERGY STORAGE

For the energy storage analysis, Black & Veatch tested two configurations: BESS alone and BESS with PV. Black & Veatch developed a modified scripting of SAM to model BESS in both configurations. Energy storage is modeled to reduce peak demand and associated demand charges, as well as shifting load between on-peak and off-peak hours. Figure 4-2 illustrates how BESS can operate with a PV system where the BESS shifts load during the peak hours to off-peak hours. It should be noted that this example uses a 400 kWh BESS for illustrative purposes; the actual model runs utilized a much smaller system size, as discussed below.

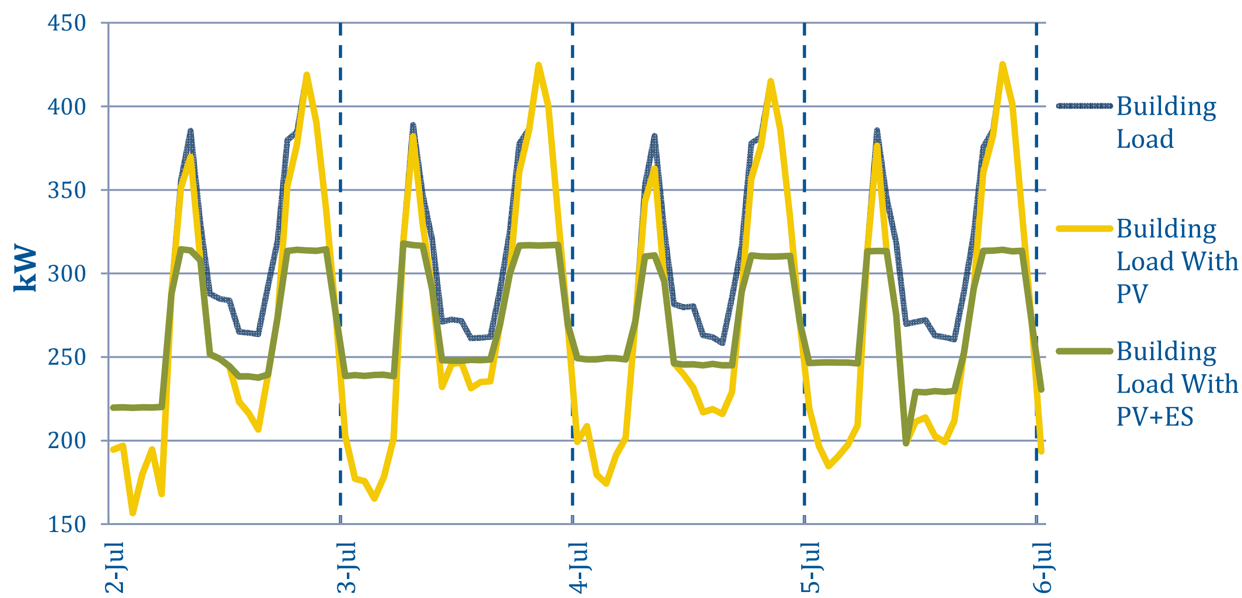

Figure 4-2 Illustrative Example of a Large Hotel Using 400 kWh BESS and PV

For financial modeling purposes, we modeled only lithium ion battery technology, due to the availability of smaller system sizes and significantly better round-trip efficiencies than flow batteries.

4.2.1 System Size

For the BESS plus PV systems, the PV systems were sized using NREL commercial customer profile data and estimates of average available rooftop space. Table 4-9 shows the PV system sizes used in the BESS plus PV cases.

Table 4-9 Solar PV System Size by Customer Type

COMMERCIAL CUSTOMER TYPE	PV SYSTEM SIZE (KW)
Full Service Restaurant	36
Hospital	262
Large Hotel	113
Large Office	249
Medium Office	116
Outpatient	55
Primary School	481
Quick Service Restaurant	16
Secondary School	686
Small Hotel	70
Small Office	36
Stand-Alone Retail	162
Strip Mall	146
Supermarket	293
Warehouse	338

To determine the battery energy storage system size, Black & Veatch ran the model using step sizes of 5 kWh and evaluated the results in terms of system size (kWh) versus payback years. In all cases, with and without PV, it can be seen that the payback continues to increase with additional storage capacity. Figure 4-3 shows the payback periods versus increasing system size for each customer. Based on this result, the battery systems have been sized to the minimum available system size of 10 kWh, as larger systems have diminishing benefits to load reduction. Black & Veatch notes that the results for small customer loads, such as warehouse, small office, quick service restaurant, are erratic beyond 10 kWh, as the system size is close to their average load and so are not shown in the graph on Figure 4-3.

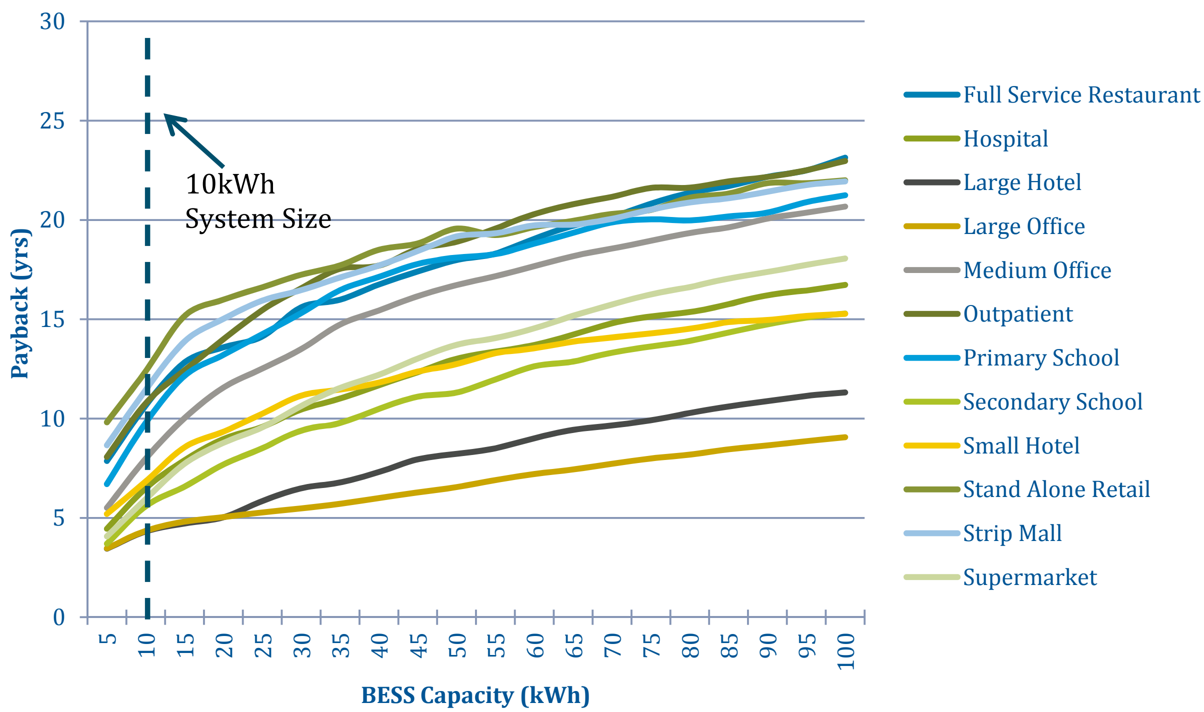

Figure 4-3 BESS Payback Curves, 2035 CPI+1

4.2.2 Results

Figure 4-4 and Figure 4-5 show the payback in years for all customer types for the 2016 and 2035 energy storage and energy storage with PV for the CPI + 1 case. It should be noted that for some of the systems that show paybacks of 25 years, the payback periods are actually well in excess of 25 years, and, therefore, not financially viable. As can be seen, particularly in the 2016 BESS-only cases, the long customer paybacks indicate poor financial feasibility. Because of the small margin between the TOU rates, there is little opportunity to take advantage of arbitrage from load shifting. Since the on-peak rates are only around 15 percent higher than the off-peak rates, after factoring in the round-trip charge/discharge efficiency of the battery system, there is very little positive (and in some cases slightly negative) financial advantage to charging during off-peak periods and discharging during on-peak periods. Given this condition, the primary advantage of energy storage is, therefore, in reducing the peak demand charges. In most cases, these charges are relatively low, further disadvantaging the energy storage financials. This is also true for the 2035 BESS-only cases, although decreased capital costs show customers with some reasonable paybacks.

In general, in 2035, customers under the large commercial customer rate (Schedule 85) with higher demand charges appear to benefit most from a BESS system with lower paybacks, around 5 years. Customers under Schedule 83 appear to achieve paybacks of about 10 years. The small office, under Schedule 32, does not benefit from BESS at all since there is no demand charge associated with that tariff.

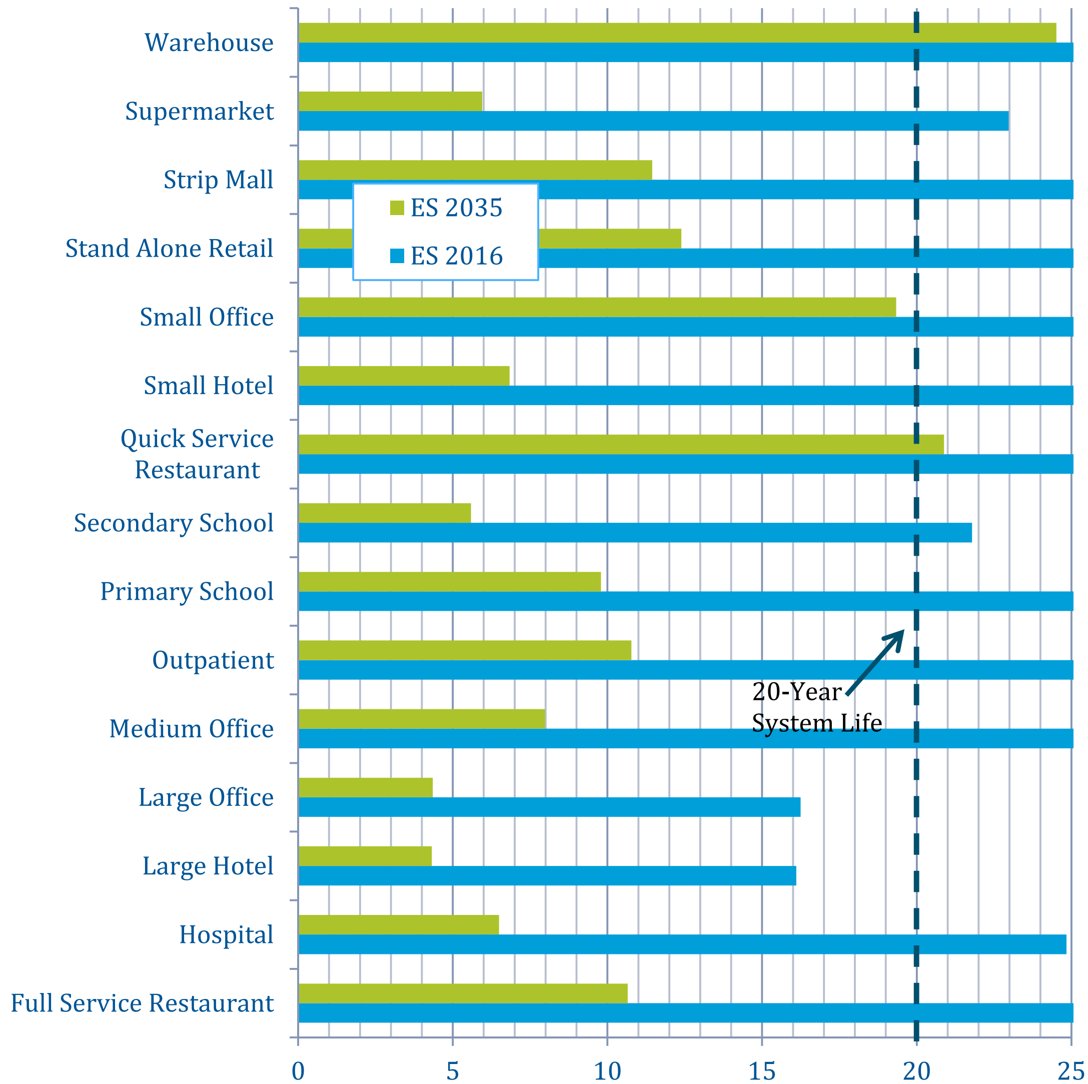

Figure 4-4 BESS Only Payback by Customer Type

Table 4-10 summarizes the payback for BESS Only under both the CPI and CPI+1 cases. Payback periods for CPI cases are greatly increased depending on the customer type.

Table 4-10 BESS Only System Payback Summary by Customer Type

	SYSTEM PAYBACK - CPI		SYSTEM PAYBACK - CPI +1	
	ES 2016	ES 2035	ES 2016	ES 2035
Full Service Restaurant	47.0	13.8	37.7	10.7
Hospital	28.6	8.2	24.8	6.5
Large Hotel	17.7	5.1	16.1	4.3
Large Office	17.9	5.2	16.2	4.4
Medium Office	34.6	10.0	29.6	8.0
Outpatient	47.6	13.9	38.0	10.8
Primary School	42.1	12.3	35.1	9.8
Secondary School	24.4	6.9	21.8	5.6
Quick Service Restaurant	>80	28.8	62.2	20.9
Small Hotel	30.1	8.7	26.0	6.8
Small Office	>80	>80	59.2	19.3
Stand Alone Retail	53.4	15.7	42.5	12.4
Strip Mall	49.5	14.5	39.9	11.4
Supermarket	26.2	7.5	23.0	6.0
Warehouse	>80	32.0	67.2	24.5

When combined with a PV system, the total system payback varies by each customer type's unique demand profile and PV system size. However, these payback calculations are worse than PV alone, so it does not appear to be financially practical to install BESS when PV currently enjoys the benefits of net metering.

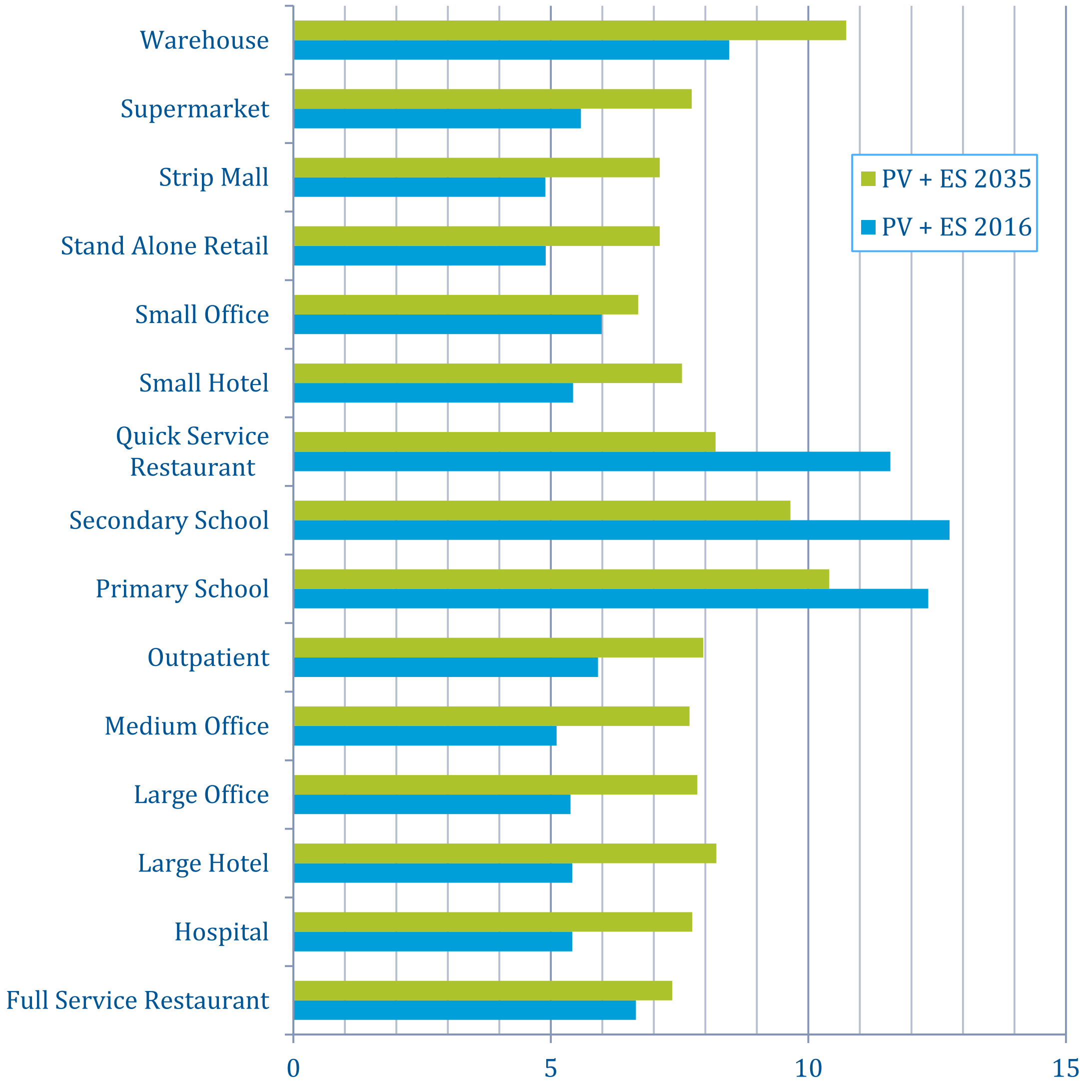

Figure 4-5 BESS plus PV System Payback by Customer Type

4.3 FUEL CELLS

Fuel cells were modeled for each technology discussed in Section 3.2: SOFC, MCFC, and PAFC. Currently, high capital and O&M costs limit commercial fuel cell use to areas with strong financial incentives, primarily under California's SGIP program. Furthermore, many current applications take advantage of the CHP capabilities of some fuel cell systems; whereas, Black & Veatch focused strictly on electric-only applications, which present somewhat limited opportunity. Black & Veatch has assumed, as shown in Table 4-2, that fuel cell costs will decrease dramatically by 2035, and in the case of SOFC, may achieve higher efficiencies in the 2035 cases. There is high uncertainty associated with these assumptions, but they are considered to be reasonable assumptions to test for long-term feasibility.

4.3.1 System Sizing

Fuel cells are modeled to run as baseload power (i.e., full nameplate capacity) with minimal load following capabilities. As fuel cells are eligible for net metering, systems have been sized for each customer type according to the average electricity demand, shown in Table 4-7. Since current commercial SOFC, MCFC, and PAFC systems are available modularly at capacities of 210 kW, 400 kW, and 300 kW, respectively, for each technology type (as identified in Section 3.0), customer types with average demand that is below the capacity of one single unit have been excluded, assuming it would not be financially viable to operate an oversized system under net metering rules. Table 4-11 shows the remaining customer types of sufficient size to be included in the financial assessment for fuel cells, along with the ultimate system size modeled for each fuel cell technology.

Table 4-11 Fuel Cell Customer Type and System Size

CUSTOMER TYPE	SYSTEM SIZE (KW)		
	SOFC (210 KW SYSTEM)	PAFC (400 KW SYSTEM)	MCFC (300 KW SYSTEM)
Hospital	840	800	900
Large Hotel	210	NA	300
Large Office	630	400	600
Secondary School	210	NA	300
Supermarket	210	NA	300

4.3.2 Results

In both the 2016 and 2035 case, the combination of capital, O&M, and natural gas fuel costs prohibit cost savings against the utility electricity rates, even with available incentives and a 1 percent rate escalation (the CPI + 1 case). Table 4-12 shows the system payback results for the CPI + 1 case.

Table 4-12 Fuel Cell System Payback by Customer Type, CPI + 1 Case, Base Fuel Cost

	2016			2035		
	SOFC	PAFC	MCFC	SOFC	PAFC	MCFC
Hospital	>80	>80	>80	27.3	>80	>80
Large Hotel	>80	>80	>80	27.3	>80	>80
Large Office	>80	>80	>80	27.3	>80	>80
Secondary School	>80	>80	>80	12.1	>80	27.3
Super Market	>80	>80	>80	27.5	>80	>80

For the 2035 scenario, incentives are assumed to be unavailable, natural gas fuel costs are forecast to increase faster than the CPI rate, and even with the assumed dramatic reduction in capital and O&M costs, the various fuel cell technologies still do not show opportunity for payback within the project life. The only customer with a payback below the 20 year project life is the secondary school SOFC case, whose high load and tax-exempt status provide enough benefit to reduce its payback relative to the other customer types.

Fuel costs are clearly a sensitive input with significant impact on the results, and are more uncertain in the 2035 case. Black & Veatch also modeled all scenarios under a “low” fuel cost forecast. Using the lower fuel costs, paybacks are reduced somewhat; however, only the secondary school (at paybacks of 7.8 years and 17.5 years for SOFC and MCFC, respectively) achieves paybacks below the 20 year project life.

Table 4-13 summarizes the LCOE for the different fuel cell scenarios. In general, the real levelized cost of energy is higher than retail energy rates for larger commercial customers.

Table 4-13 Fuel Cell Real Levelized Cost of Energy Estimates (2014$/kWh)

		SOFC		MCFC		PAFC	
YEAR	NATURAL GAS	TAX-EXEMPT	TAX-PAYING	TAX-EXEMPT	TAX-PAYING	TAX-EXEMPT	TAX-PAYING
2016	Base	$0.27	$0.24	$0.14	$0.13	$0.15	$0.13
	Low	$0.26	$0.23	$0.13	$0.12	$0.14	$0.12
2035	Base	$0.08	$0.08	$0.10	$0.10	$0.11	$0.11
	Low	$0.07	$0.07	$0.09	$0.09	$0.09	$0.10

While Black & Veatch has not presented results for the customer types excluded for being below the minimum system size, those customers were modeled and payback periods for all scenarios significantly exceeded the estimated project life.

It should be noted that all fuel cells have been modeled for electricity generation only. Some fuel cell scenarios may prove to be cost-effective if used as a CHP application, but that was not evaluated in this study.

4.4 MICROTURBINES

Microturbines are modeled based on the Capstone C65, as discussed in Section 3.3. In general, microturbines are typically deployed in niche applications, and often under significant incentives such as California's SGIP program, as their lower efficiency and relatively high cost typically preclude financial feasibility. We have assumed, as shown in Table 4-2, that microturbine cost and performance will not improve from 2016 to 2035 as it is a well-established technology.

4.4.1 System Sizing

Microturbines are also modeled to run at baseload power, because of the additional wear and tear incurred for cycling and reduced heat rates if they are run at part load. Since microturbines are not eligible to be net metered in Oregon, and it was assumed that it would not be financially viable to sell the energy back to PGE at avoided cost, systems have been sized for each customer type based on the minimum demand, as shown in Table 4-7. Using the Capstone C65 as the minimum microturbine system size of 65 kW, customer types with minimum demand that is below the capacity of one single microturbine were excluded. Table 4-14Table 4-14 shows the customer types of sufficient size to be included in the financial assessment for microturbines, together with the ultimate system size.

Table 4-14 Microturbine Customer Type and System Size

CUSTOMER TYPE	SYSTEM SIZE (KW)
Hospital	585
Large Hotel	65
Large Office	195
Secondary School	65
Supermarket	65

4.4.2 Results

In all cases, for all customer types (including those below the minimum load requirement), and for both the base and low fuel cost forecast, the model results show that high capital and O&M costs, retail fuel prices, coupled with a relatively low efficiency, and lower incentive eligibility make this technology not feasible for commercial electricity-only applications under PGE's rate schedules. Microturbines may be more financially viable operating in CHP mode but will need a suitable thermal load to accommodate the microturbine.

Table 4-15 summarizes the LCOE for the microturbine scenarios.

Table 4-15 Microturbine Levelized Cost of Energy (2014$/kWh)

YEAR	MICROTURBINE		
	NATURAL GAS	TAX-EXEMPT	TAX-PAYING
2016	Base	0.16	0.16
	Low	0.14	0.14
2035	Base	0.17	0.18
	Low	0.15	0.15

5.0 Achievable Potential

Developing estimates of achievable potential for the DG technologies examined in this study is challenging in that these technologies under current financial conditions are not financially viable in the near-term, and long-term cost outlook is quite uncertain for many of these technologies. Another added complexity is that appropriately sizing of the systems, matched to a customer's load shape, really drives the financials. In order for the technologies to be financially viable, technology costs would need to drop substantially, additional policies and incentives would need to be put in place, and changes in rate structure are needed to promote adoption. Absent those conditions, Black & Veatch forecasts minimal adoption of these technologies over the study period. If any adoption occurs, it would be toward the latter decade (2026 to 2035) of the analysis period when better clarity on costs is available. The one major caveat in this study is that Black & Veatch focused on the impact of these systems on customer electricity bills but did not account for the value of reliability and power quality to the customer. These factors are much more difficult to value and could vary widely by customer type. PGE may want to consider studying these values to customers further in future analysis.

For the energy storage options in the near-term, BESS costs are not financially viable for any of the customer types, given the lack of available federal and state incentives as well as relatively low demand charges and little arbitrage opportunity with the TOU rates. As noted in Section 4.2, only lithium ion BESS technology was modeled: flow batteries have significantly lower round-trip efficiency which would result in poor financials. For the 2035 CPI+1 case, when demand charges increase faster than inflation, most customer types were found to show payback periods of less than 20 years, assuming a BESS cost of $400 per kWh in 2014$. While technically financially viable, similar to the Solar Generation Market Research Study that Black & Veatch developed for PGE, the likelihood of adoption for individual customers is still limited by the perceived payback period. Since there does not appear to be a maximum market penetration curve available for energy storage, if commercial customer preferences for BESS are assumed to be similar to solar PV (Figure 5-1), commercial customer types that see paybacks of around 5 years have about a 20 percent chance of adoption. Using the same curve, customer types that see paybacks closer to 10 years would have a 5 percent chance of adoption.

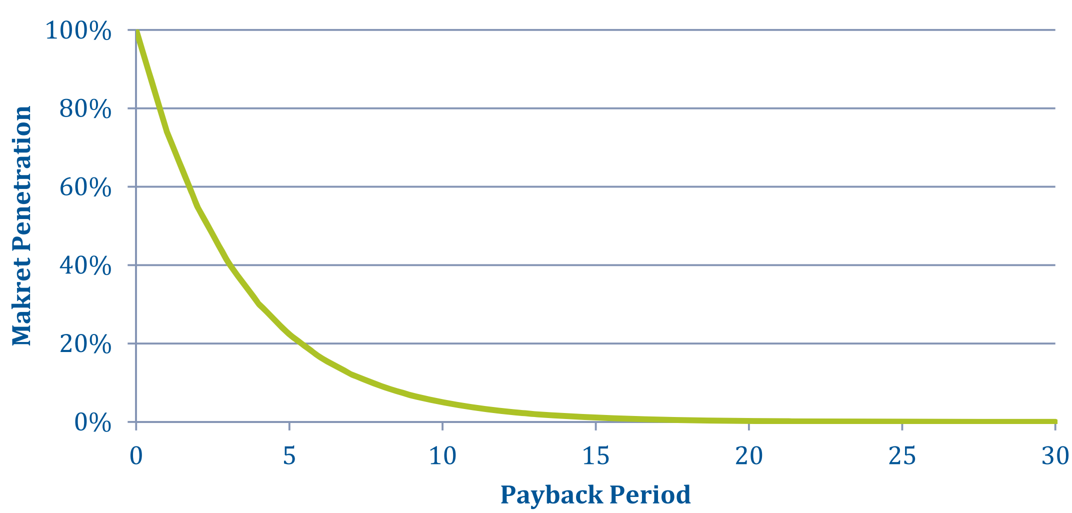

Figure 5-1 Solar PV Maximum Market Penetration Curve Relative to Payback Period

Therefore, assuming this curve holds true for BESS, only about 5 to 20 percent of commercial customers are likely to adopt by 2035. Since costs are only expected to drop to these low levels in the latter half of the study period (2026 to 2035), minimal adoption is anticipated prior to that time period. Assuming that 5 to 10 percent of PGE's commercial customers (approximately 104,000 customers) would consider BESS in the 2026 to 2035 time frame and that it is most practical to deploy smaller systems (10 kWh @ 2 hour capacity), the adoption over those 10 years could total 52 to 104 MWh or 26 to 52 MW of installations. Divided evenly across the 2026 to 2035 time frame, that is equivalent to approximately 2.6 to 5.1 MW per year of energy storage installations. Adoption may be higher if certain customer types, such as critical facilities (hospitals, schools, etc.), place some value on reliability and power quality associated with installing BESS and, thus, install larger systems and/or have wider adoption despite poor paybacks. However, this metric was not studied in this analysis.

Table 5-1 Forecasted Annual BESS Adoption

BESS CAPACITY (MW/MWH)	2016 TO 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low Adoption	0	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2
High Adoption	0	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4

For the BESS plus solar PV cases, the addition of BESS to a solar installation does not improve the financials of the combined system, and, in fact, in the 2016 cases, BESS causes payback to increase. Therefore, in the near-term, given that solar PV installations are able to net meter, there is no incremental benefit to deploying an energy storage system until net metering is no longer available. By 2035, BESS costs will have fallen enough that BESS installations, combined with solar PV, will not alter the payback significantly compared to solar PV alone. However, this also implies that a customer would be ambivalent to installing a BESS with its solar PV system, unless net metering was no longer available. Therefore, based on this analysis, the deployment of BESS with solar PV systems is not practical until net metering is no longer available. If net metering is replaced with other policies, the deployment of BESS as part of a solar PV system may become financially viable, but this will depend on the rules around the alternative rate structures.

The analysis of fuel cells and microturbines in all cases, including low natural gas price cases, showed that none of these technologies result in financial payback. One exception is that the case for secondary schools in 2035 deploying SOFC, under a low natural gas price scenario with rates that increase at CPI + 1, may make some financial sense. However, this assumes that the installed system and O&M costs drop substantially and efficiency gains are achieved for the technology, which is highly uncertain given the technology status today. Aside from capital and O&M cost, the financials of these technologies relative to utility-supplied power are penalized in two ways: higher heat rates compared to PGE's system heat rate and natural gas priced at retail rates. These drawbacks are unlikely to change under any condition.

In this study, fuel cell and microturbine technologies were modeled for electricity production only and CHP modes were not considered in the financial model. However, most commercial fuel cells and microturbines can be configured as CHP systems. While CHP may improve these technologies' financials over electricity-only operation, CHP applications are limited to specific customers that can utilize both the energy and heat. Additional studies examining specific customer load would be needed to assess the potential of fuel cells and microturbines for CHP applications.