Electricity Generation in Maryland

Natural Gas

In Maryland, coal, natural gas and petroleum are the fossil fuels utilized to produce electricity. Because of steep price declines in recent years, the primary fuel used for electricity in Maryland is natural gas.

There has been a significant increase in natural gas production in the U.S. resulting from the use of new drilling techniques. Shale gas trapped in deep, fine-grained rock formations in the southwest and northeast regions of the U.S. was not economical to recover until the development of horizontal drilling and hydraulic fracturing techniques in the 1990s. Between 2009 and 2022, as natural gas producers continued utilizing these techniques, U.S. natural gas production increased 76 percent. Over the same period, domestic natural gas consumption increased 41 percent, natural gas imports declined 19 percent, and liquefied natural gas (LNG) exports increased 411%.

U.S. natural gas spot prices at Henry Hub were between $2.00 and $2.50/MMBtu in the late 1990s,[1] and then began a steady increase, more than doubling to over $5.00/MMBtu by 2003 and reaching a high of $8.86/MMBtu in 2008. Prices then decreased, averaging between $2 and $4/MMBtu from 2010 to 2021 because of increased shale gas production (see Figure 1). Prices rose again in 2022 to $8.81/MMBtu when the Russian invasion of Ukraine triggered global concern about natural gas supply in Europe. However, U.S. natural gas prices at Henry Hub averaged $2.57/MMBtu in 2023, nearly a 62% drop from the 2022 average annual price and the lowest since 2020. The monthly average Henry Hub price was below $3.00/MMBtu in every month except January, with the lowest monthly average in May at $2.19/MMBtu. High natural gas production, flat consumption, and increasing natural gas inventories were the reasons for the lower natural gas prices.[2]

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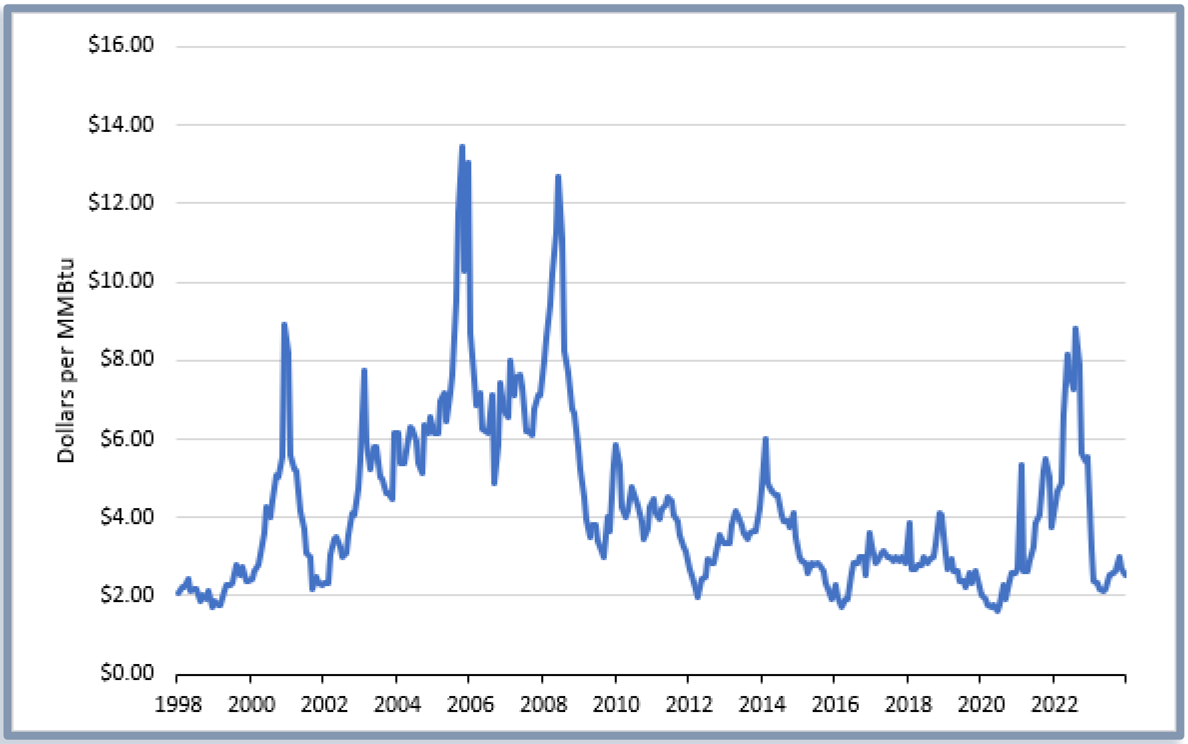
[1] Wholesale natural gas futures contracts priced on the New York Mercantile Exchange are based on the delivery price at the Henry Hub in Erath, Louisiana. Henry Hub is a major intersection of pipelines and the crossroads for a significant amount of natural gas moving to locations across the country.

[2] Energy Information Administration, "U.S. Henry Hub natural gas prices in 2023 were the lowest since mid-2020," Today in Energy, January 4, 2024, https://www.eia.gov/todayinenergy/detail.php?id=61183#:~:text=Record%2Dhigh%20natural%20gas%20production,in%20May%20at%20%242.19%2FMMBtu.

Figure 1 U.S. Natural Gas Henry Hub Spot Prices, 2000-2023



Source: U.S. Energy Information Administration, Henry Hub Natural Gas Spot Price, https://www.eia.gov/dnav/ng/hist/rngwhhdW.htm.

The price of LNG has historically been linked to crude oil prices and has increased as domestic natural gas prices have declined. The annual average export LNG price increased from $8.40 per thousand cubic feet (Tcf) in 2009 to $12.24/Tcf in 2022.[3] Export volumes at the Cove Point LNG facility in Lusby, Maryland increased 72 percent between 2015 and 2022.[4] Cove Point, which is owned by Dominion Cove Point LNG, LP, an affiliate of Dominion Resources, Inc., is one of 12 LNG import facilities and seven existing LNG export facilities operating in the U.S., with five more LNG export facilities under development.[5] On October 7, 2011, the U.S. Department of Energy (DOE) authorized Dominion Cove Point LNG, LP to enter into contracts to export LNG to countries that have free trade agreements with the U.S. On April 1, 2013, Dominion Cove Point LNG, LP announced that it had entered into 20-year contracts for all of the export capacity at Cove Point. Pacific Summit Energy, LLC (a U.S. affiliate of Japanese trading company Sumitomo Corporation) and GAIL Global (USA) LNG LLC (a U.S. affiliate of GAIL (India) Ltd.) have each contracted for half of the marketed capacity. On September 29, 2014, the Federal Energy Regulatory Commission (FERC) issued an order authorizing Dominion Cove Point LNG,

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[3] https://www.eia.gov/dnav/ng/ng_move_poe2_dcu_NUS-Z00_a.htm

[4] https://www.eia.gov/dnav/ng/NG_MOVE_POE2_DCU_YCPT-Z00_A.htm.

[5] https://www.ferc.gov/sites/default/files/2020-11/LNG_Maps_Imports_9-17-2020.pdf

LP to export LNG.[6] During the next month, construction began and the Cove Point LNG export facility was operational by April 2018. In 2022, Cove Point exported 245,914 MMcf of LNG.[7]

Distributed Generation

Distributed generation (DG) refers to those generating resources located close to, or on the same site as, the facility using power. DG is typically installed on the customer side of the meter and used to serve onsite power needs; because of this, distributed generators are not centrally dispatched by the regional grid operator. Types of DG technologies include internal combustion engines, small wind, solar, small hydroelectric, micro gas turbines and fuel cells. Some of these technologies can be used to provide electricity to the grid during times of peak demand. The majority of DG units are diesel-fired emergency backup generators. However, an increasing share of this capacity comes from solar energy, which is predominantly grid-tied for the purposes of net metering and generating solar renewable energy credits (RECs) for sale or trade (see Section 3.5.1 of CEIR-21 for discussion on RECs).

Onsite generators with a capacity of 2 MW or less are not required to obtain a Certificate of Public Convenience and Necessity (CPCN) or apply for a CPCN waiver (or exemption). In addition, certain generators of up to 70 MW in capacity are eligible to seek a CPCN waiver:

- *Facilities with a capacity of less than 70 MW, consuming at least 80 percent of the electrical output on site;*
- *Facilities less than 25 MW in capacity, consuming at least 10 percent of the electrical output on site; and*
- *Land-based, wind-powered generating stations with a capacity of less than 70 MW, subject to additional qualifications.*

The Maryland PSC requires an applicant seeking a CPCN exemption to identify its facility as one of four specific types:

- *Type I – a generator that is not synchronized with the local electric company's transmission and distribution system, and will not export electricity to the grid;*
- *Type II – a generator that is synchronized with the electric system, but will not export electricity to the grid;*
- *Type III – a generator that is synchronized with the electric system, and will be exporting electricity to the grid for sale in the wholesale energy market; or*
- *Type IV – a generator that is synchronized with the electric system, but is inverter-based and will automatically disconnect from the grid in the event of a grid power failure.*

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[6] Federal Energy Regulatory Commission, "Order Granting Section 3 and Section 7 Authorizations," September 29, 2014, elibrary.ferc.gov/eLibrary/filelist?accession_number=20140929-3053&optimized=false.

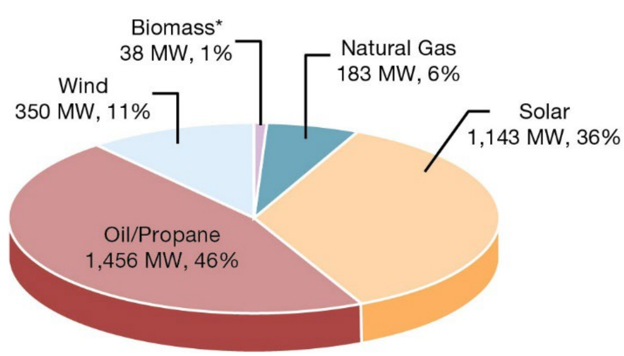
[7] Cove Point, MD LNG Exports to All Countries (eia.gov) https://www.eia.gov/dnav/ng/hist/ngm_epg0_eng_ycpt-z00_mmcfA.htm.

It is difficult to accurately estimate the total amount of DG in Maryland, as systems smaller than 2 MW are not required to obtain a CPCN exemption. The vast majority of solar DG systems fall into this category.

From 2001 through April 2024, 2,312 MW of generation capacity had been granted CPCN exemptions in Maryland, including 142 MW of natural gas-fired capacity, 127 MW of solar capacity, and 349 MW of land-based wind power. According to the 2023 PSC report on net metering, an additional 1,019 MW of solar DG and 1.45 MW of small wind facilities were installed in Maryland by June 30, 2023 under net metering arrangements.

DG units are often used to provide emergency backup power in the event that large and essential loads, such as government offices, hospitals, colleges and universities, commercial and industrial facilities, telecommunications installations and farming operations, lose electricity service. By fuel type, Maryland's distributed generators (see Figure 2) are mostly fossil-fueled, consistent with their use for backup power. A large share of DG capacity is solar, which is predominantly grid-tied for purposes of net metering and generating solar RECs (SRECs) for sale or trade. Between 2022 and 2023, for example, statewide net metered solar system capacity increased 6 percent. The solar energy requirement in the Maryland Renewable Energy Portfolio Standard (RPS) will also continue to provide an incentive to add distributed solar generation to the Maryland grid.

Figure 2 Distributed Generation by Fuel Type (MW), as of June 30 2022



Source: PSC CPCN Database and Maryland Public Service Commission, "Report on the Status of Net Energy Metering in the State of Maryland," November 2023, https://www.psc.state.md.us/wp-content/uploads/2023-Net-Metering-Report.pdf.
Note: This figure only includes solar from net metered systems and CPCN-exempted systems.
*Biomass includes digester and landfill gas units.

Demand Response

Demand response (DR) serves as a tool for bolstering energy efficiency and conservation efforts in Maryland. DR allows end-use customers to reduce their energy consumption during periods of high demand (and high prices). DR occurs when a customer reduces electricity use in response to either a change in the price of electricity or an incentive payment. Customers that reduce electricity consumption in response to high real-time electricity prices or when called on by the system operator or utility are used as an alternative to generation resources as a means of meeting load requirements. Voluntary usage reductions can come from customers of all sizes. Large industrial customers may choose to shift some high-energy intensity processes to lower-cost hours. Through these voluntary, opt-in programs, utilities can cycle residential consumers' air conditioning and electric water heaters. When aggregated across thousands of customers, these residential energy use reductions can create significant savings during times of peak demand.

Demand response within the PJM Interconnection, LLC (PJM) is utilized as a supply resource in the same way as generators. PJM runs several DR programs that compensate customers for reducing their load. DR resources are eligible to participate in PJM's energy markets, PJM's ancillary services markets and PJM's capacity market.

PJM members that act as DR providers are called curtailment service providers (CSPs). Customers can act as their own CSP or sign with another CSP that can bid load reductions into PJM markets. CSPs can participate as a capacity resource in the capacity market and can bid load reductions into the energy markets, both for reductions needed during emergency events or reductions in response to high prices (economic events).

Demand response resources with adequate response times (i.e., within 10 minutes) may bid into PJM's synchronized (spinning) reserve market, allowing PJM to utilize demand-side resources to respond to unexpected generator outages, unexpected changes in electric demand or other system contingencies. DR resources are eligible to provide regulation reserves, synchronized reserves and day-ahead reserves. However, DR resources can only provide two of the three services and are limited to 33 percent for each category. DR resources can also provide nonsynchronized (nonspinning) and supplemental reserves in PJM.

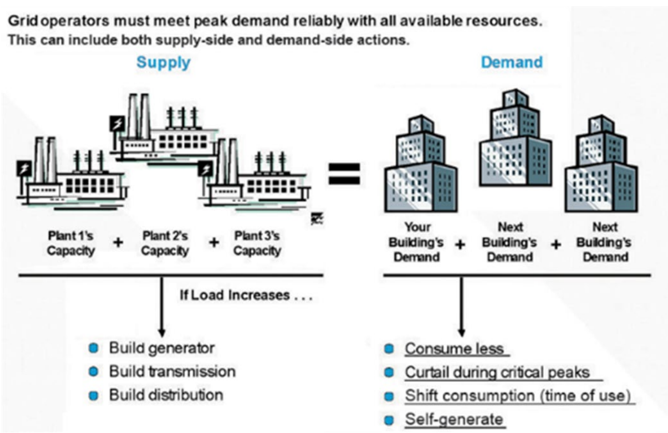
PJM's competitive capacity auction, known as the Reliability Pricing Model Base Residual Auction (RPM BRA) is conducted every three years prior to the delivery year (DY) to allow power supply resources to bid into the market to either increase energy supply or reduce demand. For example, an auction held in 2018 would be for DY 2021/2022. Prior to the RPM BRA for DY 2018-2019 (held in 2015), PJM allowed for three different types of demand resources to be bid in:

- **"Annual"** wherein a customer could be curtailed an unlimited number of times per year (the specific hours of the day vary by season), but each curtailment can only last for a maximum of 10 hours;
- **"Extended Summer"** wherein customer loads can be curtailed between May and October between 10:00 a.m. and 10:00 p.m., subject to the same 10-hour limitation; and

- **“Limited”** wherein customers may only be curtailed 10 weekdays between June and September between the hours of 12:00 p.m. and 8:00 p.m. for a maximum of six hours at a time.

In response to poor generator performance during the Polar Vortex in 2014,[8] PJM revised and restructured its capacity market. Approved by FERC in 2015, the PJM proposal eliminated the three types of DR products and created a single DR resource—Capacity Performance. The purpose of the product is to provide larger capacity payments for performance, including bonuses for overperforming, as well as to increase penalties for nonperformers. The revised capacity market went into effect with the 2018/2019 RPM BRA. In the most recent auction, the 2020/2021 RPM BRA, 9,847 MW were offered, of which 7,820 MW cleared the auction, which is 2,528 MW lower than the prior auction.[9] While a decline in prices was expected, the magnitude of the price decline was far beyond expectations. According to the 2022/2023 BRA post-auction analysis, regional transmission organization (RTO) prices cleared at $50/MW-day, reaching the lowest levels seen since DY 2013/2014. Several Locational Deliverability Areas (LDAs) separated in price from the RTO, but also saw substantial price declines. Overall, the weighted-average clearing price declined from $155.71/MW-day to $74.27/MW-day.[10] The potential factors resulting in this price drop could have been the relatively prompt timing of the

The Importance of Demand Response



Demand Response (DR) is a competitive resource that can be used to maintain the balance of supply and demand for grid operations and the associated wholesale markets. Retail electricity consumers tend to be unresponsive to wholesale prices. Therefore, as demand goes up, less efficient generators may be called on to serve higher demand. By reducing demand during these periods, the use of potentially less efficient and more expensive generation resources to meet higher demand can be avoided.

[8] The Polar Vortex was a period of intense cold weather across the PJM region in January 2014, resulting in record-setting winter peak demand and significant electricity price spikes.

[9] PJM moved the 2019/2020 BRA for DY 2022/2023 to August 2019; however, PJM suspended all auction activities and deadlines related to DY 2022/2023 and DY 2023/2024 auctions until FERC issues an order regarding PJM’s requested changes to its capacity market. Note: The DY 2022/2023 auction took place in May 2021. Auction results report: pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-base-residual-auction-report.ashx.

[10] icf.com/insights/energy/pjm-2022-2023-bra-auction-analysis#.

auction and associated resource planning constraints. Another factor could have been the long delay between auctions and the large number of market design changes that occurred for this auction which may have resulted in more cautious bidding.[11]

In March 2011, FERC issued Order 745 which established that, where it is cost-effective to do so, demand response resources are to be paid the same wholesale price of energy for energy reductions as a generator would be paid for the sale of energy at that same time. Allowing DR to bid into electricity markets and be treated as a dispatchable resource has encouraged the expansion of DR programs and services offered by both investor-owned utilities (IOUs) and competitive CSPs. In spring 2012, PJM became the first grid operator to comply with FERC Order 745. On May 22, 2014, in response to a petition filed by the Electric Power Supply Association, the American Public Power Association and the Edison Electric Institute, the D.C. Circuit Court of Appeals vacated FERC Order 745, finding that FERC overstepped its jurisdiction because states have the jurisdiction to regulate the electric retail market. In January 2016, the U.S. Supreme Court upheld FERC Order 745. The Supreme Court found that although FERC did intentionally impact the retail market, DR is a wholesale function and therefore FERC has the power to regulate the wholesale market even if it has indirect impacts on the retail market. The Supreme Court ruling did not have a significant impact on the PJM market, as PJM continued to conduct auctions.

Approved by FERC in May 2012, PJM offers Price Responsive Demand (PRD) as another class of demand response. PRD applies only to those customers on Advanced Metering Infrastructure (AMI) dynamic rate structures where consumption can vary in response to PJM wholesale market price signals (see Section 3.5.5 of CEIR-21 for a description of AMI). PRD is an aspect of the smart grid and requires the widespread deployment of advanced meters to retail customers and the introduction of dynamic retail rates. The voluntary participation of PRD providers in PJM's markets was designed to enhance grid operations and reliability and provide a closer link between the wholesale and retail electricity markets. PJM's capacity and energy markets would be cleared with the predicted reductions from PRD already included in the supply forecast. This process allows PJM's operators to better forecast system demand under real-time conditions, as a separate forecast of DR supply becomes less necessary. In 2018, Baltimore Gas and Electric Company (BGE) offered its demand response as a PRD resource.

In February 2019, PJM proposed to align the PRD program with its Capacity Performance Resources general rules, with the main change being that the nominal PRD value would be the lesser of summer and winter load reductions. However, the Independent Market Monitor (IMM) stated that the proposal does not calculate the nominal PRD value (compensation) based on how PJM customers pay for capacity, i.e., the customer's load during PJM system peak. In June 2019, FERC agreed with the IMM and rejected PJM's proposal and stated that the PRD should be more consistent with the annual peak-based billing framework for load-serving entities (LSEs). See Section 3.5.5 of CEIR-21 for more information on smart grid technologies.

[11] Ibid.

In October 2019, PJM re-submitted its suggested PRD program modifications. While PRD resources can offset the amount of required capacity resources on a one-to-one basis, PJM emphasized in its filing that the existing PRD regulations do not impose the same requirements as the rules for capacity resources. As a result, PJM proposed specific improvements to the PRD program to better align it with the regulations and standards that apply to capacity resources. PJM suggested, among other things, that PRD providers be eligible for bonus payments for load reductions that exceed the MW value pledged to be reduced during system emergencies. PJM also addressed FERC's concerns about PRD pricing in the June 2019 order by preserving the current pricing structure, which is based on an LSE's capacity obligation determined from its annual coincident peak demand. FERC approved PJM's proposals in January 2020, but in response to a protest filed by PJM's IMM, the commission ordered PJM to revise its tariffs to specify that an LSE is not eligible for bonus payments for load reductions during system emergencies if the prevailing locational marginal price (LMP) has not reached the applicable trigger price.[12]

In February 2024, FERC approved a petition from PJM to amend the capacity accreditation and testing provisions of PJM's tariff. Capacity accreditation is the amount of capacity PJM can count on after accounting for generator outages and the variability of variable generation resources, otherwise known as unforced capacity or UCAP. Previously, for thermal resources, PJM determined the UCAP by subtracting the forced outage rate from 1.[13] Therefore, for example, if a 500 MW natural gas plant had a 10 percent forced outage rate, then its UCAP would be 450 MW.

For variable generation, energy storage and hybrid resources, PJM uses Effective Load Carrying Capability (ELCC) to estimate the UCAP of these resources. ELCC measures the amount of electricity demand each resource can serve during times when the risk of disruptions to reliability is high. At its most basic, ELCC is substituting the amount of "perfect" capacity (i.e., a mythical power plant that operates 100% of the time with no outages) for the resource being evaluated. For example, if it takes 30 MW of "perfect capacity" to replace a 100 MW solar plant, the ELCC of that solar plant would be 30 MW.[14]

PJM calculated an average ELCC among all plants in a resource class (e.g., solar and wind). FERC, in its February 2024 order, approved PJM's request to switch to a marginal ELCC, where resources are accredited on their marginal contribution to resource adequacy, and to apply ELCC to all resources, thermal or variable. FERC also approved PJM's request to require generators to submit a binding notice of intent before participating in PJM capacity auctions, and to replace PJM's penalty to generators for non-performance to one-and-a-half times the clearing price of the RPM BRA rather than the net cost of new entry, which is essentially the cost of a new

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[12] troutmanenergyreport.com/2020/01/ferc-accepts-revisions-to-pjms-price-responsive-demand-program/.

[13] FERC, *Order Accepting Tariff Revisions Subject to Condition*, ER24-99-000 and ER24-99-001, January 30, 2024. https://www.pjm.com/directory/etariff/FercOrders/7147/20240130-er24-99-001.pdf

[14] Specht, Mark. "ELCC Explained: the Critical Renewable Energy Concept You've Never Heard Of," Union of Concerned Scientists blog, October 12, 2020, https://blog.ucsusa.org/mark-specht/elcc-explained-the-critical-renewable-energy-concept-youve-never-heard-of/.

generating plant.[15] One analysis estimated that change resulted in an approximate reduction in the penalty price of $135,000/MW-year to $18,250/MW-year. The change was made because of concerns that generators would not participate in the RPM because of the risk of exposure to substantial financial penalties for non-performance.[16]

Energy Storage

Overview

Energy storage allows for energy produced at one point in time to be used later. Storage systems are unique in that they can be in various forms and satisfy multiple functions, such as being able to serve as a generator, transmission asset and/or distribution asset. Examples of energy storage technologies include pumped hydroelectric, compressed air energy storage (CAES), flywheels, and various types of batteries, e.g., lead-acid batteries, lithium-ion batteries and zinc-bromide batteries. Each of the various technologies has different benefits, economics and operational characteristics. Hence, the various technologies can be used to serve multiple end-uses. The principal end-uses of energy storage include:

- <u>On-peak power supply</u> – Provides electric power at times of high demand. For example, pumped hydroelectric (or pumped storage) entails pumping water up into a reservoir during periods when the demand for electric power (and hence price) is low and using that water to generate electricity when demand (and price) is high.
- <u>Electric grid support</u> – Supports the transmission system by correcting for transient voltage anomalies. Additionally, storage can be used to help relieve transmission congestion and to relieve pressure on the local distribution system when periods of high, localized demand occur. Use of storage in this way can postpone the need to upgrade electric distribution facilities to accommodate those periods of high demand that occur infrequently.
- <u>End-user cost management</u> – Stores electric power during periods when market prices are low and draws on that power when market prices are higher.
- <u>End-user reliability enhancement</u> – Provides power supply during times when the electric grid is not available.
- <u>Variable renewable energy generation</u> – Reduces the variability of certain renewable electric generation technologies, such as wind and solar. For example, storage could be used to reduce the output fluctuations from a PV array due to passing clouds. Furthermore, storage can enhance the value of variable renewable energy production by

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[15] FERC, *Order Accepting Tariff Revisions Subject to Condition*, ER24-99-000 and ER24-99-001, January 30, 2024. https://www.pjm.com/directory/etariff/FercOrders/7147/20240130-er24-99-001.pdf

[16] Multer, Maxwell. "PJM Capacity Market Reforms Shake Up Resource Accreditation, Impose New Offer and Testing Requirements," *Power*, February 22, 2024, https://www.powermag.com/pjm-capacity-market-reforms-shake-resource-accreditation-impose-new-offer-and-testing-requirements/.

effectively allowing generation produced in one time period to be carried to a later time period when electricity prices are higher.

Historically, only pumped hydroelectric and CAES have been used nationwide to provide bulk energy services since these technologies can be sized at 100 MW or more and are capable of providing electric power to the grid for periods measured in hours rather than in minutes or seconds. Bulk energy service refers to (a) the ability to significantly shift large amounts of energy between the time of generation and the time of use; and (b) the provision of generation capacity. Recent declines in the costs of battery storage have led to a number of hybrid projects co-located with another generation technology.[17] As of the end of 2022, there were 374 such hybrid projects, each 1 MW or above, totaling nearly 41 GW of generating capacity and 5.4 GW/15.2 gigawatt-hours (GWh) of energy storage. Of these, solar+storage was the most common (213 projects with 992 MW of PV and 250 MW of storage), followed by several different fossil hybrid combinations (fossil+PV, fossil+hydro and fossil+storage). Of the planned solar projects, 457 GW of the roughly 950 GW of solar PV in interconnection queues across the country are hybrid projects, mostly paired with storage.[18] The duration of battery storage ranges from two to five hours, and applications include shifting solar energy to late afternoon/early evening hours, or minimizing/alleviating curtailment of solar generation. In the Mid-Atlantic region, battery systems and flywheels are providing transmission and distribution system grid support due to typical size and operational factors, and can also be used to provide power quality and reliability at the end-use (retail) level.

Decreases in the prices of storage devices, particularly lithium-ion battery storage, which has benefited from research and development related to plug-in electric vehicles (EVs), have been significant in recent years and prices are generally expected to continue to decline over time. Based on the potential uses of storage, energy storage can be viewed, to some degree, as a substitute for certain types of generation (e.g., peaking generation) and for certain marginal investments in the distribution and transmission infrastructure.

At the conclusion of 2022, there were 8.8 GW and 22,385 MWh of utility-scale battery energy storage installed in the United States,[19] of which 4.9 GW and 9,972 MWh were added in 2022. Batteries are used to store excess wind and solar generation. Rapidly growing wind and solar generation in California and Texas also supports growth in utility-scale batteries. These states accounted for 90 percent of the battery capacity installed in 2022.[20]

Residential markets continue to experience the highest levels of growth, likely due to policies and mandates in California, Hawaii and Vermont. The overall growth in energy storage will likely continue due to the establishment of energy storage targets in 11 states: California, Connecticut, Illinois, Maine, Maryland, Massachusetts, Nevada, New Jersey, New York, Oregon

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[17] Most, but not all, of these hybrid projects paired a generation technology with energy storage.

[18] Mark Bolinger, Will Gorman, Joseph Rand, and Seongeun Jeong, Hybrid Power Plants: Status of Installed and Proposed Projects, 2023 Edition, Lawrence Berkeley National Laboratory, August 2023. https://emp.lbl.gov/sites/default/files/emp-files/hybrid_plant_tracking_2023_08.08.2023.pdf.

[19] 2022 Form EIA-860 Data – Schedule 3 and EIA 2023 Early Release Battery Storage Figures, EIA - U.S. Battery Storage Market Trends.

[20] 2022 Form EIA-860 Data – Schedule 3. https://www.eia.gov/electricity/data/eia860/

and Virginia.[21] The declining cost of energy storage will also accelerate adoption. NREL projects that lithium-ion battery costs will decline 32 percent versus 2020 by 2030,[22] and large-scale battery capacity could total 30 GW by the end of 2024.[23]

In spring 2017, the Maryland General Assembly enacted legislation that required the Power Plant Research Program (PPRP) to study regulatory reforms and market incentives that may be needed or may benefit energy storage in Maryland. The final report, released January 22, 2019, provides a review of the energy storage technologies, their applications, efforts by other states to promote storage, the current state of storage in Maryland and the barriers that discourage widespread implementation.[24]

Following the release of the report, the Maryland Senate introduced Senate Bill (SB) 573 which requires the Maryland PSC to establish an energy storage pilot program with pilot projects ranging between 5-10 MW. The pilot is designed to evaluate energy storage ownership models and answer whether a utility can own storage in a deregulated electricity market. Under SB 573, which passed in April 2019, the state's four IOUs were required to solicit two energy storage projects for the PSC's approval by April 15, 2020 and September 15, 2020, respectively, with project operational dates by February 28, 2022. The projects must solicit offers that fall under two of the following four utility ownership models: utility-only, utility and third party, third-party ownership, and a virtual power plant. Under the last ownership model, the utility would utilize services provided by energy storage devices owned by customers or a third-party aggregator.[25]

BGE, Potomac Electric Power Company (Pepco) and Delmarva each filed two pilot applications on April 15, 2020, as described further below:

- BGE proposed a 2.5 MW / 7.1 MWh, utility-owned and -operated lithium-ion battery storage unit at BGE's Fairhaven substation in Anne Arundel County. BGE stated the Fairhaven project will improve distribution system reliability and help address any contingency overloads as a result of winter peak demand. The project is now in operation but is projected to degrade to 4 MWh over time.
- BGE's second project is a 2 MWh lithium-ion battery storage unit owned and operated by a third party, Ameresco, at one of four potential distribution sites. This Chesapeake project will serve the purposes of improving reliability during peak winter demand, participating in PJM's frequency markets and providing energy arbitrage. The project is online.
- Pepco proposed a utility-owned but third-party-operated lithium-ion facility at National Harbor. The project is rated at 1.05 MW / 4.25 MWh but is expected to degrade to 1 MW

[21] Mark A. Lazaroff and Maggie E. Curan, "State by State: A Roadmap Through the Current U.S. Energy Storage Policy Landscape, Morgan Lewis, March 4, 2024, https://www.morganlewis.com/pubs/2024/03/state-by-state-a-roadmap-through-the-current-us-energy-storage-policy-landscape.

[22] Cost Projections for Utility-Scale Battery Storage: 2023 Update (nrel.gov).

[23] U.S. battery storage capacity expected to nearly double in 2024 - U.S. Energy Information Administration (EIA).

[24] dnr.maryland.gov/pprp/Documents/Energy-Storage-In-Maryland.pdf.

[25] mgaleg.maryland.gov/2019RS/bills/sb/sb0573T.pdf.

/ 3 MWh over time. Pepco says the project will defer a new substation, provide peak shaving and grid reliability benefits, and participate in PJM markets. The project has faced public opposition and is under review at the PSC.

- Pepco's second project is a lithium-ion energy storage system at a bus depot in Silver Spring. Pepco, by contract, can utilize 3 MWh over a 3-hour period for up to 10 days per year, over 10 years. The contract can be extended to 15 years. Pepco estimates the project will defer, and perhaps avoid, a $3.6 million feeder upgrade to serve the bus depot and will also provide peak shaving and backup power during emergency grid conditions. The project is in operation.
- Delmarva proposed a virtual power plant at Elk Neck State Park in Cecil County, consisting of behind-the-meter energy storage systems at 110 homes in Elk Neck. The systems will be networked together, capable of providing 0.5 MW / 1.5 MWh, and will provide peak shaving and backup power during emergency events. Participating homeowners will own the equipment after 10 years. The energy storage systems are in operation.
- Delmarva's second project is a utility-owned and -operated lithium-ion system in Ocean City, totaling 1.0 MW / 3.6 MWh. The system will provide peak shaving, frequency regulation to PJM, emergency backup and overall improved reliability. The project is slated to come online by the end of 2024.

The PSC conditionally approved the proposals from BGE, Pepco and Delmarva in November 2020 but required that all of the projects participate in PJM markets, and that utilities file an emissions management plan and provide notice if they anticipate spending more than half of the contingency funding allocated for each project.[26]

In October 2021, BGE, Delmarva and Pepco jointly submitted to the PSC a report indicating that four of the six approved pilot projects are expected to require more than 50 percent of the contingency funding approved per project. However, the utilities added that three of these four projects are still projected to be cost-effective. Reasons cited for the higher costs include additional safety requirements, increasing system vendor costs, unexpectedly high IT and communications costs, additional engineering costs due to modifications and upgrades, retaining a PJM scheduler, site location change, more specific interconnection costs, retaining third-party engineering support and additional material needs. The utilities also indicated that five of the six projects are likely to have operational dates after the deadline required by SB 573 of February 28, 2022. The utilities cited delays related to complex design challenges, permitting processes, supply chain disruptions and protracted vendor negotiations, among others. They requested deadline extensions for "good cause," which the PSC granted in December 2021.[27]

Potomac Edison Company (PE) also filed two energy storage proposals. The first is a third-party-owned and -operated project in Little Orleans that is rated at 1.75 MW / 8.4 MWh. Known as the Town Hill project for the name of the circuit on which it will be located, the project will allow

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[26] Maryland Public Service Commission, Order on Energy Storage Pilot Proposals, Order No. 89664, November 6, 2020. https://www.psc.state.md.us/wp-content/uploads/Order-No.-89664-Case-No.-9619-Energy-Storage-Pilot-Proposal-Order.pdf

[27] Maryland Public Service Commission, Letter Order, December 15, 2021.

PE to island the circuit in the case of a reliability event and still provide power to customers and will serve as an alternative for building a connection to another circuit. PE can reserve the Town Hill project for up to 20 days annually. The Town Hill project is scheduled to come online in July 2024.

PE's second energy storage pilot project is a utility-owned and -operated 500 kW project that will serve an EV direct current (DC) fast-charging station in Urbana. In addition to providing EV charging, the Urbana pilot project will also provide demand management, frequency regulation and energy arbitrage via the PJM energy market. However, the Urbana project faced some obstacles, and PE petitioned the Commission in May 2022 to replace it with a pilot project in Myersville. The PSC granted PE's request in June 2022. At Myersville, PE pairs a 500 kW battery with two EV fast chargers and one Level 2 charging station in Frederick County. The battery supplies uninterruptible EV charging and reduces the grid power requirements during peak demand hours. The Myersville project is in operation.

Other Emerging Battery Storage Technologies

Iron-air batteries are manufactured by Form Energy of Somerville, Massachusetts. The company's batteries offer 100-hour, utility-scale storage. Form has agreed to install a 10 MW/1,000 MWh system for Xcel Energy in Minnesota that will be co-located with a 460 MW solar facility.

Nickel-hydrogen batteries manufactured by EnerVenue based in Fremont, California are designed to operate for tens of thousands of cycles and have a life of over 30 years.[28] The battery's components are contained in a pressurized tank resembling elongated scuba tanks. EnerVenue has orders for 7 GWh of storage.

Thermal storage reserves energy that is produced in the form of heat or cold to be used at a later time. An example would be to create ice for an ice chiller during off-peak hours and utilize the chiller during peak hours to assist with cooling.

Energy Storage Tax Credits

In May 2017, Maryland introduced a state income tax credit for the installation of energy storage systems, making it the first and only state to offer a tax credit for this type of technology. For systems installed between January 1, 2018 and December 31, 2024, the Maryland Energy Administration (MEA) will award tax credits for up to 30 percent of the total installed costs of the energy storage system for qualified systems installed on residential or commercial properties, up to a maximum of $750,000. The systems that qualify for the tax credit include chemical (batteries), thermal (ice/chilled water), and electrical energy and mechanical (flywheels, compressed air). As of September 20, 2021, MEA had awarded $339,000 in tax credits out of the $750,000 allocated for the 2021 tax year.[29] The tax incentive will be replaced on January 1,

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[28] NASA Battery Tech to Deliver for the Grid - IEEE Spectrum and This NASA tech might just spur a major grid battery… | Canary Media.

[29] energy.maryland.gov/business/Pages/EnergyStorage.aspx.

2025, with a grant program administered by MEA. Eligible energy storage systems include those that can store electrical energy, or mechanical, chemical or thermal energy that was formerly electrical energy and will either be used as electricity or to offset electricity consumption at peak times. Grants are limited to $5,000 for residential installations and $150,000 for commercial installations, or 30% of the total installed system costs.[30]

The IRA offers a base investment tax credit of 6 percent that increases up to 30 percent if the project meets prevailing wage and apprenticeship requirements. Energy storage projects under 1 MW of storage capacity qualify for the 30% bonus rate regardless of compliance with the prevailing wage and apprenticeship requirements.[31] The following additional bonus credits are also available:[32]

- If the project meets the 40% minimum domestic content requirement (i.e., defined as any steel, iron or manufactured product which is component of the project that was produced in the United States), a 10 percent bonus credit would increase the total tax credit to 40 percent.[33]
- If the project is sited in an Energy Community (defined as a census tract where a coal mine was closed or a coal-fired electric generation unit was retired after December 31, 2009),[34] an additional 10 percent bonus credit would increase the total tax credit to 50 percent.
- If the project is sited in a low-income community or on Indian land, an additional 10 percent bonus credit would increase the total tax credit to 60 percent.[35]

Maryland Energy Storage Goal

In 2023, the Maryland General Assembly enacted legislation directing the PSC to establish targets for the cost-effective deployment of new energy storage projects with a goal of 750 MW of total energy storage capacity by 2027; 1,500 MW by 2030; and 3,000 MW by 2033. The General Assembly authorized the Commission to include energy storage credits or market-based incentives or a requirement that IOUs install or contract for energy storage projects or energy storage credits. Multiple energy storage technologies are eligible regardless of size, storage

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30 SB 215, Maryland General Assembly, "Energy Storage Systems—Income Tax Credit and Grant Program, 2022 Session, https://mgaleg.maryland.gov/2022rs/Chapters_noln/CH_246_sb0215e.pdf.

31 Inflation Reduction Act Creates New Tax Credit Opportunities for Energy Storage Projects | McGuireWoods.

32 Summary of Inflation Reduction Act provisions related to renewable energy | US EPA.

33 IRS Releases Highly Anticipated Guidance on Domestic Content IRA Tax Credit 'Adder' – Publications (morganlewis.com).

34 https://www.sierraclub.org/sites/default/files/2023-08/2675%20IRA-EnergyCommunities_FactSheet.pdf.

35 A "low-income community" is a population census tract that (i) has a poverty rate of at least 20%, or (ii)(A) in the case of a tract not located within a metropolitan area, the median family income for that tract does not exceed 80% of the statewide median family income or (B) in the case of a tract located within a metropolitan area, the median family income for that tract does not exceed 80% of the greater of the statewide median family income or the metropolitan area median family income. See IRS Issues Guidance on Low-Income Community Bonus Credit | Paul Hastings LLP.

medium or use application and includes thermal storage, electrochemical storage, virtual power plants and hydrogen-based storage.

In October 2023, the PSC issued an order creating an energy storage working group and directed the working group to file a final report and proposed regulations by October 1, 2024, to implement the Maryland Energy Storage Program by July 1, 2025. Among other things, the PSC further instructed the working group to quantitatively illustrate cost-effectiveness for utility-scale energy storage projects and behind-the-meter virtual power plants. The working group is also to consider applicable safety and environmental requirements for utility-scale energy storage encompassing risk assessment, emergency response, fire prevention, removal of damaged batteries and decommissioning of battery storage projects. The working group is also to recommend incentive methodologies for both utility-scale and behind-the-meter energy storage, and to make recommendations for statutory changes needed to implement a successful energy storage program.[36]

[36] Maryland Public Service Commission, Order No. 90823, *Order Initiating Workgroup to Develop a Maryland Energy Storage Program*, October 2, 2023, https://www.psc.state.md.us/wp-content/uploads/Order-initiating-Maryland-Energy-Storage-Program-Workgroup.pdf.

Maryland Energy Storage Pilot Program

In May 2019, Governor Hogan signed into law SB 573 (Energy Storage Pilot Project Act), requiring the state's four investor-owned utilities (Baltimore Gas and Electric Company, Delmarva Power and Light Company, Potomac Electric Power Company and Potomac Edison Company) to propose two energy storage pilot projects per utility. Collectively, the projects were to total 5-10 MW of storage capacity. The intent of the pilot program is to test different ownership models and multi-use operating modes for energy storage, as well as to gain experience with performance metrics, contracting, accounting and billing. By December 2022, the Maryland PSC had approved nine energy storage pilot projects, as shown in the table below.

Selected Characteristics of Proposed Energy Storage Projects

	JOINT EXELON UTILITIES						POTOMAC EDISON		
	BGE		Delmarva		Pepco				
	Fairhaven	Chesapeake	Elk Neck	Ocean City	National Harbor	Bus Depot	Town Hill	Frederick County	
Ownership Model									
Utility owned/operated	X			X				X	
Utility owned/3rd party operated					X				
3rd party owned/operated		X				X	X		
Virtual power plant			X						
Operating Modes[1]									
Peak shaving	1	1		1	1	1		1	
Grid reliability / backup power			1	1		2	1	2	
PJM Markets	2	2	3	2	2		2		
DER Integration (on site) / Demand mgmt.			2			3			
Resiliency				3					

[1] These assignations reflect PPRP's effort to standardize operating mode descriptions, which vary somewhat by project.