How PV-Plus-Storage Will Compete With Gas Generation in the U.S.

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BloombergNEF

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410MW

Size of PV plant, alongside 0.3GW/1.2GWh of storage that can displace a 100MW CCGT with 30% capacity factor in CAISO in 2020.

260GW

Total CCGT capacity with a 2019 capacity factor lower than 20%

80%

Percentage of U.S. gas peakers operating at a capacity factor less than 15% in 2019.

Utilities across the U.S. are contracting more, and larger, PV-plus-storage assets. These hybrid projects can perform a wide range of roles and – along with renewables in general – represent a zero-emissions threat to gas, which is currently the workhorse of the U.S. power generation fleet. This will undermine the case for many proposed new-build gas power plants, and dramatically change the generation profiles and economics of others.

Research approach

- **Economic comparison:** PV-plus-storage has different characteristics to gas generation, but can deliver comparable services or offer similar value. For this reason, we compare these plants on an adjusted levelized cost of electricity basis when sized to perform an identical task. This approach differs from the typical integrated resource planning methodology widely adopted by the U.S. utilities. However, it allows a more accurate and direct economic comparison between these two types of technologies.
- **Market outlook**: We also projected capacity build in the U.S., and this supports the conclusions of the economic comparison section. The U.S. is modelled as part of BloombergNEF's New Energy Outlook, the company's annual long-term scenario analysis on the future of the energy economy. We use least-cost modelling to map out the future energy build under various scenarios. All commercially available technologies are evaluated and selected, based on their costs, operational performance and other factors.

Findings

- **The U.S. power system is increasingly reliant on gas generation.** Cheap U.S. natural gas has boosted both build and utilization of gas power plants. These emit less CO2 and are more flexible than coal. The mix of renewable energy and gas that replaced coal differs by market. Regions such as PJM that have access to exceptionally cheap natural gas often favor the latter.
- **Gas dispatch profiles differ a lot by market.** Combined-cycle gas generators (CCGTs) are struggling in California. High solar penetration is eating into CCGT operating hours and forcing them to start up and shut down more often. Turbines have thermodynamic inertia: they take time and energy to heat up and cool down. And things tend to wear and break if put through too many hot-cold, on-off cycles. There is a real cost (of fuel plus wear and tear) associated with starting up and shutting down a turbine.[1] Gas dispatch is more stable in markets with lower penetrations of renewables, but this is likely to change over time.
- **The operating profile of the gas fleet is diverging.** We analyzed the historical hourly generation profiles of most U.S. individual power plants contained in the EPA CEMS database. About 60% of open cycle gas turbines (OCGTs) in the U.S. never ran for more than six consecutive hours in 2019. This number has remained relatively stable over the past decade. In contrast, more CCGTs now run for more than 24 consecutive hours at full capacity at least once a year. Some 86% of CCGTs were called upon, and remained close to

[1] For BloombergNEF clients: see *Batteries Benefit When Intermittent and Inflexible Collide* (web | terminal)

nameplate capacity, for more than 24 hours in 2019. This was because of the switch from coal to gas.

- **PV-plus-storage (PVS) is now a viable, dispatchable clean energy resource for utilities**. The combination of ever-cheaper energy storage systems and state and federal policy support has heightened utilities' interest in hybrid projects. There are now over 8.9GW of PVS projects in the pipeline in the U.S. Most of them are expected to come online by 2023. There are an additional 69GW of hybrid projects in the interconnection queue. Most contracts are designed to firm solar output during their regular generation hours or shift solar energy to deliver peaking capacity. Considerable differences exist across the projects though – in terms of size, duration and design, depending on the utility's need.
- **PV-plus-storage is already competitive against many new-build peakers in the U.S.** Roughly 80% of the U.S. gas peakers had capacity factors below 15% in 2019. This low capacity factor results in a high OCGT levelized cost of energy. We sized our PVS system to perform the same job as gas plants, ensuring that they have the same value. PVS is already a cost-competitive alternative on a levelized cost of energy basis to the majority of new gas peakers in the U.S., especially in solar-rich regions such as the Southwest. PVS also is more flexible and environmentally friendly than gas peakers.
- **PVS is not yet a cost-competitive alternative to new combined-cycle gas plants, if providing an equivalent service.** The need to provide energy and capacity for extended periods of time, even infrequently, makes it challenging for PVS to compete against high capacity-factor CCGTs. This key finding is more nuanced:
  - Uptake of PVS and standalone wind and solar will affect the operating profile of CCGTs in many markets. They will likely have to cycle more frequently and will operate for fewer run hours each year, pushing up their costs. This should encourage companies, investors and policy makers to plan for the future rather than current need.
  - Even though PVS may not be a suitable like-for-like replacement for a high capacity-factor CCGT, the combination of clean energy resources such as wind, solar, storage and demand-side flexibility can provide the equivalent service in some cases. This is accounted for in our New Energy Outlook 2020 (web | terminal).

Implications

- **Full displacement**
  - PVS systems are already replacing gas peakers and will continue to do so in the near term. They are cost-competitive, they have superior operational characteristics, and they align with longer-term decarbonization goals.
  - Utilities can use PVS to provide many of the services currently offered by CCGTs, but like-for-like replacement of CCGTs will be more challenging. NEO 2020 economic modelling suggests that cheap renewables and batteries appear to reach an economic limit between 70% and 80% penetration in most markets. This is the result of two related dynamics. First, as new renewables eat into the run-hours of existing coal and gas plants, the most expensive mid-merit generators are displaced first, making the next MW of renewables marginally less competitive. Second, since renewables all generate together when the conditions are right, at high penetration each additional plant tends to increase fleet-wide curtailment, which lowers capacity factors and weakens the economic case for the next plant.
  - In some but not all cases, a combination of clean energy resources such as wind, solar, storage, demand-side flexibility and power imports can displace a CCGT. Even if clean

energy does not remove the need for some form of firm capacity, it will significantly alter the use case. Gas peakers and combined-cycle gas stay in the system, not for the hours of highest demand, but for those of lowest renewable generation.

- **A changing use case**
  - Further adoption of renewables will incrementally cut into CCGTs' operating time, undercut power prices, and ultimately change their roles. In regions with high penetration of renewable energy, these CCGTs will no longer act as mid-merit plants and instead will become seasonal, or infrequently used generation assets. Our NEO 2020 finds that CCGTs run for few hours in the year towards 2050. This change will increase the total addressable market for standalone and co-located energy storage, while still requiring some gas capacity to be available.
  - The pace of change here is tied to renewable energy adoption and coal phase-out. The change to CCGTs' generation profiles is already well underway in markets with high renewables and thin thermal penetration, such as California. This phenomenon will take a longer time to surface in markets that still have a lot of coal and relatively few renewables, such as PJM. Low gas prices will make it hard to competitively displace CCGTs in these markets.
  - A future low-carbon system will be made up of renewables, storage and some firm capacity. The firm capacity is likely to include gas generators, and these might in future even burn clean gases such as hydrogen, or utilize carbon capture. At first glance, our findings may seem to imply that gas peakers have little future in the U.S. power market and that CCGTs are here to stay. However, as renewable penetration rises and CCGT run hours are displaced, the gas fleet will increasingly be asked to operate at lower capacity factors, while still being able to meet the longer multi-hour periods when renewables are producing less. This might actually shift the balance towards gas peakers again, as they tend to be more economical at lower capacity factors. Ultimately, whether a CCGT or OCGT is best placed to provide this service will depend on the expected capacity factor, operational requirements of the plant, gas price and location.
- **Regulatory response:** Switching from coal to gas, and increasing renewable energy penetration, has proven an effective way of reducing power sector emissions over the last decade. Reducing the role of gas in power markets is the next step.
  - Regulators and utilities must consider the future role of renewables-plus-storage when approving investments today. Investments in new-build gas assets will make it significantly harder to decarbonize their power markets. The use case for these assets is changing and a failure to recognize this will result in costly, under-used or stranded assets.
  - Market reform to better enable the participation of standalone batteries and hybrid assets remains necessary. Integrated Resource Planning processes are also in need of reform to ensure the capabilities and economics of non-traditional resources are adequately assessed.
  - BloombergNEF hourly modelling suggests there is still a need for some firm capacity in future power systems. Recognizing this and exploring zero- or low-emissions alternatives to fossil gas is necessary. Early-stage options include using hydrogen for power generation, or carbon capture, use and storage. [2]

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[2] For BloombergNEF clients: See *Hydrogen: The Molecule to Power a Clean Economy*? (web | terminal) and *CCUS: Applications in Oil & Gas, Power and Industry* (web | terminal).

Outlook

There has been unprecedented gas build in the U.S. over the last decade. We expect gas to remain economically attractive in many parts of the country over the next decade due to low natural gas prices and massive coal retirement. The new build holds strong in the parts of the U.S. with relatively poor economics for renewables, particularly PJM. CCGTs account for 17% of total build, and gas peakers account for 6%, in our core scenario – the Economic Transition Scenario of NEO 2020.

However, further investment in new-build gas over the coming decade will not be as straightforward. Portfolios of clean energy resources will fully displace some CCGTs in select markets. The combination of both standalone and hybrid renewables will result in gas plants running less and ramping more, which will hurt their economics. Longer-term gas plants will become more seasonal, lower-utilization assets. There is a risk that many will become underused or stranded. Our NEO modelling suggests the national average capacity factors of CCGTs and OCGTs are likely to drop to sub-optimal levels of 32% and 7% by 2050 in the U.S., respectively.

PV-plus-storage can already competitively displace new-build CCGTs with capacity factor up to 50% in CAISO if they are sized to meet 90% of CCGTs' output. For CCGTs in other regions, PVS can beat new CCGTs with sub-20% capacity factors. The addressable market opens up as more standalone and hybrid renewables build changes gas profiles. PVS systems will have a higher chance to displace gas plants that only operate when it is economic to do so.

Cheaper, better performing batteries will also open up more opportunities for standalone energy storage and hybrid renewables-plus-storage projects. It is possible that fully installed energy storage system costs fall more quickly, and that cycle life and performance improves more rapidly than we currently project. If this does happen, this will significantly boost energy storage uptake in the U.S. at the expense of gas in particular.

The respective role for renewables plus batteries versus gas in the U.S. will also depend on the extent to which President-elect Joe Biden is able to enact his clean power proposals. A net-zero power system in the U.S. by 2035 would leave little room for gas generation. Energy storage would be a likely beneficiary.[3] The extension of the Investment Tax Credit to batteries could, for instance, almost triple the market size of batteries in the U.S. Cumulative U.S. utility-scale battery deployment in 2050 in this scenario increases from a total of 113GW/452GWh, to 325GW/1,300GWh.

[3] For BloombergNEF clients: See U.S. Election Results: The Path Ahead for Energy (web | terminal)

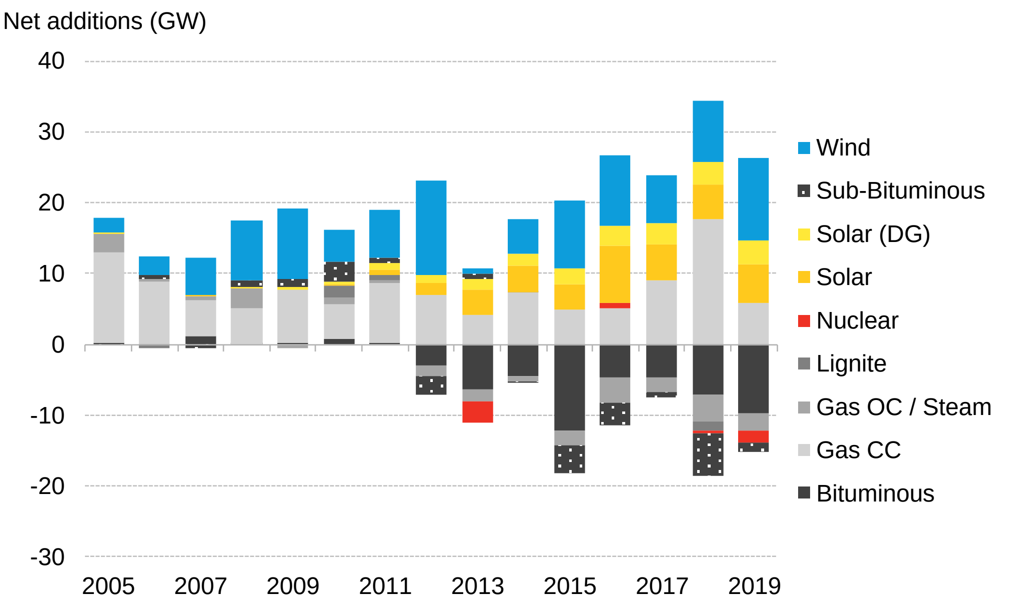
Section 2. Introduction

In this section, we provide an overview of historical net power capacity additions in the U.S. We also briefly discuss our research background, scope, and method.

2.1 Overview

Some 322GW of wind, solar and gas generation capacity were built in the U.S. between 2005 and 2019, replacing retiring coal and nuclear plants. These included 164GW of new wind and solar capacity. Only 500MW of wind and solar were retired. Just under 104GW of gas generation capacity were added in the U.S. on a net basis[4] between 2005 and 2019 (Figure 1).

Figure 1: Net power generation capacity additions in the U.S.



Source: BloombergNEF Plant Stack. Note: Net additions = New build - retirements

Gas is cheaper, more flexible and cleaner than coal. Coal-to-gas switching has lowered U.S. grid emissions and aided renewable energy integration. But gas must become much less central if the U.S. grid is to decarbonize in line with a 2 degrees scenario. Despite this, there are an additional 68GW of proposed gas generation capacity in the U.S. to be built in the mid-2020s.[5]

Hybrid renewable energy and battery storage has emerged as a zero-emission, dispatchable resource. PV-plus-storage is more common than wind-plus-storage: solar's diurnal generation pattern makes it a natural fit to pair with batteries with a few hours of storage capacity. Seasonal

4 New build minus retirements

5 Rocky Mountain Institute, Sierra Club

or long-span storage may be better suited for pairing with wind. A well-functioning, low-emissions power system would optimize for wind, solar, storage and other resources.

The first part of this Research Note (from Section 3 to Section 5) aims to make a direct comparison between PV-plus-storage and new-build gas plants. This allows us to review the competitiveness of PV-plus-storage more effectively. We also attempt to capture fully batteries' true value.[6] In this note:

- We assess the value and cost of PV-plus-storage systems compared to gas alternatives. We review whether PV-plus-storage can replicate exactly the performance of certain types of gas generators today in the U.S.
- We explore how new-build PVS will fundamentally change the use case for gas generators, even if they do not displace them fully. This should encourage policy makers, investors and power companies to reassess their planning proposals to avoid the risk of stranded assets.
- We show how gas power plants are actually used throughout the year, across the U.S. This is often quite different to how their use is commonly described.

To understand these issues, we did the following:

1. Reviewed the historical operational performance of over 3,000 gas peakers and 1,800 combined-cycle plants across various U.S. regions. Relying on historical generation profiles is useful because it ensures we're looking at real operational data. It is likely though to understate the displacement opportunity for PV-plus-storage. This is because it does not distinguish between when a gas power plant did run, and when it was economic to run. Many plants continue to generate even when it is uneconomic to do so. Removing these hours from the profiles would lower the barriers to full displacement by PV-plus-storage;
2. Compared the technical capabilities and limitations of both technologies;
3. Compared the cost competitiveness of the technologies when providing equivalent services.

System or resource planning typically involves assessing combinations of multiple resources to construct long-term new-build portfolios, rather than like-for-like comparisons of two technologies. BloombergNEF's New Energy Outlook (NEO) is an example of this type of exercise.[7] Therefore, in the last section of this note (Section 6), we provide the key modelling outputs from our NEO 2020. These validate the conclusions of the economics section.

2.2 Scope

We compare the competitiveness of PV-plus-storage versus different types of gas power plants in the U.S. We primarily looked at this from a utility planners' perspective to see which technology is more valuable and lower-cost on a new-build basis.

We focus on co-located, utility-scale PV-plus-storage, as opposed to wind-plus-storage or standalone batteries (Figure 2). Wind-plus-storage is less common, and the hybrid generation profile looks less competitive today. Standalone storage is covered indirectly here since solar and storage can complement each other, even when they are not co-located.

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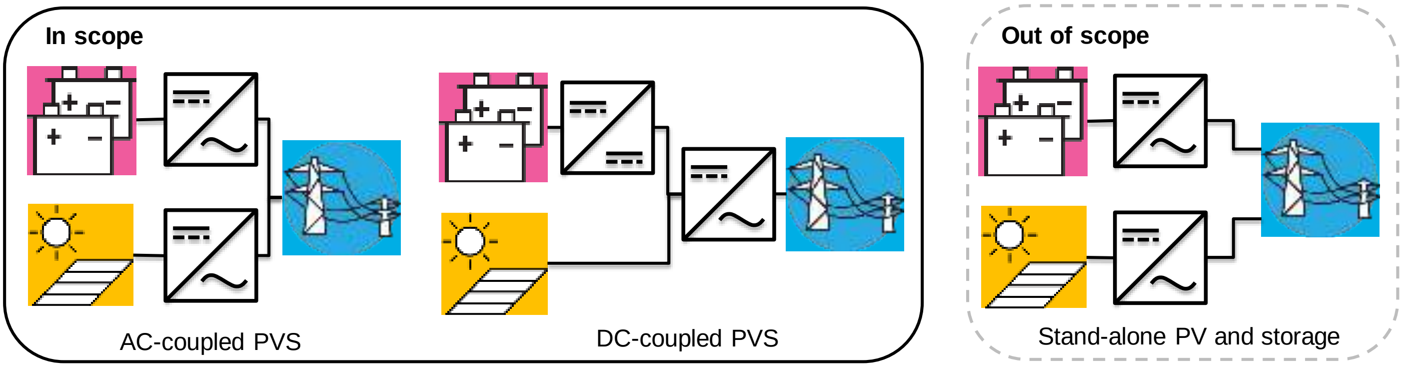
6 For BloombergNEF clients: see *Why U.S. Utilities are Rethinking How to Procure Batteries* (web | terminal)

7 For BloombergNEF clients: see *New Energy Outlook 2019* (web | terminal)).

Figure 2: PV-plus-storage simplified configurations



Source: BloombergNEF. Note: We focus on co-located configurations (AC-coupled or DC-coupled) in this note, where batteries and solar PV share the point of common coupling. Batteries can charge electricity directly from solar assets in these configurations. This is a requirement for the U.S. PVS to qualify for the Investment Tax Credit.

We analyzed the operational performance of each individual gas plant contained in the EPA CEMS database. We pulled historical hourly generation profiles, reviewed and then aggregated their dispatch profiles to generate regional and national overviews. We assessed the hybrid projects' economic competitiveness at the regional level instead of the individual power plant level.

We primarily looked at restructured, wholesale electricity markets where there is more data transparency. However, many of the issues addressed are also relevant to regions with vertically integrated electric utilities.

We also do not look at zero-emissions gas generators, such as those that use 100% *green hydrogen*.[8]

[8] For more information, see *Hydrogen: The Economics of Power Generation* (web | terminal)).

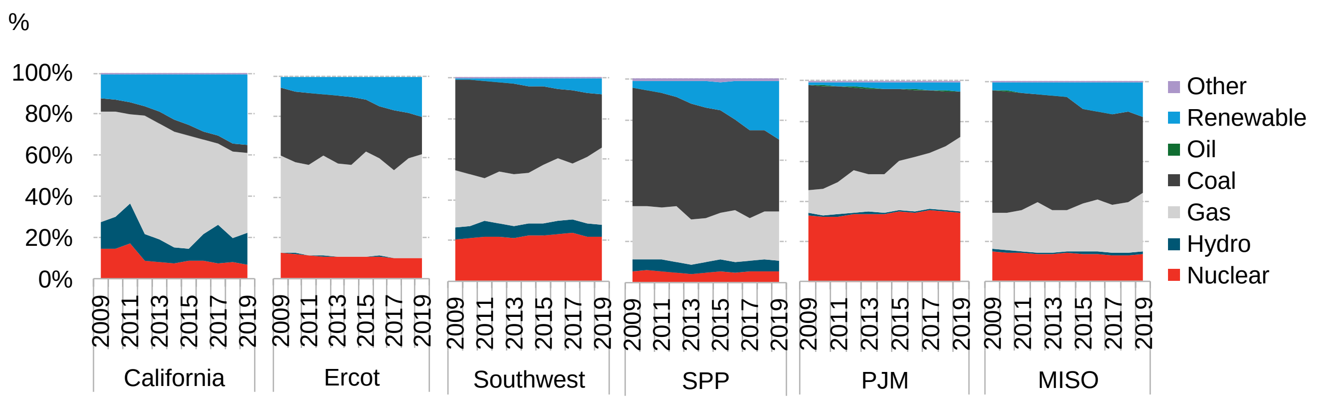
Section 3. The role of gas

In this section, we review the current state of the U.S. energy transition, its near-term gas new-build project pipeline and the historical performance of the existing fleet.

3.1 An ongoing energy transition: coal-to-gas and renewables

U.S. coal-fired capacity peaked in 2011 and has since been in decline. Cheap gas and ever-cheaper renewables have both grown in importance. Gas generation accounted for about 38% of total U.S. electric generation in 2019, up 13 percentage points from 2009. The penetration of wind and solar generation increased from 2% in 2009 to 11% in 2019. The share of coal generation dropped from 43% in 2009 to 24% in 2019. This has been an uneven transition. Some markets shifted straight towards renewables, while others leant towards gas (Figure 3).

Figure 3: Power generation mixture evolution by power region



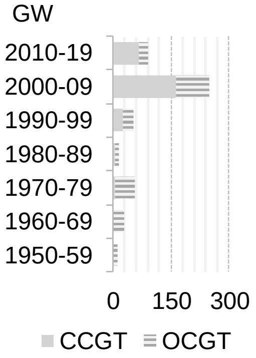
Source: BloombergNEF

- **California** has a goal to source all electricity from renewable and zero-carbon resources by 2045. Wind and solar made up roughly 28% of generation in 2019, and gas plants are being forced to ramp frequently and steeply, making them less efficient. Some units have also been kicked out of the supply curve completely, because startup is too slow or too expensive.[9]
- **Texas (Ercot)** still has several coal and nuclear plants, as well as gas and the highest concentration of wind power in the nation. High-runtime thermal plants are facing challenges as renewables cut into their running hours while also depressing clearing prices. There has been a notable shift from building combined-cycle plants to constructing low-capacity factor gas peakers. The peakers provide capacity during summertime in Ercot. [10]
- Wind generation has soared in **Southwest Power Pool (SPP)** at the expense of coal. Gas generation has remained relatively stable, mostly due to low gas prices.

9 For BloombergNEF clients: see *Batteries Benefit When Intermittent and Inflexible Collide* (web | terminal))

10 For BloombergNEF clients: see *Ercot Power Prices Invite New Open-Cycle Peaker Capacity* (web | terminal).

Figure 4: Online gas capacity by commission year



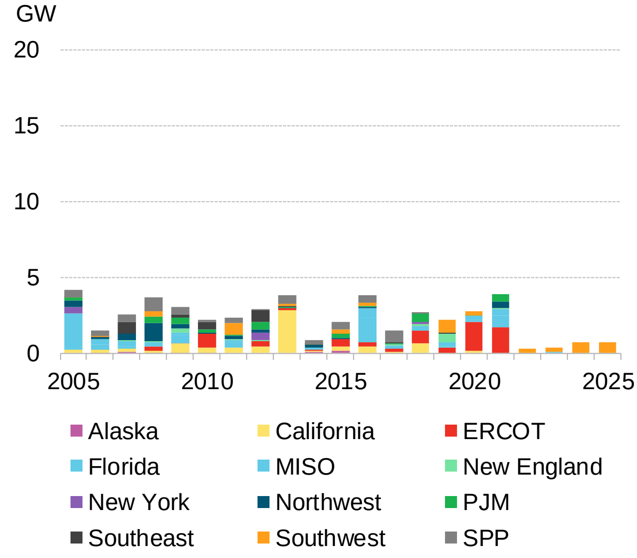
Source: BloombergNEF, EIA

- Efforts to reduce carbon emissions are underway across the solar-abundant **Southwest** states. Renewables will be key to this: New Mexico passed a bill to increase its renewable portfolio standard (RPS) from 20% to 50% by 2030. Nevada also has a 50% RPS target by 2030, and aims to be 100% carbon-free by 2050.
- New gas build continues to grow in **PJM** while renewables development lags behind. Low-cost gas generation often sets the market price, accelerating coal retirement.
- **Midwest (MISO)** is also going through a major transition towards renewable energy. The combination of wind and cheap gas is pushing out older and less efficient coal plants.

Gas generation is now the nation's power workhorse, and its role is expected to grow (Figure 5, Figure 6). We currently track about 8.7GW of OCGT and 47GW of CCGT, in terms of pipeline capacity due to come online by 2025. A review of integrated resource plans and other filings suggests the true number is even higher: there have been announcements of 68GW of gas generation capacity in the U.S. proposed to be built in the mid-2020s.[11] The majority of near-term new CCGT build is expected to be in PJM.[12]

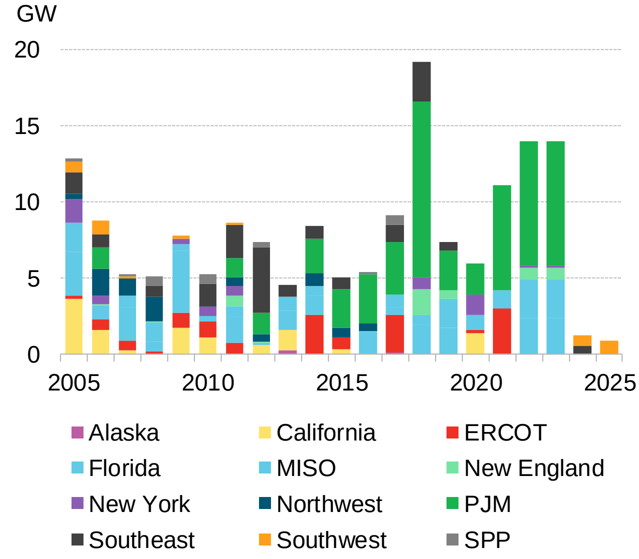
Assuming a life span of 40 years, we expect about 123GW of peak capacity and roughly 44GW of CCGTs to retire over the next 20 years (Figure 4). What replaces this capacity will be key to decarbonization efforts.

Figure 5: Gas OCGT pipeline capacity by region



Source: BloombergNEF, EIA. Note: Bloomberg Power Plant Stack contains BloombergNEF and EIA's project pipeline.

Figure 6: Gas CCGT pipeline capacity by region



Source: BloombergNEF, EIA. Note: Bloomberg Power Plant Stack contains BloombergNEF and EIA's project pipeline.

[11] Rocky Mountain Institute, Sierra Club. Sierra Club's map relies on sources including the EIA, S&P, and utilities' integrated resource plans.

[12] For BloombergNEF clients: see *U.S. CCGT Economics: PJM Leads, Ercot Bleeds* (web | terminal).

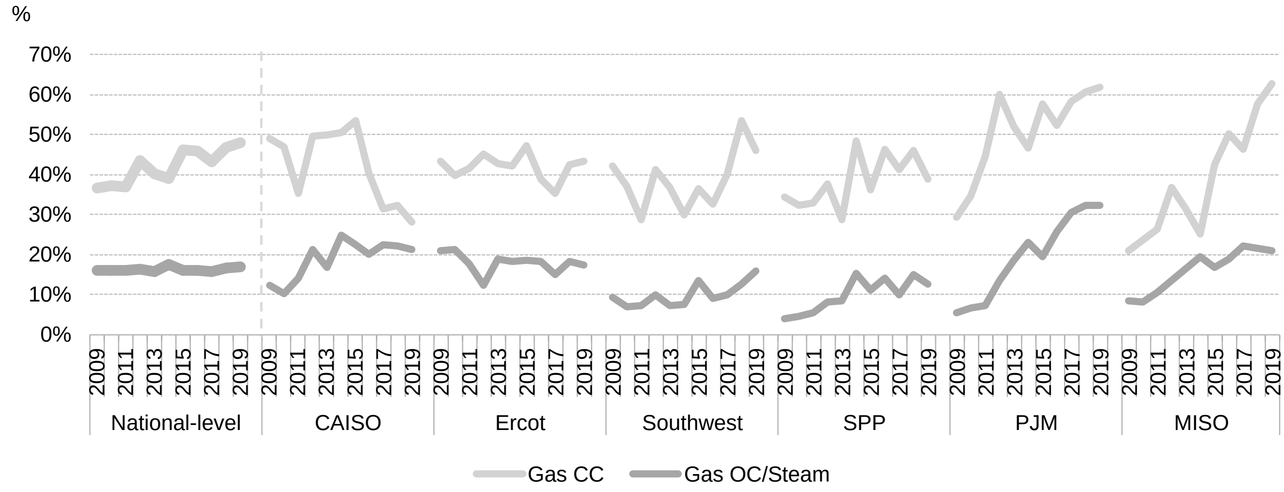
3.2 Operational performance of U.S. gas plants

Capacity factors

National trend

U.S. combined-cycle capacity factors have steadily increased over the last decade, mainly as a result of gas displacing coal. The ups and downs are primarily driven by gas price volatility. Open-cycle capacity factors have remained relatively stable at the country level (Figure 7, left chart).

Figure 7: Capacity factor of utility-scale natural gas power plants by region



Source: BloombergNEF, Energy Information Administration (EIA)

Regional trends

California, a market with high renewable integration and massive coal phase-out, has highlighted gas-fired generators' struggle.

Gas operations vary a lot by region, depending on the specific local power market transitions (Figure 3). Capacity factors tend to rise in regions where coal-to-gas switching is underway, such as PJM, MISO, and the Southwest (Figure 7), but are flat in markets such as SPP and Ercot that have strong renewables growth and some remaining coal.

The average CCGT gas capacity factor in PJM has doubled over the last decade, and gas peakers today run like CCGTs ran 10 years ago. This is because gas run hours have increased at the expense of coal, but wind and solar have yet to make a dent in the market.

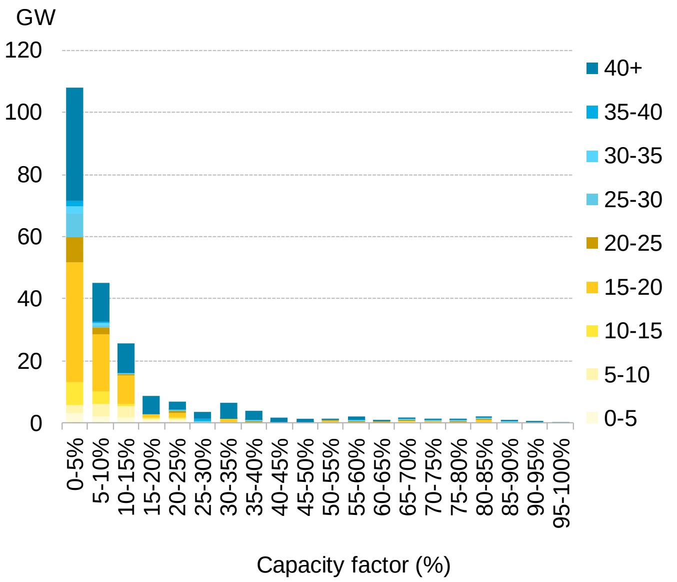
California stands out. The coal phase-out and a renewables boom have pushed CCGTs to the margin of the dispatch stack. These plants, which are supposed to run at a relatively stable output for a long duration, now only generate electricity at times of high demand and low renewables output. They are increasingly uneconomic and some units are facing early retirement. For instance, the La Paloma Generating Co LLC, a 1,028MW CCGT, filed for bankruptcy in 2016 after running for just 13 years. The plant had a capacity factor of 11.8% in 2018.

California's OCGT capacity factors doubled between 2010 and 2015 before stabilizing. CAISO frequently dispatches these gas peakers during the evening peak to meet its astonishing ramping needs. Batteries will reduce the reliance on OCGTs for this role in the near term.

Capacity factor distribution by turbine age

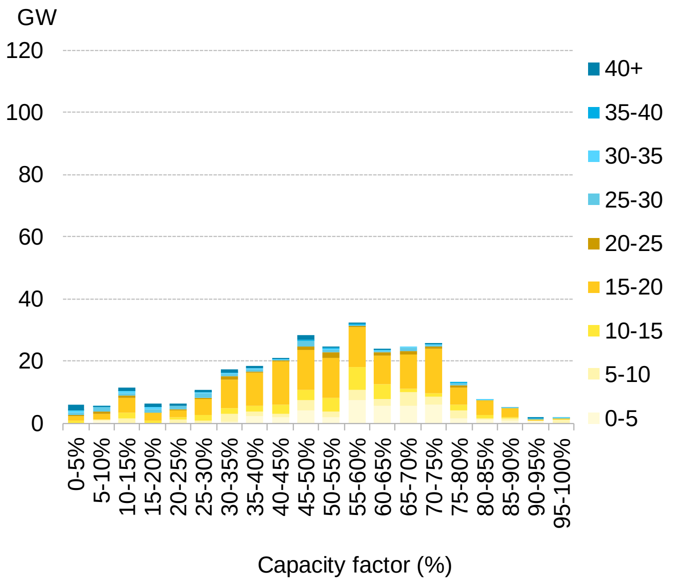
Some 80% of OCGT capacity in the U.S. operates at a capacity factor below 15%. Some 53% of this capacity was commissioned in the last 20 years (Figure 8). Capacity payments (if applicable) and extreme prices spikes are critical to their viability.

Figure 8: U.S. OCGTs' capacity factor range distribution by turbine age, 2019



Source: BloombergNEF, U.S. Energy Information Administration, Forms EIA-923. Note: This chart is calculated based on 3,375 OCGT gas plants totaling 223GW of capacity in this chart.

Figure 9: U.S. CCGTs' capacity factor range distribution by turbine age, 2019



Source: BloombergNEF, U.S. Energy Information Administration, Forms EIA-923. Note: This chart is calculated based on 1,805 of CCGT gas plants totaling 289GW of capacity in this chart.

There is a more even distribution of CCGT capacity factors (Figure 9). About 84% of online capacity had a capacity factor of more than 30% in 2019. That still leaves 16% of the fleet that is seriously underperforming, with capacity factors below 30%. Over 62% of these underperforming CCGTs are less than 20 years old.

Operations and runtime

Operations and runtime are also important indicators of a gas plant's performance. They determine a plant's efficiency and semi-fixed costs.[13] They also determine the type of service required of batteries or renewables-plus-storage if they are to displace gas plants. For instance, PVS can provide longer-duration services by oversizing the batteries and PV system, but this comes at a cost. In some cases, depending on runtimes, this may not be needed.

In this section, we show how the maximum number of consecutive hours for which individual plants operate has changed over time. We also look at the distribution of dispatches based on duration, ie, how many of a plant's cycles are for a short versus a long period.

[13] For BloombergNEF clients: see *Batteries Benefit When Intermittent and Inflexible Collide* (web | terminal)

To conduct this analysis, we used data from EPA's Continuous Emission Monitoring System (EPA CEMS) database. It contains the hourly generation data of all combustion plants that are larger than 25MW and maintain a continuous emission monitoring system.

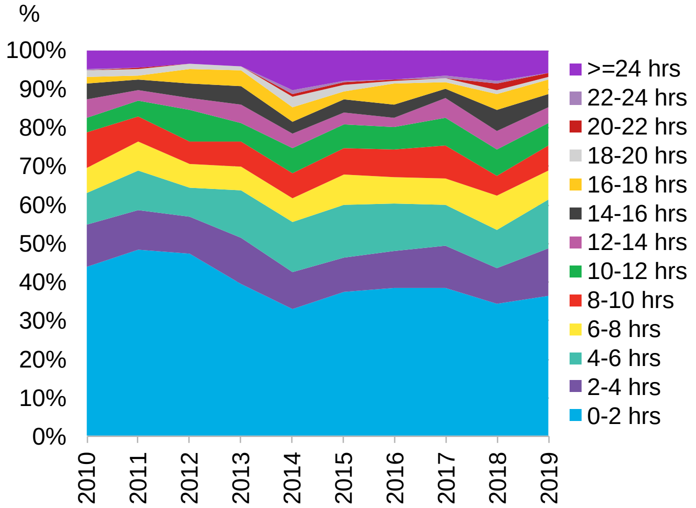
Maximum consecutive running times

U.S. CCGTs have moved to operate at full capacity for longer durations over the last decade, driven by the coal-to-gas shift.

The number of consecutive hours for which a plant has to operate at full capacity is crucial to understanding what resources could displace it. We reviewed the runtime for each individual plant when operating at maximum capacity, which we set at 95% of rated capacity[14]. We aggregated the data and conducted the statistical analysis at the regional and national level. We also tested thresholds of 90% and 85% but they had similar outcomes. To maintain consistency, we only included units that have remained online over the entire timeframe (2010-2019).

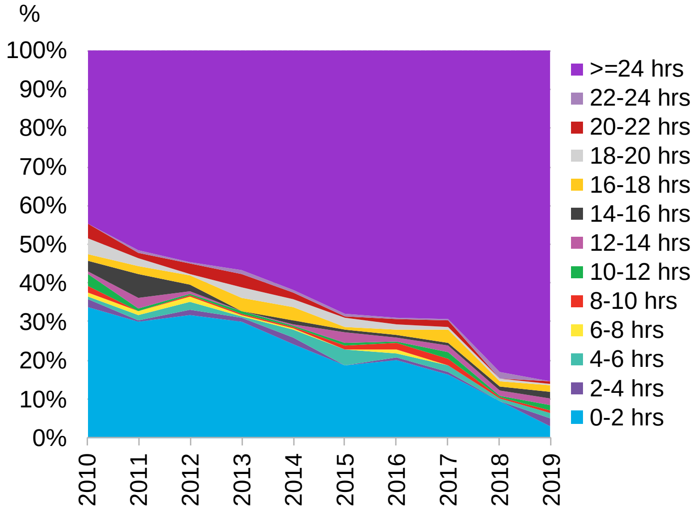
Figure 10 and Figure 11 show the distribution of these U.S. OCGTs and CCGTs, based on the run-time length when operating close to full capacity.

Figure 10: Distribution of U.S. OCGTs' annual max consecutive running time operating at 95% of nameplate capacity, by percentage of units



Source: BloombergNEF. Note: This chart is calculated based on date of 487 units of OCGT assets across the U.S.

Figure 11: Distribution of U.S. CCGTs' annual max consecutive duration operating at 95% of nameplate capacity by percentage of units



Source: BloombergNEF. Note: This chart is calculated based on data of 278 units of CCGT assets across the U.S.

- About three-fifths of OCGT units in the U.S. had an annual maximum full-load running time of less than six hours in 2019. This has remained constant for the last decade. Some 28 units out of 487 units experienced at least one consecutive operation duration of over 24 hours.
- The number of consecutive hours that gas combined-cycle plants operate for has increased over the last decade. This is largely a result of coal-to-gas switching. About 82% of units in 2019 operated at max capacity for over 24 hours at least once. Some plants operate at

14 EPA data often reports individual combustion turbines (CTs) separately. The load generated by the steam turbines (STs) are uniformly distributed between the CTs. We have taken this into account and processed the data accordingly.

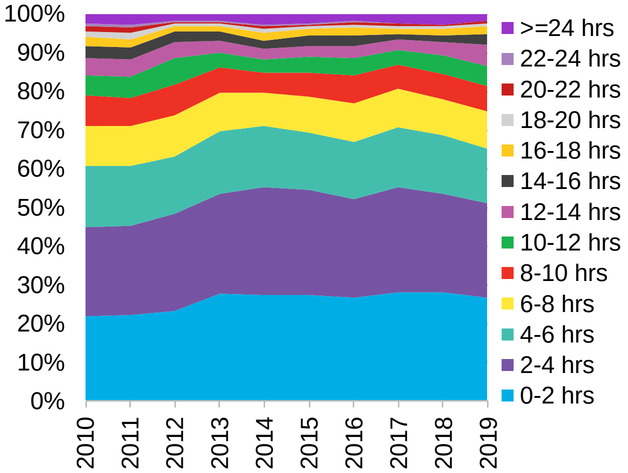
maximum capacity continuously for months. These plants will be challenging to replace with PV-plus-storage, or indeed clean energy portfolios, in the near term.

- The story is similar at the regional level (see Appendix A for California and Ercot charts), except that OCGTs operate for notably shorter running times (mostly between zero and two hours) in high-renewables markets.

Breakdown of run times

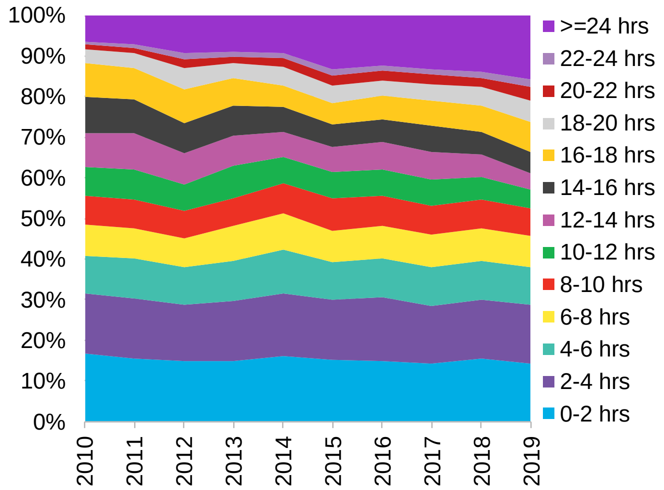
We also reviewed the dispatch profiles of each individual gas plant to quantify the distribution of consecutive running hours. We count each dispatch runtime based on when a plant ramped up above its 95% of rated capacity and dropped from this threshold. Results were similar when we changed the threshold to 90% and 85% of rated capacity.

Figure 12: OCGT operational endurance time distribution



Source: BloombergNEF. This chart is calculated based on date of 487 units of OCGT assets across the U.S.

Figure 13: CCGT operational endurance time distribution



Source: BloombergNEF. Note This chart is calculated based on data of 278 units of CCGT assets across the U.S.

- Over 60% of the runs, OCGTs were called upon and operated for less than six hours. Across the fleet, OCGTs remained at peak capacity for more than 24 hours for just 2% of the runs (Figure 12).
- A growing number of CCGTs are required to run for more than 24 consecutive hours, but they do so infrequently. The frequency has increased over the decade, however. Some 16% of CCGT dispatch runs at peak capacity in 2019 were longer than 24 hours (Figure 13). CCGTs were called upon and operated continuously for less than eight hours in 46% of runs. This portion of CCGT operation could be taken by stand-alone batteries or PVS without much difficulty. Longer-duration dispatches would need to be tackled by oversized solar-plus-storage assets, which are still economically challenging with today's costs.

How renewables affect gas operations: California case study

A higher penetration of renewable energy will require combined-cycle plants to ramp up and down more frequently. These gas plants will need to provide more operational flexibility in response to net load variation.

Gas plants are more flexible thermal resources than coal or nuclear, and newer turbines are able to cycle more easily. More cycles have a cost for most plants though: this includes reduced efficiency by running at part-load condition, higher emissions, increased wear and tear and shortened lifetime.

Figure 15 shows the operational profile in March of a CCGT located in California. The plant was commissioned in 2005, and went from operating fairly constantly to fast ramping and frequent starting up and shutting down. This trend is likely to become commonplace in regions with increasing renewables. This expected change to operations and the additional accompanying costs to gas generators should be accounted for in resource planning and capacity modelling.

Figure 14: CCGT hourly profile evolution 2010-2019, Donald Von Raesfeld Power Plant (CC1)

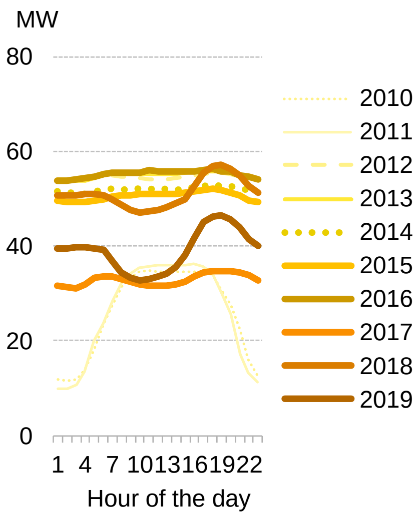
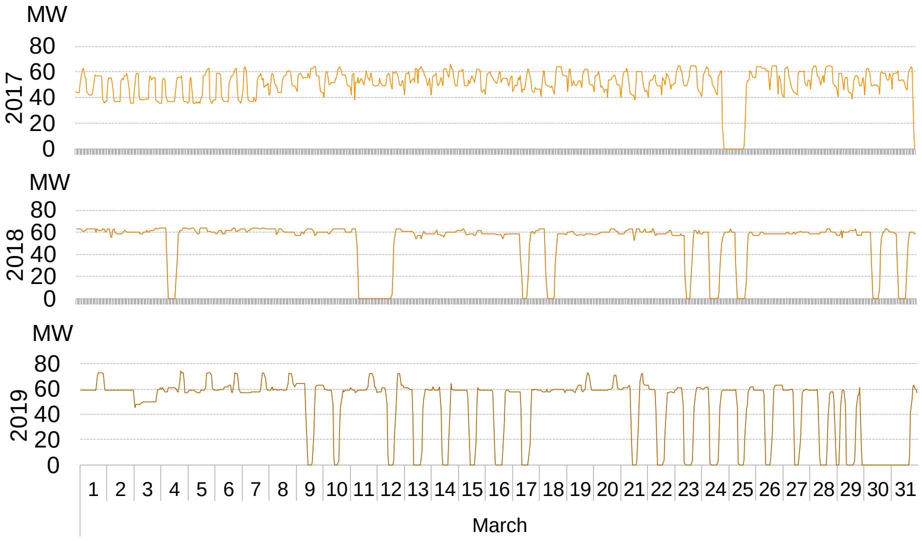


Figure 15: Donald Von Raesfeld Power Plant (CC1) hourly generation time series in March, 2017-2019



Source: BloombergNEF, EPA Continuous Emission Monitoring System (EPA CEMS).

Section 4. PV-plus-storage versus gas

In this section, we review the competitiveness in both cost and technical terms of PV-plus-storage versus gas power plants. We compare the costs of each option when providing an equivalent service.

4.1 Economic comparison

Sizing the PV-plus-storage plant

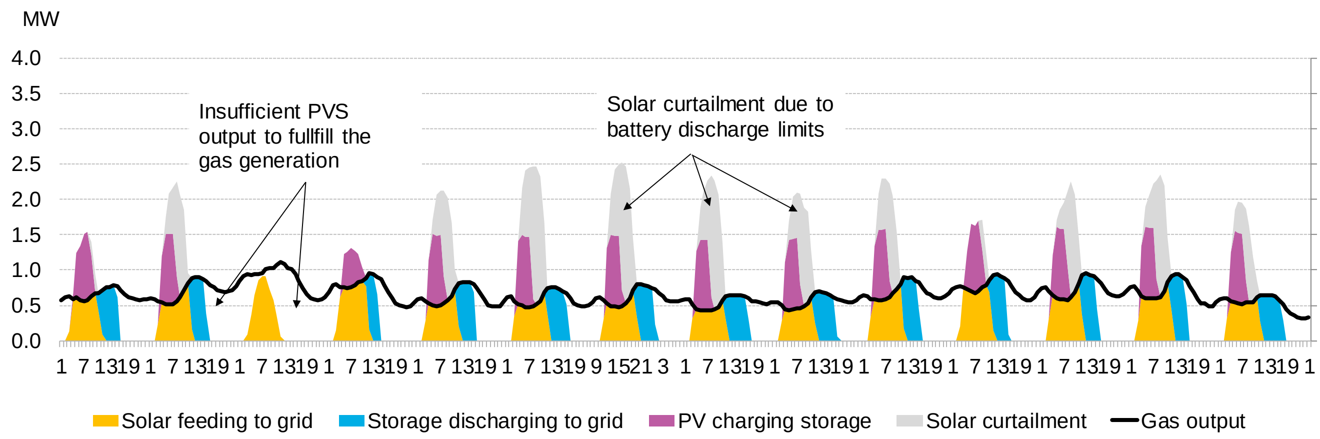
PVS will be able to do the identical work to gas plants – if it is oversized and dispatched at lower power output in a continuous manner.

If two generators provide identical operational benefits or value to the power system, a cost comparison is relatively simple. Gas power plants and batteries are, however, very different assets.

A key difference is that batteries do not have unlimited run time. To account for this, we size the PVS asset so that it can provide the same service to the power system as the gas plant. It is sized to be able to generate the same amount of electricity at exactly the same time as a given gas plant throughout the year. Doing this typically requires us to oversize the PV-plus-storage project.

We provide an illustration in Figure 16: a 1MW/4MWh battery storage system is paired with a 4MWDC solar asset, in an attempt to generate the same output as a comparable gas plant (normalized to 1MW for simplification). The battery charges from the solar system when PV output exceeds the gas generation profile. This stored electricity is dispatched later to firm the PV's output. However, this PV-plus-storage system is unable to match the gas plant's output, and there is also a lot of solar curtailment.

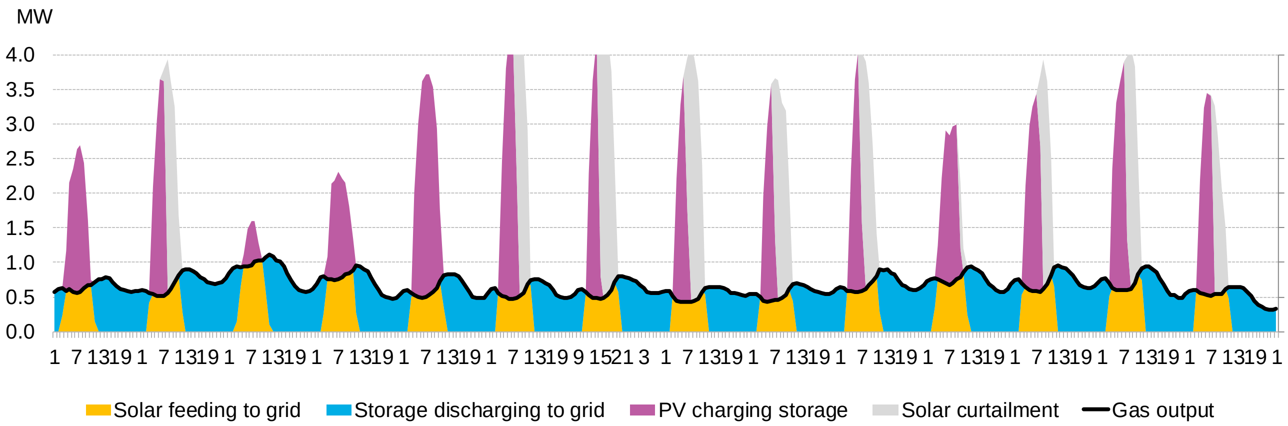
Figure 16: Illustration: 1MW gas vs. co-located PV (4MWDC) plus storage (1MW/4MWh)



Source: BloombergNEF. Note: To simplify the study, we normalize the gas plant capacity to 1MW. X axis numbers represent hour of the day. Due to the length constraints, we only show a few days' simulation here. In our analysis, we sized PVS to simulate the whole year's output.

If we increase the PVS system size to 7MWDC PV plus 6MW/24MWh storage, a larger amount of excess solar electricity can be stored in the battery for later use. This larger plant can deliver the same round-the-clock output as the gas plant (Figure 17). In reality, optimizing round-the-clock renewables will likely require generation from multiple sites rather than using a single generation profile (*Round-the-Clock Renewables Threaten Coal Power in India* (web | terminal)). This would probably reduce the required oversizing on each occasion, depending on the configuration.

Figure 17: Illustration: 1MW gas vs. co-located PV (7MWDC) plus storage (6MW/24MWh)



Source: BloombergNEF. Note: To simplify the study, we normalize the gas plant capacity to 1MW. X axis numbers represent hour of the day. Due to the length constraints, we only show a few days' simulation here. In our analysis, we sized PVS to simulate the whole year's output.

As the PVS system in Figure 19 is now able to do the same job as the gas unit, it is now easy to compare the economics of these two types of assets.

Cost comparison

We compare the two plants on an LCOE basis, with some adjustments. Below are potential adjustments we considered.

- There are extra services that both PVS and gas can provide to the grid in addition to energy value and capacity value. Ancillary services, for instance, make up around two-thirds of the merchant revenue for a stand-alone four-hour battery now in CAISO.
- Thermal generators' cycling costs are another factor that could be accounted for; these can be treated as negative revenue to gas plants.
- Revenue from the sale of excess PVS electricity. We over-size our PVS to match a gas generator's output throughout the whole year. As a result, there are other times during the year when there is additional energy remaining in the battery after it has already matched the gas output. We attempted to lower the battery state of charge on a daily basis to reduce curtailment as much as possible (see Appendix B).

Of these potential modifications, we only included the PVS surplus electricity discharge revenue[15]. We subtracted the value of this revenue stream from the cost of the system. This gives us a modified levelized cost of electricity. See simplified formula below.

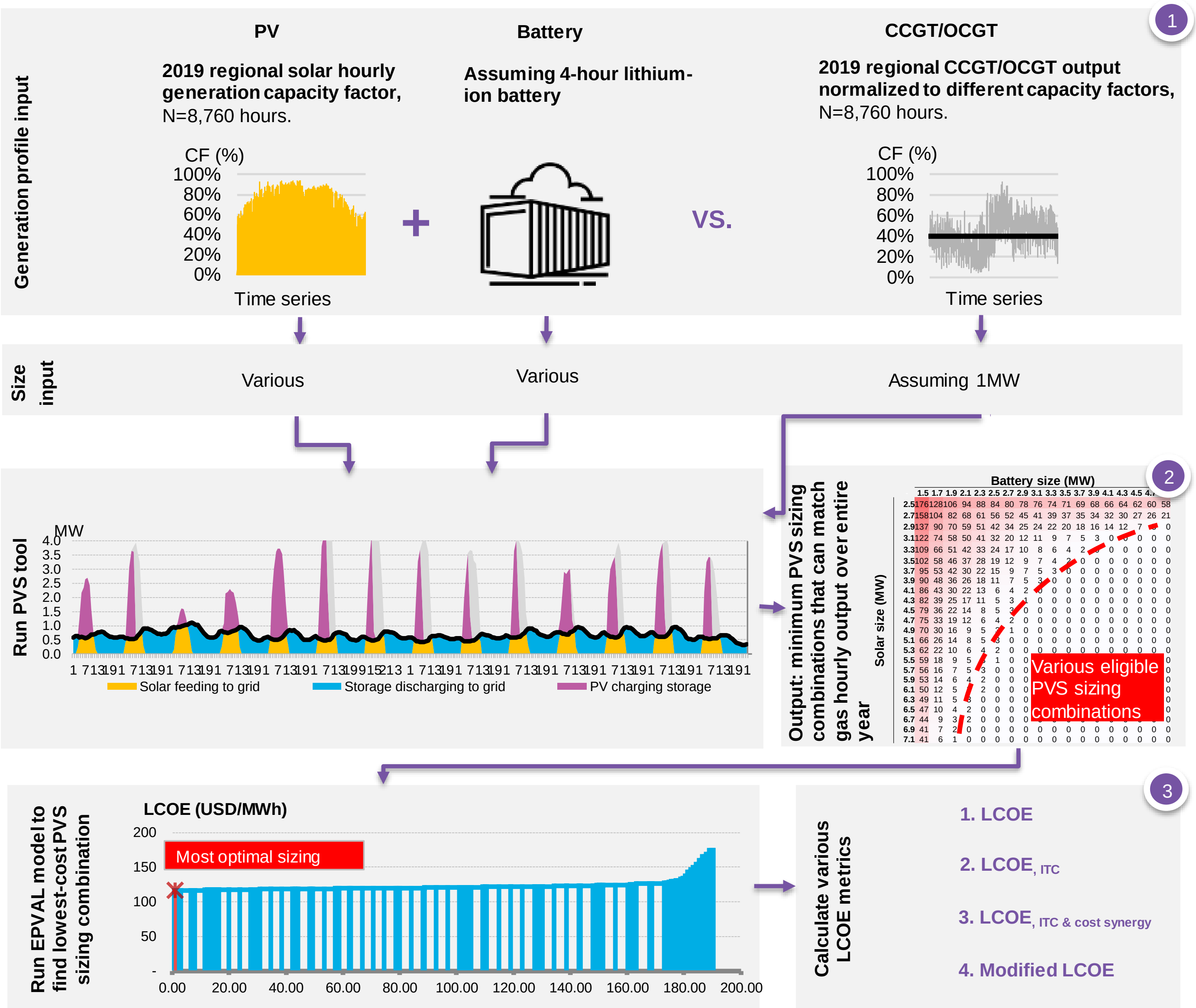
$$Modified\ LCOE = \frac{Total\ lifetime\ investment - additional\ monetary\ value}{Total\ firmed\ energy\ output\ (or\ total\ gas\ generation)}$$

[15] PVS surplus electricity discharge revenue = $\sum$Daily excess electricity$_{\text{Day i}}$ (MW) × 2019 actual hourly power prices$_{\text{Day i}}$ ($/MWh). The power prices we deployed is 2019 actual hourly power price when power discharge occurs, normally in the early morning before sunrise. For more details, see Appendix B**Error! Reference source not found.**.

Some other studies also include frequency regulation revenues for batteries but we did not. This is because it is tricky to estimate accurately the future revenues from ancillary services; this revenue stream may be unavailable in many markets, and it may diminish over time. Thermal generators' cycling costs are also not accounted for. These are still a minor cost in most regions, and are often overlooked in utilities' integrated planning processes. Since the two assets are providing equivalent capacity services, we did not separately include capacity revenues. We included the Investment Tax Credit and some cost synergies from co-locating when calculating PV-plus-storage assets' capex. Detailed assumptions can be found in Appendix B.

Analytical approach

Figure 18: Illustration of research methodology



Source: BloombergNEF. Note: We only listed 4-hour battery results in this note, which is a typical battery deployed in the U.S. A sensitivity assessment has been carried out using different battery duration assumptions (including 2-hour and 6-hour). The results do not differ significantly from those involving the 4-hour batteries.

Data inputs: For each power region, we used the 2019 solar and gas profiles in our PVS generation simulation tool. The regional gas profiles are normalized to different average capacity factor levels, representing a variety of gas power plants with which PVS competes.

PVS minimum sizing calculation: We then iterate through various combination of PVS sizes to compare their output (8,760 hours over the entire year) with the normalized gas profiles at different capacity factor levels. We use various sizes that can meet the gas profiles as inputs for the LCOE calculation.

LCOE calculation: We used our proprietary Energy Project Valuation Model (EPVAL) to calculate the LCOE. PVS' excess electricity sales revenue is factored in as a negative annual opex. We used various combinations of LCOEs, and then selected the least-cost configuration in our regional comparisons (see Appendix B for LCOE assumption).

Cost competitiveness findings

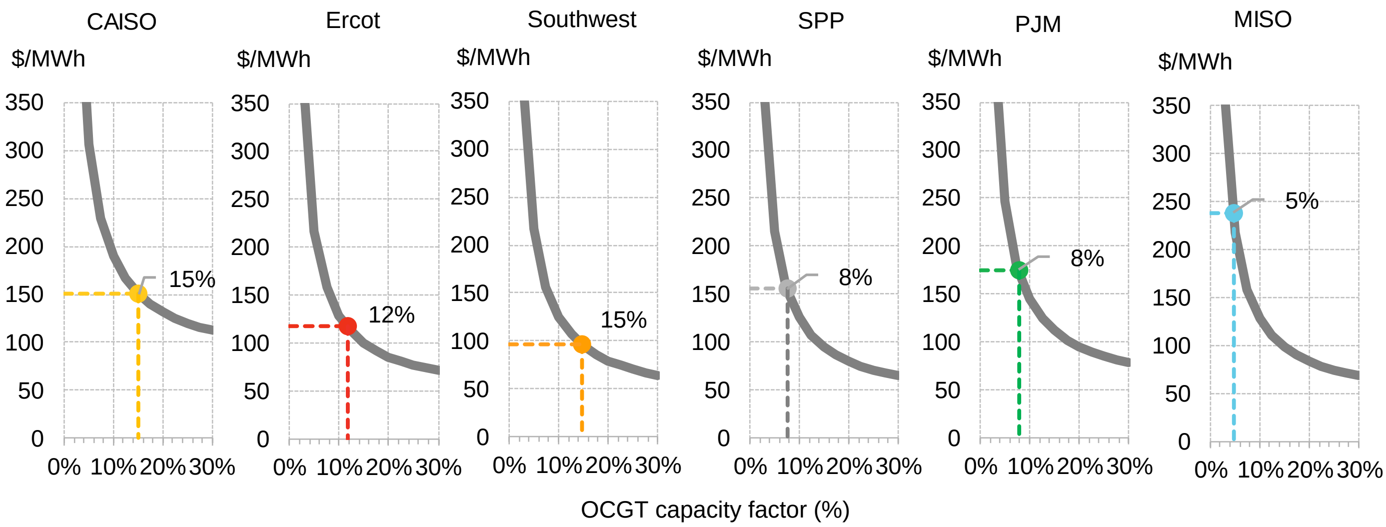
In this section we review three different comparisons. The first two show the competitiveness of PV-plus-storage when providing a like-for-like service to an OCGT, and to a CCGT. The final comparison shows the competitiveness of PVS when it is only partially displacing a CCGT.

PVS appears now to be a cost-attractive alternative to fully displace gas peakers in many regions.

Like-for-like OCGT displacement is possible at today's prices

PVS is already a cost-competitive substitute to many new OCGTs, especially in solar-rich regions (Figure 19). This uses the latest cost assumptions from *1H 2020 LCOE: Data Viewer* (web | terminal). The PV-plus-storage sizing is different for each region. A breakdown of PVS system sizes can be found in Appendix B.

Figure 19: PV-plus-storage modified LCOE (dotted colored line) versus OCGT LCOE by region, 2019



Source: BloombergNEF. Note: The gas LCOE curves are calculated based on the regional average capex, opex, fuel costs etc for local plants built in the last five years. We provide detailed data inputs in Appendix B.

- The PVS LCOE was lowest in the **Southwest** region, at $96/MWh. The high-quality solar resources and a low occurrence of extreme events allow for a smaller PVS sizing and lower LCOE. In this region, PVS is a competitive alternative to new-build gas peakers that have an expected average capacity factor below 15%, in a typical gas LCOE scenario.

- The LCOE for PVS in **Ercot** is $118/MWh. This LCOE can displace OCGTs with capacity factors below 12%. With an LCOE of $150/MWh, PVS is competitive with gas peakers in **CAISO** operating at a capacity factor of up to 15%.
- **PJM and MISO** have the highest PVS LCOEs currently, due to poorer solar resources. Here, PVS can displace local gas peakers with capacity factors up to 8% and 5%, respectively.

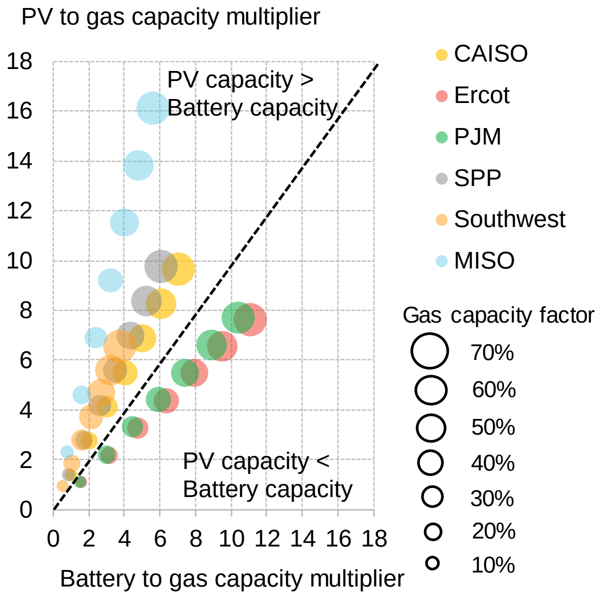
Some 80% of U.S. gas peakers have capacity factors below 15%. PVS is therefore competitive with new-build gas peakers, assuming no further severe gas price reductions.

PVS vs. CCGTs: like-for-like displacement is unlikely in the near term

Regional minimum PVS sizing requirement (like-for-like scenario)

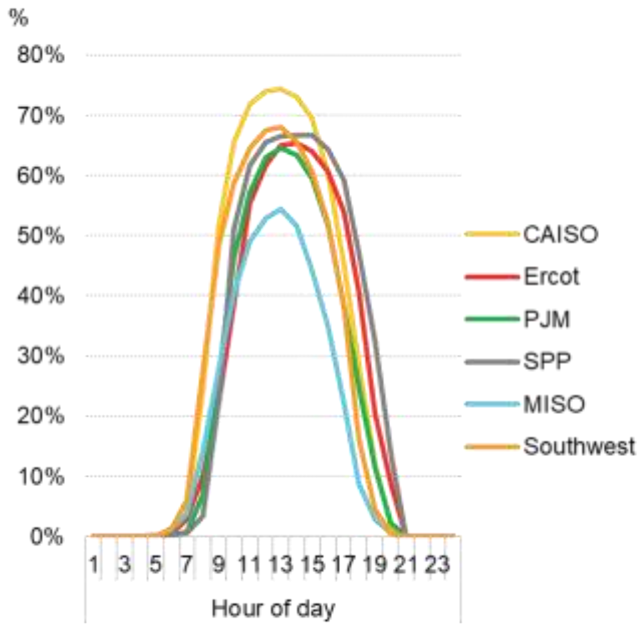
Co-located PV-plus-storage projects (at a single site) need to have nameplate capacity sized at many times that of a CCGT plant in order to displace it (Figure 20). For example, the chart shows that a 100MW CCGT in CAISO operating at 70% capacity factor could be displaced by a system consisting of 960MW of PV plus 710MW/2,822MWh of batteries.

Figure 20: PVS minimum size multiplier by region



Source: BloombergNEF. Note: We assume a 1MW comparable gas plant and a 4-hour battery.

Figure 21: Regional solar daily profile by region, 2019



Source: BloombergNEF

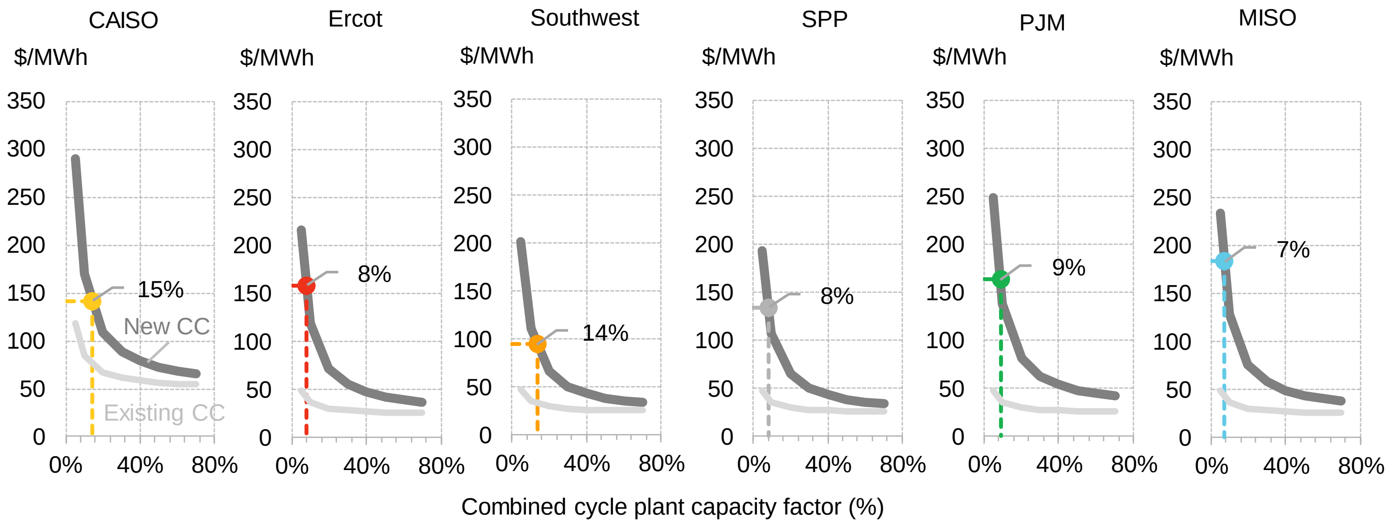
The current hybrid PV-plus-storage cost still does not favor a like-for-like displacement for CCGTs.

A large PV-to-battery capacity ratio is needed in less sunny places (Figure 21). MISO, for instance, requires the PV asset to be sized at roughly 16 times the megawatts in order to replicate the yearly output of a gas plant with a 70% capacity factor. It also needs to be paired with a battery sized at 5.6 times the gas plant's capacity on a MW basis. In the Southwest, the solar asset and battery system only need to be sized at 6.5 times and 3.7 times a CCGT with a 70% capacity factor. PJM and Ercot are two regions requiring relatively high battery-to-solar ratios.

Economic comparison (like-for-like scenario)

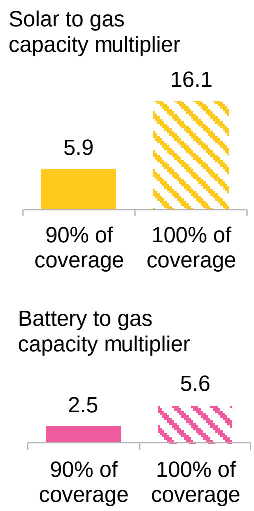
PVS systems can only beat new-build CCGTs running at capacity factors between 7% and 15% (Figure 22). They cannot yet compete with existing CCGTs, which have sunk investment costs and only require variable costs (fuel and carbon expenses) for daily operation. Based on 2020 costs, PVS is not a cost-effective alternative to high-efficiency combined-cycle plants.

Figure 22: Regional PVS modified LCOE (dotted colored line) vs gas combined-cycle plant LCOE, 2019



Source: BloombergNEF. Note: We provide detailed data inputs in Appendix B

Figure 23: Solar and battery size multiplier to displace CCGT with 70% of capacity factor level in MISO



Source: BloombergNEF

PVS vs. combined-cycle plants: partial displacement

PVS' cost competitiveness improves when it is sized to cover most (90-95%), but not all, of the gas plant's yearly operations.

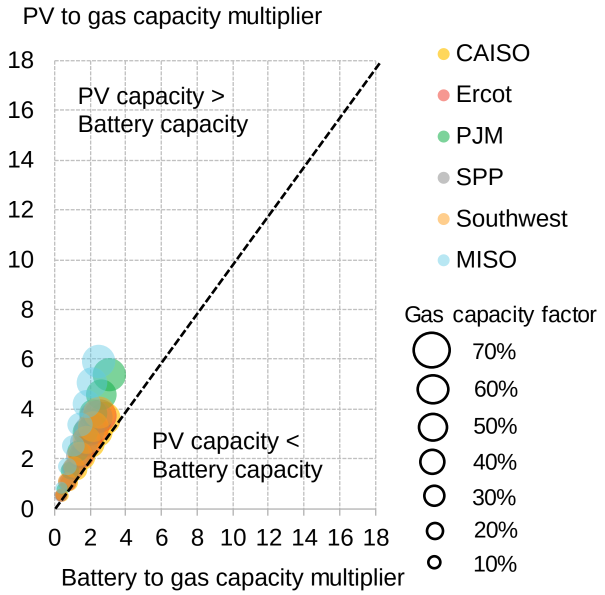
Regional minimum PVS sizing requirement (partial displacement scenario)

PVS system sizes follow a hockey stick shape, with the required size to displace 100% of a CCGT's output many times larger than what is required to meet 90%. For instance, for a CCGT in MISO with a 70% capacity factor, you would need a PV and battery to be sized at 5.9 and 2.5 times of gas nameplate capacity respectively, to cover 90% of its run hours. The multiple grows to 16.1 and 5.6 times for PV and storage respectively when required to meet 100% of generation hours (Figure 23).

In a partial displacement scenario, and with no smart charging rules in place, the PVS system can meet most evening peak power needs, but the gas asset is needed in the early morning. In reality, a battery operator would optimize when they discharge based on power prices.

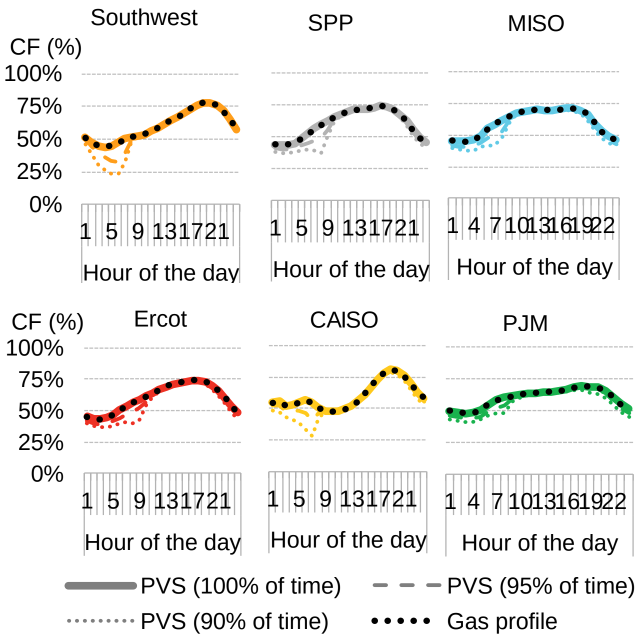
If PVS ends up competing with CCGTs for up to 90% of their run hours, this will change the use case for the gas assets. Indeed, CCGTs may no longer be the optimal asset type. System planners should explore whether existing dispatchable generators (such as other gas plants) running at higher capacity for these periods could offset the need for some new-build plants. They should also assess the capabilities of other resources such as clean power portfolios, power imports, or demand-side flexibility.

Figure 24: PVS minimum sizing to meet 90% of gas CCGT output time



Source: BloombergNEF

Figure 25: Annual average PVS profile if sized to meet 100%, 95% and 90% of CCGTs' energy output



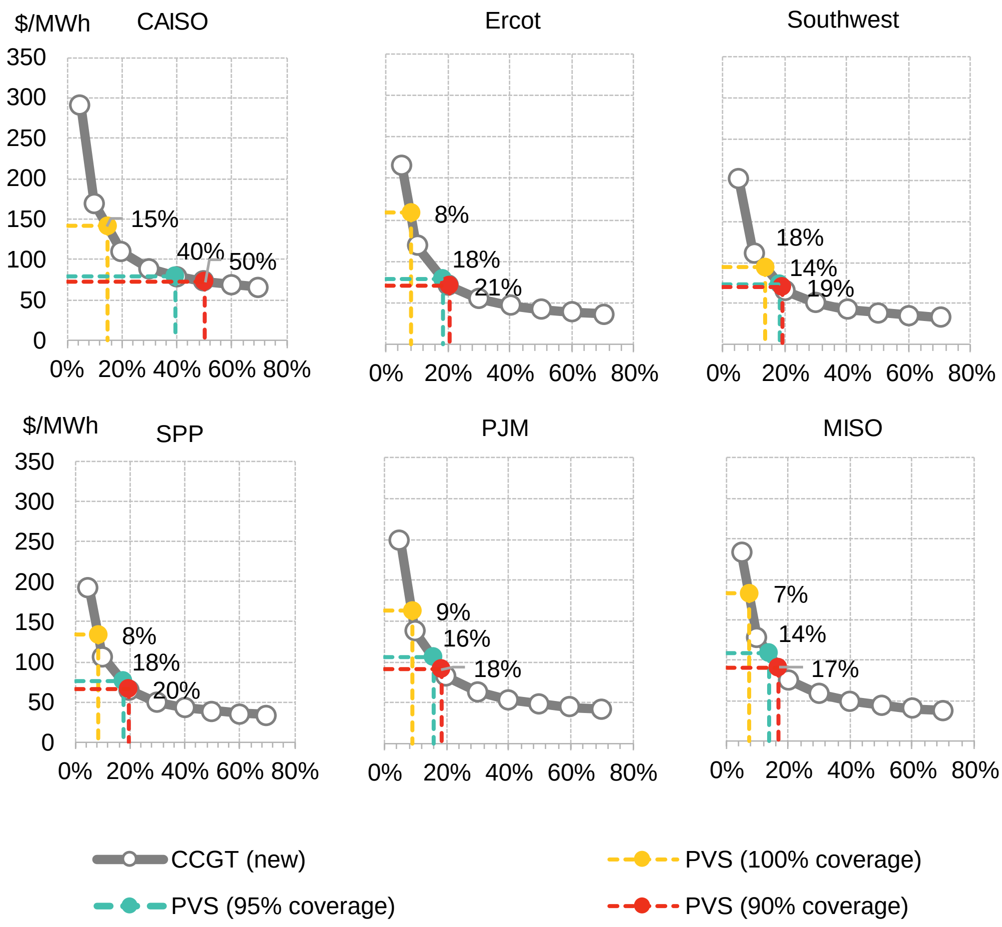
Source: BloombergNEF

Economic comparison (partial displacement scenario)

PVS' economics improve noticeably if sized to firm most but not all of a CCGT's output (Figure 26). This is especially evident in California – the market with the highest gas LCOE of all the regions. A PVS system sized to meet 90% of CCGT generation time can now outcompete a new CCGT operating at a 50% capacity factor.

PV-plus-storage assets can only outcompete CCGTs in one of the six service territories (CAISO) we analyzed with today's prices. Some 10% – or 260GW – of current CCGTs in the U.S. have a capacity factor lower than 20%, which is roughly the tipping point based on 2019 prices. However, hybrid projects will become more competitive as renewables eat into CCGTs' normal run hours, and cause these plants to incur higher start-up and shutdown costs. The potential introduction of carbon prices in these markets would also worsen gas plants' economics. Ongoing cost reductions of batteries and PV assets will further boost the case for PVS assets, so new-build gas plants face a higher risk of becoming stranded before their rated lifespan. In fact, this phenomenon is already evident in California.

Figure 26: PVS and gas CCGT economic competitiveness comparison, 2019



Source: BloombergNEF. Note: X axis refers to the gas generation capacity factor. For PVS sizing breakdown, see Appendix B.

Economics outlook (partial displacement scenario)

We also review how the cost competitiveness may change over time in two scenarios. In the first, the PVS covers 100% of the CCGT output and in the second it matches the CCGT output for 90% of the time. In this section, we compare PVS LCOEs with national high and low gas LCOE scenarios for ease of visualization. This is different to the approach in Figure 26 where we compare PVS LCOEs with regional CCGT LCOEs calculated based on the past five years' local gas project data.

There are two major findings:

- Fully displacing combined-cycle plants with PVS is likely to be difficult even with the expected cost reductions from both PV and batteries, if gas capacity factors and prices remain stable. Southwest is the only market that shows some cost overlaps by 2040.
- Partial displacement is highly possible. PVS can already competitively provide up to 90% of a gas plant's output – when using the national range of gas LCOEs – in all markets except for MISO and PJM. Using narrower, regional gas LCOEs – derived from local gas power plants

built in the past five years – worsens the current competitiveness for PVS, but falling costs of PV and storage suggest partial displacement will become more commonplace.

The biggest uncertainty here surrounds the future gas LCOE. The outlook shown here is based on the range of today's fuel prices, rather than any future projections. Similarly, gas capacity factors remain fixed here, whereas in reality we expect them to continue to change. We have reviewed the modelled changes to gas capacity factors in our New Energy Outlook 2020. The introduction or increase of carbon prices would also push up the gas LCOE relative to the PVS.

Figure 27: Regional PVS vs CCGT LCOE comparison with 100% of gas profile firmed, 2019-40

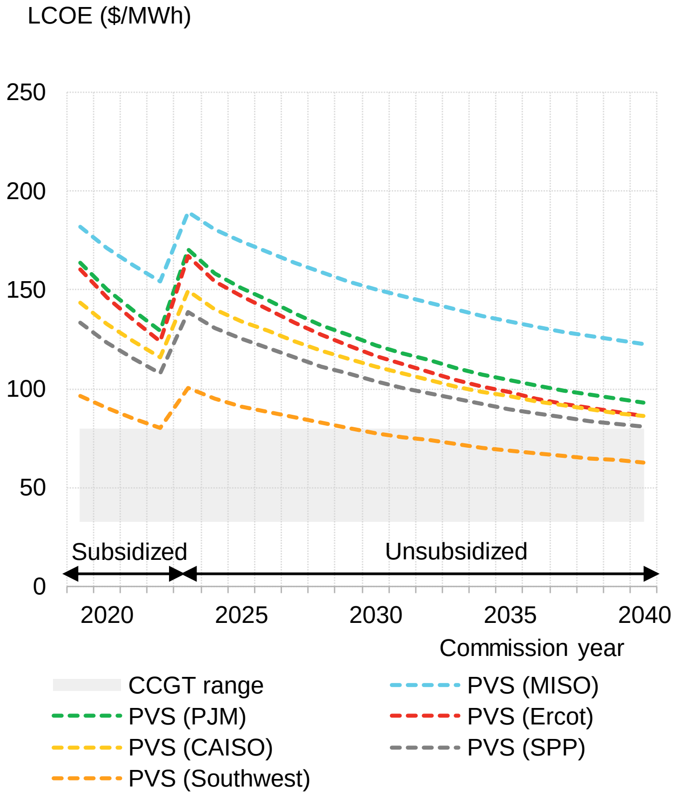
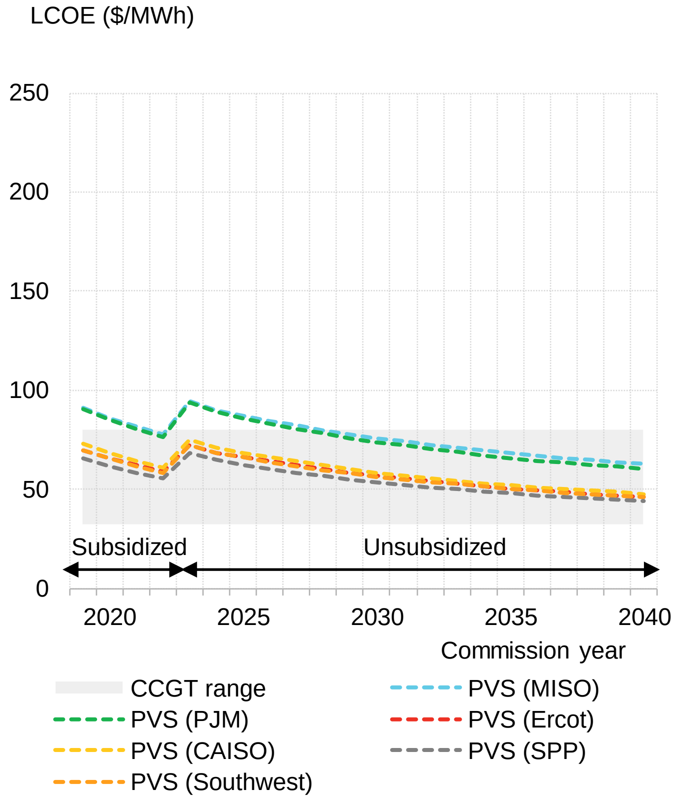


Figure 28: Regional PVS vs CCGT LCOE comparison with 90% of gas profile covered, 2019-40



Source: BloombergNEF. Note: CCGT LCOE upper range assumption includes capex=$921,810/MW, fixed opex=$27,616/MW per year, variable opex=$2.02/MWh, capacity factor=25%; CCGT LCOE lower range assumption includes capex=$721,426/MW, fixed opex=$8,976/MW per year, variable opex=$1.5/MWh, capacity factor=70%, no carbon price, operation lifetime=35 years.

4.2 Operating characteristics

Batteries ramp faster, and are quicker to permit and build than gas plants. These characteristics will become increasingly important as more renewables are connected to the grid. Batteries have finite duration limits though, which is a major disadvantage.

- **Start-up time**: Typical open-cycle gas turbines take between 10 and 20 minutes to start up. A combined-cycle plant will normally take 30 to 60 minutes to start up. Batteries can ramp up in seconds to minutes. They also do not have minimum run and down times. As a result, they can pop in and out of the generation supply stack when needed.

Solar paired with battery storage can now provide dispatchable clean energy, competing with natural gas for resource adequacy services

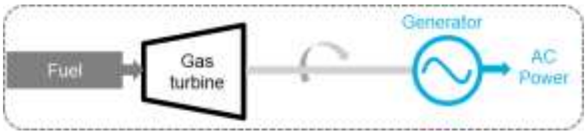
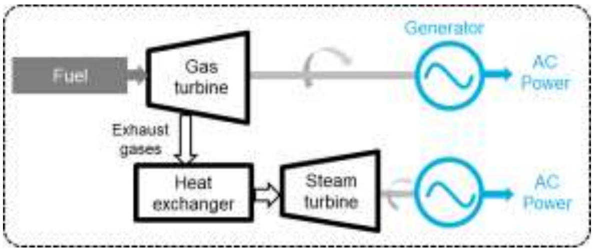
- **Ramping capability**: Typical CCGTs can ramp up 5-10% of their rated capacity per minute, while OCGTs can ramp up at 20% of the rated capacity per minute. Battery storage has the ability to do this even more quickly and precisely, given its lack of moving parts. The steeper the ramp (see California), the more likely batteries will be a preferred solution.
- **Operational constraints**: Discharge duration is storage's shortcoming. A gas plant can run continuously for hours or days, with availability limited only by fuel supply and the need for maintenance. A battery is limited by storage capacity. Most batteries in the U.S. currently have a four-hour duration or less.

Technical characteristics comparison: CCGTs versus OCGTs

U.S. gas generators use either combustion turbines (commonly referred to as CTs or OCGTs) or combined-cycle turbines (commonly referred to CCs or CCGTs).

They perform different roles and have very different generation profiles due to their distinct operational characteristics and costs (Table 1). Peak demand is often met using OCGTs, which can start and ramp quickly, whereas CCGTs are often deployed for mid-merit or longer dispatch runs.

Table 1: Comparison between OCGTs and CCGTs

	Open-cycle gas turbines	Combined-cycle gas turbines
Simplified configuration		
Descriptions	The combustion engine converts gas to mechanical energy, which spins the generator and produces electricity.	A CCGT runs two successive cycles. The additional heat recovery system and steam turbine capture the exhaust heat and convert it to electricity.
Operating characteristics and costs	• Lower capital costs (+) • Less efficient and more expensive to operate (-) • Shorter start-up time (+) • Better ramping capacity (+) • Higher emissions (-)	• High capex compared with OCGTs (-) • More efficient and less costly to run (+) • Slow to start and slower ramping compared with OCGTs (-) (Start-up time is highly dependent on steam turbine size and off-line time) • Lower emissions compared with OCGTs (+)
Designed usage and dispatch role	• OCGT units typically have faster ramping capability and therefore are quicker to respond to instantaneous changes in demand and price signals. Most OCGTs contribute primarily to peak load and run infrequently. Their high operational cost and low capital costs make them well suited to use at low annual capacity factors.	• CCGT plants retain some of the flexible characteristics of OCGTs but operate at a higher efficiency and, therefore, lower cost. Consequently, these units are dispatched more frequently than OCGTs and are often used for mid-merit and/or baseload power.

Source: BloombergNEF

Section 5. The rise of PV-plus-storage

This section provides an overview of the current project development status of PV-plus-storage in the U.S. We also compare our modelled PV-plus-storage costs against actual power purchase agreements, or PPAs, being signed.

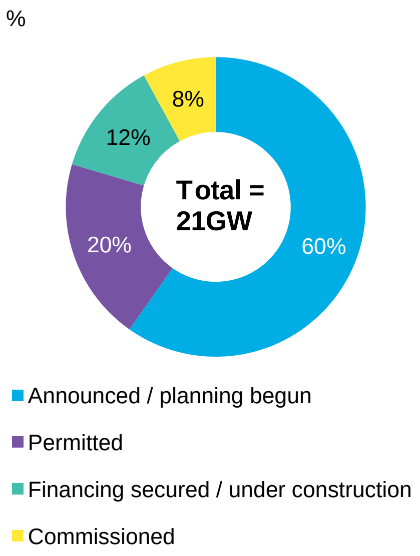
1.1. Pipeline

The known pipeline of U.S. solar-plus-storage projects continues to grow (Figure 29, Figure 30). For instance, a few major deals have been unveiled in 2020:

- Hawaiian Electric contracted 459MW of solar and 2.85GWh of energy storage to replace two coal plants totalling 435MW.
- Southern California Edison announced seven contracts on May 1, 2020, for a combined 770MW/3,080MWh of battery projects to replace gas plants. Most of the winning projects were PV-plus-storage hybrids.
- Italy-headquartered utility and generator Enel revealed a plan to add 1GW of batteries to its U.S. renewables fleet by 2022.

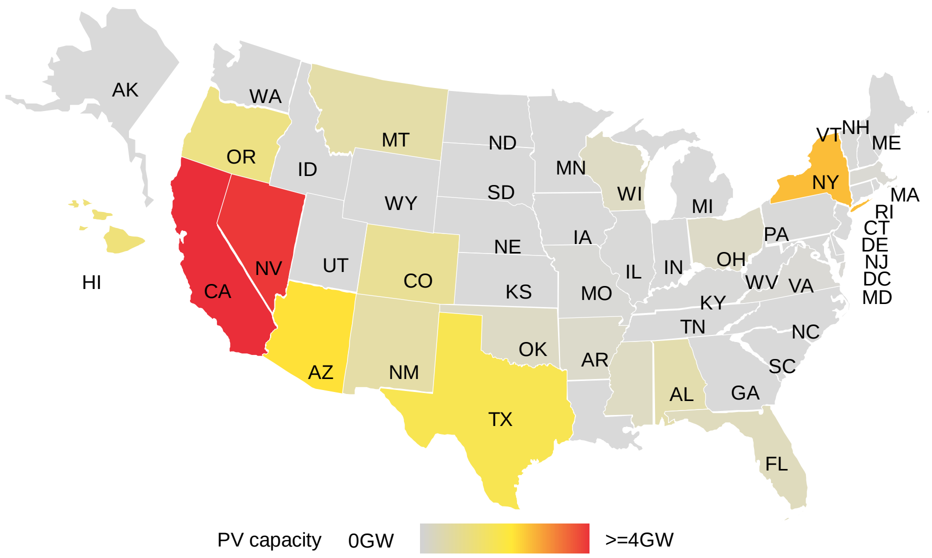
The total hybrid capacity in the interconnection queue is higher still, at 102GW.[16]

Figure 29: PVS solar capacity distribution by project status



Source: BloombergNEF. Note: Project data updated as of September 2020.

Figure 30: Geographical distribution of U.S. PVS projects by solar capacity



Source: BloombergNEF. Note: We only include immediate project pipeline tracked in the BloombergNEF renewable project database here.

[16] Bolinger, M., Wiser, R., et al, 'Hybrid Power Plants: Status of Installed and Proposed Projects', Lawrence Berkeley National Laboratary, July 2020

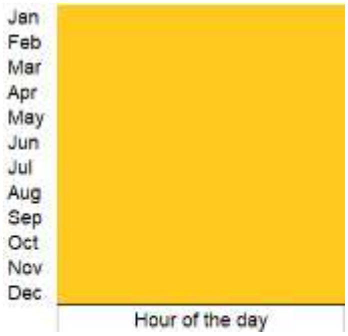
1.2. How does our PVS LCOE compare with actual PVS PPAs

We compare our regional PVS LCOEs (like-for-like displacement of CCGTs) with contracted PVS power purchase prices in the U. (Figure 31).

Our PVS LCOEs are higher than the PPA prices signed for Nevada PVS contracts, and are relatively close to Hawaii PPAs. The price differences can be explained by the contract types and associated PVS sizing requirements.[17]

In Nevada's PVS contracts, the role of PVS is to firm the PV output during regular solar generation hours (Table 2). This needs a relatively small, and therefore low-cost battery. Hawaii's variable renewable dispatchable contracts require the hybrid asset to shift solar output to firm the evening peak. The PVS project essentially mirrors a gas peakers' operation. This more valuable service requires a relatively large and higher-cost battery.

Table 2: Committed target capacity factor of various contract types

	Nevada PVS contracts	Hawaii variable renewable dispatchable project contracts	PVS modelled to fully displace regional CCGTs
Committed target capacity factor			

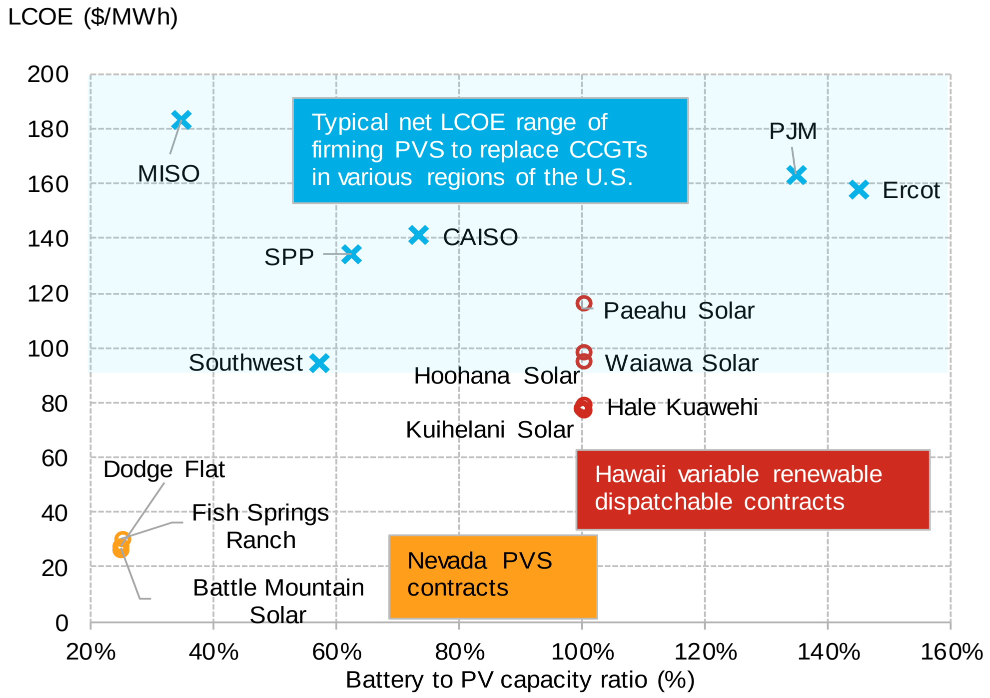
0% firmness 100% firmness

Source: BloombergNEF

In our PVS model, the hybrid system is sized to provide hourly output identical to gas plants over the entire year. The system needs to be oversized to do this, and is more costly.

17 When procuring PV-plus-storage, utilities normally outline a preferred dispatch profile of the PVS projects, a service used to be only available from thermal generators. The bidders will need to design their PVS asset to guarantee the availability around target capacity factor.

Figure 31: Comparison of modelled PVS LCOE vs. selected PVS PPA prices



Source: BloombergNEF. Note: LCOE represents like-for-like displacement of CCGT by region.

Section 6. U.S. power outlook

In this section, we show the long-term outlook for new build in the U.S., based on our proprietary least-cost capacity expansion model. This differs from the like-for-like approach we employ in the previous sections. It allows us to understand the implications of the economics section on overall system build. The findings from the NEO analysis largely support our previous conclusion that fully displacing gas will be challenging based on economics alone. However, gas plants will be utilized less over time. Their role will gradually evolve from supplying periods of highest demand, to mainly backing up renewables output. Policy could hasten their decline much more quickly than economics alone.

6.1 New Energy Outlook 2020 introduction

We primarily focus on three U.S. markets in this section, namely California, Ercot and PJM. The analysis and data is based on our *New Energy Outlook 2020* (web | terminal). The report provides an assessment of the economic drivers and tipping points that will shape the sector to 2050.

Table 3: Scenario coverage in this report

	ETS	RPS
U.S.	●	
CAISO	●	●
Ercot	●	
PJM	●	

Source: BloombergNEF Note: ETS = Economic Transition Scenario

For the near term, NEO makes market projections based on an assessment of policy drivers and BloombergNEF's proprietary project database, which provides a detailed insight into new power plant development, retrofits and retirements, by country and sector. For the medium to long term, NEO results emerge from a least-cost optimization exercise, driven by the cost of building different power generation technologies to meet projected peak and total demand, taking into account seasonal weather extremes, country by country.

The 2020 outlook has three major components:

- The **Economic Transition Scenario** (ETS) is our core economics-led scenario that employs a combination of near-term market analysis, least-cost modelling, consumer uptake and trend-based analysis to describe the deployment and diffusion of commercially available technologies. Over the long term, we remove policy drivers to uncover the underlying economic fundamentals of the energy transition. As such, this scenario does not bake in climate targets, nor does it mandate aspirational national energy policies.
- Our **NEO Climate Scenario (NCS)** investigates pathways to reduce greenhouse gas emissions to meet a 'well-below-two-degree' emissions budget. This year we have focused on a clean electricity and green hydrogen pathway.
- The final component is called **Implications for Policy**. This offers the BloombergNEF perspective on some of the most important policy areas that emerge from our ETS and NCS scenarios.

In this section, we mainly focus on the ETS scenario outlook, because we are focused on the economic comparison between these technologies. For California, the market with the most ambitious renewables target, we also provide a Renewable Portfolio Standard policy scenario for comparison (Table 3).

Methodology difference: NEO versus like-for-like displacement approach

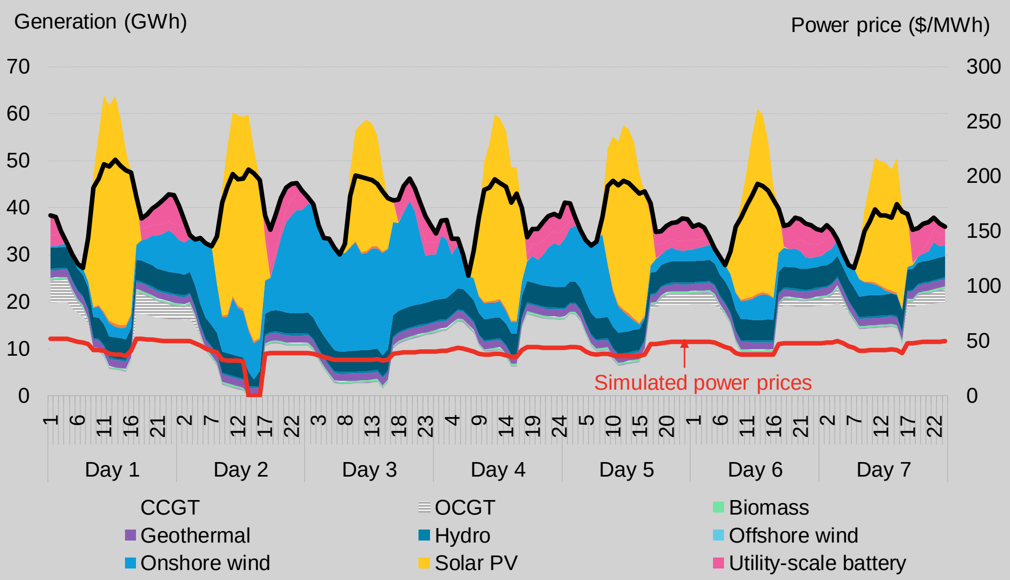
The first part of the report focuses on a direct comparison between PV-plus-storage and gas generators (both CCGTs and OCGTs). We investigate when and where PV-plus-storage assets are economically viable to fully displace gas plants on a like-for-like basis[18]. PV-plus-storage is sized to match or exceed the hourly generation output of gas units at all times throughout the year. We also consider any additional value delivered by each technology. This allows us better to understand the specific dynamics between the technologies.

Utilities' long-term investment decisions are typically made at the system level, rather than by comparing individual technologies. We replicate this exercise in our New Energy Outlook. It is a market-agnostic projection, concerned only with achieving a lowest system-cost solution. PV and storage assets are built to achieve lower overall system cost, rather than displace gas plants specifically.

In the NEO modelling, we consider all generating technology types that are commercially available. We do not separate out PV-plus-storage as an asset class, and instead allow batteries to charge from all types of energy resources as long as they are cost-competitive, rather than only from solar. Batteries are dispatched to fill the net load deficit, rather than just to match gas outputs.

Nevertheless, in NEO, batteries' dispatch behavior closely aligns with the PV-plus-storage operation pattern. They charge when there is severe solar curtailment and get dispatched when solar generation diminishes (see illustration chart below). In general, more solar build leads to higher battery deployment.

Illustration of modelled one-week power dispatch sample



Source: BloombergNEF

We only consider utility-scale technologies (i.e, batteries) in this analysis. Behind-the-meter resources such as solar and batteries are modelled separately in another proprietary model called Small-Scale PV & Storage Model (SSPVS). The output from SSPVS is used to adjust the demand profile – an input for this NEO model.

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18 For explanation of like-for-like displacement, see Section 4.1 Analytical approach.

6.2 New Energy Outlook 2020 U.S. results

Cheap renewables and batteries fundamentally reshape the U.S. electricity system.

United States

Our NEO 2020 Economic Transition Scenario suggests that cheaper renewables and gas will continue to displace coal and nuclear in the U.S. over the next three decades.

In the U.S., there were 236GW of coal and 102GW of nuclear plants online as of 2019, making up 29% of installed capacity and 42% of generation. Our modelling suggests that age and economics will push out about 100GW of nuclear and 220GW of coal over the next 30 years.[19] By 2050, both technologies have almost disappeared from the electricity mix (Figure 32 and Figure 33).

Figure 32: Cumulative installed capacity, U.S. (ETS scenario)

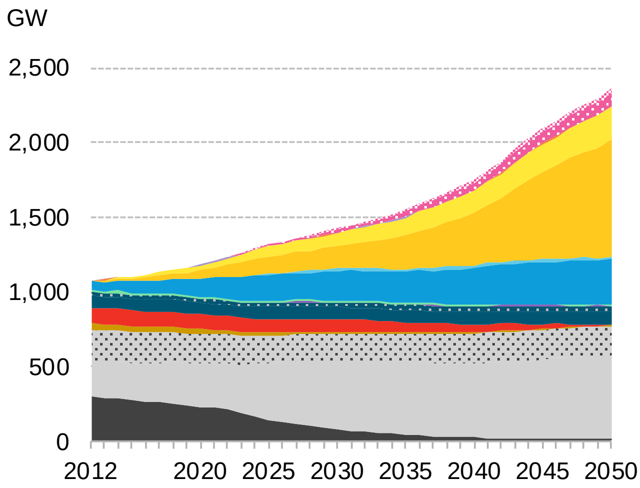
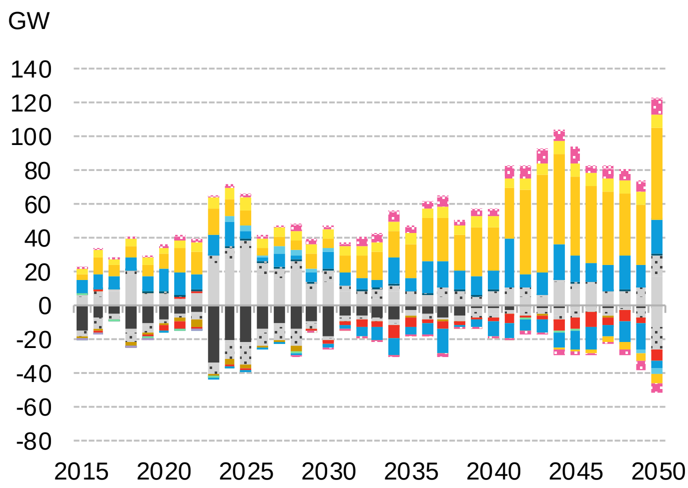


Figure 33: Capacity additions & retirements, U.S. (ETS scenario)



Coal | Combined-cycle gas | Peaker gas | Oil | Nuclear
Hydro | Pumped hydro | Geothermal | Biomass | Onshore wind
Offshore wind | Utility-scale PV | Small-scale PV | Solar thermal | Other
Utility-scale batteries | Small-scale batteries

Source: BloombergNEF

Source: BloombergNEF

Renewables including batteries increasingly dominate new-build due to their continuous cost decline. Solar and wind make up about 43% and 14% of the U.S. generation mixture by 2050. They also become the largest generation technologies in 2050, supplying roughly 57% of U.S. demand (Figure 34 and Figure 35).

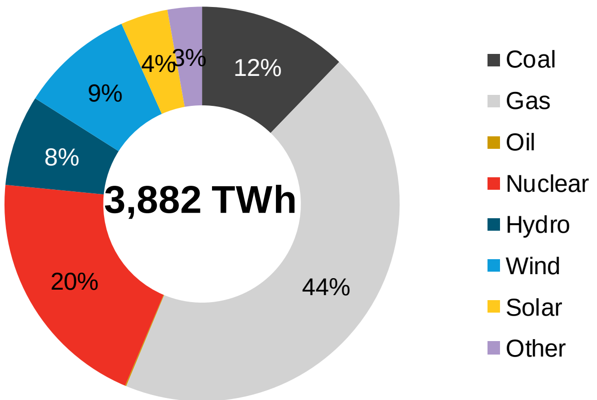
The surge of renewables and decline in coal and nuclear lead to new build of gas plants. Their flexible characteristics complement renewables' intermittency and provide firm capacity during periods of low renewables output. Cumulative CCGT capacity increases from 292GW in 2020 to

[19] For BloombergNEF clients: see *BloombergNEF, U.S. Coal and Nuclear Retirement Monitor* (web | terminal).

about 557GW in 2050. Cumulative gas peaker capacity in the U.S. remains flat over the next 30 years, averaging at about 200GW.

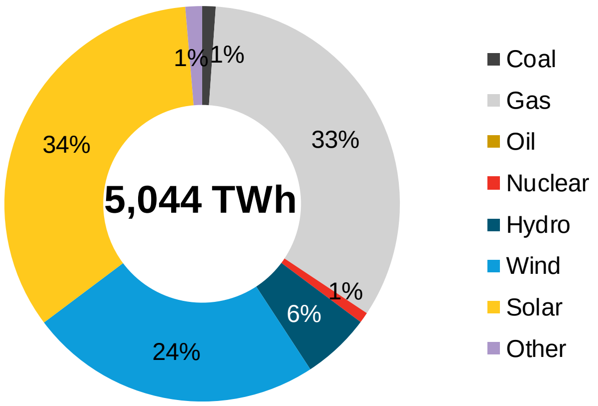
Contrary to the capacity build growth, gas generation shrinks over time (Figure 34 and Figure 35). In 2050, combined-cycle gas provides 1,600TWh, meeting 31% of demand, and OCGTs provide just 3%.

Figure 34: U.S. generation mix, 2019 (ETS scenario)



Source: BloombergNEF

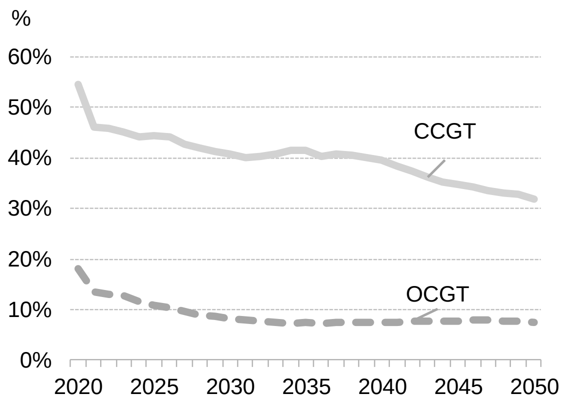
Figure 35: U.S. generation mix, 2050 (ETS scenario)



Source: BloombergNEF

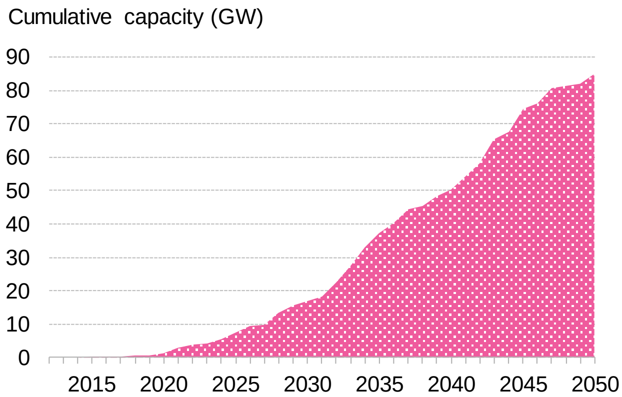
Gas generators, especially CCGTs, run for fewer hours as cheap renewables gradually eat into their generation time (Figure 36). Their role evolves to back up renewable generation instead. In our Economic Transitions Scenario, the national average capacity factor of CCGTs and OCGTs drops to 32% and 7% by 2050 in the U.S., respectively.

Figure 36: Capacity factor of gas plants, U.S. (ETS scenario)



Source: BloombergNEF

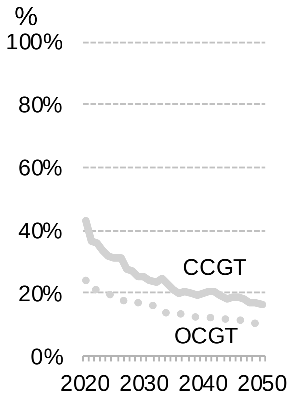
Figure 37: Cumulative utility-scale battery capacity, U.S. (ETS scenario)



Source: BloombergNEF

The renewables boom and ever-cheaper costs lead to more battery build (Figure 37). Battery prices are already down almost 90% since 2010. We expect battery pack prices to fall to $61/kWh by 2030, down some 54% from today. In our ETS scenario, the cumulative utility-scale and small-scale battery capacity reaches 85GW and 33GW respectively by 2050 in the U.S. Batteries'

Figure 38: Capacity factor of gas plants, Ercot (ETS scenario)



Source: BloombergNEF

addressable market grows further if we take into account policy drivers: Adjusting for California's Renewable Portfolio Standard increases the U.S. total to 146GW by 2050.

Ercot (Texas)

In Ercot, renewables increasingly dominate over time (Figure 39). Solar grows the most, rising from 3% of Ercot's electricity generation today to 32% in 2050. By 2050, variable renewables supply about 80% of electricity in Ercot, up roughly 50 percentage points from 2020, based on our ETS scenario modelling (Figure 40).

As renewables penetration rises dramatically in Ercot, gas plants' role evolves to provide valuable dispatchability and flexibility to the power system. CCGTs grow from 42GW to 70GW by the end of outlook, up 67%. Gas peaker generating capacity declines slightly, from 18GW in 2020 to 15GW in 2050.

The usage of both types of gas plants drops over time (Figure 38). CCGTs and OCGTs operate at low capacity factors of 16% and 8.6% in 2050, respectively. They get deployed to help provide backup across prolonged lulls in renewables generation, and seasonal peaks. In fact, curtailing generation when there is too much cheap renewable energy, and running back-up plants when there is a shortfall, is a feature of a future high-renewables electricity system.

Figure 39: Cumulative installed capacity, Ercot (ETS scenario)

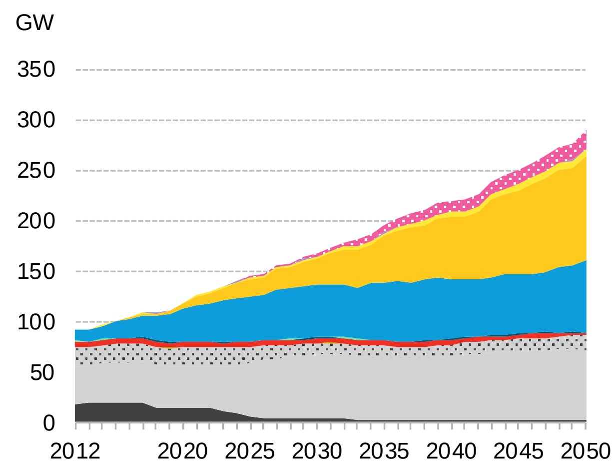
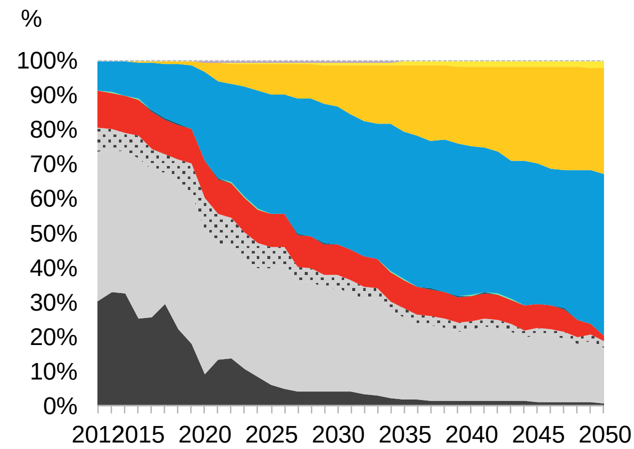


Figure 40: Power generation, Ercot (ETS scenario)



Source: BloombergNEF

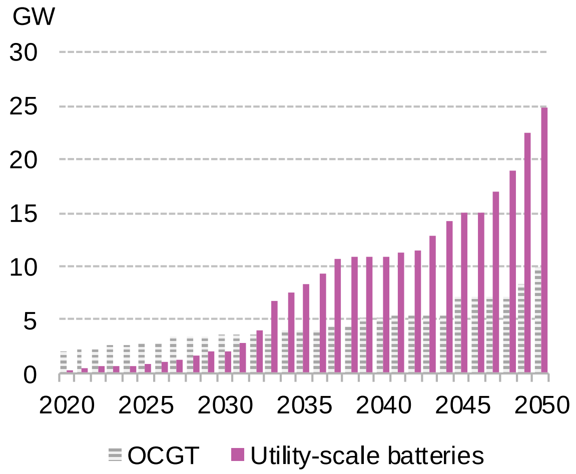
Source: BloombergNEF. Note: The dramatic drop of coal penetration in 2020 is a result of the Covid-19 pandemic[20].

[20] While both coal and gas have generally run less this year due to COVID-19, the pandemic has put further downward pressure on gas prices, pushing coal to its lowest ebb yet.

In 2050, only 35% of CCGT units located in Ercot operate for over 24 consecutive hours at any point in the year (Figure 42). This is a sharp decline from today: about 85% of CCGT units ran for at over 24 hours at least once in 2019.

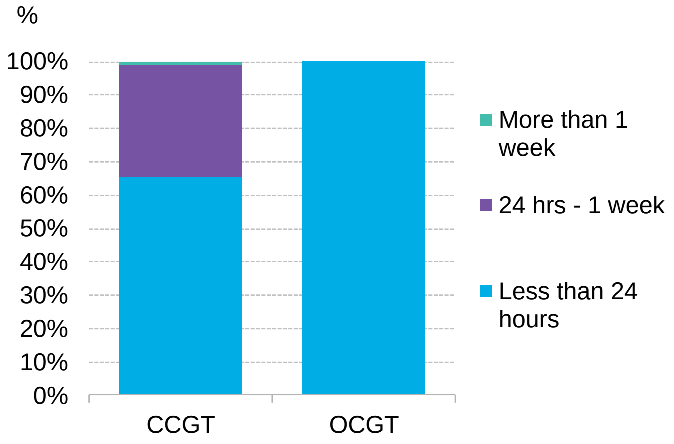
The shortened runtime and lower capacity factor of gas plants make batteries an increasingly competitive alternative. The cumulative utility-scale battery capacity exceeds the cumulative capacity of gas peakers for the first time around 2032, based on our Economic Transition Scenario. (Figure 41). By the end of the outlook, around 25GW of utility-scale batteries are required to be added to the power system in Ercot to help shift excess generation to times when the wind is not blowing and the sun is not shining.

Figure 41: Cumulative peaker gas and utility-scale battery capacity additions, Ercot (ETS scenario)



Source: BloombergNEF

Figure 42: Ercot gas generators max consecutive run time distribution, 2050 (ETS scenario)



Source: BloombergNEF

CAISO (California) – ETS scenario

As renewables get cheaper and gas prices rise, solar (both utility-scale and small-scale) and onshore wind increasingly dominate new-build in CAISO (Figure 43). By 2050, there are 111GW of PV and 33GW of wind, making up 46% and 14% of installed capacity.

Large amounts of PV also force thermal plants to ramp down, and even shut off, during the middle of the day. The additional costs incurred in ramping back up for the evening put upward pressure on power prices during those hours. Batteries can take advantage of this peaky intraday net load curve and pair with PV in sunny regions to meet demand, particularly where other peaking capacity is expensive.

In California, gas peaker capacity drops from 14GW in 2020 to about 8GW by 2050. CCGT capacity remains relatively flat over the entire timeframe in the Economic Transition Scenario. The share of generation supplied by peaker gas drops from 7% today to less than 1% by 2050.

Figure 43: Cumulative installed capacity, California (ETS scenario)

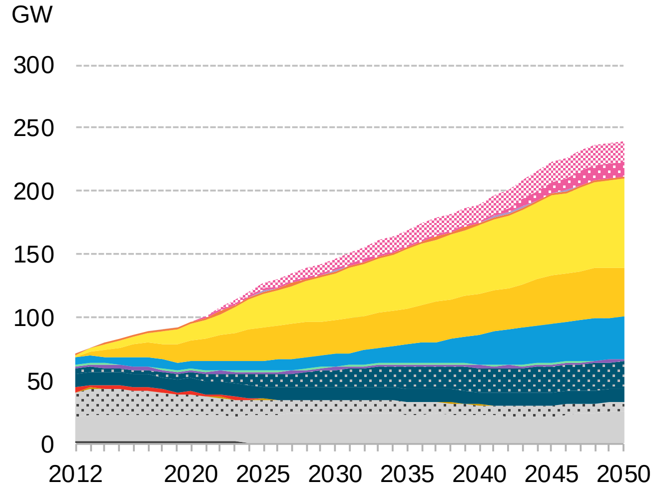
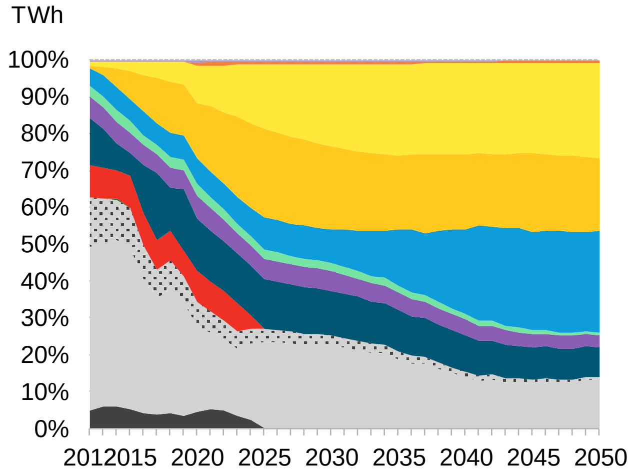


Figure 44: Power generation, California (ETS scenario)



Source: BloombergNEF

Source: BloombergNEF

Variable renewable generation in CAISO reaches about 74% of total generation by 2050, from roughly 33% in 2020. In contrast, gas generation, including both combined-cycle plants and gas peakers, drops to 14% in 2050, down over 50% from 2020.

Figure 45: Capacity factor of gas plants, California (ETS scenario)

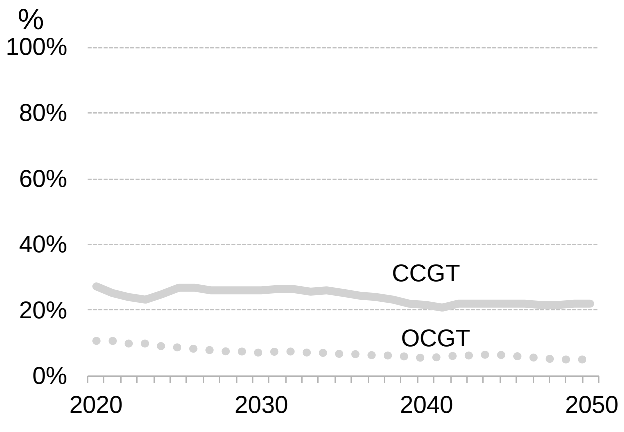
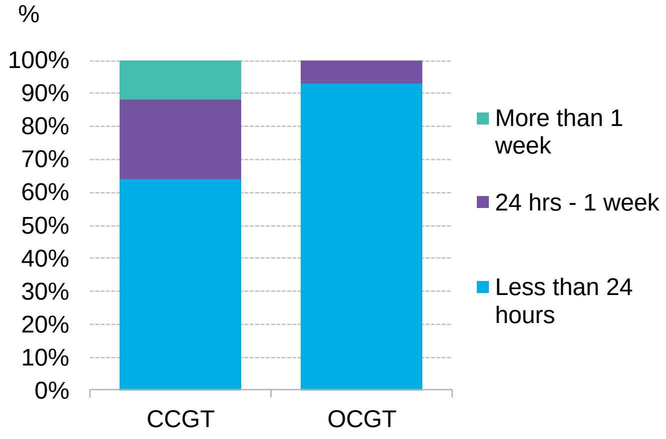


Figure 46: California gas generators max consecutive run time distribution, 2050 (ETS scenario)



Source: BloombergNEF

Source: BloombergNEF

The capacity factors of gas generators remain at sub-optimal range (Figure 45). About 35% of CCGT units in California have the max consecutive runtime of over 24 hours in 2050, compared to 90% today (Figure 46). Our modelling suggest there is a slight increase in the number of gas peakers that run for more than 24 consecutive hours in 2050. They are mainly deployed during periods of prolonged low renewable energy output.

CAISO (California) – RPS scenario

In the Economic Transition Scenario, we explicitly exclude long-term policy targets. In this additional sub-analysis, we have modelled California's Renewable Portfolio Standard, which is one of the most ambitious in the U.S.

Senate Bill 100 (SB 100) mandates 60% of energy sold in the state to come from renewables by 2030, and has a non-mandated target of 100% renewables by 2045. Between 2015 and 2019, California built 16.6GW of solar and 0.5GW of wind, however, to meet its goal, California will need to increase deployment almost fivefold by 2045 (Figure 47 and Figure 48).

Figure 47: Cumulative installed capacity, California (RPS scenario)

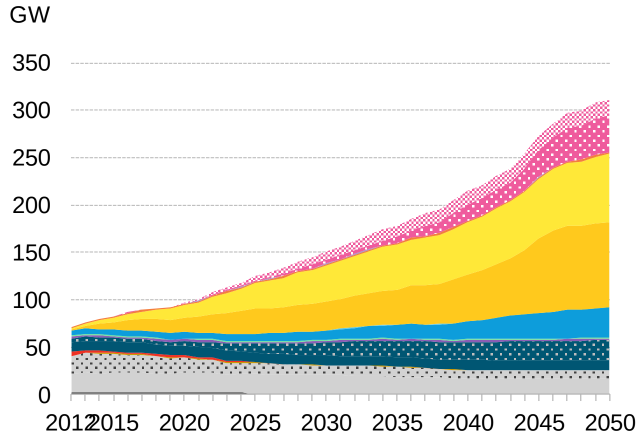
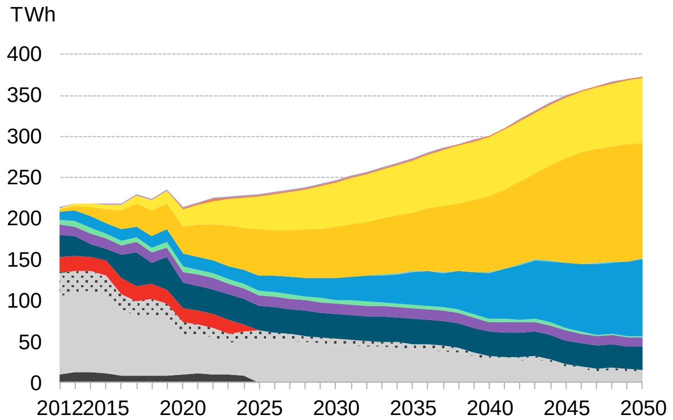


Figure 48: Power generation, California (RPS scenario)



Coal, Combined-cycle gas, Peaker gas, Oil, Nuclear, Hydro, Pumped hydro, Geothermal, Biomass, Onshore wind, Offshore wind, Utility-scale PV, Small-scale PV, Solar thermal, Other, Utility-scale batteries, Small-scale batteries

Source: BloombergNEF

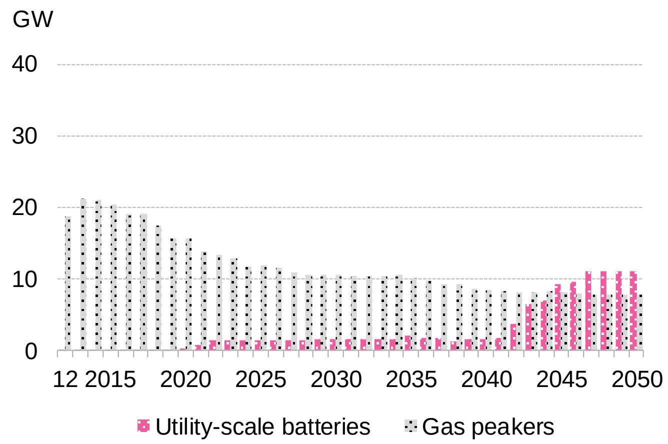
Source: BloombergNEF

In this scenario, the few existing coal and nuclear plants on the California grid retire by 2025. They are replaced by a combination of wind, solar, storage and gas. The 4GW of gas built to help replace these retirements is the only significant gas to be commissioned to 2050 in this modelling. In contrast, about 15GW of gas plants retire over the next 28 years.

Solar installation accelerates in this scenario despite facing rising curtailment. By 2030, California has 31GW of installed solar capacity. And in 2050, there are 90GW of utility-scale solar in the state – six-times the amount installed today.

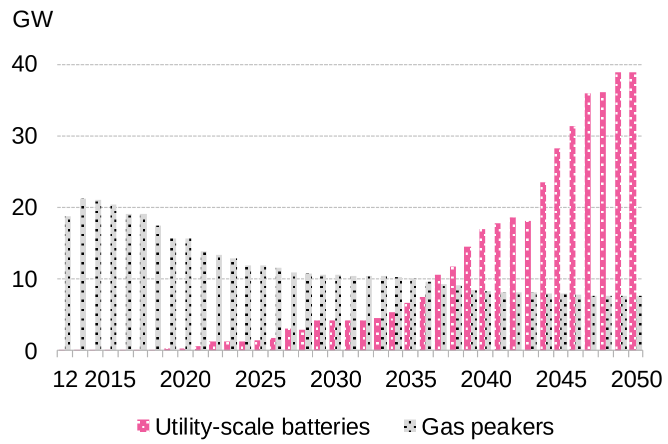
Batteries support this growth, with about 39GW of utility-scale batteries in California in 2050, charging almost exclusively from grid-tied solar power (Figure 50). Batteries improve the competitiveness of renewables by reducing curtailment and improving capacity factors, and help support renewables by discharging during period of low renewables generation. Behind-the-meter, small-scale batteries serve similar, supplementary functions to small-scale solar systems. By 2050, there are 18GW of small-scale batteries in California.

Figure 49: Cumulative peaker gas and utility-scale battery capacity additions, California (ETS scenario)



Source: BloombergNEF

Figure 50: Cumulative peaker gas and utility-scale battery capacity additions, California (RPS scenario)



Source: BloombergNEF

PJM

Gas build holds strong in PJM, with access to cheaper gas and relatively poor economics for renewables. Between 2020 and 2050, combined-cycle gas plants account for 23% of total build and gas peakers account for 8% (Figure 51). Combined-cycle gas supplies 34% of demand in 2050, and OCGTs provide an additional 2% (Figure 52).

Figure 51: Cumulative installed capacity, PJM (ETS scenario)

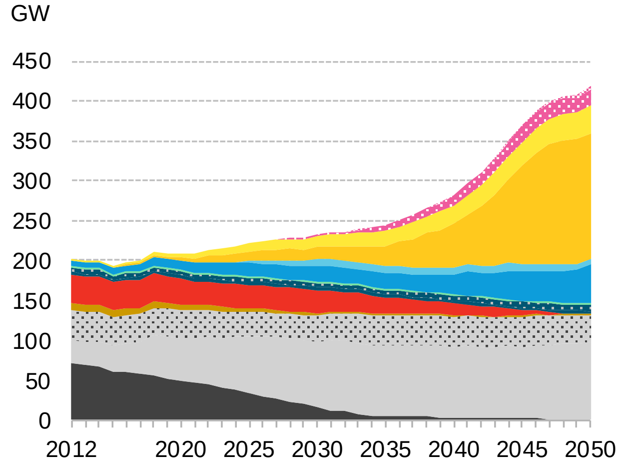
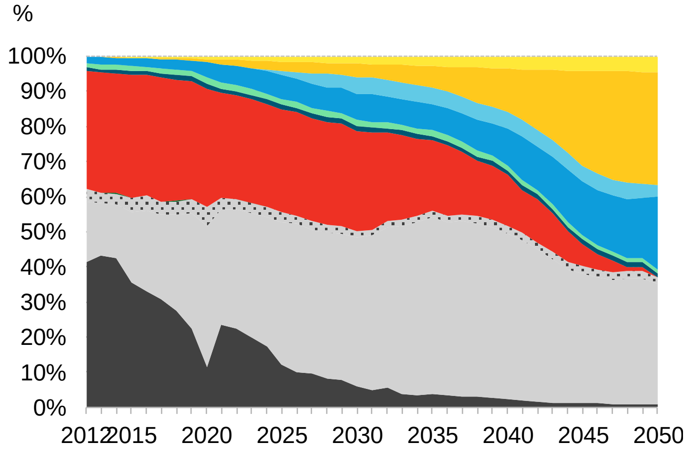


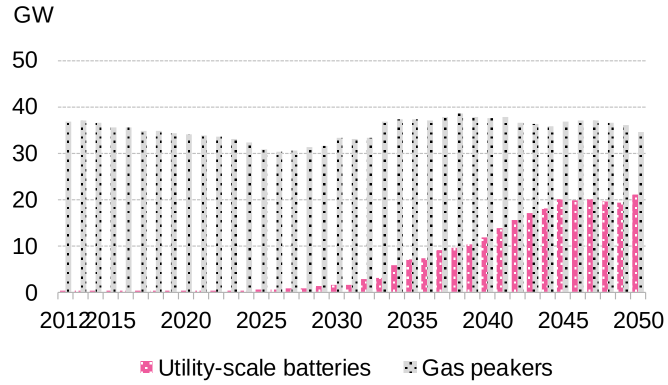
Figure 52: Power generation, PJM (ETS scenario)



Source: BloombergNEF Note: The dramatic drop of coal generation in 2020 is a result of the COVID-19 pandemic. We expect demand to recover to pre-crisis levels by the late 2020s.

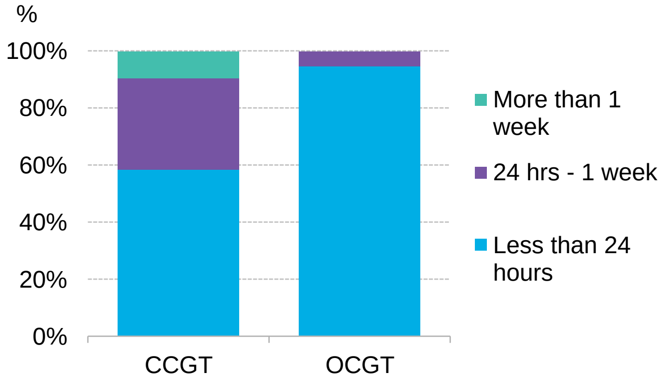
The cumulative build of utility-scale batteries reaches about 21GW in PJM, according to our model (Figure 53).

Figure 53: Cumulative peaker gas and utility-scale battery capacity additions, PJM (ETS scenario)



Source: BloombergNEF

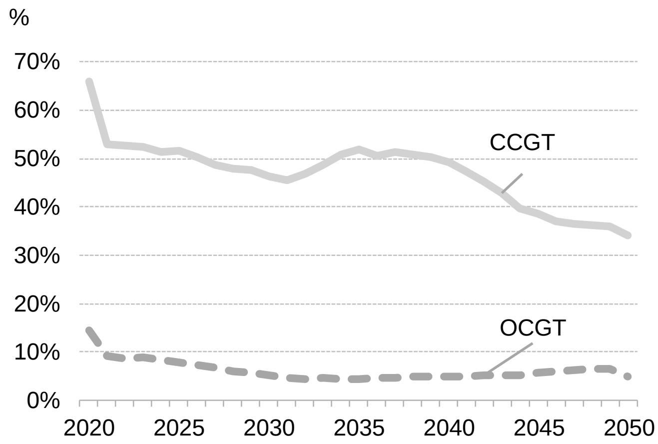
Figure 54: PJM gas generators max consecutive run-time distribution, 2050 (ETS scenario)



Source: BloombergNEF

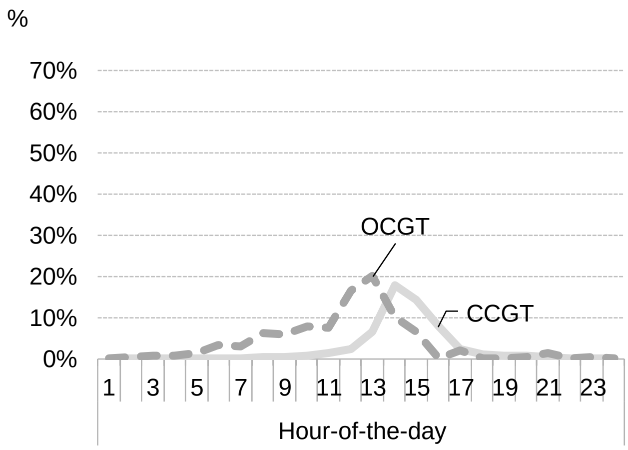
Gas generators, especially CCGTs, in PJM find themselves run less and for fewer consecutive hours in 2050 than today (Figure 55). The average capacity factor of combined-cycle gas generators in PJM declines from 65% in 2020 to about 34% in 2050. Only 40% of CCGT units in PJM ever run for more than 24 consecutive hours in 2050 (Figure 54). Their daily generation pattern is likely to evolve from consistent high output to supplying high-value hours only (Figure 56).

Figure 55: Capacity factor of gas plants, PJM (ETS scenario)



Source: BloombergNEF

Figure 56: Gas plant hourly profile simulation, PJM, 2050 (ETS scenario)



Source: BloombergNEF

Biden's clean energy scenario

U.S. President-elect Joe Biden has positioned his Climate Plan as a central part of his proposed policies and efforts for reviving the U.S. economy in the wake of the Covid-19 pandemic. Biden seeks $400 billion in federal spending on clean energy innovation over 10 years to bridge 'valley of death' financing issues.

Biden's Climate Plan calls for substantial investment in clean energy development and battery storage, amending and extending tax incentives.

He has not stated a position on extending tax credits to stand-alone energy storage. Should he favor such a policy enhancement, one vehicle would be to enact a version of H.R.2, the Moving Forward Act (likely requiring a new Democratic majority in the Senate). This would incentivize stand-alone energy storage and increase its addressable markets.[21]

In this section, we model the potential market size of utility-scale batteries assuming they are granted access to the ITC (Figure 57 and Figure 58). We run this analysis using our proprietary NEO model, assuming a battery capex reduction of 30%.

The modelling suggests the introduction of ITC for storage could almost triple the market size of batteries in the U.S. Cumulative utility-scale battery deployment increases from a total of 113GW/452GWh to 325GW/1,300GWh by 2050.

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[21] *For BloombergNEF clients, see Biden vs. Trump: U.S. Energy Policy in The Balance (web | terminal).*

Figure 57: Utility-scale battery build without federal investment tax credit

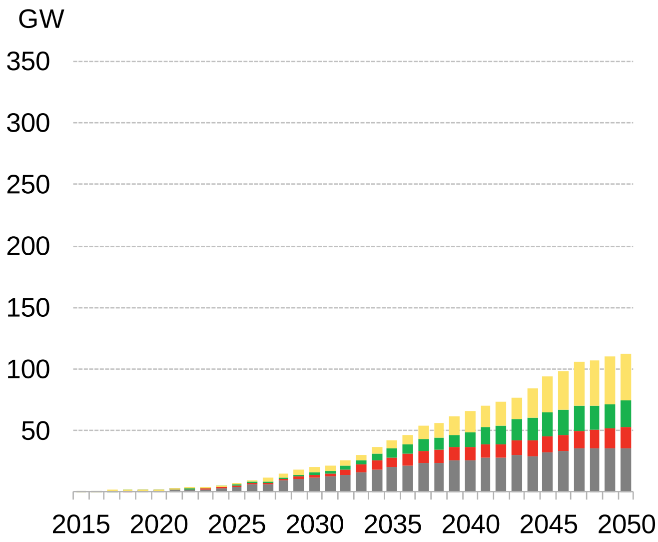
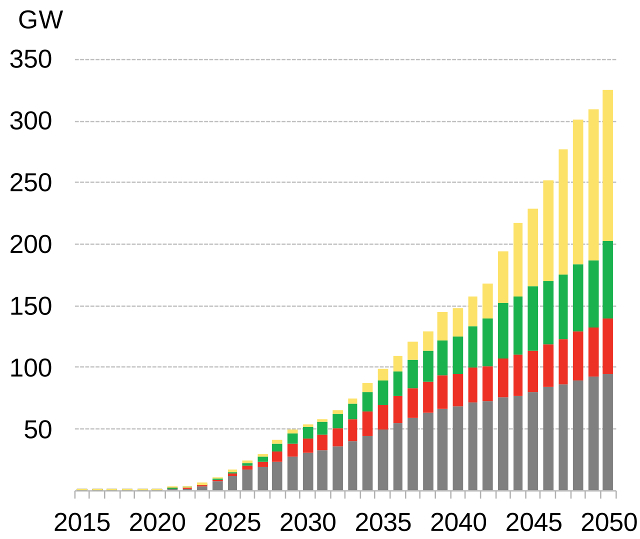


Figure 58: Utility-scale battery build with federal investment tax credit



U.S. - California U.S. - PJM U.S. - ERCOT Other U.S.

Source: BloombergNEF Note: Based on the RPS scenario for CAISO and ETS scenario for other U.S. markets

Source: BloombergNEF Note: Based on the RPS scenario for CAISO and ETS scenario for other U.S. markets

Section 7. Literature review

For further context, we have also provided a high-level comparison between the approach and findings in this note, and a few recent studies focused on the U.S.

Rocky Mountain Institute: *The Growing Market for Clean Energy Portfolios*

- **Approach and scope:**
  - In scope and approach, this 2019 report more closely resembles our New Energy Outlook, since it looks at how portfolios of clean energy resources can displace new-build and existing gas power plants in the U.S. It does not provide a detailed comparison of how PV-plus-storage will affect gas operations specifically.
  - The RMI analysis "requires each portfolio to provide the same (or more) monthly energy as the proposed gas plant, match or exceed the gas plant's expected availability during the peak 50 demand hours (net of renewable generation), and provide the same level of grid flexibility." Our assessment matches gas profiles throughout every hour of the year. This sometimes results in longer sequences of consecutive run hours.
  - The RMI study assess 88 gas plants across the U.S. and then aggregates their results. Our report is also based on bottom-up analysis of specific plants but we compare the options at the regional level to highlight differences in the competitiveness of PVS and gas across different markets.
- **Findings:**
  - The RMI report concludes that clean energy portfolios are likely to undercut the operating costs of over 90% of proposed new combined-cycle capacity by 2035, creating stranded asset risk for investors. The aggregate composition of a clean energy portfolio in the RMI study to replace the proposed 56GW of pipeline combined cycle in the U.S. is 59GW solar, 24GW energy storage, 22.5GW wind, 35GW energy efficiency and 33GW demand flexibility.
  - In our New Energy Outlook, we found that it is challenging for the combination of wind, solar, energy storage and demand side flexibility fully to displace gas power plants on a least-cost system basis. The analysis in this research note supports that assessment: Full displacement of high running-hour, firm capacity like CCGTs with PV-plus-storage is still highly challenging despite the latter's falling cost. The difference in findings is likely to be partly due to different assumptions on the role of energy efficiency and demand flexibility. We also found that hourly modeling revealed a need for more gas than when we modelled based on representative days and hours.
  - We do not see a clear, lowest-cost path to completely displace gas power generation in the U.S., unless seasonal storage assets become commonplace. Despite this difference, we do agree with many of the RMI study's key conclusions. Increasing combinations of renewable energy, energy storage and demand-side flexibility will fundamentally alter the use case for new-build gas assets in the U.S. This could result in stranded or uneconomic gas assets and a risk that this cost will be borne by ratepayers, or in losses for merchant operators.

National Renewable Energy Laboratories: *The Potential for Battery Energy Storage to Provide Peaking Capacity in the United States*:

- **Approach and scope:**
  - This June 2019 paper looks at the total addressable market for batteries of different durations to provide peak capacity. It also looks at how higher renewables penetration will increase the potential for energy storage.
- **Findings:**
  - The report finds that there is a 28GW addressable market for four-hour batteries, based on current grid conditions and demand patterns. Increasing penetration of PV increases the market size to over 50GW.
  - The scope of NREL's report is different to both this note, and our New Energy Outlook. The conclusions are aligned with our understanding of the market.

Carnegie Mellon Tepper School of Business, Fluence: *Solar + Storage as a Mid-Merit, Utility-Scale Generating Asset*

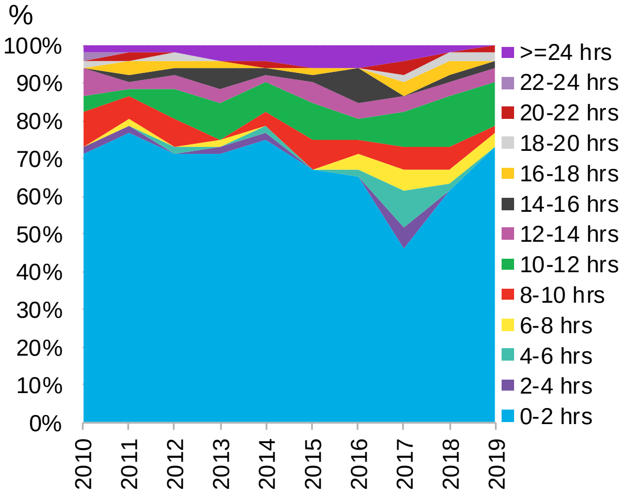
- **Approach and scope:**
  - This 2018 study was completed by a group of MBA students at Carnegie Mellon's Tepper School of Business, sponsored by Fluence. They asked whether PV-plus-storage could compete with mid-merit, load-following combined-cycle power plants in the U.S. It compares the plants based on a net LCOE, which is similar in principle to the approach in our study, although the inputs differ. The main difference in approach is that the Carnegie study uses generation profiles based on hourly output by the typical combined-cycle plant. We review how gas power plants operated throughout the whole year and have sized our PVS plants accordingly. The economic metrics adopted are also slightly different. In our note, we mainly look at levelized cost of energy without factoring in additional revenue streams such as ancillary services, to avoid potential uncertainties.
- **Findings:**
  - We share a similar approach to comparing gas power plants and PV-plus-storage. The main difference is that we believe using average generation profiles (rather than looking at full-year operations) overestimates the value of PVS compared to gas generation.

Appendices

Appendix A. Regional gas plants' operations

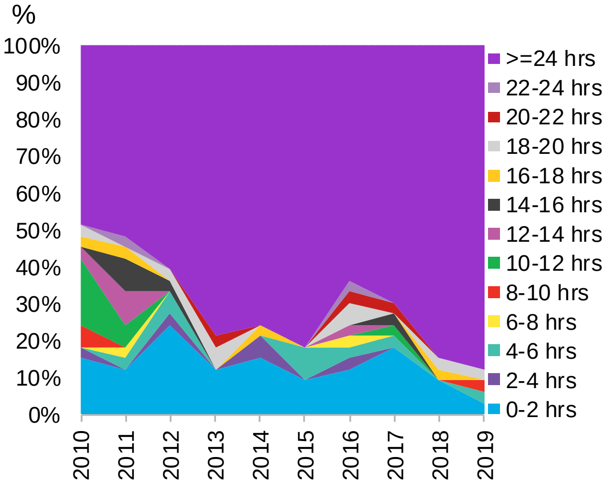
A.1. Gas plants' max consecutive operation duration by region

Figure 59: Distribution of California OCGTs' annual max consecutive running time by number of plants



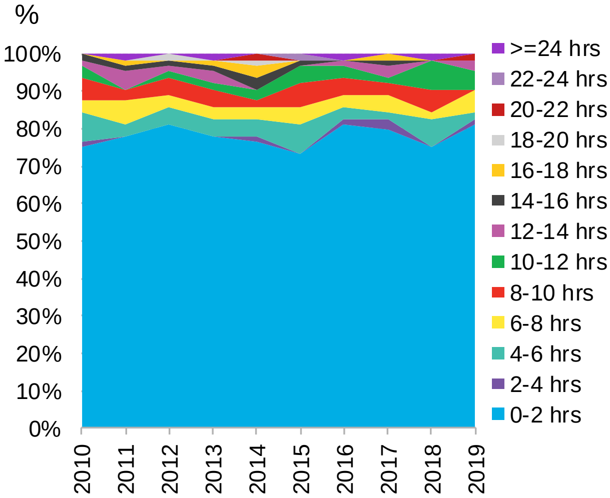
Source: BloombergNEF

Figure 60: Distribution of California CCGTs' annual max consecutive running time by number of plants



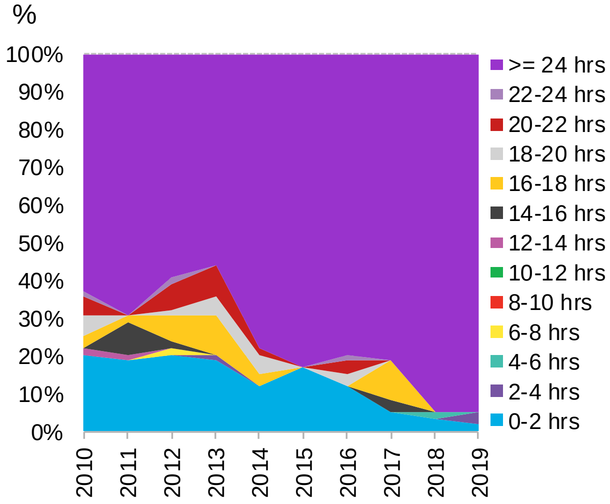
Source: BloombergNEF

Figure 61: Distribution of Ercot OCGTs' annual max consecutive running time by number of plants



Source: BloombergNEF

Figure 62: Distribution of Ercot CCGTs' annual max consecutive running time by number of plants



Source: BloombergNEF

Appendix B. Methodology and notes

B.1. Factors taken into account for modified PVS LCOE calculation

Table 4: Additional values or revenue streams considered for modified PVS LCOE metric

Element	Gas units' eligibility	PVS' eligibility	Included in modified LCOE?	Our reasoning
Capacity payment	Yes	Yes	No	• Both PVS and gas plants can provide resource adequacy, and can be eligible for capacity payments if available. • We exclude capacity payments from the modified LCOE for a few reasons: 1) Capacity payment mechanisms differ from one market to another and are subject to change; 2) As we size our PVS assets to achieve the same dispatchability as the gas fleet, it is reasonable to assume they have a similar capacity value.
Ancillary service	Yes	Yes	No	• Ancillary service market payments may serve as an important revenue stream for both PVS and gas plants. Both technologies can provide a suite of grid services such as frequency regulation and reserves. • In this study, ancillary services are excluded. This is because we are reviewing a much larger addressable market (energy and capacity) and did not want the findings to rely on a relatively small revenue stream.
Cycling costs	Yes	No	No	• Cycling cost is an additional expense associated with thermal generators' cyclical operation. As more renewables are added to the grid, thermal generators will need to cycle more often to accommodate them. • Cycling costs can be seen as a negative cost (or positive revenue) to PVS assets when compared to gas units. • However, as cycling costs are still minor and often overlooked in utilities' integration studies, we do not account for any savings here.
PVS' excess electricity sales	No	Yes	Yes	• In our analysis, we assume PVS assets' excess electricity will be sold to the grid one hour before they start to charge every day. This will lower PVS' solar curtailment, while still meeting the generation profile of gas plants. • The discharge amount is calculated as the excess electricity left in the battery plus expected solar generation of the day, minus gas generation for the day. The discharge amount is limited to the max battery discharge capacity and batteries' state of charge. • This electricity amount is then multiplied by the historical power prices when the electricity is discharged. This normally takes places in the morning – one hour before the battery switches to charging mode. We assume the battery operator has perfect foresight of expected gas generation and solar output for the day. This excess electricity accounts for less than 10% of total output and is sold at a low price. We believe this assumption should not severely skew the overall LCOE assessment (see Figure 37 for illustration).

Source: BloombergNEF

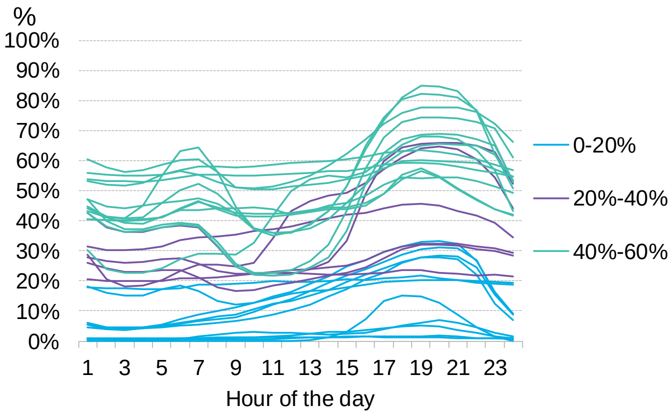
B.2. Some further explanation on research methodology

We provide some further explanation of our research method below:

- **Battery duration assumption**: In this analysis, we only modelled four-hour batteries, the typical size deployed in the U.S. We also ran this analysis with different battery duration assumptions (including two-hour and six-hour). The results do not differ significantly from the four-hour batteries.
- **Regional-level assessment**: We employed regional generator profiles instead of individual plant profiles when estimating the minimum PVS sizing requirement for different regions. This assumption comes with limitations, as individual solar / gas plants may operate differently from the regional profile. However, as individual power profiles are more subject to change and can introduce numerous uncertainties, we used the regional profile for simplification and better regional representation.

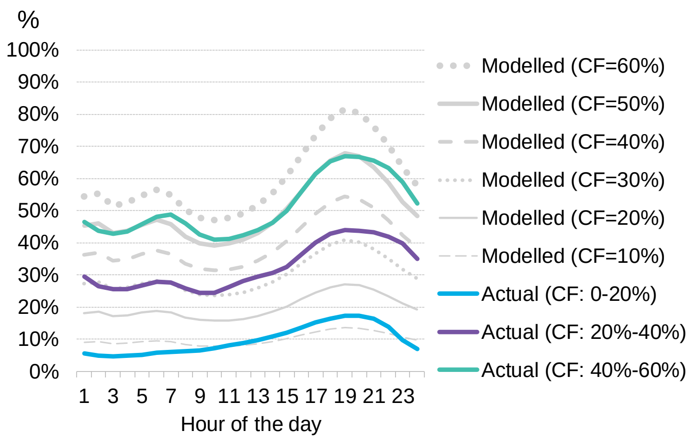
  We normalized (scaled) the regional profile to different capacity factor levels, to represent gas plants operating at different capacity factors. This is not perfect either: gas turbines operating at one capacity factor may have different operational patterns from those operating at a different capacity factor. In order to validate our method, we compare our modelled regional profiles with the actual gas plant profiles grouped into different capacity factor ranges (see CAISO's sample in Figure 63 and Figure 64). Overall, they look similar, meaning our approach should not introduce significant bias.

Figure 63: CAISO's individual CCGT profiles by average capacity factor ranges



Source: BloombergNEF, EPA CEMS, EIA

Figure 64: CAISO's actual average CCGT profiles versus modelled regional profiles



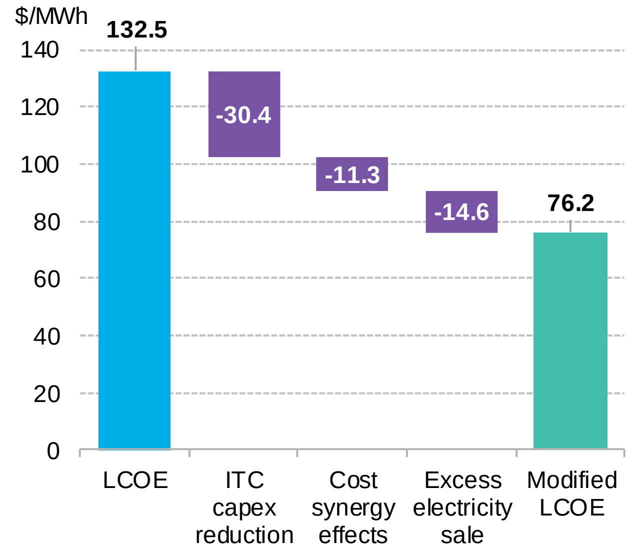
Source: BloombergNEF, EPA CEMS, EIA

- **Single-year data**: We used historical single-year (2019) data to represent regional solar and gas performance. However, generators' profiles could differ from one year to another, resulting in different PVS sizing requirements. We chose not to use the average generation profile calculated based on multiple years, as this could potentially dilute the extreme conditions – a determinant factor of minimum PVS sizing.

B.3. Key elements of PVS cost assumption

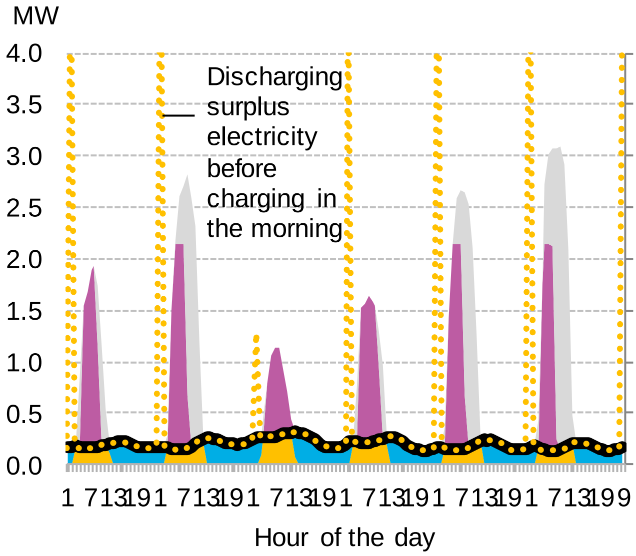
When calculating the PVS LCOE, we accounted for factors including ITC, co-located project cost synergies, and revenues from the sale of surplus electricity. The first two elements will affect PVS' capex assumption and the last element was used as a negative annual opex cost.

Figure 65: Illustration of modified LCOE calculation sample



Source: BloombergNEF. Note: Above chart showed a sample of PVS LCOE calculation. In this case, we assume an 80MW/320MWh of battery paired with a 100MW solar asset.

Figure 66: Illustration of surplus electricity sale – a negative cost value goes into LCOE metric



Source: BloombergNEF

- **Investment Tax Credit:** A U.S. PVS project is eligible to receive an ITC equal to 30% of eligible capex (including both PV asset and battery asset), if more than 75% of charging input comes from renewable energy. We assume PVS systems installed by 2022 are safe-harbored and will be eligible for the full subsidy payment until it expires.
- **Co-located project cost synergies:** Co-location enables sharing of the same hardware, balance of plant work, interconnection costs, land acquisition costs and O&M costs between PV and energy storage systems. In this note, we assume the solar capex is about 15% cheaper and the battery is 10% cheaper for a co-located project, compared to that of two stand-alone assets (see Table 5 for details).
- **Revenue from sale of surplus electricity:** As we illustrated previously, the surplus electricity will be discharged one hour before sunrise and charging starts, on a daily basis. The batteries are discharged at the price of 2019 historical power prices of that hour. The battery discharge amount is limited to the battery nameplate capacity and state-of-charge (SoC). We assume the battery operator has perfect foresight of the electricity needs and solar generation of the day.

B.4. LCOE input assumptions

Table 5: EPVAL inputs for various LCOE calculation scenarios

	LCOE	LCOE with ITC benefits	LCOE with ITC benefits and cost synergy	Net LCOE (with ITC reduction, cost synergy, excess electricity sale)
PVS cost information				
Solar plant capex ($/MW)	1,000,000	1,000,000	850,000	850,000
Solar opex ($/MW/Yr)	11,886	11,886	11,886	Varies depending on project
Battery duration	4 hours	4 hours	4 hours	4 hours
Battery 1 capex ($/MWh)	328,000	328,000	295,000	295,000
Battery 2 capex ($/MWh)	210,496	210,496	189,000	189,000
Battery opex % of capex (%)	1%	1%	1%	1%
U.S. investment tax equity financing inputs				
ITC equity structure	N/a	Partnership flip	Partnership flip	Partnership flip
ITC tax equity investor contribution (%)	N/a	40%	40%	40%
Investment Tax Credit (%)	N/a	30%	30%	30%
Tax equity investor Ebitda pre-flip (%)	N/a	10%	10%	10%
Tax equity investor Ebitda post-flip (%)	N/a	5%	5%	5%

Source: BloombergNEF. Note: We assume PVCsiNo Track PV plant and lithium-ion battery, 30 years of PV asset lifetime and one replacement of battery assets within the 30-year project lifetime.

Table 6: OCGTs' regional cost inputs

Region			Capex		Opex
	Development cost ($/MW)	Balance of plant cost ($/MW)	Equipment cost ($/MW)	Fixed opex ($/MW/Yr)	Variable opex ($/MWh)
Ercot	115,096	325,072	179,101	12,592	3.48
PJM	139,932	395,218	217,749	11,750	3.48
CAISO	156,288	441,413	243,200	16,232	3.49
Southwest	126,605	357,579	197,011	10,908	3.50
SPP	122,365	345,603	190,413	11,917	3.50
MISO	121,154	342,181	188,526	11,388	3.51

Source: BloombergNEF

Table 7: PVS minimum sizing breakdown

Type	Category	CAISO	Ercot	MISO	PJM	Southwest	SPP
OCGT (100% firming)	Cross-over point gas capacity factor (%)	15%	12%	15%	8%	8%	5%
	Solar size to displace 100MW gas plant (MW)	173	125	399	136	66	85
	Battery size to displace 100MW gas plant (MW)	218	117	189	104	55	47
CCGT (100% firming)	Cross-over point gas capacity factor (%)	15%	8%	14%	8%	9%	7%
	Solar size to displace 100MW gas plant (MW)	210	90	320	90	80	100
	Battery size to displace 100MW gas plant (MW)	150	130	110	120	50	60
CCGT (95% firming)	Cross-over point gas capacity factor (%)	40%	18%	18%	18%	16%	14%
	Solar size to displace 100MW gas plant (MW)	260	119	203	186	96	92
	Battery size to displace 100MW gas plant (MW)	180	79	72	102	68	55
CCGT (90% firming)	Cross-over point gas capacity factor (%)	50%	21%	19%	20%	18%	17%
	Solar size to displace 100MW gas plant (MW)	258	112	160	153	99	89
	Battery size to displace 100MW gas plant (MW)	200	77	67	87	65	56

Source: BloombergNEF. Note: The PVS sizing represents the minimum sizing at cross-over point. All batteries are four-hour duration in this analysis.

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