



THE GROWING MARKET FOR CLEAN ENERGY PORTFOLIOS

ECONOMIC OPPORTUNITIES FOR A SHIFT FROM NEW GAS-FIRED GENERATION TO CLEAN ENERGY
ACROSS THE UNITED STATES ELECTRICITY INDUSTRY



AUTHORS & ACKNOWLEDGMENTS

Authors

Charles Teplin, Mark Dyson, Alex Engel, and Grant Glazer

** All authors from Rocky Mountain Institute unless otherwise noted.*

Contacts

Charles Teplin, cteplin@rmi.org

Mark Dyson, mdyson@rmi.org

Suggested Citation

Charles Teplin, Mark Dyson, Alex Engel, and Grant Glazer. *The Growing Market for Clean Energy Portfolios: Economic Opportunities for a Shift from New Gas-Fired Generation to Clean Energy Across the United States Electricity Industry*. Rocky Mountain Institute, 2019, <https://rmi.org/cep-reports>.

Images courtesy of iStock unless otherwise noted.

Acknowledgments

The authors thank the following individuals/organizations for offering their insights and perspectives on this work:

- Dan Cross-Call, Rocky Mountain Institute
- Joe Daniel, Union of Concerned Scientists
- Jeremy Fisher, Sierra Club
- Rachel Gold, American Council for an Energy-Efficient Economy
- Leia Guccione, Rocky Mountain Institute
- Elizabeth Hartman, Rocky Mountain Institute
- Chelsea Hotaling, Energy Futures Group
- Maggie Molina, American Council for an Energy-Efficient Economy
- Mike O'Boyle, Energy Innovation
- Ric O'Connell, GridLab
- Brendan Pierpont, Sierra Club
- John Romankiewicz, Sierra Club
- Anna Sommer, Energy Futures Group
- Nathan Wyeth, Sunrun
- Todd Zeranski, Rocky Mountain Institute
- Xin Zhang, Rocky Mountain Institute

ABOUT US



About Rocky Mountain Institute

Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables. RMI has offices in Basalt and Boulder, Colorado; New York City; the San Francisco Bay Area; Washington, D.C.; and Beijing.

Funding from the Rudy and Alice Ramsey Foundation supported this work



TABLE OF CONTENTS

EXECUTIVE SUMMARY	05
1: INTRODUCTION	14
2: MARKET SNAPSHOT	17
3: METHODOLOGY	21
4: FINDINGS	31
5: IMPLICATIONS & RECOMMENDATIONS.....	46
6: TECHNICAL APPENDIX	51

EXECUTIVE SUMMARY



EXECUTIVE SUMMARY

Clean energy is now cost-competitive with new gas-fired generation

For more than a decade, gas-fired power plants have dominated new generation investments for the US grid, and the trend is set to continue. Public announcements include approximately \$70 billion of planned gas-fired generation investment through the mid-2020s.

However, due to dramatic price declines of wind, solar, and storage (WSS) technologies, clean energy portfolios (CEPs)—optimized combinations of WSS and demand-side management—are now similar in cost to new gas-fired power plants. Further, recent CEP projects prove that these clean technologies can reliably meet grid needs. As a result, new gas investments have slowed.

This study compares the economics of CEPs against every proposed gas plant in the United States

In 2018, RMI released [*The Economics of Clean Energy Portfolios*](#), which introduced a methodology for comparing CEP costs against new gas-fired generation and showcased four case studies across the United States. The present study expands upon the original work. We systematically optimize least-cost combinations of region-specific WSS, efficiency, and demand flexibility to provide grid services equivalent to every proposed combined-cycle and combustion turbine gas project in the United States. Our approach 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 approach forces CEPs to match the grid services of gas generation. The model therefore forces CEPs to compete only on gas generation's own metrics, and omits other clean technology benefits, such as the network



value of distributed technologies, the reduced risk of smaller projects, and carbon emissions reductions. Our modeling approach treats each proposed power plant independently, and assesses the economics of a CEP alternative based on how gas plants would be used when built with currently-planned growth in renewables. As such, our results are applicable to the economics and risks of near-term gas power plant investments, rather than the long-term role of gas generation in a future with a very high share (i.e., >50 percent) of renewable energy.

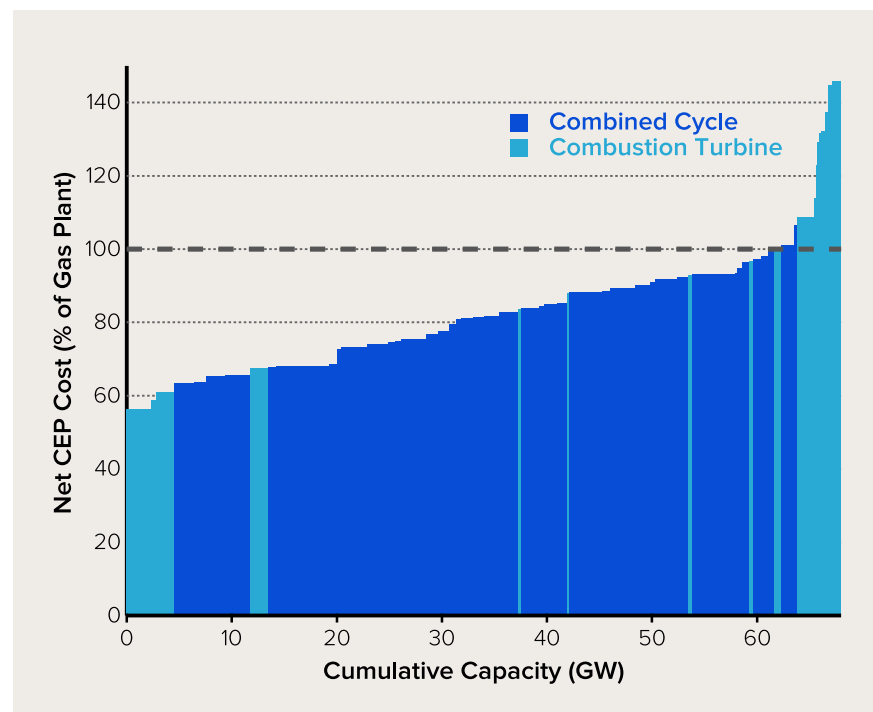
The analysis presents compelling evidence that 2019 represents a tipping point, with the economics now favoring clean energy over nearly all new US gas-fired generation. We present seven key findings:

1. CEPs are lower cost than 90 percent of the proposed 68 gigawatts (GW) of gas-fired power plant capacity

We find that CEPs are lower cost than 90 percent of proposed gas-fired generation at the proposed plant's in-service date (Figure ES 1). Investment in CEPs instead of new gas capacity would save customers over \$29 billion and reduce CO₂ emissions by 100 million tons (MT)/year—equivalent to ~5 percent of current annual emissions from the power sector.¹

FIGURE ES 1

NET CEP COST AS PERCENTAGE OF EQUIVALENT GAS PLANT COSTS AT PLANNED GAS BUILD IN SERVICE YEAR²



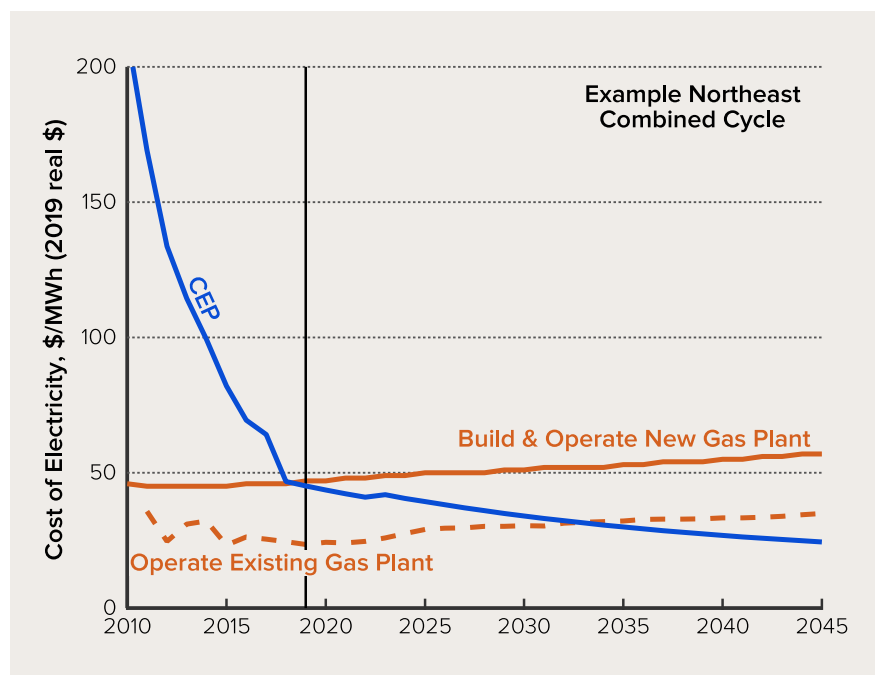
¹ Each case is analyzed independently, but we present aggregate results in this and subsequent findings by summing case study results across all 88 gas plants. This is reasonable because the 88 plants would 1) make up only ~7 percent of installed US generation capacity, limiting the impact of interactions between CEPs, and 2) we restrict the selection of CEP resources to ensure they are distinct from resources chosen in other CEPs.

² Net cost is shown here as total net present costs of the CEP compared to the gas plant, net of value from energy provided by the CEP and not provided by the gas plant; see Methodology section for details.

2. 2019 represents a tipping point for CEP economics

FIGURE ES 2

HISTORICAL AND PROJECTED EVOLUTION OF CEP COSTS



Note: The “kink” in the CEP cost curve in 2018 reflects the difference between historical cost decline rates for renewables and storage, and the much more moderate future cost decline rates predicted by technology analysts.

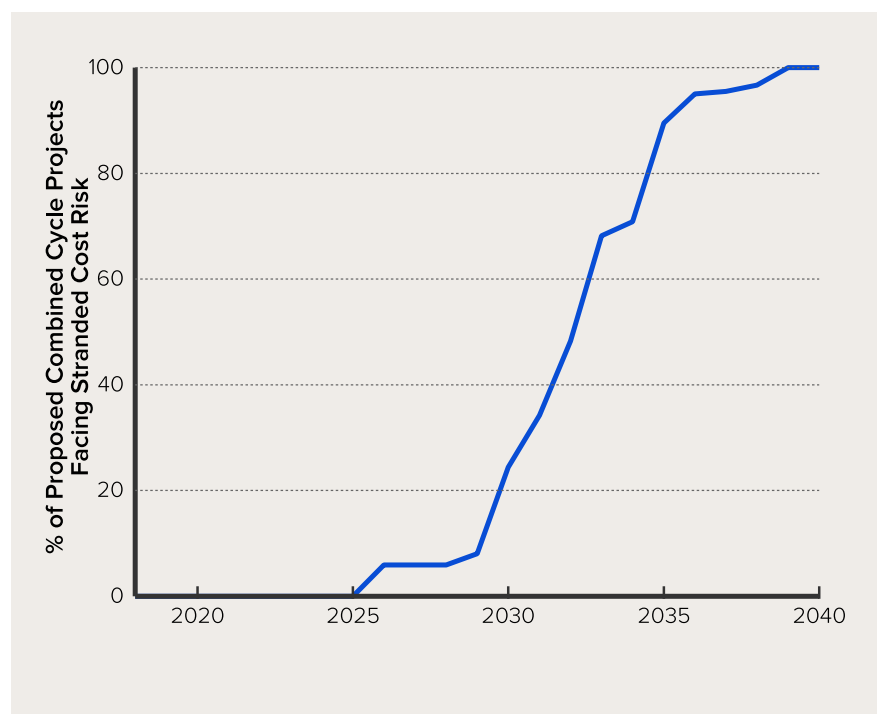
We find that the economics of new generation technologies in the United States are at a tipping point. Figure ES 2 compares the historical and projected costs of a representative CEP and the new combined-cycle plant it could replace for the years 2010 through 2045. The CEP’s cost has declined by approximately 80 percent in the past decade, and, as of 2019, is lower than the costs of building and operating a new gas plant. Further, this typical CEP is likely to outcompete just the go-forward operating costs of a combined-cycle gas generator by the early 2030s. A number of factors, including continued fast clean technology cost declines or carbon pricing, would accelerate this timeline.



3. CEPs are likely to undercut the operating costs of over 90 percent of proposed new combined-cycle capacity by 2035, creating stranded asset risk for investors

FIGURE ES 3

PERCENT OF PROPOSED COMBINED-CYCLE GAS TURBINES (CCGTs) FACING STRANDED COST RISK IN EACH YEAR 2020–2040



Just as falling natural gas prices have limited the economic life of legacy coal assets and led to a wave of coal plant retirements, falling clean energy costs are likely to compromise the economic position of gas generation. For each proposed combined-cycle plant, we estimate the year in which the plant's operating costs will be higher than the costs of a new-build CEP that provides the same services (Figure ES 3). We find that nearly all combined cycles will be economically precarious well before they are fully paid for.³ In 2035, it will be more expensive to operate 90 percent of proposed combined-cycle generation than to build new CEPs. We note that this analysis likely understates the economic case for future clean energy economics because it assumes a dramatic slowing of clean energy cost declines (Figure ES 2) and ignores the impact of potential local or national climate policies.

These economic trends imply significant risk for gas project investors. If gas generators are cost-effectively replaced by CEPs at a cost savings to customers, investors will be unable to meet the revenue targets needed to pay off the remaining gas plant book value and may not be able to cover outstanding debt or provide return on equity to investors. If planned projects are built, investors will likely face tens of billions of dollars' worth of stranded assets in the 2030s, as running these gas plants quickly becomes more expensive than building new CEPs.

³ Conservatively assuming a 20-year planned economic life

4. The case for CEPs is strong across a range of modeling inputs

We analyzed the sensitivity of CEP economics against variations in all key model inputs, and found that in all cases, CEPs are robust against changes in component technology prices and gas prices. Our sensitivity analysis highlights a key value of piecemeal, modular clean energy investments. Unlike lump-sum investments in new gas-fired power plants, if one component of the CEP is more or less expensive than expected, it is possible to reoptimize the portfolio composition. In comparison, the economics of gas assets rely on a single capital expenditure and a single fuel source.

We also find that if clean technologies continue their recent, fast cost declines instead of following much slower industry projections (the difference explains the “kink” in the Figure ES 2 CEP curve), the case for CEPs is further accelerated.

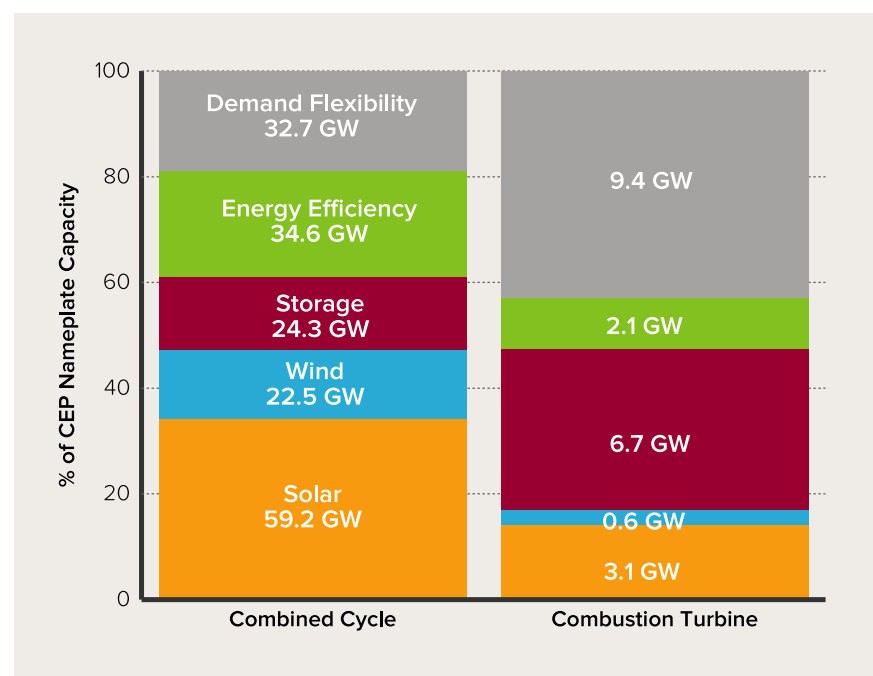
5. Ignoring the value of energy efficiency (EE) and demand flexibility shrinks the near-term market for CEPs to replace new gas by 70 percent and delays the economic opportunity by eight years

We consider portfolios of only WSS that omit EE and demand flexibility. Efficiency and demand flexibility are among the most cost-effective resources available to utility planners and investors, but usually require favorable state policies to achieve scale. If these cost-effective demand-side management resources are ignored, WSS is competitive with only 25 percent of proposed new gas plant capacity, compared with 90 percent for CEPs that include demand-side management. Using industry-standard projections for cost declines, we find it takes an additional eight years, on average, for WSS to reach cost parity with proposed gas plants.

6. CEP composition varies widely by region; all five clean technologies play important roles

FIGURE ES 4

AGGREGATE COMPOSITION OF CEPs ACROSS THE UNITED STATES



Note: More capacity, in megawatts (MW), of CEP resources is usually required to replace a given amount of gas capacity because the capacity factor (CF) of renewables is lower, though the levelized cost per MW is usually also lower.

Figure ES 4 shows the aggregated resources that compose the CEPs equivalent to the proposed 56 GW of combined-cycle plants and 12 GW of combustion turbine plants. In total, CEPs designed to replace combined-cycle gas projects leverage low-cost wind and solar resources as well as EE. CEPs designed to replace lower-capacity factor, combustion turbine gas projects tend to favor storage and demand flexibility to provide peak-hour capacity.

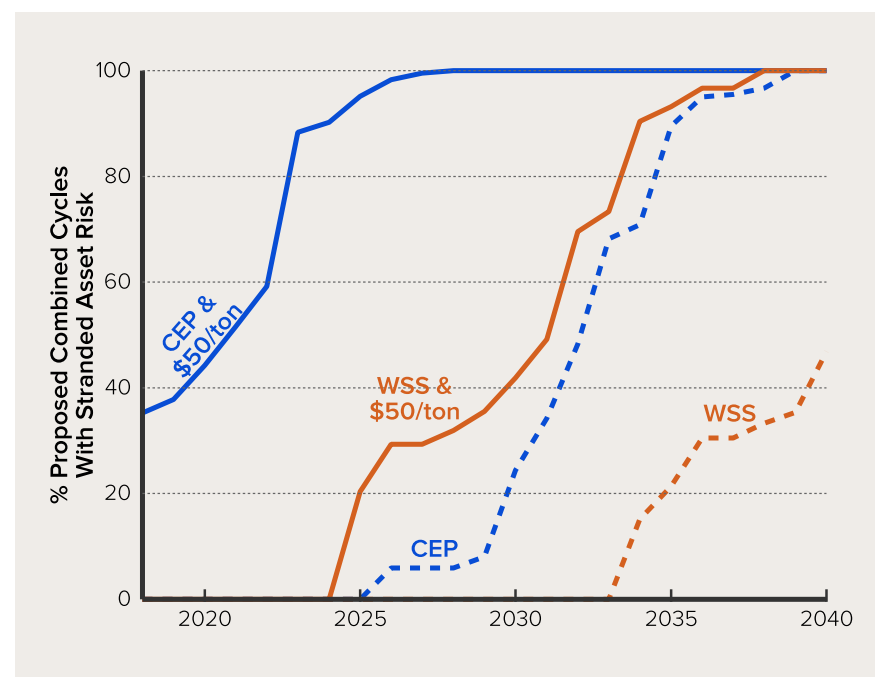
Regional differences in least-cost CEP composition reflect both regional resource quality as well as the existing and predicted adoption of renewables. For example, Western region CEPs contain little new solar because significant existing solar capacity in California makes additional solar resources comparatively less valuable. In contrast, Texas CEPs prioritize solar relative to wind because of the large amount of existing and predicted wind capacity in Texas.



7. Carbon pricing bolsters the case for CEPs and accelerates stranded asset risk

FIGURE ES 5

TIMELINE OF WHEN GAS PLANT OPERATING COSTS EXCEED NEW-BUILD CEP INVESTMENT COSTS, WITH SENSITIVITIES FOR CO₂ PRICING AND EE AND DEMAND FLEXIBILITY



Our central analysis case assumptions do not include any explicit or implicit price on carbon emissions; even without carbon pricing, CEPs outcompete 90 percent of proposed gas-fired generation capacity. As a sensitivity, we assessed the impacts of imposing a \$50/ton price on direct CO₂

emissions—on par with emissions prices used for planning in leading US jurisdictions. We do not account for upstream methane leakage. Figure ES 5 shows the implications; even a modest price on carbon pulls forward the timing of stranded asset risk for new-build gas-fired power plants by 5–10 years. For all-resource CEPs (blue lines), a \$50/ton carbon price accelerates the economic risk for gas by 10 years so that 90 percent of plants are uneconomic in the early 2020s and all combined cycles are uneconomic in 2030. Even without EE and demand flexibility (orange lines), ~50 percent of proposed gas plants would be outcompeted by WSS in the early 2030s.

Implications and recommendations

The currently strong and quickly growing economic case for CEPs has significant implications for how investments in the electricity system are planned, incentivized, and regulated. The changing economics present an immense near-term opportunity—if the industry can quickly prioritize new, least-cost resources. On the other hand, there are significant risks if the industry is slow to evolve and continues to prioritize gas plant investments.

Informed by our findings, we suggest the following practices:

For vertically integrated utilities: Adopt emerging best practices with all-source, technology-neutral procurement

In leading vertically integrated utility service territories, where utilities invest in generation and regulators allow cost recovery through customer rates, utilities and their regulators are pioneering all-source, competitive bidding procurement processes where the economic advantages of CEPs emerge naturally. These procurement processes include the following proven steps:

- 1. Define necessary grid services, not resource characteristics.** Start the planning and procurement process by specifying the services required, rather than characteristics of legacy generators that have historically provided them. Defining the need, not the solution, is crucial to ensuring the least-cost outcome.

- 2. Create a level playing field for all resources.** Utility modeling tools must appropriately capture the capabilities of new, clean energy technologies, including storage, efficiency, and demand flexibility.
- 3. Use competitive bidding to discover true resource prices and keep customer costs low.** Competitive bidding processes and real market input are essential to define the pricing assumptions used in planning and procurement.

For state utility regulators: Account for the significant risk that uneconomic gas generation will increase customer rates

Our analysis shows clean energy is lower cost than new gas-fired generation today and that its cost advantage will only increase with time. Before approving or rate-basing new gas generation, we suggest that regulators consider carefully whether gas generation is truly the lowest-cost way to meet the required grid services. Further, regulators should consider the risks of near-term gas investments, given the likelihood of continued clean energy cost declines and the potential for future carbon pricing. If new gas does appear marginally economic today, regulators may wish to mitigate risks to rate payers by 1) delaying approval of new gas investments, if possible; 2) requiring accelerated amortization schedules that reflect the limited economic life of new gas-fired power plants; and/or 3) changing risk allocation to protect customers.

For utilities and regulators: Embrace the value of demand-side resources in optimizing power supply portfolios

Historically, resource planning tools have not treated efficiency and demand response as resources on equal footing with centralized generation. Further, most cost-recovery regulation and utility business models do not incentivize utilities to reduce energy use. New incentives and mandates for demand-side resource investment, including

performance incentive mechanisms and other forms of performance-based regulation, can provide utilities a profit motive for prioritizing and deploying these least-cost resources. These regulations can also encourage utilities to value other distributed energy resources (DERs), such as behind-the-meter solar and storage, in resource planning processes.

For wholesale market stakeholders: Restructure rules to encourage technology-neutral market competition to meet system needs

Approximately 60 percent of proposed gas-fired capacity is slated for construction in territories with restructured power markets, including the Northeast and Texas, where power plant investors respond to market signals for new capacity and the most cost-effective generation is deployed to meet demand. Unfortunately, the rules in these markets were designed to encourage competition primarily between fossil, nuclear, and hydro generation. With the dramatic declines in clean energy costs and demonstrated ability of these resources to meet grid needs, it is time to update market rules to promote technology-neutral competition for grid services, including demand side efficiency and flexibility. For example, the Federal Energy Regulatory Commission's (FERC's) **new storage participation rules** are an opportunity to test whether existing participation models match actual grid needs, or whether new models are needed to capture the full value of storage.

For merchant gas investors: Carefully consider the risk that new gas generation will be underused or stranded

We find that CEPs are lower cost than new generation today, and that clean energy is very likely to undercut the go-forward cost of electricity from deployed gas in the coming 10–15 years. Therefore, even if other estimates suggest new gas generation will be profitable given today's clean technology prices, building new gas today is a bet against any of the following three events:

- **Carbon pricing:** Even a modest carbon price (<\$50/ton) accelerates the year in which new gas projects become uneconomic by 5–10 years.
- **Continued cost declines of clean energy:** Slightly faster learning rates for wind, solar, and batteries, splitting the difference between recent history and analyst forecasts, would reduce the expected economic lifetime of new gas plants by five years.
- **Market rules allowing full resource participation:** Current wholesale market rules favor legacy grid resources. The lag between market rule changes delays the transition to new technologies. However, participation rules for storage, demand flexibility, and EE are being tested and improved. As these rules are implemented, CEPs will become even more competitive in organized markets

Any one of these events would accelerate the economic case for CEPs and further degrade the profitability of new gas, and associated investor returns. Were two or three of these events to occur, the economics would tilt overwhelmingly in favor of CEPs, with dire consequences for investors in legacy assets.



1

INTRODUCTION

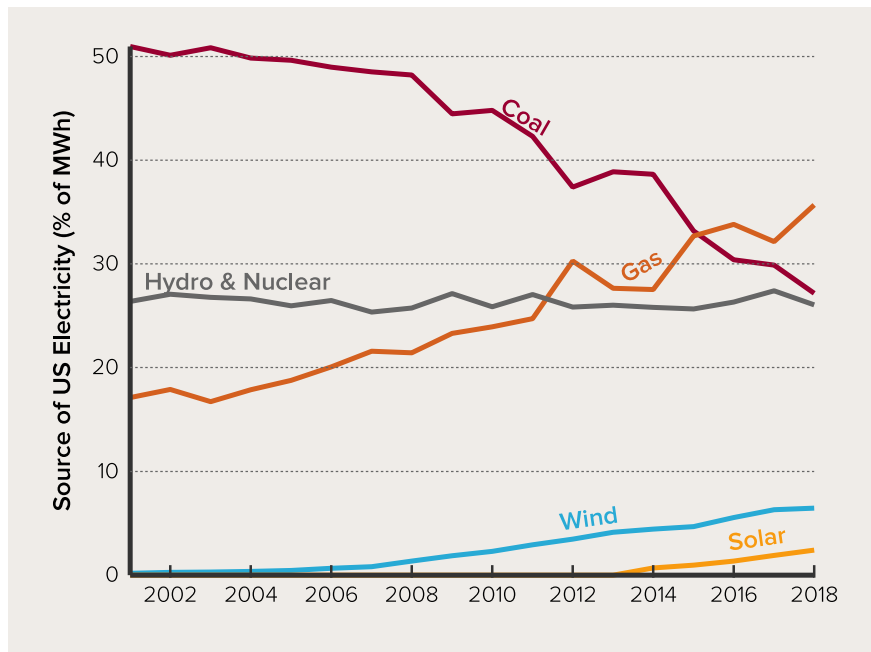


INTRODUCTION

The accelerating pace of clean energy progress

Since 2005, the United States has shifted its sources of electricity generation dramatically, away from coal and toward natural gas. Natural gas is now the largest single fuel source for generation (Figure 1) and falling natural gas prices have contributed to keeping average electricity rates stable across the United States. While direct emissions from natural gas are less carbon-intensive than the coal it has replaced, increased gas generation is contributing significantly to rising power sector CO₂ emissions.

FIGURE 1
SOURCE OF US ELECTRICITY



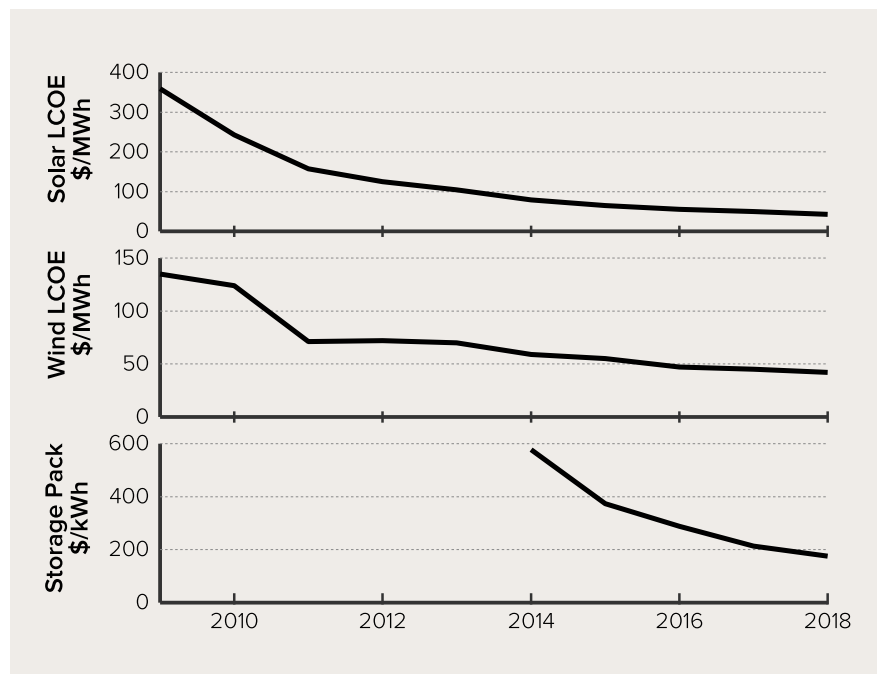
However, the growing market share of natural gas is only part of the story. Solar, wind, and battery storage prices have dropped precipitously (Figure 2), with prices for new renewables and storage projects significantly undercutting the levelized costs of new gas generation, and even approaching the typical operating costs of existing gas plants. For example, in June 2019, the Los Angeles Board of Water and Power Commissioners approved a 25-year contract for solar electricity supplemented with battery storage at less than \$33 per megawatt-hour (MWh), significantly lower than the benchmark price for new gas-fired generation of \$41–74/MWh. Solar and wind now contribute a meaningful and increasing portion to the country's electricity mix (Figure 1).

Now that solar, wind, efficiency, and demand response have proven track records, wholesale electricity markets and utilities are beginning to embrace how these resources can provide the reliability services that have previously been reserved for gas- or coal-fired generators. With continued cost declines, growing consumer and corporate demand, and a proven at-scale track record, solar and wind adoption is likely to accelerate.

However, despite the economics, planners are continuing to emphasize new gas generation projects; as described below, we identify 68 GW of new gas capacity proposed for construction across the United States. This continuing “rush to gas” is an economic risk to investors and utility customers, and represents significant committed CO₂ emissions if proposed projects are built.

FIGURE 2

UNSUBSIDIZED COSTS OF SOLAR, WIND, AND BATTERY STORAGE.



In RMI's 2018 [paper](#), we described how CEPs⁴ can provide grid services equivalent to fossil generators. Specifically, we showed that CEPs can provide monthly energy, peak-hour capacity, and flexibility that is equivalent to new gas-fired power plants. Our 2018 paper described the risks of building new gas-fired generation when clean energy portfolios are already cost-competitive and there is an implied stranded asset risk to investors (i.e., assets with undepreciated costs exceeding their expected future value).

⁴ Also referred to as "virtual power plants."

This report expands RMI's 2018 analysis of four CEP case studies by analyzing the economics of a CEP alternative to every proposed gas power plant in the United States, using updated data and an improved methodology.



2

MARKET SNAPSHOT



MARKET SNAPSHOT

Gas-fired generation investment is falling as economics increasingly favor clean energy

Overall, the US market for new gas-fired generation is cooling. Final investment decisions to build new natural gas-fired power plants in the United States have declined each year since 2014. Investors in companies that made bets on the gas generation market have paid the price; General Electric's 2015 acquisition of gas-power business Alstom led to a significant write-down as the market for new gas generation projects declined, and the firm's competitors have taken notice and made moves to exit the declining gas power market.

The US power industry is instead increasingly investing in new clean energy technologies. Across the country, utilities have accelerated their transition to clean energy, and either minimized or avoided entirely any planned investment in new gas generation:

- In Michigan, Consumers Energy filed a Clean Energy Plan that voluntarily exceeds Michigan's 15 percent renewable portfolio standard (RPS), closes most remaining coal plants by 2030 and all by 2040, dramatically increases investments into efficiency and demand flexibility, plans for 5 GW of solar, and sets a target for 25 percent renewable electricity generation in 2030, all without investment in new gas-fired generation.
- In Colorado, Xcel Energy will voluntarily retire two coal plants ahead of schedule and replace them with WSS, without construction of new gas-fired power plants. Company-wide, Xcel has publicly stated its

intention to reduce carbon emissions by 80 percent by 2030 (from 2005 levels) and generate 100 percent carbon-free electricity in 2050.

- In Minnesota, Xcel is replacing its final two coal plants primarily with a combination of solar, existing gas, and ~800 MW of efficiency programs. This choice was due, in part, to Xcel's resource modeling that now includes efficiency programs alongside supply-side resources.
- In Indiana, NIPSCO's 2018 integrated resource plan (IRP) process included technology-neutral open procurement, and led to a proposal to replace all of the utility's coal generation with clean technologies while avoiding new gas generation. The utility found that "the most viable path for customers involves accelerating the retirement of a majority of NIPSCO's remaining coal-fired generation in the next five years and all coal within the next 10 years. Replacement options point toward lower-cost renewable energy resources such as wind, solar, and battery storage technology."
- Arizona Public Service (APS) has committed to building 850 MW of storage to work alongside existing and new solar generation in order to meet their peak capacity needs. APS will install the first 200 MW in 2020 and 2021.
- Portland General Electric in its 2019 Integrated Resource Plan selected a preferred portfolio calling for efficiency, renewables, demand flexibility, and battery storage to meet growing capacity needs as existing coal retires, without requiring investment in new gas-fired generation.

State-level regulators have been increasingly reluctant to burden consumers with the risks of rate-based natural gas investments:

- In Indiana, the Indiana Utility Regulatory Commission (IURC) rejected a utility proposal to construct an 850 MW gas plant. The IURC **stated**, “The proposed large scale single resource investment for a utility of Vectren South’s size does not present an outcome that reasonably minimizes the potential risk that customers could, sometime in the future, be saddled with an uneconomic investment or serve to foster utility and customer flexibility in an environment of rapid technological innovation.”
- In Rhode Island, the Energy Facility Siting Board **rejected a developer’s application** to build a 900 MW combined-cycle gas plant in Burrillville, RI, because it was not necessary to meet the state’s needs, and clean energy resources, including offshore wind, would instead be sufficient.
- In Arizona, the Arizona Corporation Commission **voted to extend a moratorium** on construction of new gas-fired generating facilities, in recognition of an uncertain technology and clean energy policy landscape that could lead to stranded asset risk for such investments.

Even when new gas plants are proposed or approved, utilities find that downsizing the gas plant and treating it as a supplement to lower-cost clean energy resources is the most economic path forward:

- In the West, **PacifiCorp has announced** that the most economical way to replace coal generation in Montana, Wyoming, and Colorado is to replace it with wind, solar, storage, and small gas peaking plants.
- In California, Glendale Water & Power has **proposed** to reduce the size of its planned repowering of an existing gas-fired generator by 60 percent, replacing many of the services currently provided by the existing gas plant with a portfolio of solar, efficiency, and demand response to meet the utility’s reliability needs.



- In North Carolina, Duke Energy has effectively canceled a previously planned gas-fired power plant, in part because the utility was able to procure significant battery storage, EE, and demand flexibility resources to obviate the need for the gas plant through the end of its planning horizon.

Technical and financial analysts have come to the same conclusions as leading US utilities regarding the market outlook for new gas-fired power plants in the United States:

- A recent report from Carnegie Mellon and Fluence assessed the ability of solar and storage systems to compete with “mid-merit” combined cycle generators, finding that solar and storage systems were similar in cost—and less expensive when ancillary service revenue was credited to the solar and storage systems.
- A study from the National Renewable Energy Laboratory illustrates how solar and storage together can replace peaking gas capacity across the United States, with the potential for storage to offset more than 50 GW of peaking capacity nationwide as solar generation continues its rapid pace of adoption.

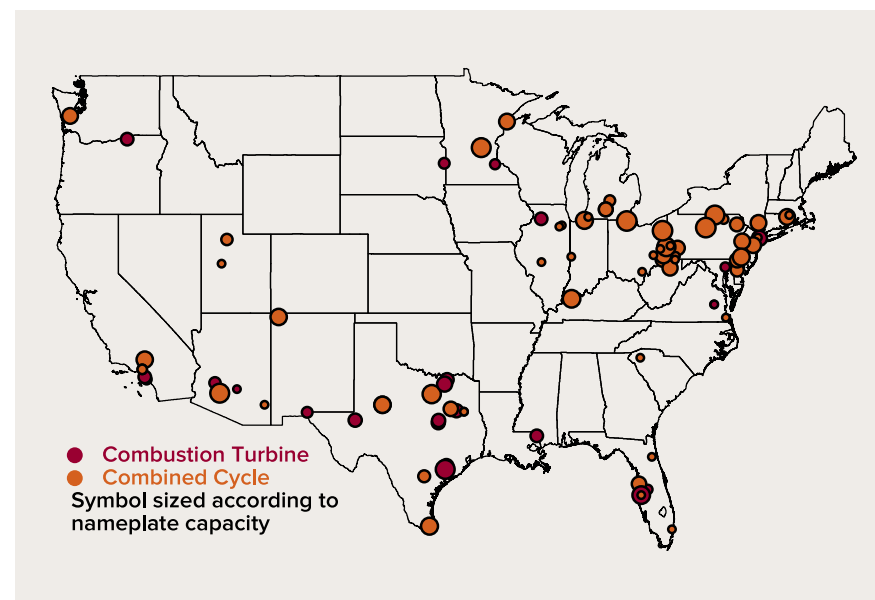
However, even as utilities and regulators across the country increasingly prioritize clean energy investment after critical assessment of the economics and risks of investment in new gas-fired generation, there remains a large, but shrinking, quantity of planned projects. We identified 88 proposed gas-fired generation projects, 25 combustion turbines and 63 combined-cycle plants, with a cumulative nameplate capacity of 68 GW that have been announced to begin operation by 2025 but not yet begun construction (as of early 2019). In addition to the named, sited projects reflected in these numbers, utility IRPs include a significant quantity of new gas capacity, often proposed for construction post-2025.

⁵ Assuming average construction costs of ~\$1/W

Together, the announced and IRP projects represent at least ~\$90 billion in investment that would ultimately be borne by US electricity customers.⁵ If built and run as planned, the identified plants would emit over 100 million tons of CO₂ per year, equivalent to 5 percent of present-day US power sector emissions. With the aim of informing stakeholders, regulators, utilities, and customers of alternatives to continued gas investments, this report comprehensively considers the economic case for clean energy portfolios as an alternative to investment in each of these plants.

FIGURE 3

ANNOUNCED GAS-FIRED GENERATION PROJECTS





METHODOLOGY

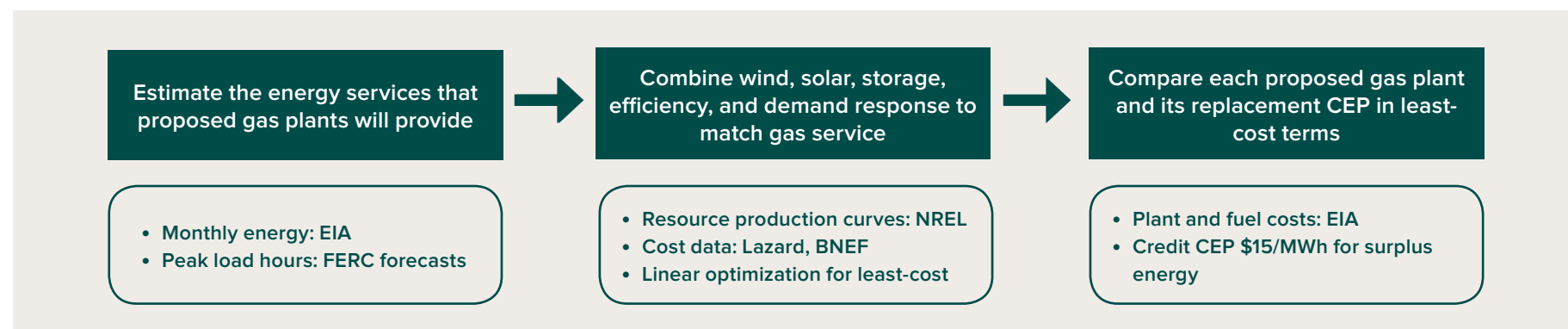
The Clean Energy Portfolio modeling approach

The model uses a three-step approach (Figure 4) to compare the economics of gas and clean energy. First, the model estimates the services of the proposed gas plant; then, it calculates the optimal combination of wind, solar, storage, efficiency, and demand flexibility to match these services; and, finally, we compare the total net costs of each option. We compare costs in two ways:

- **Total new-build costs for CEP and gas plant:** We compare the net present cost of building and operating a proposed gas plant and the CEP designed to replace the proposed gas plant. This is a comparison of a new gas plant with a new CEP, including capital, operating and maintenance, and variable operating costs (including fuel purchases, in the case of gas plants). For each proposed gas plant, we compare these costs for each year from the present day until 2045, to capture changing fuel and CEP technology costs.
- **Total new-build cost of CEP vs. cost of running existing gas plant:** We compare the cost of building and operating a new CEP with the go-forward cost of operating a gas plant in a future year. This is a comparison of an existing gas plant with a new CEP, including capital, operating and maintenance, and variable operating costs for the CEP, but only fuel purchases and other variable costs for the gas plant. For each proposed gas plant, we compare these costs for each year from the present day until 2045, to capture changing fuel and CEP technology costs. When new-build costs for a CEP fall below the go-forward costs of a gas plant, we refer to a stranded asset risk for the gas plant, as it would no longer be economic to run at expected CFs.

FIGURE 4

HIGH-LEVEL SUMMARY OF MODEL APPROACH



Below and in the Appendix, we describe our approach in greater detail. In the description, we provide example data for a representative (i.e., near the median in cost-effectiveness) combined-cycle project located in the Northeast, in order to illustrate the data used and optimization approach.

Clean energy portfolios must match the monthly energy and peak demand services of the gas plant

Our CEP model calculates the composition of least-cost portfolios of clean energy resources that can provide the same grid services as a proposed natural gas-fired power plant. The model requires that the CEP meet three key service requirements:

- **Monthly energy:** The CEP must produce at least as much energy each month as the gas plant. We estimate the gas plant's monthly CF by assuming operators will run the plant similarly to other comparable plants in the proposed region.
- **Peak-hour capacity:** The total power output (in megawatts) of the CEP must match or exceed the gas plant's seasonally adjusted nameplate capacity during the region's top 50 hours of peak net load in a year. These hours can be, but are not necessarily, sequential. To calculate peak net load, we start with the predicted total regional hourly load and subtract projected wind and solar (distinct from the CEP) installed to meet the state's RPS, if one exists.
- **Flexibility:** The total power output (in megawatts) of the CEP must match or exceed the gas plant's seasonally adjusted nameplate capacity during the hour when the region experiences its greatest one-hour increase in net load. Further, the model requires that the CEP not exacerbate ramping issues (i.e., the "duck curve"), by requiring that during the largest four-hour ramp-down of CEP solar generation, CEP total power output must be able to remain constant or increase (e.g., by charging storage during peak solar photovoltaic (PV) output and discharging as solar PV power output drops).

In Figure 5 and Figure 6, we show the required monthly energy and peak demand (black lines), and how each CEP technology contributes to meeting them (discussed below), for the example Northeast combined cycle.

FIGURE 5

MONTHLY ENERGY REQUIREMENT OF THE EXAMPLE NORTHEAST COMBINED CYCLE

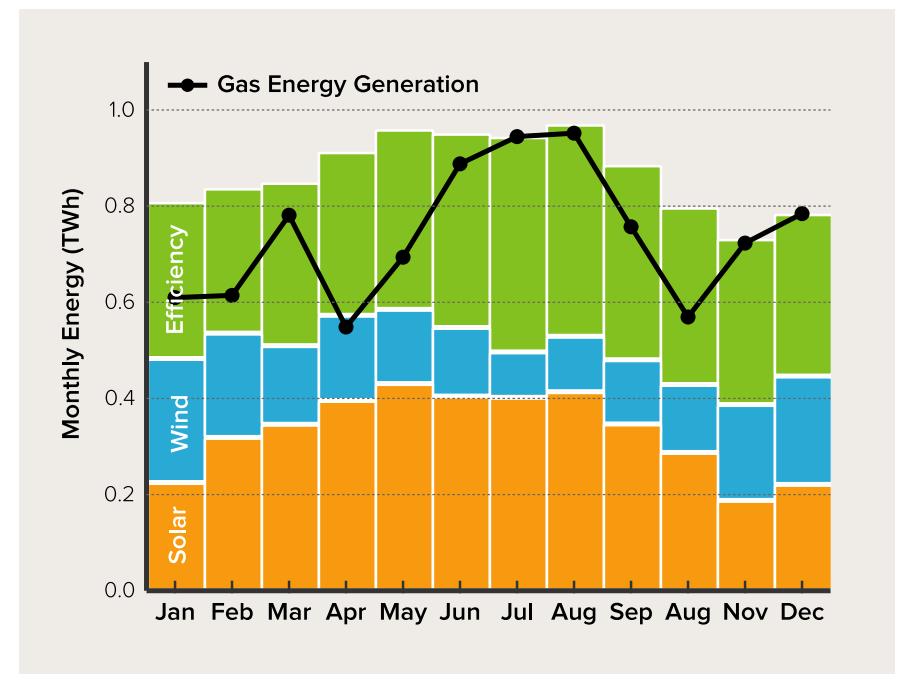
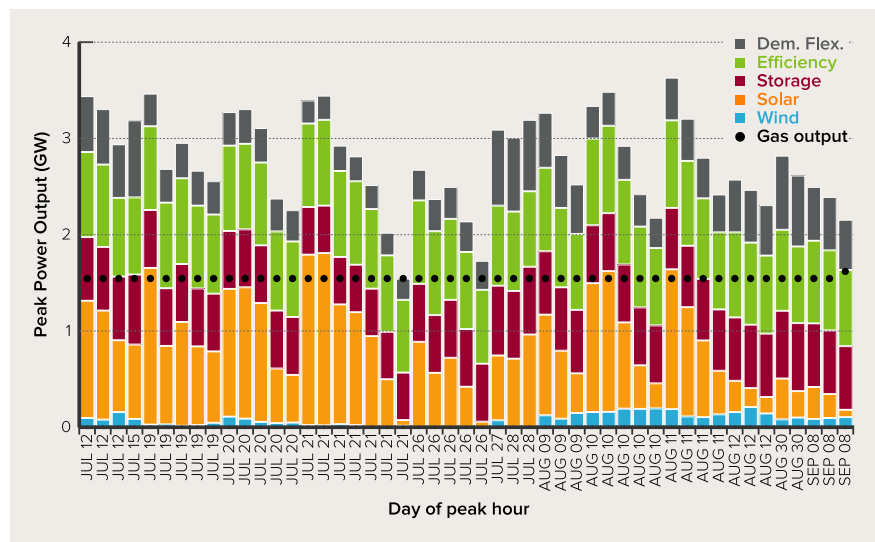


FIGURE 6
PEAK DEMAND REQUIREMENT OF THE EXAMPLE NORTHEAST
COMBINED CYCLE



The CEP model calculates the least-cost combination of clean technologies to match the gas plant services

We use linear programming-based optimization to compute the least-cost combination of clean energy technologies that meet the required services described above. Our optimization methodology remains largely unchanged from our 2018 study's approach; see the Appendix of that report for detailed methodology and mathematical formulations. As in the 2018 study, we include five technologies in CEPs:

- **Energy efficiency:** We model the use of programs (either utility- or other administrator-enabled) to reduce the use of electricity while maintaining or improving the quality of end-use services. We estimate hourly demand reductions associated with these programs using

historic regional, end-use load data, and model the associated program administrator costs based on regional data.

- **Demand flexibility:** We model the use of programs (either utility- or other administrator-enabled) to shift the timing of the use of electricity while maintaining the quality of end-use services. We estimate hourly demand reductions associated with these programs using historic regional, end-use load data, and model the associated program administrator costs based on regional data.
- **Utility-scale wind:** We model the ability of wind projects to contribute energy to the power grid, using modeled regional hourly production profiles matched to load profiles, and costs based on analyst forecasts.
- **Utility-scale solar:** We model the ability of solar projects to contribute energy to the power grid, using modeled regional hourly production profiles matched to load profiles, and costs based on analyst forecasts.
- **Battery energy storage:** We model the capability of batteries to reduce peak hour demand and provide flexibility to meet both system- and plant-level ramping needs, based on both power capacity and duration. We use analyst forecasts of expected pricing for battery projects of one- to eight-hour durations.

Figure 5 shows how solar, wind, and efficiency contribute to meet the monthly energy of the example Northeast gas plant. The most challenging months for energy generation are July, November, and December; the model adds solar, wind, and efficiency to just match the gas output in these months. In the other months, the CEP generates more energy than the gas plant, sometimes significantly more. As described below, we assume the value of this excess energy is \$15/MWh, and net that value against the total cost of the CEP.

As shown in Figure 6, all five technologies contribute to meeting peak demand. The most challenging day is July 21, which includes 7 of the peak

50 hours. On the last of these hours, there is almost no contribution from wind or solar and peak demand is met with efficiency, storage, and demand flexibility. We find that it is common for the most challenging hour to be on a day with multiple hours among the top 50. To match the gas plant's power output on these days, the CEP model typically selects storage projects with increased power output capacity (to meet demand when solar and wind do not contribute) and increased duration (to meet demand across multiple hours on the same day). In our example plant, the storage is composed of approximately two-thirds six-hour storage, with a mix of one-hour, two-hour, and four-hour making up the remainder.

The efficiency and demand flexibility components of the example plant are a mix from different sectors and end uses, whose hourly production profiles we estimate from historical end-use survey data. The optimal CEP for each gas plant often includes significant quantities of specific end-use efficiency measures (e.g., commercial lighting) due to lower relative costs. We do note, that if these end uses are unavailable for continued efficiency program expansion (for example, because it had already been depleted by previous programs), it is generally possible to add the next most cost-effective efficiency option with a de minimis impact on total cost.

Cost comparison

We compare the costs of a proposed gas plant and an equivalent CEP using a metric of “net cost,” in units of \$/MWh for combined-cycle generation and dollars per kilowatt-year for combustion turbine projects. For combined-cycle plants, this \$/MWh metric is similar to a standard levelized cost of energy (LCOE). For CEPs designed to replace combined-cycle plants, we calculate net cost by assessing the net present cost of all CEP resources, subtracting the value for the excess energy produced by the CEP over what the gas plant would produce, and dividing the result by the gas plant's expected energy production. We net out the value of



“excess” energy produced by the CEP because, to meet the most constraining month for energy production and the most constraining days of peak demand, a CEP always generates more overall total energy and more average peak capacity than an equivalent gas plant. We assign a value of \$15/MWh for this excess energy, which is much lower than typical wholesale market energy prices of **\$30–50/MWh**, as a conservative estimate of the value of renewable energy during times when a gas-fired power plant would not be economically dispatched. As discussed below, the analysis is not overly sensitive to the choice of \$15/MWh.

We use a different cost metric for combustion turbine (CT) projects, as these projects are often expected to run less than combined-cycle assets, and primarily provide peak capacity, rather than bulk energy. We define a cost metric for CTs as the annualized net present cost of all capital, operational, and fuel expenses of the gas plant assuming a 20-year lifetime, divided by the maximum power output of the generator. For a CEP in each case, we define the net cost metric as the annualized net present cost of all capital and operational expenses of the CEP, netting out the value of energy sales in excess of gas plant production (as described above for combined-cycle plants), divided by the gas plant’s maximum generating capacity (which the CEP is optimized to be able to provide during peak demand).

As described above, we compare the net cost of a CEP to both the cost of new gas plants and, for combined-cycle plants, to the operating costs of existing gas plants. The metric for the go-forward cost of an existing gas plant is the same as the metric for combined-cycle plants, except we exclude capital expenses. We compare CEPs to the go-forward operating cost of proposed gas plants in order to assess if and when CEPs would be able to cost-effectively replace gas plants, if they are built as proposed.

This metric allows for an estimate of the year in which proposed gas projects would become uneconomic to run, and face risks of becoming stranded assets for their investors.

Key methodology updates from RMI’s 2018 study

We made the following improvements to the 2018 report:

1. We use hourly load profiles from wider regions to calculate when the CEP needs to meet peak demand, to better match renewable production data and minimize outlier effects for smaller balancing areas.
2. We adjust the maximum gas plant power output for the region and season using Energy Information Administration historical data.
3. We include multiple options for storage duration (one-hour, two-hour, four-hour, six-hour, and eight-hour) in order to provide the most flexibility to the model in optimizing a CEP.
4. We limit EE to account for no more than 50 percent of the required annual energy output and limit demand flexibility to average no more than 50 percent of the CEP peak hour capacity.
5. We calculate battery degradation rates (and the associated operating costs to replace degraded cells) by assuming storage used in CEPs to replace combined-cycle plants cycles 25 times each year in addition to the cycles necessary to meet the peak hour service requirements; for combustion turbines we assume an additional 10 cycles each year.
6. We consider CEPs both with and without EE and demand flexibility.

Data sources and key assumptions

We use data from a variety of vetted and established sources, detailed below, to parameterize the CEP model:

1. Planning area peak and growth forecasts: FERC [714](#)
2. Expected gas plant dispatch and monthly energy generation: Energy Information Administration (EIA) Forms [860](#) and [923](#)
3. Fuel costs: EIA [Annual Energy Outlook 2019](#)
4. Clean energy resource costs: [Lazard Levelized Cost of Energy v11](#), Levelized Cost of Storage v4, Bloomberg New Energy Finance (BNEF) New Energy Outlook 2018: Charts. August 3, 2018, Lawrence Berkley National Lab (LBNL) [Program Administrator Cost of Saved Energy for Utility Customer-Funded Energy Efficiency Programs](#), EIA Form [861](#)
5. US State RPSs: Center for Climate Energy Solutions [U.S. State Electricity Portfolio Standards](#)
6. Renewable Potential: NREL
7. Demand Flexibility Potential: FERC [A National Assessment of Demand Response Potential](#)
8. EE Potential: Electric Power Research Institute (EPRI) [State Level Electric Energy Efficiency Potential Estimates](#)
9. End Use Penetration: EIA Residential Energy Consumption Survey ([RECS](#)) and Commercial Buildings Energy Consumption Survey ([CBECS](#))
10. Planning area customer data: EIA Form [861](#)
11. Proposed gas projects: S&P Market Intelligence
12. Regional hourly load shapes: RMI's [Reinventing Fire](#)



We summarize the key analysis assumptions in Table 1.

TABLE 1

KEY ASSUMPTIONS USED IN CEP MODEL

ISSUE	ASSUMPTION
Storage duration	Model optimizes a combination of one-, two-, four-, six-, and eight-hour battery storage
Contribution of energy efficiency (EE)	Energy reduction from EE cannot account for >50% of the monthly energy requirement, on an annual basis. We also limit total available EE to the lesser of twice the fraction of the gas plant's capacity to the planning area's peak demand or 25% of the planning area's assessed EE availability.
Contribution of demand flexibility	Power reduction from demand flexibility cannot account for meeting >50% the required power output during peak demand hours. We also limit demand flexibility to the lesser of twice the fraction of the gas plant's capacity to the planning area's peak demand or 25% of the planning area's assessed demand flexibility availability.
Gas plant monthly CF	We use historical dispatch data from similar plants in the proposed plant's region and calculate the average monthly CF. For combined-cycle gas turbine projects (CCGTs), we disregard plants with CF<0.35, assuming that they are not representative of a new-build plant's likely operating characteristics.
Hours of peak demand	CEPs are required to match maximum gas power output during the top 50 hours of net peak demand. These hours are determined by extrapolating hourly demand profiles from 2010 regional load in Reinventing Fire and adjusting them to account for renewables deployment according to state-specific renewable energy targets.
Value of excess CEP Energy	We assign a value of \$15/MWh for any energy produced by a CEP in excess of the expected production of the gas plant.
Imported wind	We allow the import of high CF wind for inclusion in CEPs, which is relevant particularly in regions without high-quality local wind resources. This resource carries transmission costs that are five times those of local wind.
Investment Tax Credit (ITC)	We assume that solar installations will benefit from a 26% ITC (the 2020 rate), even for plants built after 2020 on the assumption that they will take advantage of the "safe harbor" rule. We do not apply the ITC to storage.

TABLE 1

KEY ASSUMPTIONS USED IN CEP MODEL

ISSUE	ASSUMPTION
Production Tax Credit	Not included.
Battery charging	In all cases, the CEP generates the energy needed to charge the battery storage. We assume a round-trip charge/discharge efficiency of 90%.
Battery operating expenses (OpEx)	Storage operating expenses are dominated by the need to replace lost capacity that accumulates with each cycle. We assume 0.03% of energy storage capacity is lost each time the battery is cycled.
Valuation of ancillary services	We do not value any ancillary services that could be provided by the CEP or the gas plant.
Social cost of carbon	Our model does not consider any social impacts of carbon or other pollution in its optimization of resources. However, we consider and present sensitivity cases where gas plant costs are affected by carbon pricing.
Discount rate and time	We assume a 20-year life for the CEP. For resources with useful lives that are longer (e.g., solar PV) or shorter (e.g., some efficiency measures) than 20 years, we adjust their capital expenditures (CapEx) costs by taking the present value of 20 years of that resource's annualized CapEx. We use a real discount rate of 6%.
Accounting for deployment of future wind and solar	When estimating future demand shapes, we adjust the shape by accounting for solar and wind resources that allow each state to meet their RPS, if one exists. If an RPS does not exist, or if a state has exceeded its RPS, we assume that future renewable generation accounts for the same proportion as it does currently. We do not account for renewable generation implied but not specified by state-level, economy-wide greenhouse gas emissions targets such as those in CO and NJ. We do not account for renewable generation implied by CEPs designed in this study.

Rationale for the assumptions used and limitations of the model

Our study presents a conservative treatment of the potential value of CEPs relative to gas plants:

- **Clean energy portfolio costs:** We do not assume renewables and storage will continue their historical pace of rapid cost reductions, and instead use middle-of-the-road forecast assumptions for continuing cost declines, which historically have been systematically biased upward relative to observed cost declines. The average LCOEs assumed in this study for solar and wind are \$34/MWh and \$38/MWh, respectively, which are far above currently announced benchmark prices and well above more-aggressive future predictions of continuing cost declines. In addition, we do not consider the advantages of combining solar and/or wind with storage into hybrid systems that reduce cost with shared interconnection, nor do we apply the ITC to storage systems.
- **Ancillary and incremental value of clean energy portfolios:** We do not credit storage with any ancillary service values, even as other analysts have quantified the incremental revenue that could be captured by storage relative to gas power plants. We also do not credit CEPs with any incremental value associated with reducing demands on the transmission and distribution systems, as such revenue is location-specific and difficult to quantify.
- **Constrained optimization of CEPs:** We assess the economics of CEPs solely on their ability to perform the same services as gas plants. This approach implicitly starts with the assumption that a gas plant would closely match the grid's actual needs. By forcing CEPs to replicate gas plant services, we eliminate even lower-cost CEPs that would match actual grid needs, such as those identified in a true resource planning study.

- **Externalities:** Our base results do not assume any cost for carbon or other emissions.

We intend for our analysis to reveal the economics of *marginal* additions to regional generation capacity, assuming currently-planned levels of renewable generation growth and typical load and weather years. This analysis does not comprehensively assess gas plants' role in a dramatically different grid, such as one with a very high share (i.e., >50 percent) of renewable generation. For investors, policymakers, and system operators considering resources for a reliable, very low-carbon grid (typically in years after 2035), we recommend holistic models that account for the different needs of a system with high wind and solar penetrations.

In our analysis, each CEP is constructed independently, but we present aggregate results by summing all 88 gas plants in our sample. This is reasonable because 1) our sample would compose only ~7 percent of installed US generation capacity, and 2) our conservative resource selection assumptions ensure the resources selected within candidate CEPs are distinct from those in other CEPs.

Finally, this approach does not quantify the local impacts of clean energy and gas infrastructure development such as air pollution that adversely affect human health or the economic benefits of job creation. These and other local considerations are essential to any holistic and integrated resource planning process. We focus the economics of clean energy portfolios using the financial metrics traditionally used for fossil generation in order to inform near-term investment decisions and identify financial risks.



FINDINGS

1. CEPs are lower cost than 90 percent of proposed gas-fired power plant capacity, presenting an opportunity to save customers \$29 billion and prevent 100 million tons of annual CO₂ emissions

We find that CEPs have a clear economic advantage over proposed gas-fired plants:

- CEPs outcompete 61 GW, or 90 percent, of the 68 GW of proposed gas-fired plants in our sample.
- Cumulative customer savings from winning CEPs would total \$29 billion over 20 years on a net present value basis.
- By building winning CEPs, we would reduce CO₂ emissions by 100

million tons per year—approximately 5 percent of current US power sector emissions. Were CO₂ emissions valued at \$50/ton, reduced emissions would save \$5 billion per year.

In Figure 7, we show the costs of CEPs relative to the gas plants they are designed to replace. For combined cycle replacements (top panel), we also show the levelized cost of electricity for the CEP in \$/MWh. For combustion turbine replacements (bottom panel), we also show the CEP capacity cost. CEPs more easily replace combined-cycle plants, outcompeting 96 percent of the proposed combined-cycle capacity, compared to 61 percent of proposed combustion turbine capacity.

FIGURE 7

ECONOMICS OF CEPs DESIGNED TO REPLACE COMBINED CYCLE AND COMBUSTION TURBINE GAS POWER PLANTS

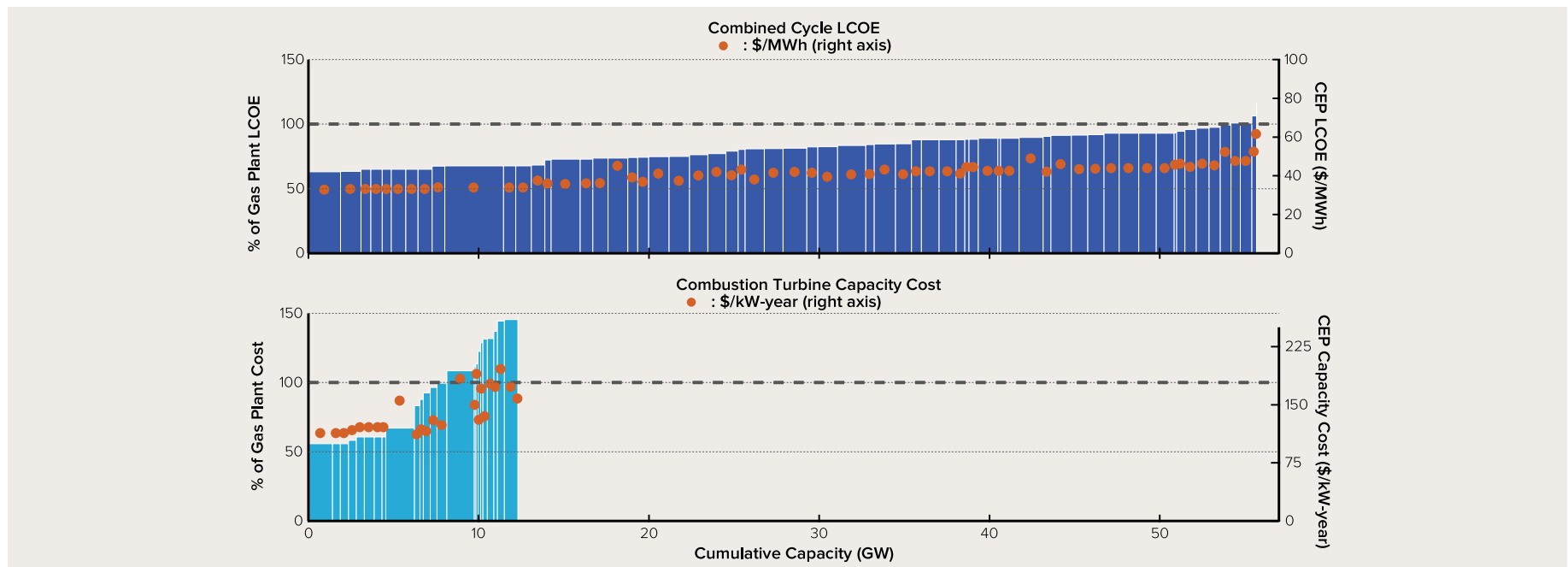
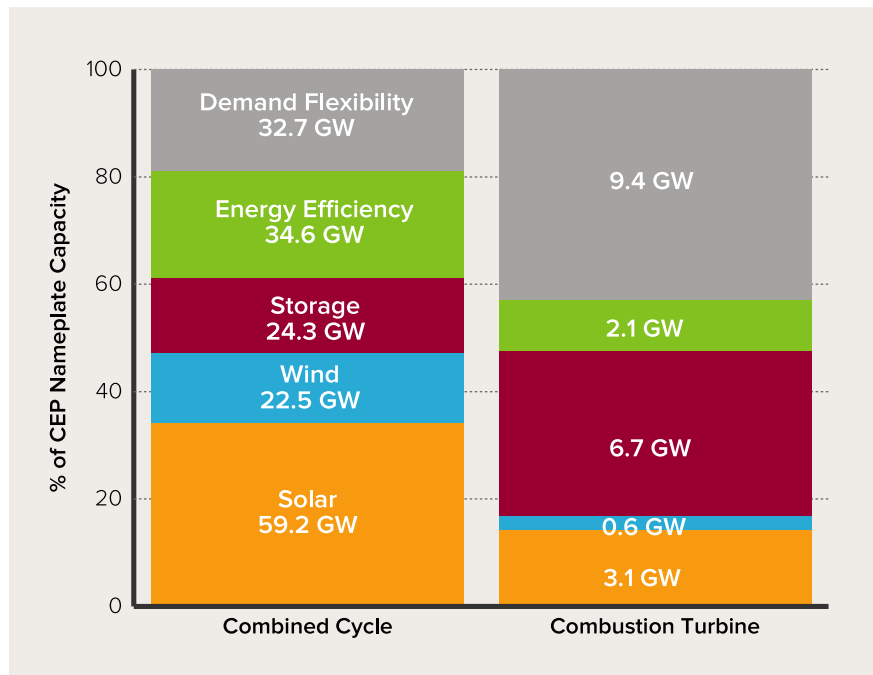


Figure 8 shows the cumulative contribution of the individual CEP technologies; all technologies play significant roles. Storage and demand flexibility play larger roles in CEPs designed to replace combustion turbines, where capacity during peak demand hours is most important. Efficiency and solar play large roles in CEPs designed to replace combined-cycle plants, where cost per MWh is more important.

FIGURE 8

TOTAL RESOURCE COMPOSITION OF ALL 88 CEPs



2. 2019 represents a tipping point for CEP economics

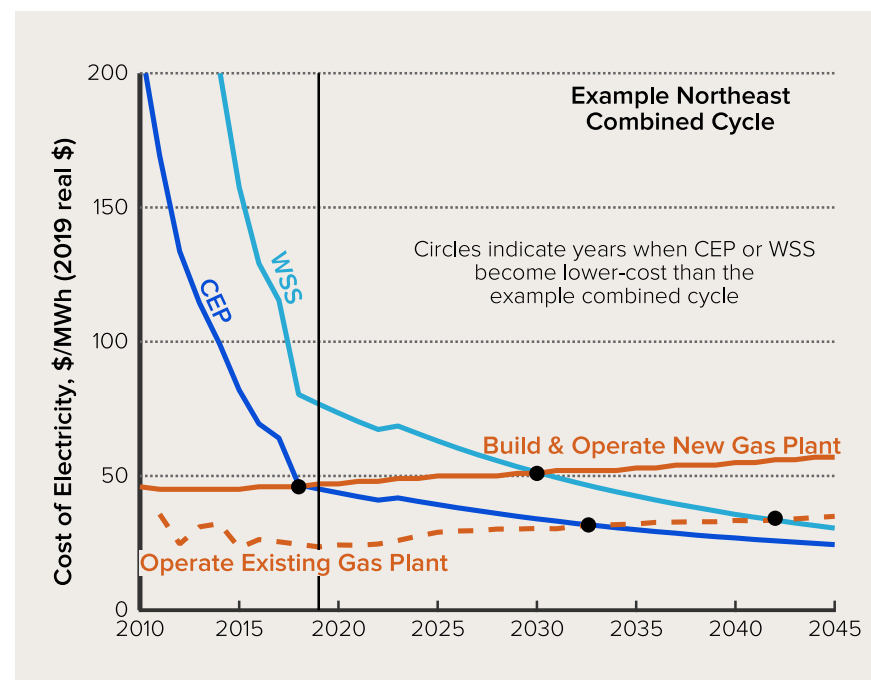
We summarize the historical evolution and trajectory of CEP economics using a representative Northeastern combined cycle (the same plant referred to in the Methodology section) in Figure 9.

Figure 9 illustrates the present tipping point in relative costs between CEPs and combined-cycle gas plants:

- **CEP costs have fallen 80% since 2010:** The falling costs of WSS has driven down the cost of a CEP equivalent to a typical CCGT by 80% since 2010.
- **CEPs win today against new gas:** It is now more cost-effective to build a new CEP in place of the vast majority of proposed new combined-cycle plants.
- **Further price declines will rapidly improve CEP economics:** Technological advances and market maturation for wind, solar, and batteries are expected to continue to drive the down costs of clean energy portfolios. By the early 2030s, we expect new-build CEPs to compete head-to-head with just the operating costs of modern, high-efficiency gas plants. If proposed gas plants are built, they risk becoming stranded assets.
- **Omitting demand-side resources delays the opportunity by ~8–10 years:** If we exclude efficiency and demand flexibility from CEPs, the combination of WSS will outcompete new gas in 2030 and outcompete just the operating costs of an existing gas plant by the early 2040s.

FIGURE 9

HISTORICAL AND PROJECTED EVOLUTION OF CEP COSTS



3. Clean energy portfolios are likely to undercut the operating costs of over 90 percent of proposed new combined-cycle capacity by 2035, creating stranded asset risk for investors

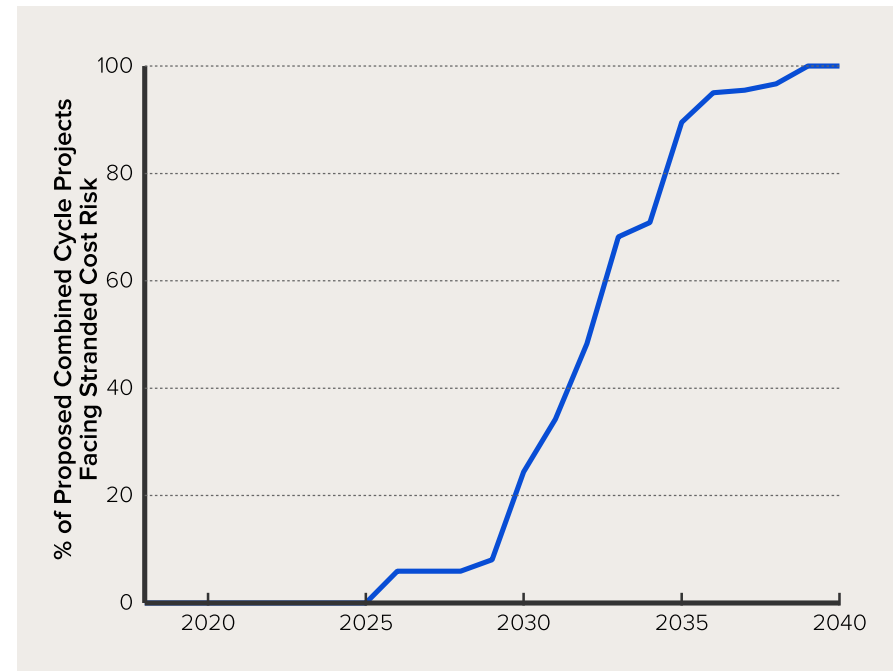
Just as the falling price of shale gas has allowed gas power plants to undercut coal plant operating costs, expected price declines in renewables and storage may soon strand existing or proposed gas plants. We find that over 90 percent of proposed combined-cycle gas plants, if they are built, will have higher operating costs than new CEPs in 2035.

Figure 10 summarizes the impacts of this economic trend for proposed combined-cycle projects. Within 15 years, nearly all currently proposed gas plant capacity will likely have operating costs higher than the cost of a new-build CEP, due to expected continued cost declines in WSS. The clear implication is that utilities or investors that move ahead with proposed plants face significant financial risk; consumer savings and/or market competition will dictate that the plants be shut down while book life remains. In short, combined-cycle investors face significant **stranded asset risk**.

We find that combustion turbines, expected to run at low CF, are less likely to have their operating costs undercut by the new-build costs of CEPs in future years. The cost structure of CT projects is dominated by capital costs (given the lower expected CF), leaving little total savings available in the case of retirement.

FIGURE 10

PERCENT OF PROPOSED CCGTS FACING STRANDED ASSET RISK IN EACH YEAR 2020–2040



4. The case for clean energy portfolios is strong across a range of modeling inputs

FIGURE 11

SENSITIVITY OF CEP ECONOMICS TO 25% CHANGE IN COST COMPONENTS—COMBINED-CYCLE PLANTS

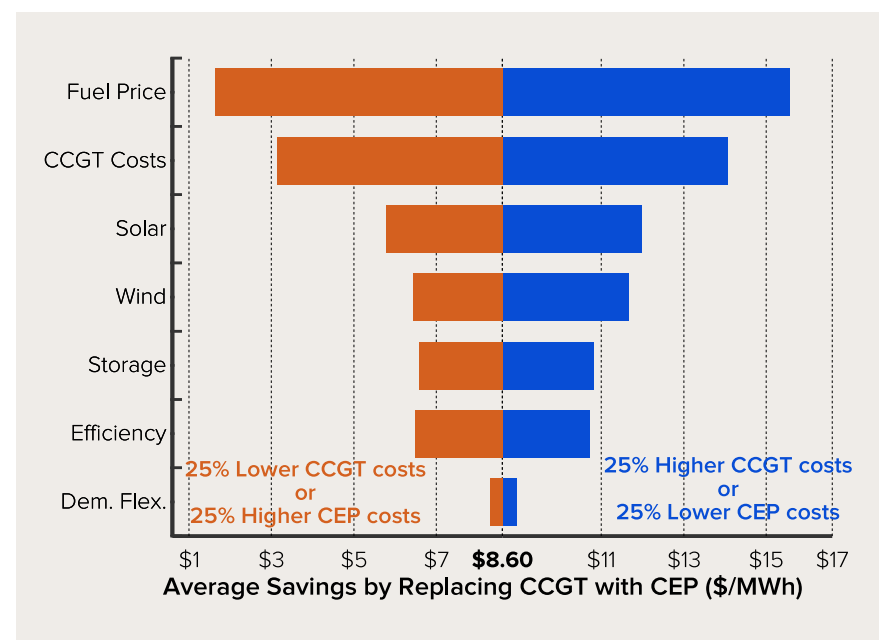


Figure 11 summarizes the sensitivity of our analysis to changes in individual cost inputs by showing the change in CEP savings when each of 7 costs is changed by ± 25 percent. We find:

- Natural gas prices and combined cycle costs (CapEx and OpEx combined) have the most impact on savings, consistent with the fact that fuel accounts for just over half the net present cost of combined cycles, with capital and operating and maintenance costs making up the remainder.
- Changes to individual CEP technology costs have less overall negative impact because substitution between clean energy resources can mitigate the total cost increase. For example, if solar is assumed to be more expensive, the model may substitute wind because it is now comparatively more cost-competitive.
- The analysis is sensitive to WSS prices that have been dropping precipitously for a decade.

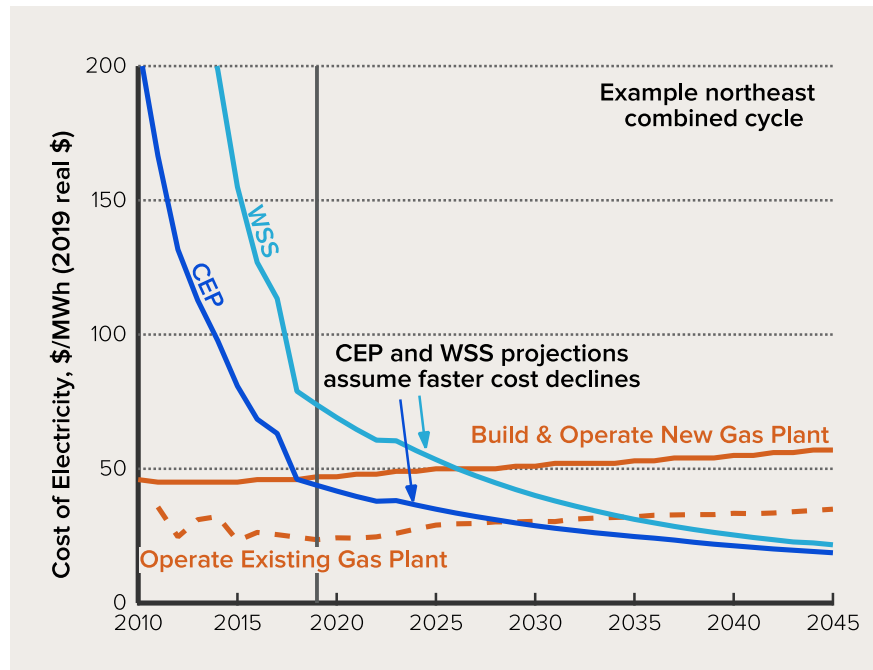
In Figure 12, we highlight the impact of clean energy technology cost declines using the example Northeast combined cycle plant. Figure 12 differs from Figure 9 only in that we assume 50 percent higher learning rates for wind, solar and storage than those predicted by BNEF. We consider the impact of a higher learning rate because 1) the higher learning rates are closer to recent, rapid cost declines of solar and storage (though still slower), 2) these technologies have only begun to scale and progress along their learning curves, and 3) historical cost projections have been uniformly too pessimistic. The figure shows:

- With faster cost declines, CEPs would outcompete existing gas in 2028 (dark blue line).
- With faster cost declines, WSS would outcompete a new gas plant in 2026 and outcompete the operating costs of this gas plant in 2034 (light blue line).

- Even with the 50 percent higher learning rate for WSS, the CEP cost declines are still dramatically lower than the historical rate (i.e., there is still a kink between historical and projected CEP costs).

FIGURE 12

HISTORICAL AND PROJECTED CEP COSTS, WITH FASTER CLEAN TECHNOLOGY LEARNING RATES.

**FIGURE 13**

SENSITIVITY OF CEP ECONOMICS TO 25% CHANGE IN COST COMPONENTS—COMBUSTION TURBINE PLANTS

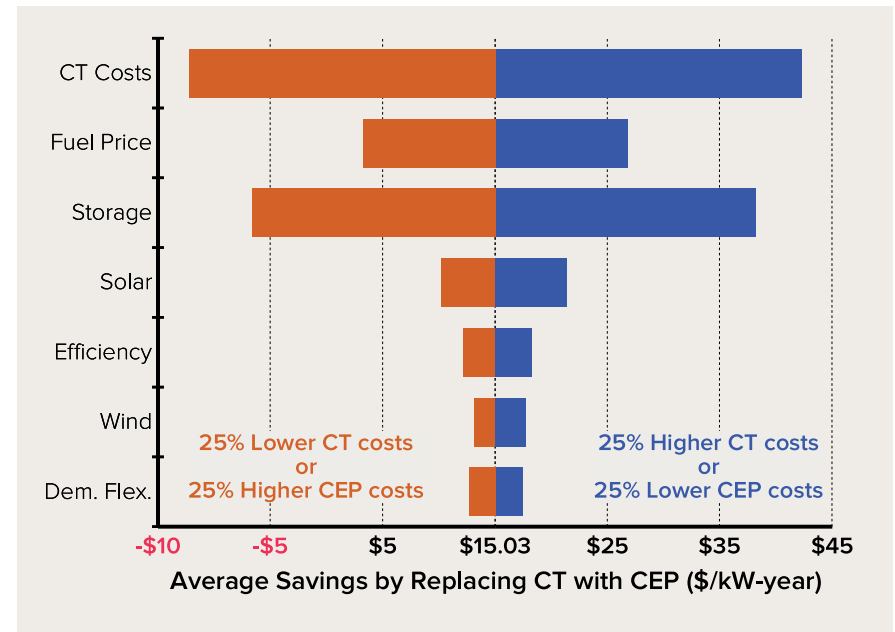


Figure 13 summarizes the sensitivity of combustion turbine results to changes in individual costs assumptions. There are two primary differences from combined cycles:

- Plant costs are much more important than fuel costs, consistent with the expectation that such “peaking” plants run at much lower CFs, and thus fixed costs are a much higher percentage of total costs.
- Total CEP cost is extremely sensitive to storage prices. Storage is often the only CEP technology that can meet some peak demand hours, and meeting peak capacity needs dominates peaker plant requirements and cost structures.

We note that CEP economics are not dramatically impacted by our choice to value “surplus” CEP energy (energy generated when the gas plant would not run) at \$15/MWh. At this value for excess energy (compared with the marginal cost to operate a new gas plant at ~\$25/MWh), the excess energy only represents 7 percent of the CEP’s value for combined cycle systems, on average. For combustion turbines, excess energy represents only 3 percent of the system value, on average.

In addition to assessing the impact of individual cost drivers, we also estimate the impact of applying the ITC to storage technologies, a practice commonly used today by developers of solar-plus-storage projects but omitted from our analysis. We note that in our comparisons of future CEP costs, we do assume that the ITC is retired in 2023; the ITC retirement explains the 2023 CEP and WSS cost increases visible in Figures 9 and 12. We summarize the impact of applying the ITC to storage in Table 2. Because of the increased importance of storage for combustion turbines and when efficiency and demand flexibility are excluded, these cases benefit more from the extension of the ITC to storage.

TABLE 2
BENEFIT OF APPLYING THE ITC TO STORAGE ON CEPS AND WSS.

	COMBINED CYCLES		COMBUSTION TURBINES	
	% PLANTS WHERE CEPS ARE LOWER COST	TOTAL SAVINGS	% PLANTS WHERE CEPS ARE LOWER COST	TOTAL SAVINGS
CEP. ITC not applied to storage	94%	\$25.2B	56%	\$3.5B
CEP. ITC applied to storage	98%	\$30.3B	72%	\$4.5B
WSS. ITC not applied to storage	16%	\$2.3B	40%	\$1.1B
WSS. ITC applied to storage	27%	\$3.8B	52%	\$2.1B

5. Ignoring the value of EE and demand flexibility shrinks the near-term market for CEPs to replace new gas by 70 percent, and delays the economic opportunity by eight years.

In our base case analysis, we allow the CEP model to select targeted demand-side management programs (i.e., **EE** and **demand flexibility**) that can provide energy, capacity, and flexibility to the grid. Efficiency and demand response are among the most cost-effective resources available to utility planners and investors, and can provide grid services comparable to generation and storage technologies, but usually require favorable state policies to scale effectively. As a sensitivity analysis, we also consider portfolios of only WSS that omit EE and demand flexibility.

Figure 14 shows the results of this analysis, by summarizing for each proposed gas plant (one per row) the timeline for when either a new-build CEP or new-build WSS undercut the costs of the proposed plant:

- **Near-term market shrinks by 70 percent.** Figure 14 shows that most CEPs begin to undercut the costs of new gas-fired generation in or before the early 2020s (dark blue dots). However, excluding EE and demand flexibility (light blue dots) means that by the expected in-service date of most proposed gas plants, WSS is still more expensive.
- **Ignoring demand-side resources delays opportunity to cost-effectively avoid new gas by eight years, on average.** Lines representing each proposed gas plant in Figure 14 show the delay between when CEPs outcompete a proposed gas project, and when WSS alone does the same. On average, ignoring EE and demand flexibility pushes out the date of cost parity by eight years.

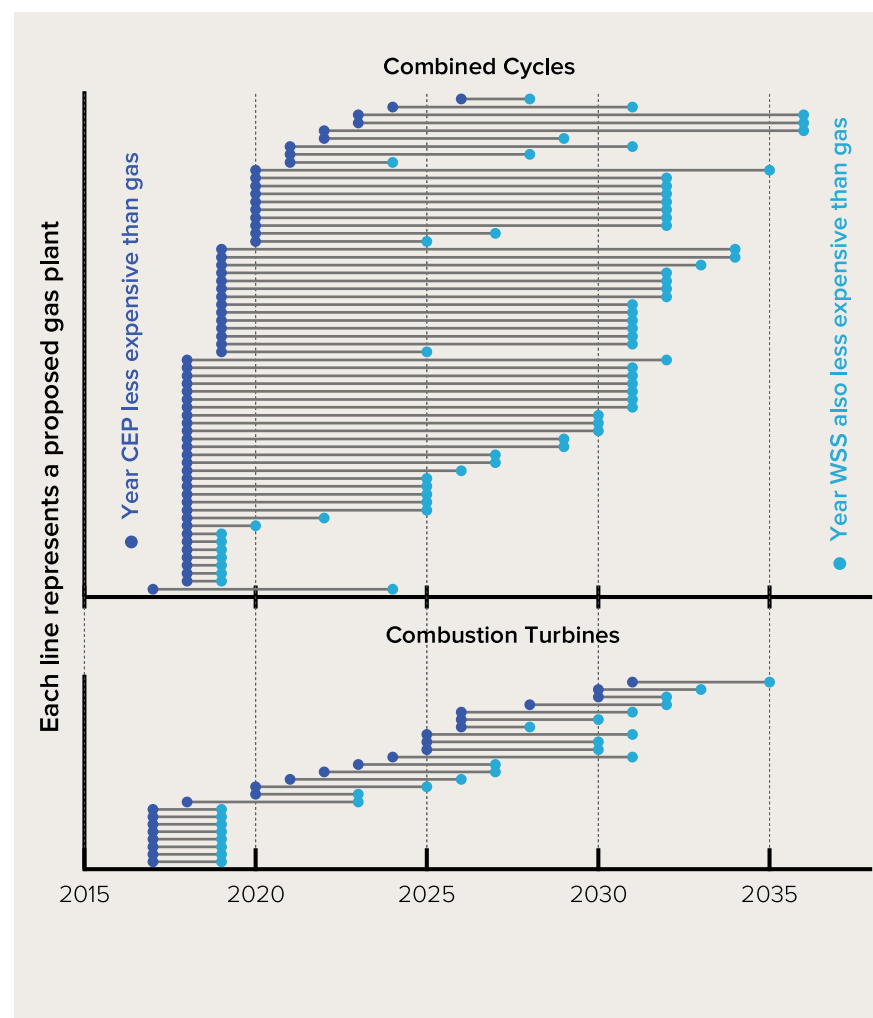




Delaying the market for clean energy by ignoring efficiency and demand flexibility both reduces customer value and increases carbon emissions. Available customer savings from WSS projects alone declines by 88 percent, to \$3.5 billion, compared to the value available from CEPs that include demand-side management of \$29 billion. Annual CO₂ emissions from proposed gas plants more cost-effective at their in-service date than WSS total 77 million tons, nearly all of which could be avoided by allowing demand-side resources to compete with gas as part of CEPs.

FIGURE 14

TIMELINE FOR EACH PROPOSED GAS PLANT SHOWING ECONOMIC OPTIONS FOR NEW GENERATION



6. Least-cost CEP composition varies, reflecting regional price, load, and renewable generation profiles

Figure 15 shows the regional variation in CEP composition for combined-cycle and combustion turbine gas plants. We show the state-by-state regional definitions in Figure 16. All five clean technologies play important roles in portfolios designed to replace both combustion turbines and combined cycles. The requirements to replace combined-cycle projects weight monthly energy production more heavily than peak capacity; therefore, their CEP replacements rely more heavily on wind, solar, and efficiency. In contrast, the requirements to replace combustion turbine projects heavily favor availability during peak demand; therefore, CEPs designed to replace CTs rely more heavily on storage and demand flexibility.



FIGURE 15

REGIONAL VARIATION IN AVERAGE LEAST-COST CEP COMPOSITION

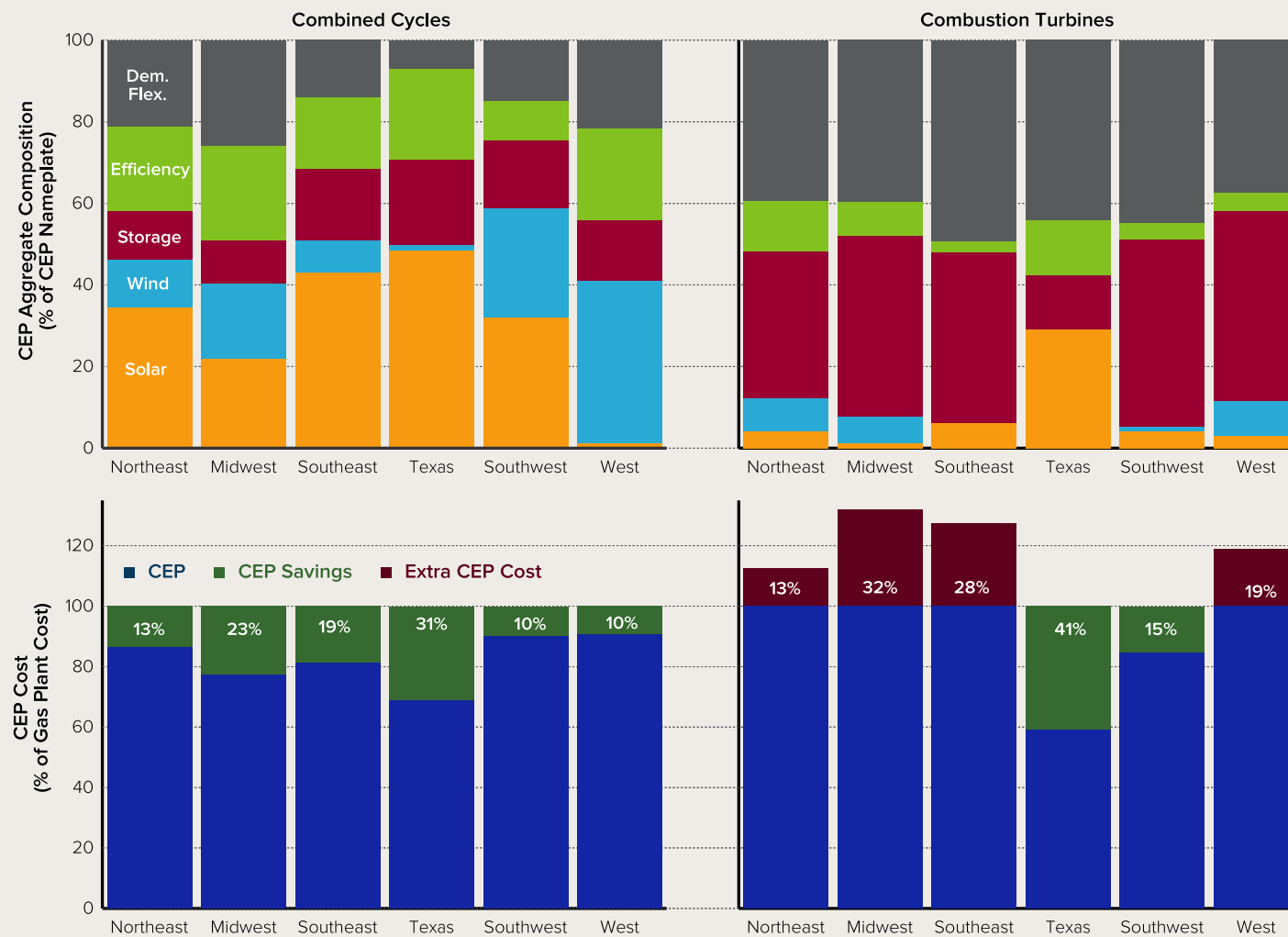
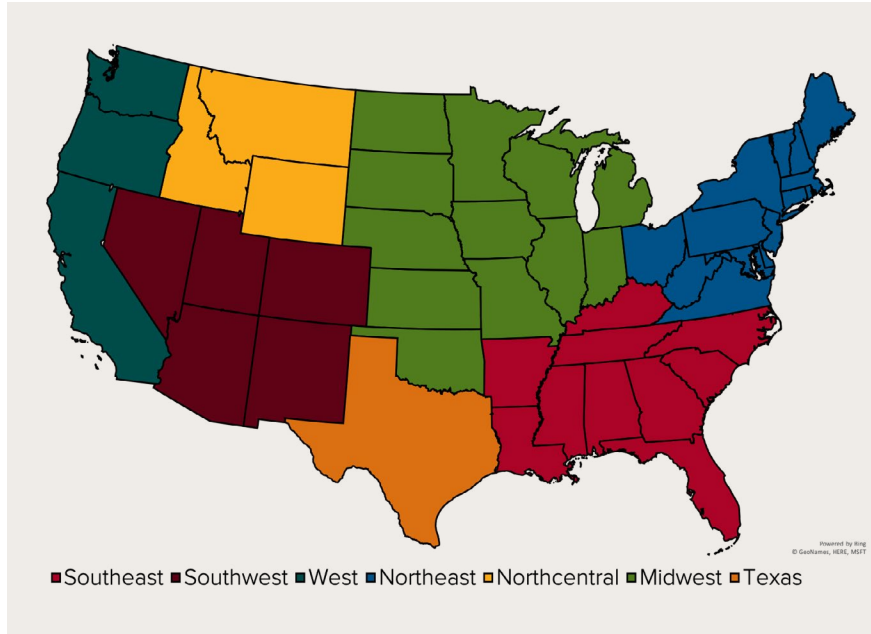


FIGURE 16
REGIONS USED IN CEP ANALYSIS



Below, we summarize key regional differences (note that some states have no new planned gas):

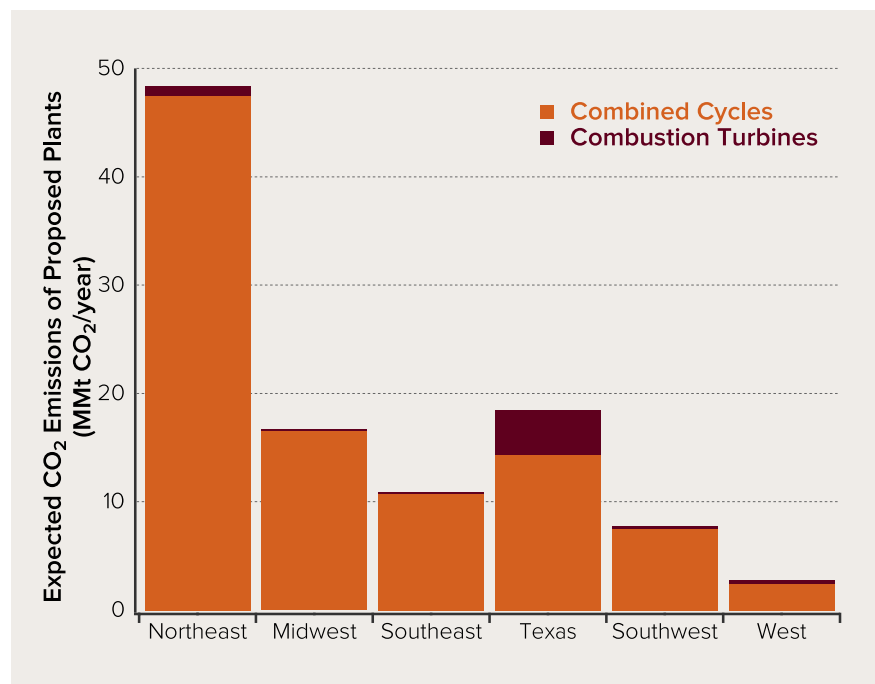
- **Northeast** (CT, DE, MD, NJ, NY, OH, PA, RI, VA, WV): Northeast CEPs include a balanced technology mix. Combined cycle replacements include a relatively higher share of solar, due to a relatively smaller onshore wind resource; this analysis does not model the contribution of offshore wind projects as part of CEPs.
- **Midwest** (IL, IN, MI, MN, SD, WI): Midwestern CEPs include balanced mixes of the five clean technologies.
- **Southeast** (FL, KY, LA, SC): Southeastern CEPs designed to replace combined-cycle projects include a great deal of solar due to its availability and low cost. Southeastern CEPs designed to replace combustion turbines are dominated by demand response and storage.
- **Texas**: Solar dominates CEP composition for both combined-cycle and combustion turbine projects, due to load profiles in the state that are well-aligned with solar production profiles and the large amount of existing and planned wind.
- **Southwest** (AZ, NM, UT): Renewables dominate CEP composition of combined cycle replacements, reflecting the region's excellent renewable resources.
- **West** (CA, OR, WA): Solar is largely absent from CEPs in this region, due to the large amount of existing California solar capacity; instead, CEPs preferentially include wind that balances solar generation.

7. Pricing carbon amplifies the economic case for clean energy portfolios and accelerates stranded asset risk for gas plants

Our main analysis case does not include any implicit or explicit CO₂ pricing. Figure 17 shows the predicted, cumulative regional emissions from proposed combined cycle and combustion turbine plants included in this study. To quantify the impact of emissions pricing, we analyze CEP

FIGURE 17

EXPECTED ANNUAL CO₂ EMISSIONS OF PROPOSED GAS PLANTS

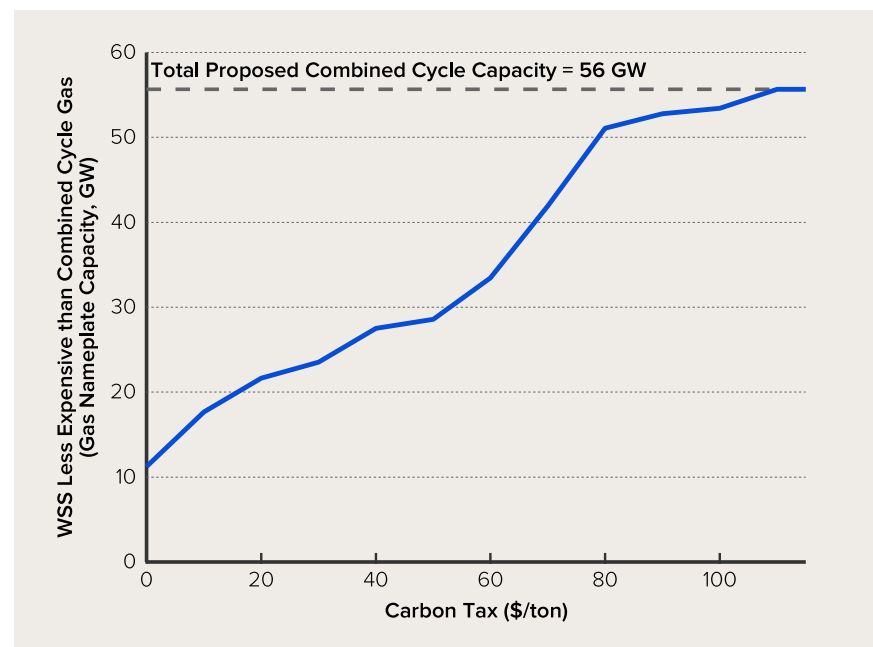


economics with carbon prices ranging from \$0 to \$100 per ton of CO₂ emitted. CO₂ pricing primarily impacts combined-cycle gas plants, as these plants run with much higher CFs.

In Figure 18, we show the combined-cycle gas capacity that is economically displaced by just WSS as a function of carbon price. We highlight portfolios of just WSS because, with efficiency and demand flexibility, CEPs are lower

FIGURE 18

IMPACT OF CARBON PRICING ON ECONOMICS OF WSS RELATIVE TO COMBINED-CYCLE PROJECTS



net cost than combined-cycle plants even without any carbon price. We find that the economic capacity of WSS grows smoothly until the price reaches \$100/ton, when WSS is less costly than all proposed combined cycles.

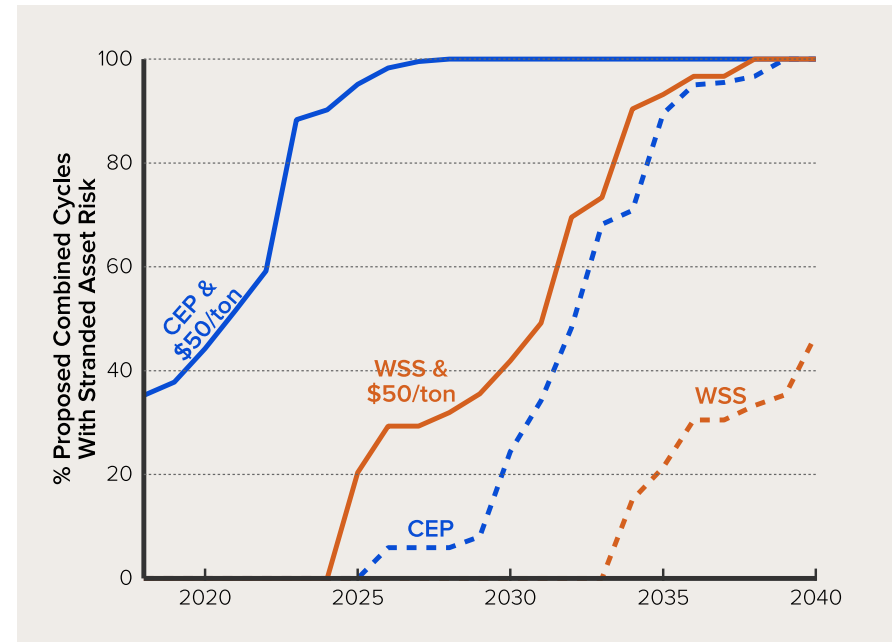
For plants that are built (or already in service), a carbon price accelerates the timeline for when the gas plant's operating costs become higher than the new-build CEP cost. Figure 19 summarizes the impact of a \$50/ton price on carbon dioxide—similar to prices already included in [utility planning processes](#) or [policy requirements in leading states](#)—on the crossover point for both CEP and for portfolios of WSS:

- With a \$50/ton carbon price, new CEPs start to outcompete existing combined-cycle gas plants in 2019, and would render nearly all combined-cycle plants uneconomic by 2025 (solid blue line).
- With a \$50/ton carbon price, WSS alone start undercutting gas plant operating costs in the early 2020s (solid orange line), and would outcompete nearly all proposed gas capacity by 2035, much faster than WSS competing against gas without any carbon price (dashed orange line).

In short, a \$50/ton carbon price accelerates the year in which a gas power plant becomes uneconomic to run relative to a new-build CEP by ~10 years; higher carbon prices would have a greater effect.

FIGURE 19

TIMELINE OF WHEN CCGT OPERATING COSTS EXCEED NEW-BUILD CEP INVESTMENT COSTS, WITH SENSITIVITIES FOR CO₂ PRICING AND EXCLUSION OF DEMAND-SIDE RESOURCES





IMPLICATIONS & RECOMMENDATIONS

The currently strong and quickly growing economic case for clean energy portfolios has significant implications for how investments in the electricity system are planned, incentivized, and regulated.

On one hand, lower clean energy costs are an obvious and enormous opportunity. If the economic value of clean energy portfolios can be fully captured, customers would save \$29 billion through 2040 and the electricity sector would reduce CO₂ emissions by 100 MT/year.

On the other hand, if the electricity sector fails to embrace the transition to clean energy, there are enormous risks for investors, customers, and the climate. Our results suggest that 90 percent of proposed combined-cycle plants could be uneconomic by 2035, less than 10–15 years after construction. Under current regulatory structures, captive utility customers will ultimately bear most of this risk and be left paying for fixed costs after the assets have been replaced by lower-cost clean technologies.

Planners and regulators can help the industry capture the opportunity at hand and mitigate the risks of this ongoing energy transition.

For vertically integrated utilities: Adopt emerging best practices around all-source, technology-neutral generation procurement

In leading vertically integrated utility service territories, where utilities invest in generation and regulators allow cost recovery through customer rates, utilities and their regulators are pioneering all-source, technology-neutral procurement. Technology-neutral procurement allows the economic advantages of clean energy portfolios to emerge naturally. Numerous states including Hawaii, Colorado, Indiana, and California have found that clean energy resources meet system needs at lower costs than both legacy fossil and new gas-fired generation. These procurement processes share the following commonalities:

1. **Define necessary grid services, not resource characteristics.** Legacy procurement and resource planning processes tend to define characteristics of specific generating technologies and request vendors bid accordingly. By definition, such a process limits new technologies from bidding, even if they can provide the needed grid services. Instead, we suggest starting the planning and procurement process by specifying the services required (i.e., by specifying the problem instead of the solution).
2. **Allow all resources to compete on a level playing field.** Legacy planning processes frequently omit certain resources, most notably EE, in consideration of candidate technologies to meet grid service needs. Additionally, legacy modeling software that is used to evaluate a technologies' ability to provide grid services often fails to account for advances in wind, solar, and battery storage capabilities. These legacy software tools were originally developed to model cost tradeoffs between coal, gas, nuclear, and hydro, and in many cases are structurally unable to properly represent the ability of battery storage and renewable energy to meet system reliability requirements. Now, processes and modeling tools deployed by leading utilities increasingly show a path forward for properly assessing and modeling these resources in the resource planning and selection process.
3. **Use competitive bidding to discover resource prices.** Legacy utility planning and procurement processes tend to use administratively determined assumptions relying on outdated data to generate cost inputs for portfolio optimization software. With costs for renewable energy and storage technologies falling so rapidly, this approach risks grossly misrepresenting the costs of these technologies; leading utilities are now using competitive bids and other market input to determine pricing assumptions used in planning and procurement, and relying on the same competitive bidding process to ensure that costs for final selection passed on to customers are as low as possible.

For state utility regulators: Account for the significant risk that uneconomic gas generation will increase customer rates

Our analysis shows that most proposed gas plants are both uneconomic today and, if built anyway, likely to be outcompeted before the end of their useful lives by clean energy. However, we acknowledge that some regional constraints (not considered in our model) can favor new gas-fired capacity. We hope this study will motivate regulators to carefully assess grid service needs, encourage competitive processes, and test renewable and storage costs assumptions as they assess proposals to build new gas-fired generation.

In addition to considering today's economics of proposed gas plants, regulators should also consider the long-term viability of gas investments,

given likely continued clean energy cost declines and the potential for future carbon emission pricing. For example, we find that a carbon price of \$50/ton reduces the expected useful life of a new-build gas plant by 10 years (Figure 19). Further, cost declines of renewables and storage closer to recent rates would lower useful lifetime for a gas plant by approximately five years (Figure 12). Power purchase agreement prices disclosed at the time of this report's release indicate Lazard and BNEF cost assumptions for current and future clean energy resources may already be **out-of-date**. Before saddling customers with these and other risks, regulators should consider mitigating actions such as delaying approval of new gas investment decisions until price trends become more clear, accelerated amortization schedules, or changing risk allocation to ensure customers are protected.



For utilities and regulators: Embrace the value of demand-side, distributed resources in optimizing power supply portfolios

Our modeling shows that EE and demand flexibility continue to be the least-cost route to meeting energy, capacity, and flexibility needs, and including them as candidate resources in CEPs unlocks \$25 billion in net customer savings. Utilities should include these resources as options in selecting least-cost power supply portfolios, following the example of leading [utility proposals](#) and [regulatory requirements](#) in the past several years.

However, common regulatory frameworks and utility business models make it difficult for utilities to profit from energy conservation or reduced peak demand. [Performance incentive mechanisms and other performance-based regulation](#) can allow utilities to capture the value of demand-side resources.

There is also demonstrable value available from distributed generation and storage, not systematically modeled as part of this study due to limitations in scope of analysis and available data, which should be considered in evaluating all resources for inclusion in CEPs. For example, distributed solar-plus-storage systems, where allowed to compete in [all-source procurements](#) or [wholesale energy markets](#), can bid in at lower net costs to the utility or market due to the customer-facing value they provide. Utilities and regulators can extend the same planning, procurement, and cost-recovery processes that help scale efficiency and demand flexibility to other DERs, and allow them to play a greater role in cost-effectively avoiding new gas investment.

For wholesale market stakeholders: Reconsider wholesale market participation rules to better align with system needs and the capabilities of emerging clean energy resources

Approximately 60 percent of proposed gas-fired capacity is slated for construction within restructured power markets, including much of the Northeast United States and Texas, where merchant investors respond to market signals for new capacity. However, most recent examples from the United States of clean energy portfolios avoiding construction of new gas plants are from vertically integrated, regulated service territories, where leading utilities have pioneered new approaches to planning and resource procurement that can accurately compare clean energy portfolios against legacy and incumbent asset types. There is an opportunity to use the present tipping point in clean energy resource costs and capabilities to test the extent to which wholesale energy markets, designed for an era in which fossil, nuclear, and hydro generators competed only against each other, are well-suited to enabling open and fair competition within a growing class of electricity resources. For example, the [current process of defining participation rules for storage](#) within organized electricity markets presents a clear opportunity to test whether current participation models are well-matched to grid needs, or whether new models can allow markets to capture more value from emerging resources.

For merchant gas investors: Carefully consider the risks of merchant projects in the face of falling clean energy prices and other future uncertainties

Investors in merchant gas-fired power plants are already beginning to realize the financial risks of investment in long-lived assets in markets that offer only short-run cost recovery assurance, but significant capacity (60 percent of the capacity included in this study) remains in the planning queue in such markets. However, our results illustrate the fact that continued prioritization of investment in new gas projects in these regions represents a bet against any of the following three outcomes occurring:

- **Carbon pricing:** Our results indicate that including even a modest carbon price accelerates the stranded asset timeline for new gas projects by 5 to 10 years.
- **Continued cost declines of clean energy:** Slightly faster learning rates for wind, solar, and batteries, splitting the difference between recent history and analyst forecasts, would accelerate stranded asset risk timelines for new gas plants by three to six years.
- **Market rules allowing full resource participation:** As explained above, current wholesale market rules tend to favor the last generation of resources, reflecting a lag time in rulemaking and change management at large and reliability-oriented institutions. As this lag is resolved, clean energy portfolios will become even more competitive in organized markets (e.g., as participation rules for storage, demand flexibility, and EE are tested and improved).

Any one of these events would accelerate the economic case for clean energy portfolios and further degrade the future profitability of new gas plants and associated investor returns. Were two or three of these events to occur, the economics would tilt overwhelmingly in favor of clean energy portfolios, with dire consequences for investors in legacy assets.





TECHNICAL APPENDIX

Clean energy portfolio model data sources

- We use FERC [714](#) as the starting point for planning area load growth forecasts and peak load. We construct projections of gross load profiles in future years, as described below.
- We use EIA Form [860](#) (2017) to identify capacity, build year, and location of existing power plants. We also use EIA Form 860 to identify plants comparable to proposed plants in order to estimate future monthly energy generation and to calculate the planning areas' current renewable capacity.
- We also use EIA Form [923](#) (2017) to estimate existing power plants monthly energy generation.
- We use EIA Form [861](#) (2017) to obtain utility customer counts, energy sales by customer class, and demand response program costs. We use the former two data types in our bottom-up estimates of efficiency and demand flexibility resource potential. The latter data type is the basis for our estimates of the cost of demand flexibility resources.
- We use EIA [AEO 2019](#) for natural gas price projections.
- We use [Lazard Levelized Cost of Energy v11](#) for CapEx and OpEx for gas-fired power plants, CapEx and OpEx for wind, and OpEx for Solar.
- We use [Lazard Levelized Cost of Storage v4](#) for storage OpEx, including what Lazard refers to as “augmentation costs,” which are the equipment and/or operational costs required to maintain the system at the assumed performance level for 20 years.
- We use BNEF New Energy Outlook 2018: Charts. August 3, 2018 for solar and battery energy storage CapEx as well as CapEx learning rates for solar, wind, and battery energy storage.
- We use LBNL [Program Administrator Cost of Saved Energy for Utility Customer-Funded Energy Efficiency Programs](#) for EE program costs.
- We use Center for Climate Energy Solutions [U.S. State Electricity Portfolio Standards](#) for each state's renewable portfolio target percentage and year. This data is used to estimate projected renewable capacity in future years to construct projected net load profiles.
- We use NREL's [Estimating Renewable Energy Economic Potential in the United States](#) for state-level estimates of total installable capacity for solar, onshore wind, and offshore wind.
- We use FERC's [A National Assessment of Demand Response Potential](#) for sector-level potentials for demand flexibility by state that constrain CEP use of demand flexibility.
- We use EPRI [State Level Electric Energy Efficiency Potential Estimates](#) for sector-level potentials for EE by state that constrain CEP use of EE.
- We use EIA [RECS](#) and [CBECS](#) for the penetration of the various electricity end uses by region. This data is used in our bottom-up estimates of EE and demand flexibility potential.
- We use S&P Market Intelligence to identify planned gas-fired power plants in the continental US, excluding Alaska. The plants in this analysis are from the Power Plants database as of June 3, 2019. The list is further screened to only include plants whose status is Announced, Early Development, or Advanced Development; whose capacity is greater than 100 MW; and which are not combined heat and power units.
- We use RMI's [Reinventing Fire](#) for hourly load, end use, and renewable profiles by region. The hourly load is used to calculate gross and net load profiles for each proposed plant and the renewable profiles are used to predict hour-by-hour renewable generation output. We also use *Reinventing Fire* scenario data to assess the cost of incremental transmission needs associated with wind and solar projects.
- We use [Public Service Company of Colorado 120 day Report](#), in addition to *Reinventing Fire* data, for transmission costs that we add to renewable costs.

Scenarios

In the analysis, we used our model to construct least-cost clean energy portfolios using various combinations of assumptions that we call “scenarios”:

- **The CEP scenario** includes all clean energy resources: EE, demand flexibility, utility-scale wind, utility-scale solar, and battery energy storage. We detail this scenario in Table 1: Key assumptions used in CEP model.
- **The WSS scenario** is identical to the Main scenario except that it excludes EE and demand flexibility from portfolios.
- The **faster cost declines scenario** is identical to the Main scenario except that the learning rates for WSS CapEx are increased to 150 percent of those in the Main scenario.

Methodology

This analysis compares the net present value (NPV) of cost for a proposed gas plant with a portfolio of DERs and utility-scale renewables. The CEP alternative is constructed to provide at least as much energy, capacity, and flexibility as the gas plant.

The analysis includes five steps:

1. Service requirement calculation
2. Resource potential assessment
3. Resource cost assessment
4. Portfolio optimizer
5. Gas plant cost assessment.

1. Service requirements model

The service requirements model begins by forecasting hourly system net load for the gas plant plant’s in-service year by applying our projection of the planning area’s peak load to a normalized 2010 regional load profile

and subtracting projected renewable generation. We derive projected renewable generation from current renewable capacity and the capacity additions necessary to meet the state’s RPS.

We use the top 50 hours of system net load in the capacity constraints, and the hour of highest system net load increase for the flexibility constraints. We calculate hourly system net load in the plant’s in-service year by projecting gross hourly system load and then subtracting the system’s projected hourly renewable production. We project gross hourly system load by first projecting gross system peak in the plant’s in-service year based on the planning area’s 2017 peak as reported in FERC 714 and the planning area’s growth rate calculated from FERC 714’s demand forecasts. We then apply that projected peak value to the plant region’s normalized hourly load profile from *Reinventing Fire*. To determine projected hourly renewable production, we begin with the planning area’s current annual renewable production, as reported in EIA Forms 923 and 860, and add the amount of renewable generation that would be required for the planning area to be on track to meet the state’s RPS (we assume that the current ratio of wind to solar energy is maintained into the future). We then convert these values for projected energy from wind and solar into projected wind and solar capacity using regional CFs. The resulting capacities are then applied to regional renewable hourly profiles from *Reinventing Fire* to get projected hourly renewable production.

We base monthly energy requirements on average monthly CFs for the newest half of plants of the same type in the gas plant’s planning area. To determine the CFs of combined-cycle plants, we use an additional screen that removes plants with annual CFs below 35 percent. The data for these monthly CF calculations comes from EIA’s Forms 923 and 860.

We define an additional set of flexibility requirements by determining the largest four-hour decline in solar production during the year and require that that decline is fully offset by increases in wind, efficiency, demand flexibility, and storage. In this constraint, storage can contribute two times at its installed capacity to account for its ability to charge at the beginning of the decline and discharge at the end.

2. Resource potential assessment

The resource assessment performs bottom-up estimates of EE and demand flexibility potential by end use along with top-down potential estimates by customer sector. Top-down sector estimates for EE potential are calculated from EPRI state-level economic potential for EE savings by sector, which are percentages that we scale by the gross load from the service requirement model to determine sector-level potential.

Top-down estimates of achievable demand flexibility participation by sector are based on FERC-estimated shares of peak load that could be reduced by DR and the gross load from the service requirement model. Both demand flexibility and EE top-down potential estimates serve as sector-level limits on EE and DR resources available to the clean portfolio linear programming model. Bottom-up estimates for EE and demand flexibility are used to limit potential resources for a given end use.

For EE, these estimates are based on RECS 2015 and CBECS 2012 shares of households and businesses with a given electrical end use for the applicable region and EIA data on the number of customers for a given planning area. Potential for these end uses is estimated by multiplying the number of devices by the assumed average peak reduction on a given end-use technology. Demand flexibility end-use potential is estimated in the same fashion, with estimates of the number of devices from RECS and CBECS along with average peak reduction from enabling demand

flexibility. This provides the total amount of efficiency or demand flexibility potential for each end use in a given planning area. For any particular plant we analyze, we multiply those planning area potentials by the lesser of 25 percent or twice the ratio of the proposed plant's capacity and the planning area's peak.

In addition to the previously described top-down and bottom-up constraints placed on EE and demand flexibility, we also limit these resources at the plant level. The contribution of EE to a CEP's energy production is limited to 50 percent of the annual energy of the gas plant. The contribution of DR to meeting the CEP's capacity requirement is limited to 50 percent of the gas plant's capacity.

The resource potential assessment also determines the amount of solar, onshore wind, and offshore wind potential based on NREL's estimates of the state-level economic potential of each renewable resource.



3. Resource cost assessment

Renewable and energy storage CapEx and OpEx costs and annual CapEx declines are taken from Lazard LCOE v11, Lazard LCOS v4, and BNEF. We apply the 2020 value of the ITC to solar resource costs in all cases to reflect the use of the law's safe-harbor provisions.

CapEx for all resources are converted to present costs for the in-service year by decreasing capital costs where appropriate to reflect the impact of a learning rate, and then discounting back to the current year. For resources with lives that differ from the assumed life of a gas plant of 20 years, we adjust that resource's CapEx by annualizing it and then taking the present value of the first 20 cash flows. OpEx for the first 20 years of the resource's life is discounted back to the current year.

For utility-scale wind and utility-scale solar, an additional term is added to both CapEx and OpEx to account for the cost of new transmission to connect those resources to the system. Those adders are derived from PSCO's 120-day report and *Reinventing Fire* scenarios. For wind imported from other regions, those transmission adders are multiplied by five.

The OpEx for battery energy storage includes what Lazard refers to as "augmentation costs," which are the equipment and/or operational costs required to maintain the system at the assumed performance level for 20 years. We calculate those costs by assuming that supplying one MWh of energy through the battery reduces its storage capacity by 0.03 percent,

which must then be replaced. We assume that the cost of this replacement falls over time as battery pack prices fall. To determine the number of MWh supplied by the battery, we assume that a battery is used 25 times per year (10 times for combustion turbine cases) in addition to the occasions necessary to meet the peak hour service requirements.

EE resource costs are based on estimated costs of running an effective EE program, and have a CapEx cost from incenting the deployment of EE measures but no OpEx costs. CapEx costs for particular EE end-use resources are based on the levelized-savings weighted-average costs from the LBNL PACSE study for the most similar measure category in the study. These levelized costs are converted to first-year costs with a capital recovery factor, and scaled by annual energy saved by a single MW of that particular end use which is region specific. We then adjust CapEx costs to account for the different lives of different EE measures as described above.

Demand flexibility cost estimates are also program based, and calculated for each sector from 75th-percentile annual DR program costs in EIA's Form 861. We assume 10 percent of that cost is for fixed annual O&M, and the remainder is CapEx that can be de-annualized into a first-year cost with a capital recovery factor. In addition to fixed O&M, demand flexibility OpEx includes variable O&M, which assumes it will be used 25 times per year (10 times for combustion turbine cases) in addition to the occasions necessary to meet the peak hour service requirements.

4. Portfolio optimizer

We use linear programming to select the portfolio of resources that can provide at least the same energy, capacity, and flexibility services as the gas plant for the lowest cost. To do this, we use resource cost estimates from the resource cost assessment, service requirements from the service requirement model, and available resources from the resource potential assessment. These three elements form our linear program's objective function, and its two groups of constraints: service constraints and resource constraints. The objective function states, mathematically, what we are trying to achieve: the lowest-cost portfolio. The constraints state all requirements (e.g., produce a certain amount of energy each month) and limitations (e.g. don't include more efficiency than we estimate is reasonable) the portfolio must satisfy. The full mathematical formulation of the optimization model is available in the appendix of our 2018 paper.

5. Gas plant cost assessment

The gas plant cost assessment includes CapEx, fixed O&M, variable O&M, fuel expenses, and carbon expenses (if any). Cost data used to determine gas plant CapEx, fixed O&M, and variable O&M are taken from Lazard LCOE v11 as are heat rates by plant type. Cost data used to determine gas fuel costs are from EIA's AEO 2019 reference case . These values are region-specific time series of annual fuel price projections from 2018 through 2050. Cost data used to determine carbon expenses are set by a parameter. In our base case, we do not include a price on carbon dioxide. In a few sensitivity cases, we set a price of \$50/ton of CO₂ emitted.

Gas plant CapEx is calculated by multiplying the per unit capacity cost of CapEx by the nameplate capacity of the gas plant. Annual gas plant fixed O&M is directly proportional to the plant's nameplate capacity. Annual gas

plant variable O&M is a direct function of the plant's annual energy production, the calculation for which is explained above as the monthly energy requirement for the CEP. Annual gas plant fuel expenses are calculated as the product of the plant's yearly fuel need and the per unit fuel price for the given year. A plant's yearly fuel need is calculated as the product of the plant's annual energy production and its heat rate. A plant's lifetime fuel expenses are calculated assuming a constant annual fuel need and a variable per unit fuel price for each year, as specified by the fuel cost data. Finally, annual gas plant carbon expenses are a function of the plant's yearly fuel need, a value for carbon intensity per unit energy, and a carbon price per ton of emitted carbon dioxide. The carbon intensity used for all gas-fired power plants was 53.07 kg CO₂/MMBtu, as reported by EIA . Our analysis excludes the effect of upstream greenhouse gas emissions from the natural gas system including leaks.

To convert annual gas plant expenses (fixed O&M, variable O&M, fuel expenses, and carbon expenses) into lifetime expenses, we follow two standard accounting steps:

- Take the present value of all annual expenses for 20 years (the value used for plant lifetime) using a 6 percent real discount rate
- Discount the present value of all annual expenses to the current year

We also discount gas plant CapEx to the current year for consistency.

Calculating CEP excess energy

As a post-optimization step, the model assesses how much energy the portfolio produces beyond the service requirement, reduced by round-trip losses in the batteries, we call the resulting amount "excess energy." We value this excess energy at \$15/MWh.

Cost comparison

We compare the costs of a proposed gas plant and an equivalent CEP using a metric of “net cost,” in units of \$/MWh for combined-cycle generation and \$/kW-y for combustion turbine projects. We use a standard LCOE metric for combined-cycle plants. We calculate this LCOE as the present value of all lifetime capital, operational, and fuel expenses of the gas plant, divided by the present value of all lifetime energy produced by the gas plant, assuming a 20-year lifetime.

$$\text{CC Cost (\$/MWh)} = \frac{\text{NPV of CC total cost (\$)}}{\text{NPV of energy produced by CC (MWh)}}$$

For CEPs designed to replace combined-cycle plants, we define a cost metric by assessing the present value of the lifetime capital and operational expenses for all CEP resources, subtracting the value of the excess energy produced by the CEP over what the gas plant would produce, and dividing the present value of all lifetime energy produced by the gas plant, assuming a 20-year lifetime.

$$\text{CEP Net Cost (\$/MWh)} = \frac{\text{NPV of CEP total cost (\$)} - [\text{CEP excess energy (MWh)} \times \$15/\text{MWh}]}{\text{NPV of energy produced by CC (MWh)}}$$

We use a different cost metric for CT projects, as these projects are often expected to run less than combined-cycle assets, and primarily provide peak capacity, rather than bulk energy. We define a cost metric for CTs as the annualized net present cost of all capital, operational, and fuel expenses of the gas plant assuming a 20-year lifetime, divided by the gas plant’s average operating capacity during the system’s top 50 net load hours.

$$\text{CT Cost (\$/kW-y)} = \frac{\text{CT total cost, annualized (\$/y)}}{\text{Average peak power output of CT (kW)}}$$

For CEPs that replace combustion turbines, we define a cost metric as the annualized present value of all capital and operational expenses of the CEP, less the value of energy sales in excess of gas plant production (as described above for combined-cycle plants), divided by the gas plant’s average operating capacity during the system’s top 50 net load hours.

$$\text{CEP Net Cost (\$/kW-y)} = \frac{\text{CEP total cost, annualized (\$)} - [\text{CEP annual excess energy (MWh/y)} \times \$15/\text{MWh}]}{\text{Average peak power output of CT (kW)}}$$

As described above, we compare the net cost of a CEP to both the cost of new gas plants and, for combined-cycle plants, to the go-forward costs of existing gas plants. The metric for the go-forward cost of an existing gas plant is similar to the metric for combined-cycle plants, except we exclude capital expenses.

$$\text{CC operating cost (\$/MWh)} = \frac{\text{Annual fuel, variable, and fixed costs (\$/y)}}{\text{Annual energy produced by CC (MWh/y)}}$$

Stranded asset risk

Our analysis of stranded asset risk compares the net cost of CEPs to the operating cost of proposed gas plants in order to assess if and when CEPs would be able to cost-effectively replace gas plants if said plants are built as proposed. The stranded asset analysis reruns the optimization for each year from 2010 to 2045 and compares, in terms of \$/MWh, the net cost of a new-build CEP to the go-forward cost of operating the proposed gas plant in that year. The year in which the cost of a new-build CEP is less than the go-forward cost of operating the proposed gas plant is the year in which the gas plant is rendered uneconomic. Gas plants that are outcompeted by an equivalent CEP before the end of their expected useful life are considered to be at risk of becoming stranded assets for their investors. Note that we only include cases for combined-cycle gas plants in our stranded asset analysis, to reflect the greater risk associated with these plants, typically designed and financed to run at high CFs, if they are outcompeted by clean energy technologies and thus run significantly fewer hours.

Carbon dioxide emissions

We calculate the expected annual carbon dioxide emissions in million tons of CO₂ per year as a function of the plant's annual energy production, heat rate, and CO₂ emissions factor.

$$\text{Annual CO}_2 \text{ emissions (MT CO}_2\text{/y)} = \text{Annual energy production (MWh/y)} * \text{Heat rate (MMBtu/MWh)} * \text{CO}_2 \text{ emissions factor (MT CO}_2\text{/MMBtu)}$$

As referenced above, in this study we use a CO₂ emissions factor of 53.07 kg CO₂/MMBtu and do not include upstream greenhouse gas emissions from the natural gas system including leaks.



22830 Two Rivers Road
Basalt, CO | 81621 USA
www.rmi.org

© September 2019 RMI. All rights reserved. Rocky Mountain Institute® and RMI® are registered trademarks.

