



PROSPECTS FOR GAS PIPELINES IN THE ERA OF CLEAN ENERGY

HOW CLEAN ENERGY PORTFOLIOS ARE REDUCING US POWER SECTOR DEMAND FOR NATURAL GAS AND CREATING STRANDED ASSET RISKS FOR GAS PIPELINES

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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.

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EXECUTIVE SUMMARY



EXECUTIVE SUMMARY

Power sector demand for gas has increased alongside gas pipeline capacity

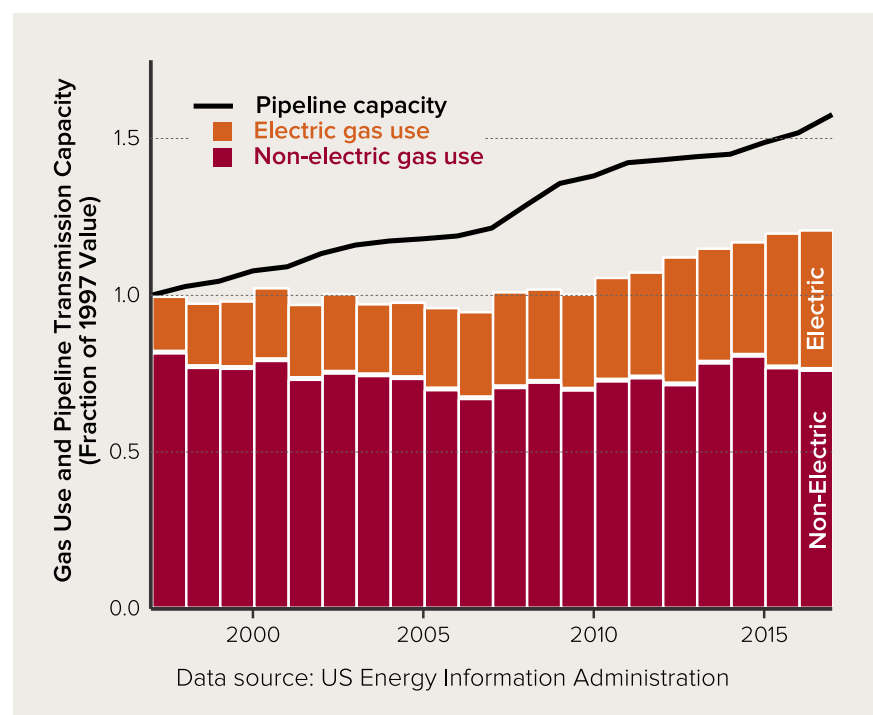
Domestic natural gas production has fundamentally reshaped the US electricity sector over the past two decades. Natural gas is now the single largest source of generation in the United States, with gas use in the power sector growing by over 160 percent in the past two decades. Gas-fired power plants have driven over 90 percent of the growth in total US gas demand, as use in other sectors of the economy has plateaued over the same period.

At the same time, natural gas transmission pipeline capacity to bring gas to power plants and customers in other sectors has increased by over 60 percent since 1997, as pipeline developers have invested over \$115 billion in new intra- and interstate projects. Figure ES 1 illustrates these linked trends at the national level. This national dynamic of increasing gas use in the power sector alongside increasing gas pipeline capacity is visible across most regions of the United States where electricity generation has undergone a rapid transition to gas.

This trend of coupled and growing investment in gas power plants and gas pipelines is set to continue. There are at least \$90 billion worth of new gas-fired power plants planned for construction in the coming 10–15 years, along with over \$30 billion of investment associated with gas transmission projects.

FIGURE ES 1

CHANGES IN NATIONAL GAS USE AND PIPELINE TRANSMISSION CAPACITY



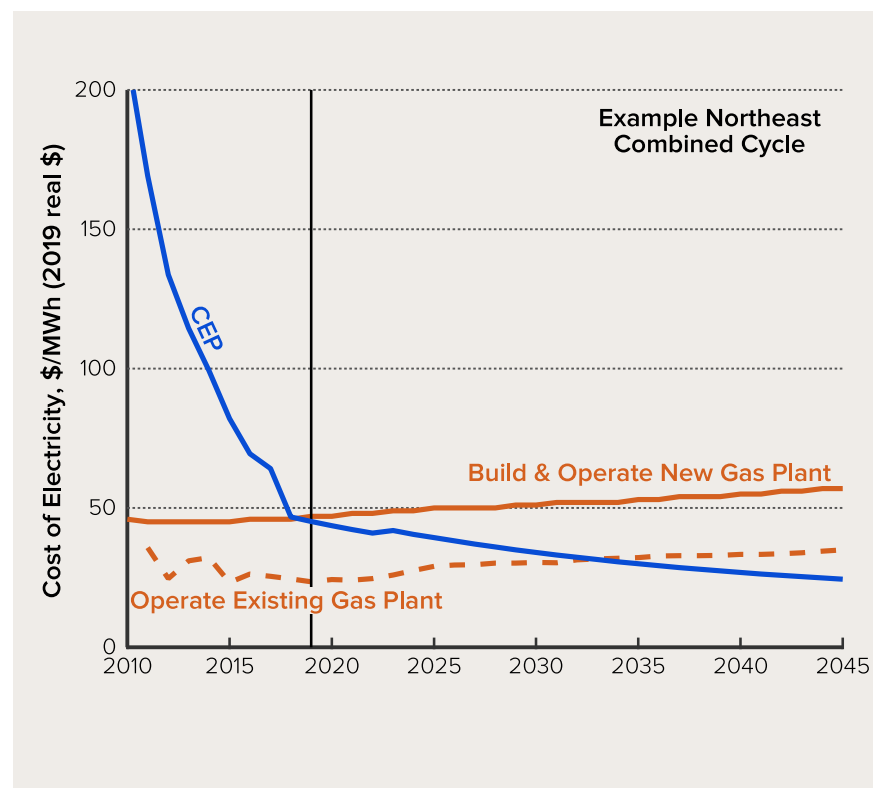
Gas-fired generation economics are at risk from clean energy

However, the fundamental economics of different electricity generation resources no longer support this continued “rush to gas” in the US power sector. This study, together with a [companion report](#), documents a turning point for the relative economics of clean energy resources (including wind, solar, storage [WSS]; energy efficiency [EE]; and demand flexibility) versus new gas-fired generation. For the first time, the rapidly falling costs of renewables and batteries are allowing optimized combinations of these resources—which we term clean energy portfolios (CEPs)—to systematically outcompete gas-fired generation on a cost basis while providing all the same grid services. As shown in Figure ES 2, the costs of a CEP equivalent to a combined-cycle gas plant have fallen by 80 percent since 2010 and now undercut the cost to build and run a typical new gas-fired power plant. By the mid-2030s, we expect the cost of building a new CEP to fall below the cost to operate an existing gas-fired power plant. These results do not assume any cost of carbon emissions from gas plants, which would make the cost advantage of CEPs even larger.

Capitalizing on these changing economics, utilities, policymakers, and regulators are beginning to reconsider the economic viability of new gas-fired generation, and instead are prioritizing investment in clean energy resources. The gas pipeline industry, at the same time, is recognizing the risks of this economics- and policy-driven shift away from gas-fired generation, a sector that currently comprises the largest source of demand for pipeline services but whose growth may soon plateau and then decline.

FIGURE ES 2

HISTORICAL AND PROJECTED EVOLUTION OF CEP COSTS



This study assesses the implications of CEPs for gas pipeline economics

This study uses a region-based approach to compare CEPs against new gas-fired generation and estimate the reductions in expected gas use that result from choosing cost-effective CEPs as well as the corresponding impact on demand for and delivered price from new pipelines:

- We focus on five regions of the country with significant proposed market growth in gas generation and gas pipeline projects, and combine a historical analysis of regional gas demand by sector with a forward-looking model of the economic viability of new gas plants proposed for construction in each region.
- In the forward-looking model, we compare the costs of proposed gas plants to the costs of CEPs that can provide the same or more energy, peak capacity, and flexibility to regional grids, both in the proposed in-service year of the planned gas plant and then for every year through 2045.
- When we find that CEPs are lower-cost than new or existing gas plants, we assess the impacts on operating gas plant capacity and expected gas fuel use in the power sector.
- Finally, we estimate the impacts on expected demand for gas transported via new pipelines, as well as the implied changes to the per-unit delivered price of gas from new pipelines associated with falling sales revenue spread over the sunk construction costs, in order to assess the risk of new pipelines becoming underutilized and uneconomic well ahead of their proposed lifetimes.

Overall, our approach assesses the economics of investment in new gas generation, and implications for pipelines, within the context of today's system, with adjustment made for future growth of renewables implied by current state-level renewable energy standards. However, we do not model the financial viability or value of gas plants or CEPs in a system with very high (i.e., >50 percent) shares of wind and solar energy. Thus, our results are best interpreted as consistent with near-term investment decisions that developers must make in assessing project viability over the next 10–20 years, but not necessarily reflective of the long-run role of gas-fired or other thermal generation resources as the grid moves to ever-higher shares of variable generation.



Findings

Our study presents four main findings, detailed below. In short, continued cost declines in clean energy resources will create significant stranded asset risk for newly built gas plants, and to the extent that new pipeline projects rely on revenue from gas-fired generators to justify project economics, this changing dynamic in the power sector will create significant stranded asset risks for pipelines.

1. CEPs are lower cost than over 80 percent of proposed gas-fired power plant capacity

We find that CEPs have a clear economic advantage over proposed gas-fired plants in our focus regions. Figure ES 3 shows the net present

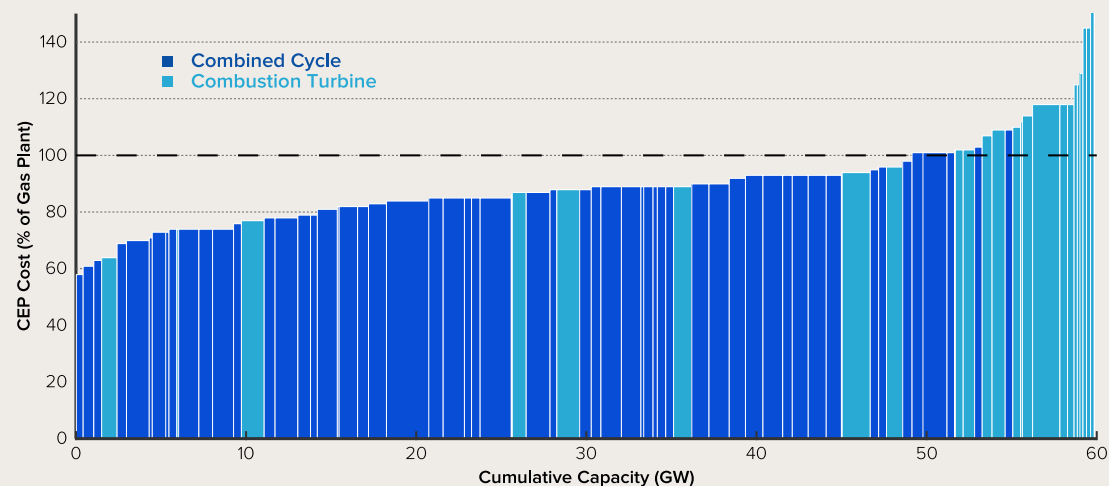
value (NPV) costs of a CEP equivalent to each of the 84 planned gas plants in our study, as a percentage of the NPV costs of the proposed gas plant. CEPs outcompete 49 gigawatts (GW), or 81 percent, of the 60 GW of proposed gas-fired power plants across the five focus regions of this study; investment in these CEPs to avoid the costs of new gas plants represents a \$16 billion NPV savings opportunity for customers.

2. If proposed gas plants are built, the falling costs of clean energy will likely render over 70 percent of planned capacity uneconomic by 2035

The falling cost of new CEPs threatens to force existing or proposed new gas plants (if constructed) into early retirement. Just as the falling

FIGURE ES 3

RELATIVE COSTS OF CEPs AND PROPOSED NEW GAS-FIRED GENERATORS IN FOCUS REGION



gas prices have undercut coal plant operating costs, clean energy technology price declines will soon undercut the costs to maintain and operate existing and proposed gas plants. Our analysis shows that by 2035, 71 percent of planned capacity would have higher operating costs if built than the new-build costs of an equivalent CEP. This changing economic picture for new gas plants will create stranded asset risks for utilities or other investors. Sooner than expected, new gas plants will become uneconomic to run, and leave investors with significant, undepreciated asset value on their books, not offset by future revenues.

3. Competition from clean energy will nearly eliminate expected demand growth for gas from the power sector

Due to the declining economic case for continuing to operate gas plants, by 2035 we find that approximately 85 percent of expected fuel use from new gas-fired generation will likely be avoided, and that energy and other grid services will be instead provided cost-effectively by new-build CEPs. By 2045, only 3 percent of expected fuel use from proposed gas-fired power plants will remain economic within the focus regions.

On a regional level, this decline in power sector demand for gas will lead to an estimated loss of throughput on new pipelines of 20 to 60 percent by 2035 (Figure ES 4), depending on the share of power plant demand to total regional demand and the share of proposed power plants out-competed by CEPs.

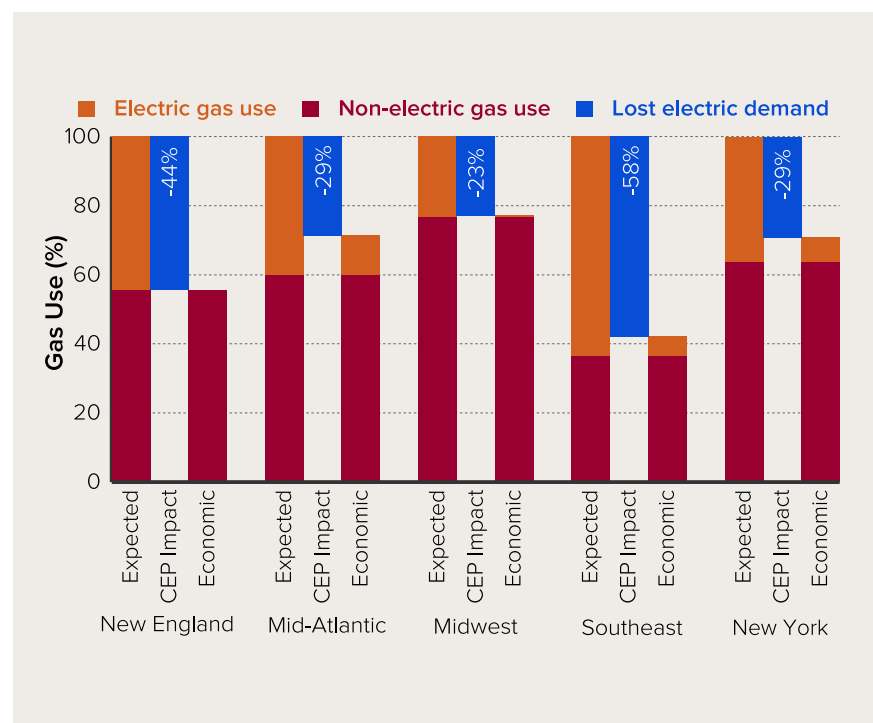
4. Lower-than-expected demand will significantly increase the per-unit cost of gas from newly built pipelines

Declining throughput for newly built gas pipelines will force sunk pipeline cost recovery over fewer units of delivered fuel. Estimated declines of 20 to 60 percent of pipeline throughput across the five regions (Figure ES 4) correspond to increases of 30 to 140 percent in

per-unit delivered cost of fuel (Figure ES 5). This dynamic risks setting up a reinforcing feedback loop, sometimes referred to as a “death spiral,” for gas pipelines whose unit costs rise as throughput declines—if these rising unit costs are passed on to gas generators as increased rates for transporting gas through a pipeline, this in turn leads to additional loss of throughput and further unit cost increases.

FIGURE ES 4

IMPACT OF CEP COMPETITION ON EXPECTED DEMAND FROM NEW PIPELINES IN FOCUS REGIONS

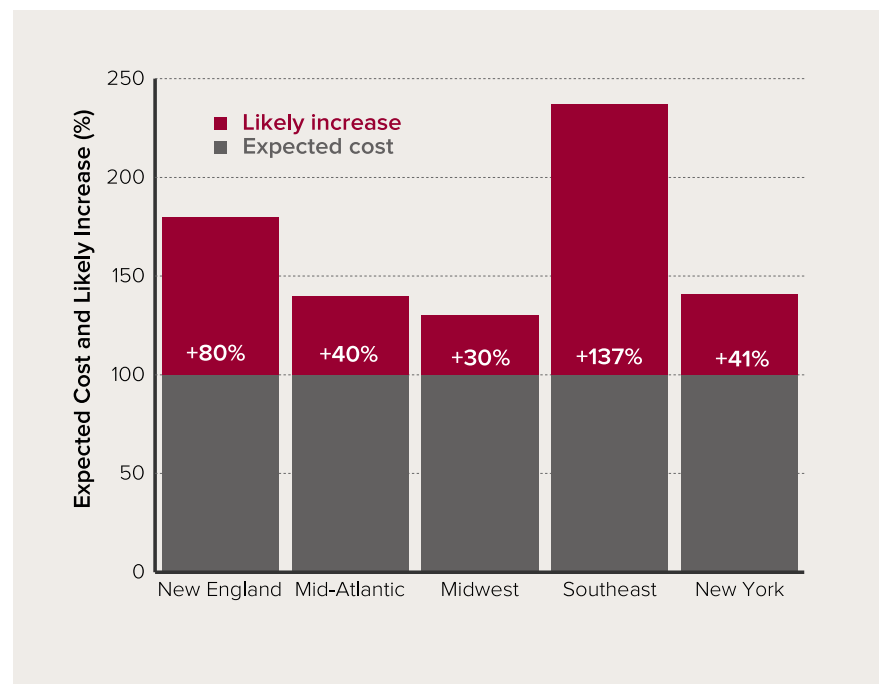


Implications & Recommendations

The financial implications for gas pipelines of clean energy outcompeting gas power plants are dire, but where the ultimate risk lies depends on the contract and off-take structure for a specific pipeline. In many cases, captive customers of regulated gas and electric utilities ultimately bear the financial risks of investment today in assets—pipelines and power plants—that are likely to become uneconomic sooner than anticipated.

FIGURE ES 5

IMPACT OF CEP COMPETITION ON PER-UNIT DELIVERED COSTS FROM NEW GAS PIPELINES



We provide recommendations for developers, investors, and regulators to mitigate these risks and help temper near-term investment in over \$100 billion in gas infrastructure that will likely be underutilized and uneconomic within the next 15 years.

For asset developers and investors: Carefully consider economics of new gas power plants and pipelines in light of clean energy competition

All gas plant and pipeline developers, and investors that provide them capital, should carefully assess the market and competitive position of contemplated gas-fired power or pipeline projects.

- *For vertically integrated electric utilities and holding companies:* Utilities and holding companies considering a position in new pipeline capacity should carefully assess their risk tolerance for stranded costs associated with new gas infrastructure investment, given the emerging dominance of clean energy resources.
- *For merchant power plant developers:* Similar to electric utilities, merchant gas power plant developers should reconsider the competitiveness of gas-fired generation over the expected lifetime of the project, and contract for pipeline capacity accordingly—likely over much shorter durations than previously considered.
- *For investors in pipeline projects or companies:* The current rush to gas in the US power sector, combined with the negative economic outlook for new gas plant and pipeline capacity additions, suggests the real and growing potential of ongoing overbuild and future overcapacity of gas infrastructure. Investors should carefully reassess the fundamentals of the industry and the competitive position of new projects in light of the economic advantages of clean energy resources in the near term.

For regulators: Assess likely future demand for gas pipelines when determining public benefit and allocating risk

Regulators for both electric and gas utilities have a role to play in shielding captive customers from risks imposed by utility investment in or contracting with new pipeline projects:

- *For regulators of vertically integrated electric utilities:* Electric utility regulators in vertically integrated markets should ensure that utilities use best practices in prioritizing generation investment (e.g., market-based, all-source resource procurement), so that utility forecasts of gas pipeline capacity needs are robust and reflective of the ongoing transition in the power sector.
- *For gas utility regulators:* Gas distribution companies are often the primary contract holder for new pipeline capacity, even though electric generators are increasingly the largest users of pipelines, because gas distribution companies resell their capacity rights to generators. Gas utilities rely on these revenues to keep costs low for their customers; a loss of revenue in the secondary market due to falling power sector demand will effectively raise the price paid by captive gas customers. Gas utility regulators considering proposed gas utility positions in new pipeline capacity should carefully assess the risks imposed on customers if expected electric sector demand fails to materialize, and allocate risks and incentives accordingly.
- *For other federal- and state-level pipeline regulators:* The Federal Energy Regulatory Commission (FERC) issues certificates for new pipelines in part based on determination of need for new pipeline capacity. Our analysis suggests that FERC has the opportunity to examine more holistically, and over a longer time horizon, the need for additional

pipeline capacity, and adjust amortization periods and associated cost recovery rates accordingly. At the state level, regulators that influence the construction of new pipelines should similarly evaluate the demonstrated need for new projects in the context of improving clean energy economics and likely demand sources for new pipeline capacity.



1

INTRODUCTION



INTRODUCTION

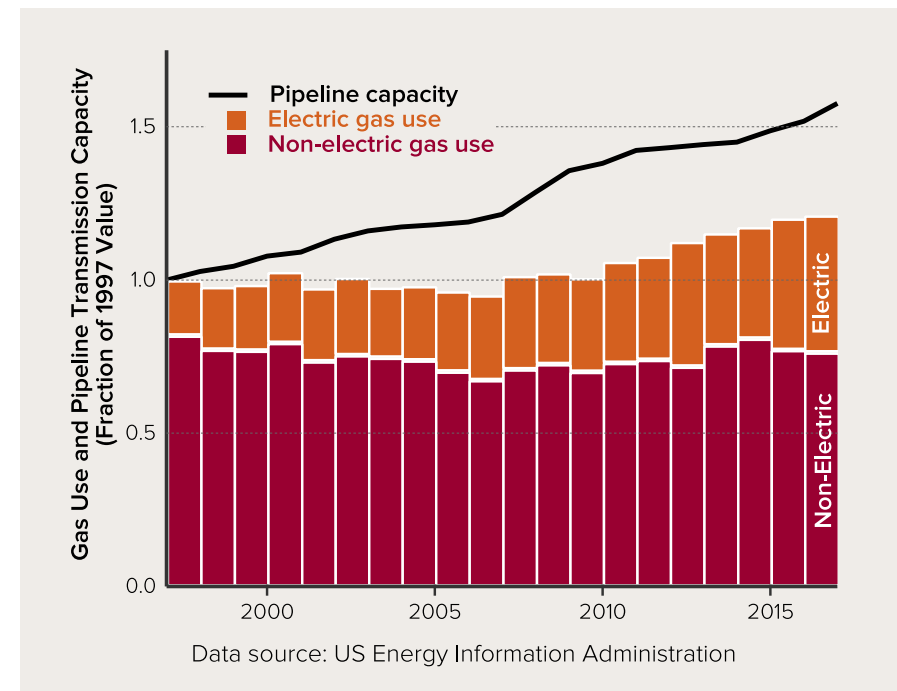
The diminishing need for gas-fired generation and gas pipelines

The combination of natural gas and renewable energy resources, in particular wind and solar, has fundamentally reshaped the US electricity sector over the past two decades. Advances in shale gas extraction technologies and processes have catapulted gas into its current role as the single-largest fuel source for US electricity generation. What was once an expensive, niche fuel for electricity generation has now taken over from coal as the leading domestic primary energy source for the power sector.

Increasing gas use in the power sector is driving growth in overall natural gas demand in the United States and is concurrent with significant investment in gas pipelines to bring gas from production regions to new gas-fired power plants and other users. Demand for natural gas outside of the power sector has been flat, rising only 4 percent from 1997–2018, while use for electricity generation has risen by over 160 percent in the same period. At the same time, pipeline companies have invested over \$115 billion in inter- and intra-state transmission pipeline projects,¹ resulting in the growth of gas transmission capacity between and within major US market regions by over 60 percent in the same period as power sector demand grows and production regions shift. Figure 1 highlights this national trend.

FIGURE 1

CHANGES IN NATIONAL GAS USE AND PIPELINE TRANSMISSION CAPACITY



¹ This and all dollar values in this report are presented in real 2018\$. Data source: Energy Information Administration (EIA) pipeline project database available at <https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx>

The national trend of growing gas demand in the power sector, flattening demand in other sectors, and pipeline capacity investment is amplified in regions of the country with the most growth in gas generation in the past decades. This paper, focusing on gas use in the electricity sector, defines nine US market regions in the contiguous United States. These regions are broadly coincident with regional electricity market regions (Figure 2).

FIGURE 2
REGIONAL DEFINITIONS FOR THIS ANALYSIS

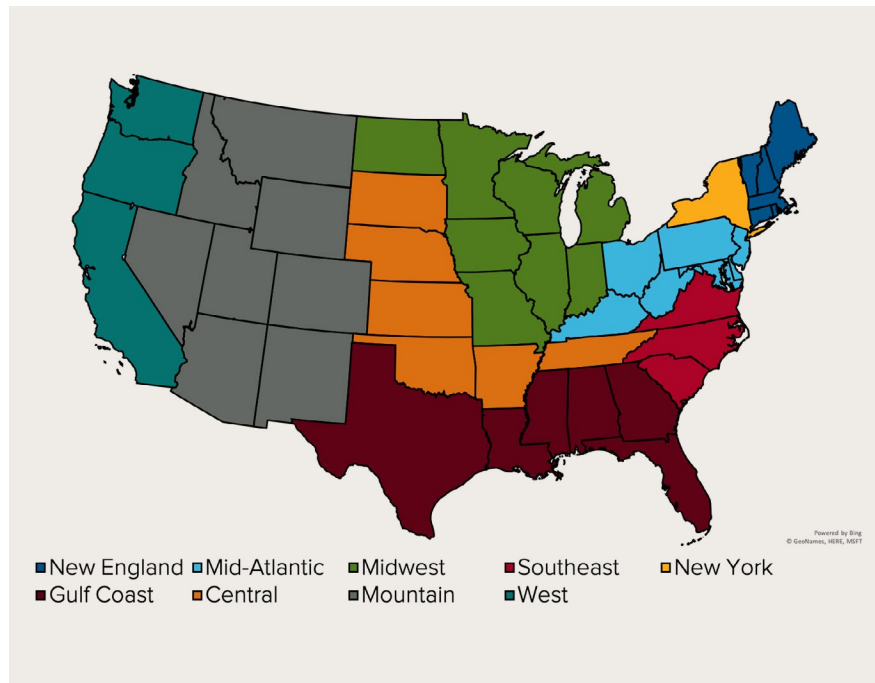
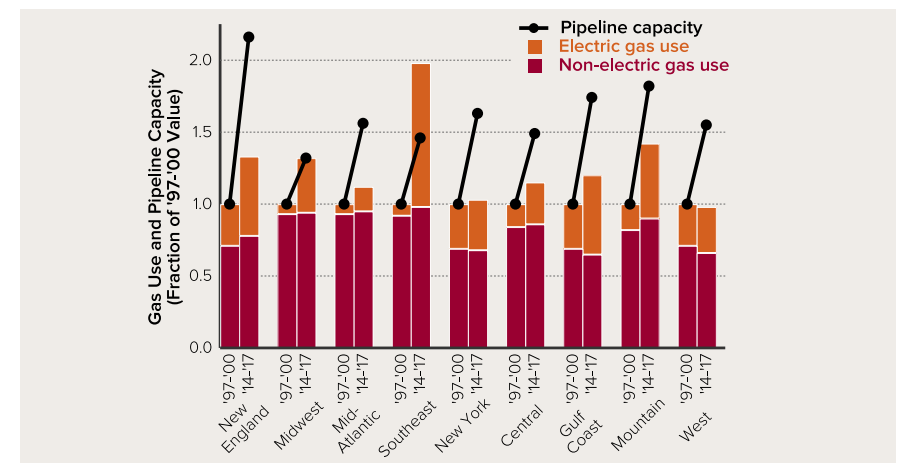


Figure 3 illustrates the regional trends in gas use both in and outside of the power sector for each region, as well as historical increases in transmission pipeline capacity into and within each region, which we define as import capacity from states outside the defined market region plus intra-regional projects that cross state lines.² Pipeline capacity into each region has grown at the same pace or faster than electric sector demand, while non-electric sector use (e.g., gas burned directly in buildings or consumed in industrial facilities) has been flat or declining. Across these markets, pipeline import capacity increased by 35 to 90 percent between 1997 and 2018. At the same time, new gas plants and increased use of the gas-powered fleet resulted in total gas use growing by around 20 percent nationwide and in some regions by up to 95 percent.

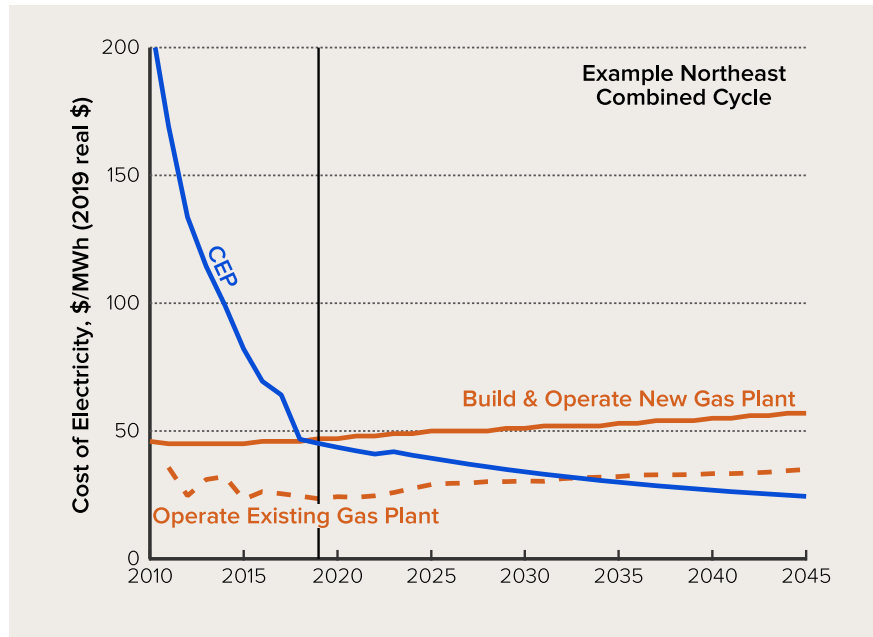
FIGURE 3
CHANGES IN REGIONAL GAS USE AND TRANSMISSION CAPACITY



² In our graphs showing historical and forecast additions to pipeline capacity, we exclude intrastate pipeline capacity in both the start period and the end period, as complete data on historical intrastate gas transmission capacity is not available.

This trend of coupled and growing investment in gas power plants and gas pipelines is set to continue. As shown in [a complementary companion report](#), there are approximately \$68 billion worth of new gas-fired power plants proposed or planned for construction across the United States in the next five years, and at least another \$20 billion of investment in new gas plants recommended in long-term utility plans. At the same time, there is over \$31 billion of planned investment in [gas pipeline projects](#) announced for construction over the next four years. The near-term gas power plant

FIGURE 4
RELATIVE COSTS OF CEPS AND PROPOSED NEW GAS-FIRED
GENERATORS IN FOCUS REGION



construction proposals alone would emit 100 million tons of CO₂ emissions per year—accounting for nearly 25 percent of the emissions budget of a power system with **80 percent lower emissions than 2005 levels**—even assuming zero greenhouse gas emissions associated with [upstream and midstream methane leakage](#). The assumed economic lifetimes of these assets—20 to 30 years for the proposed gas plants and 40 to 50 years or more for the pipelines purported to supply them—would lock in these emissions for decades.

However, due to the cost and climate implications of these long-lived assets that have not yet begun construction, there is a pressing opportunity for industry players to reassess the continued “rush to gas” that has been driving the evolution of the US power system, and the pipeline infrastructure that feeds it, for the past decade. There is now a clear economic signal that continuing investment in gas power plants, and any associated pipeline infrastructure, risks creating new stranded costs for investors, ratepayers, and society at large as clean energy technologies begin to outcompete gas-fired generation.

As we lay out in [the companion report](#), combinations of wind, solar, storage (WSS) and demand-side resources can form “clean energy portfolios” (CEPs) that, together, can cost-effectively provide the same energy, capacity, and reliability services to the grid as gas-fired power plants. We find that 2019 represents a tipping point in the economics of CEPs; CEPs equivalent to a typical new gas plant have declined by >80 percent in cost since 2010, now beating new gas power plants on price, and are expected to undercut the costs of operating existing gas by the early 2030s. Figure 4 illustrates typical economics, both historic and projected, of a CEP (composed of an optimized mix of WSS, demand flexibility, and EE technologies) compared to both the new-build and go-forward operating costs of a combined-cycle gas plant, and demonstrates the present turning point in CEP economics.

In this study, we examine the implications that the improving economics of clean energy will have on the economics of planned gas pipeline capacity. We use the framework of CEPs, laid out in the companion report and summarized here, to estimate the changes to demand for gas transportation via new pipeline projects, when the gas plants are either not built, or they

are out-competed by clean energy and stop running sooner than expected. We then assess the risks that pipeline capacity subscribers face if the power sector—the historical and expected driver of demand growth for gas in the United States moving forward—instead turns to clean energy. Lastly, we offer recommendations to mitigate risks to consumers and investors.



2

MARKET SNAPSHOT



MARKET SNAPSHOT

Economics and policy increasingly favor clean energy, putting future of gas demand growth in question

Natural gas consumption in the United States has risen to new records as of 2018, but across sectors, future demand growth for gas is increasingly uncertain due to emerging clean energy resource economics and public policy priorities. As a result, pipeline owners and developers have themselves sounded the alarm on the risks their industry faces in light of uncertain or falling demand in the near- to mid-term future. The following sections lay out emerging trends across sectors relevant to pipeline economics and summarize the response to date of pipeline companies.

Power sector: Utilities are prioritizing CEPs at the expense of new gas plant investment

Across the country, utilities have accelerated their transition to clean energy, and either minimized or avoided entirely any planned investment in new gas generation. Nationwide, final investment decisions to build new natural gas-fired power plants have declined each year since 2014. This national trend is exemplified across major market regions in the United States. In the Midwest, Consumers Energy and Northern Indiana Public Service Company are planning to retire most or all of their remaining coal assets and replace them with new WSS and demand-side resources, avoiding any investment in new gas-fired generation and saving their customers billions of dollars. In Colorado, Xcel Energy will retire two coal plants ahead of schedule and replace them with WSS and demand-side resources, again avoiding any investment in new gas and while delivering savings to their customers.

Other states are deploying clean energy technologies at scale, including the following:

- **Arizona:** Arizona Public Service will build 850 megawatts (MW) of storage to help new and existing solar meet their peak capacity needs.
- **California:** Southern California Edison will use batteries in lieu of new gas to meet reliability needs.
- **North Carolina:** Duke Energy effectively canceled a new gas plant in lieu of battery investment and customers' use of weatherization and other efficiency measures.
- **New England:** Sunrun's aggregated residential portfolio of solar and storage won a competitive bid in Independent System Operator-New England's (ISO-NE) forward capacity market.
- **Oregon:** Portland General Electric will use a portfolio of efficiency, WSS, and demand flexibility to meet growing capacity needs, while also avoiding investment in new gas.
- **Southern states,** including Arkansas, Tennessee, Georgia, and Florida: Utilities are allowing batteries to compete alongside conventional resources in their procurement processes.

Pipeline companies, in turn, recognize this competition from clean energy technologies as a threat to the economics of gas pipelines. For example, in 2015, Tallgrass Interstate Gas Transmission noted,³ “The average PPA (Power Purchase Agreement) price (sic) for wind in 2013 and 2014 are below natural gas fuel costs alone.” In 2017, Great Lakes Transmission acknowledged competition from renewables when it testified that, “Since most end-use consumption of natural gas can likely be substituted with electricity, this shows the potential for renewable energies to significantly diminish demand for firm deliveries of natural gas. Wind generation in particular has increased significantly in Michigan, Minnesota, and Wisconsin in recent years.”⁴

Public policy: Climate goals are driving gas out of power sector and buildings

Across the United States, state-level clean energy standards will increasingly preclude use of gas plants that lack emissions abatement technologies. Already, six states and Puerto Rico have signed laws targeting a 100 percent clean electricity generation mix within the next 20 to 30 years. [Hawaii](#) was the first to do so in 2015, followed by [California](#) in 2018, and [New Mexico](#), [Nevada](#), [New York](#), [Washington](#), and [Puerto Rico](#) each in 2019. At least six other states have executive orders, pledges, or proposals under consideration for achieving 100 percent clean electricity generation, including [New Jersey](#), [Colorado](#), [Maine](#), [Wisconsin](#), [Illinois](#), and [Minnesota](#). Together, these 12 states and Puerto Rico account for [23 percent of national electricity sales](#).

Outside the power sector, policymakers across the United States are prioritizing [electrification of buildings’ space and water heating loads](#), thus limiting future growth of gas demand within the buildings sector. New York City passed the [Climate Mobilization Act](#), comprehensive legislation that requires large buildings to cut their climate emissions 80 percent by 2050. In support of its climate goals, [California is deploying \\$200 million](#) over four years to encourage gas-free homes, and over [50 cities across California](#) are considering building electrification as an emissions reduction pathway. [Marin County and Palo Alto](#) have adopted building codes to encourage electrification, and [Berkeley recently banned gas in new homes](#).

Momentum toward electrification extends beyond New York and California, including the following examples:

- [New Jersey](#) is pursuing “maximum electrification of the transportation and building sectors” in its efforts to achieve 100 percent clean energy.
- [Maine](#) is targeting deployment of 100,000 heat pumps.
- [Rhode Island](#) is prioritizing decarbonization of heating systems.
- [Vermont’s](#) Renewable Energy Standard requires that its gas distribution companies participate in decarbonization.
- [Massachusetts](#) has authorized electrification as an emissions reduction strategy.
- Additionally, the mayor of [Seattle](#) has proposed a heating oil tax to encourage electrification.

³ Tallgrass Interstate Gas Transmission, LLC, Section 4 Rate Case, Docket No. RP16-137, Exhibit No. TIG-34 at page 25, lines 2–4 (October 30, 2015)

⁴ General Section 4 Rate Filing, Docket No. RP17-598, Exhibit No. GL-011 at page 32, lines 2–6 (March 31, 2017)

As Rocky Mountain Institute (RMI) has shown in previous work, building electrification will result in less total gas use, even if all electricity to supply heat pumps is generated by gas-fired power plants, because heat pump efficiency more than makes up for gas plant inefficiency.

Pipeline companies, in turn, have cited such climate-focused policy as a threat to the future profitability of gas pipelines. In 2016, Dominion Cove Point (DCP) testified that such efforts “could reduce the demand for natural gas in the long-run, negatively impacting the demand for all of DCP’s services.”⁵ In 2017, Eastern Shore Natural Gas Company cited a Department of Energy study showing that decarbonization of the US electric system would necessitate reducing gas-fired generation by up to 72 percent. Eastern Shore Natural Gas Company wrote, “Such a large decrease in natural gas use would cause a significant amount of excess pipeline capacity to exist and could greatly impact the ability of pipelines to collect their fixed costs.”⁶

Liquefied natural gas (LNG) for export is a growing driver of demand for pipeline capacity outside of this study’s focus region

The LNG export market is a relevant driver of demand for new pipeline capacity in some regions of the United States with existing or planned LNG export facilities. However, most LNG export facilities, both operating or proposed for construction, are outside of the focus regions of this study, where historical and expected future growth in demand for natural gas is

dominated by the power sector. As such we do not directly consider LNG export in our assessment of demand for transportation from new pipelines in this study’s focus regions. See the Methodology section and Appendix for additional discussion of this study’s treatment of uncertainty in LNG export demand.

Pipeline developers recognize risk of declining demand growth and overcapacity

Recognizing the uncertainty in future demand growth for gas, pipeline company executives have noted that the industry is building more pipeline capacity than is needed. For example, a senior vice president at Range Resources, a large exploration company operating in the northeastern United States, said in 2017, “We don’t think there’s going to be enough near-term supply to fill all the [pipeline] capacity Historically, every play gets overbuilt.” Kelcy Warren, CEO of Energy Transfer Partners said in 2015, “The pipeline business will overbuild until the end of time.”

Such an overbuild of pipeline capacity suggests that pipeline owners will be unable to fully recoup sunk costs associated with underutilized assets. Accordingly, companies have been filing comments and requests for accelerated depreciation schedules to fully recover sunk costs,⁷ further illustrating that the future demand outlook for gas transportation services via pipelines is becoming more uncertain over the multi-decade planning horizon associated with new gas plant and pipeline investment.

⁵ Dominion Cove Point LNG, LP, Section 4 Rate Case, Docket No. RP17-197, Exhibit No. DCP-0088 at page 19, lines 17-22 (November 23, 2016)

⁶ Eastern Shore Natural Gas Company, Section 4 Rate Case, Docket No. RP17-363, Exhibit No. ES-23 at page 21, lines 10–23 (January 27, 2017)

⁷ Comments of Environmental Defense Fund (EDF) in FERC Docket No. PL18-1-000 (2018), Exhibit EDF-1, page 5

3

METHODOLOGY



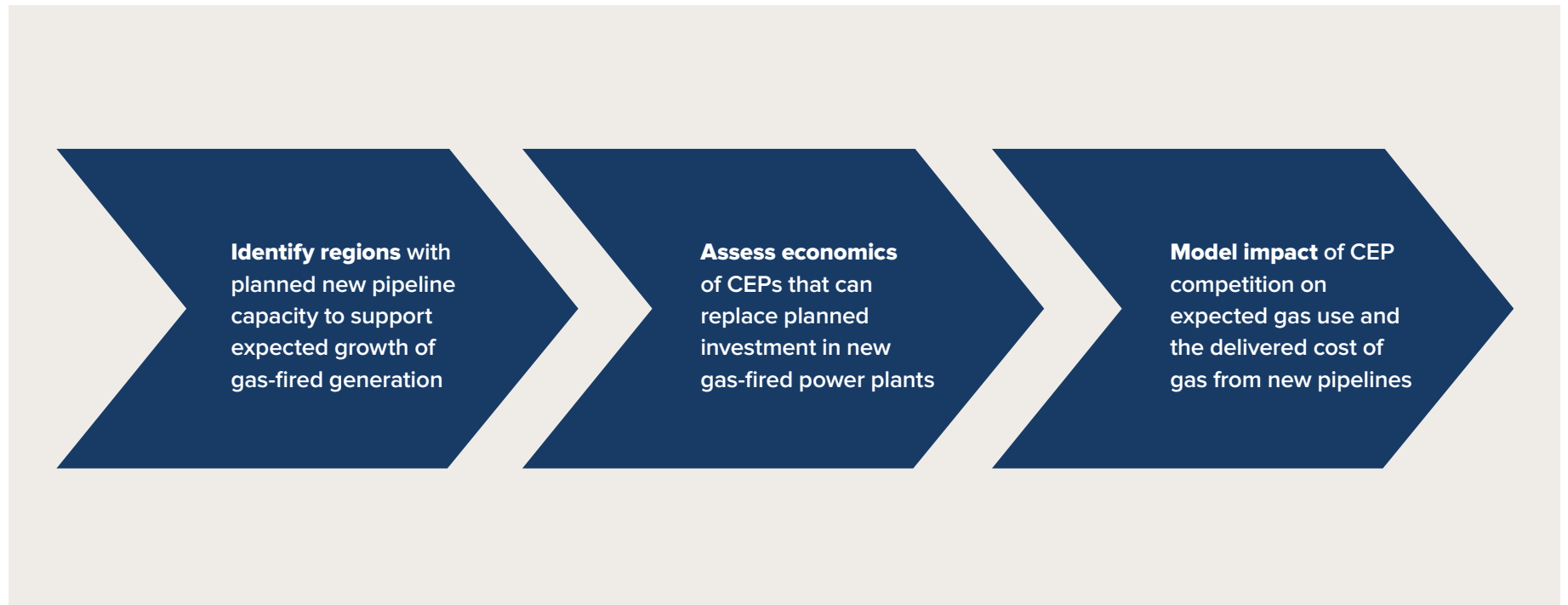
METHODOLOGY

Overall approach

Our study uses a region-based approach to assess the economics of CEPs against new gas-fired generation and estimate the reductions in expected gas use that result from choosing cost-effective CEPs, as well as the corresponding demand for and delivered price from pipelines. Figure 5 summarizes this approach at a high level, and subsequent sections provide details.

FIGURE 5

OVERALL STUDY APPROACH



Regional analysis scope

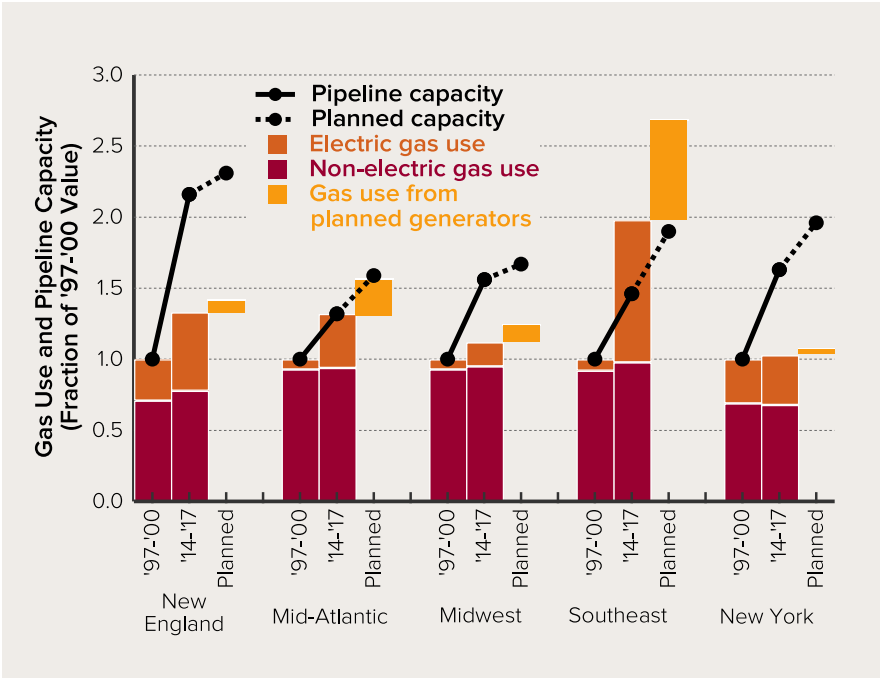
We focus on five regions of the country with significant proposed market growth in gas generation and gas pipeline projects (Table 1). These regions generally correspond to Eastern US electricity market regions, with different characteristics of generation competition and cost recovery that influence risks and opportunities outlined in a later section of this report.

TABLE 1
STUDY FOCUS REGIONS

FOCUS REGION	PRIMARY ELECTRICITY MARKET ORGANIZATION	PRIMARY MODE OF COST RECOVERY AND COMPETITION FOR GAS-FIRED GENERATION
New England	ISO-NE	Restructured market with open competition
Mid-Atlantic	PJM	Restructured market with open competition, with some exceptions (i.e., KY, WV)
Midwest	Midcontinent Independent System Operator	Cost of service recovered in rates
Southeast	Vertically integrated utilities	Cost of service recovered in rates
New York	New York Independent System Operator	Restructured market with open competition

For each region, we examine historical gas use and pipeline import capacity using US EIA data, proposed pipeline import capacity using EIA data, and proposed new gas plant capacity using a combination of S&P Global Market Intelligence data and review of integrated resource plans (IRPs) published by vertically integrated utilities. Figure 6 shows the scale of proposed generator and pipeline investment, through the end of

FIGURE 6
HISTORICAL AND PROJECTED CHANGES IN FOCUS REGION GAS DEMAND AND PIPELINE CAPACITY



announced planning periods, for each region. The focus regions have all experienced a significant rise in pipeline import capacity since 1997, and all have significant pipeline projects proposed through the mid-2020s. Regulated utilities and/or independent power producers in each studied region have proposed new gas-fired power plants for construction, with some regions expecting significant growth (Figure 7).

FIGURE 7
PROPOSED GAS-FIRED POWER PLANTS IN FOCUS REGIONS

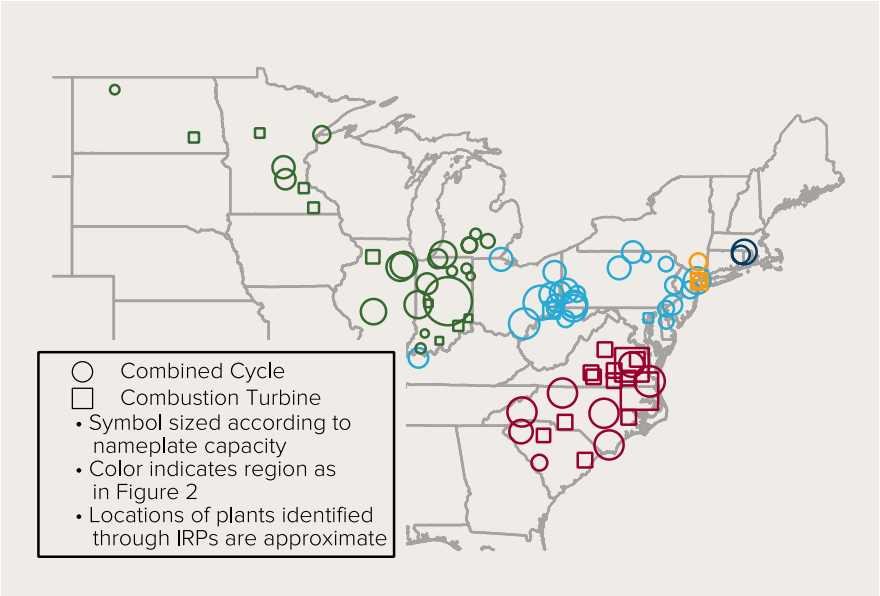
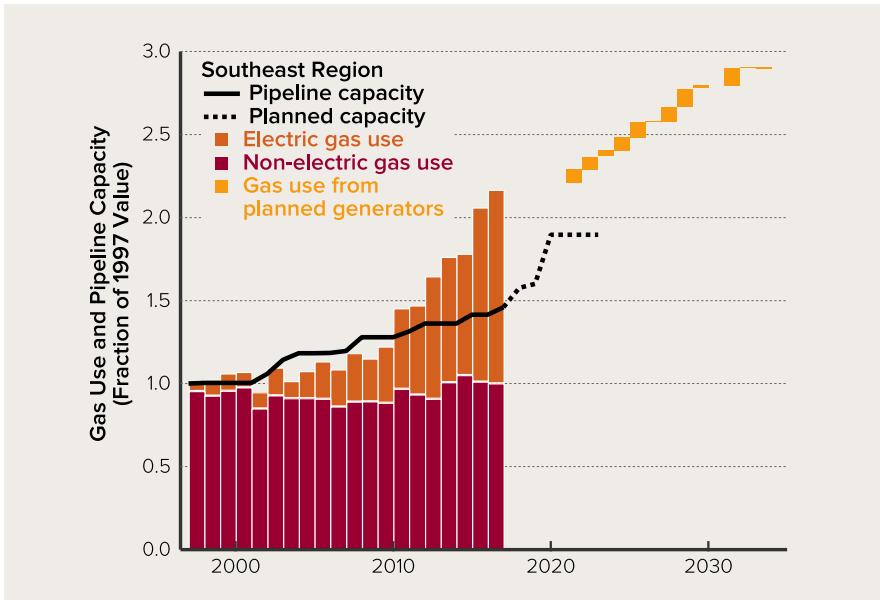


Figure 8 shows a detailed breakdown for two focus regions, the Southeast and the Mid-Atlantic, of historic changes in gas use and pipeline development, and projected additions to both transmission pipeline capacity (dotted lines) and gas use from new power plants proposed for construction (light orange). In both cases, the growth of gas demand in the power sector has driven all regional growth in overall gas demand, and, at the same time, gas transmission capacity into and within the region

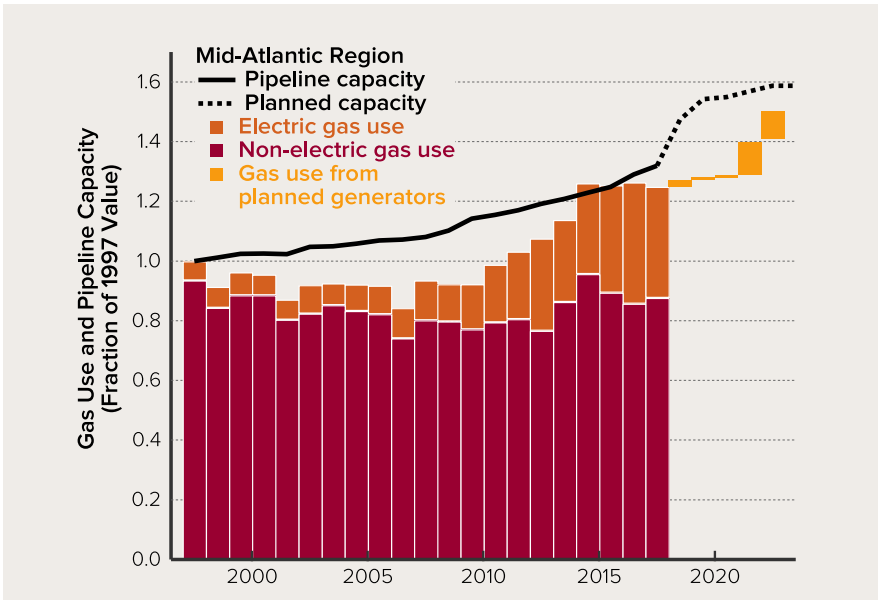
FIGURE 8A
HISTORICAL AND PROJECTED CHANGES IN SOUTHEAST REGION GAS DEMAND AND PIPELINE CAPACITY



⁸ Intrastate capacity has also grown steadily, but with significantly lower cost and flow capacity than intrastate projects, and as such, we exclude intrastate projects from representations of historical and forecast pipeline expansion.

has grown steadily.⁸ Also in both regions, there is proposed construction for significant new gas generation, along with several major pipeline projects. In the Southeast, the timeline of expected gas plant additions extends into the 2030s based on long-term utility IRP filings, whereas in the Mid-Atlantic, most proposed investment is not announced in IRPs, but rather is secured by the results of shorter-term (i.e., one-year commitment, three-year forward) FERC-regulated capacity market auctions.

FIGURE 8B
HISTORICAL AND PROJECTED CHANGES IN MID-ATLANTIC REGION GAS DEMAND AND PIPELINE CAPACITY

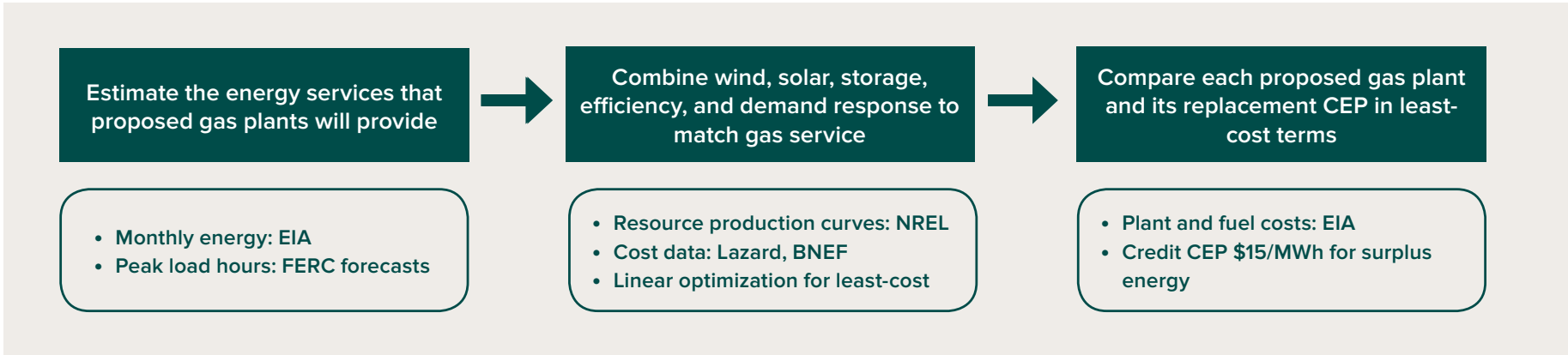


CEP modeling approach

We define CEPs as sets of diverse clean energy technologies that, together, can provide the same grid services as new gas-fired power plants, often at lower cost. RMI introduced the concept of CEPs in our 2018 paper [*The Economics of Clean Energy Portfolios*](#), an effort we have updated in the companion report to this study by assessing the economics of CEPs against all proposed new gas plants, nationwide.

In this study, each CEP is optimized to replace a proposed gas plant by providing the same or better energy and reliability services. For each case, we consider unique service requirements that the proposed gas plant would meet performance characteristics of clean energy resources and costs. The diagram and text below provide an overview of the approach we use to design CEPs; detailed methodology is available in the Technical Appendix.

FIGURE 9
HIGH-LEVEL SUMMARY OF MODEL APPROACH



Required energy services

To consider a CEP at least the equivalent of a gas-fired power plant and provide the same availability and reliability services to the grid, we estimate the level of three grid services that each proposed power plant and CEP would provide:

- **Monthly energy:** Each CEP must produce at least as much energy as the gas plant it would replace in each month of the year. We estimate the gas plant's monthly capacity factor (CF) by assuming operators will run the plant similarly to other comparable plants in the region where proposed for construction.
- **Peak-hour capacity:** The CEP must match or exceed the gas plant's power output during the region's top 50 hours of peak net load (i.e., total regional load minus hourly expected wind and solar energy production). To define net load, we include expected wind and solar energy production from existing renewable resources, planned generation to meet state-level renewable portfolio standards (RPS), and CEPs that would have out-competed new gas plants in previous years.
- **Flexibility:** The CEP must be able to match the gas plant's power output 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 ramp-down of 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 PV power output drops).

Modeling of candidate CEP capabilities and costs

Each CEP consists of some combination of the following technologies:

- **Renewable energy generation:** utility-scale onshore wind and solar photovoltaics (PV). Estimated monthly and hourly CFs from National Renewable Energy Lab (NREL) data informed the performance of particular CEPs. We account for both project costs and required transmission investment.
- **Battery energy storage:** utility-scale lithium ion projects, with dispatch durations between one and eight hours. We simulate dispatch during peak hours to meet CEP capacity requirements, and derate storage when more than one peak hour occurs on the same day. We account for both AC (i.e., power output) and DC (i.e., storage duration) costs, as well as replacement of cells lost to degradation during battery cycles.
- **Energy efficiency:** efficient heat pumps and lighting. We model hourly profiles of EE savings associated with specific end uses using historical hourly end-use data (based on EIA and survey data), and estimate the associated contributions to CEP capacity, energy, and flexibility constraints. We use Lawrence Berkeley National Lab (LBNL) data to account for the costs of saved energy from such programs.
- **Demand flexibility:** technologies or programs that enable flexible loads to shift outside of peak hours and/or to coincide with renewables generation. We model hourly capabilities of end-use specific programs to estimate how demand flexibility can meet CEP capacity and flexibility constraints. We use EIA data to account for the costs of utility programs to enable load shifting.

We use an optimization model to find the least-cost combination of investment in clean energy resources that can meet the service requirements of a proposed gas-fired power plant. We include a detailed conceptual explanation of our model framework in the Technical Appendix.

Cost comparison of CEPs and gas plants

The output of the CEP optimization model is a combination of clean energy resources that can provide the same essential services as a proposed gas-fired power plant. We then compare each CEP to the gas plant it was designed to replace by a number of metrics, including net present total cost.

We consider total lifetime costs associated with each clean energy resource, including all major capital, operational, and replacement expenses, levelized to allow for direct comparison with other technologies. We include transmission cost adders for utility-scale renewable resources. Our data for resource cost comes from publicly available and subscription service sources, such as Bloomberg New Energy Finance (BNEF), Lazard, and EIA. For a conceptual explanation of our approach and sources, see the Appendix.

Key changes to approach used for this study

We augmented the CEP modeling approach used in our May 2018 study and the September 2019 update to better represent the region-wide interdependencies between the competitiveness of gas in the power sector and the economics of new pipelines.

- Region-level impacts of CEP adoption:** In this study, we explicitly account for interactions between CEPs in each state by adjusting system net load forecasts and total available resource potential by including renewable generation implied from winning CEPs in our modeling. Thus, while our core CEP modeling approach considers only the marginal CEP, the approach taken for this study considers many of the key interactions between CEPs in aggregate. This adjustment has the greatest effect in the Southeast and Mid-Atlantic regions of this study, where proposed gas plant capacity is equivalent to a significant fraction (~10–20 percent) of present-day peak demand.
- Region definitions:** The regions used in this study are adjusted from those used in our previous and companion studies to better reflect electricity market regions and regions with significant proposed pipeline capacity additions.
- Inclusion of IRP gas plants:** In this study, we include proposed gas plants announced in publicly available utility IRPs, despite being less certain than specific projects announced for construction, to reflect expected long-term demand for gas in the power sector that, in some cases, proposed pipelines may be used to meet.

Implications for pipeline economics

This paper extends our companion study by assessing the regional impact on pipelines of reduced gas demand due to substituting proposed gas generators with clean energy.

Expected demand for transportation services

While data for some specific pipeline projects is available that indicates likely sectors, or even power plants, using the transported gas, there is no comprehensive source for such estimates of offtake and ultimate end use by pipeline. Thus, we estimate the sector-specific demand for transportation services from new pipelines into each focus region by using the present-day breakdown of consumption, modified to account for gas demand from planned new gas power plants. We take a three-part approach to estimating this demand:

1. **Assess current sector-level demand for gas in each region.** We use 2017 data (the latest year for which comprehensive regional data is available for gas demand outside of the power sector) as a starting point for the assumed market of a newly built pipeline into a given region. For example, in the Southeast region, power sector demand made up approximately 51 percent of gas use in 2017.
2. **Add expected demand from proposed power plants.** To capture the dynamic of pipeline developers responding in part to expected new demand in the power sector when making investment decisions, we look out to the end of available planning cycles for gas plant investment to estimate expected capacity. We also estimate expected CFs for proposed plants by benchmarking against similar plants

already in operation in each region. For example, in the Southeast, there are about 18 GW of proposed or planned gas-fired power plants with online dates before 2034 in our sample; if run at assumed CFs, these plants would increase the power sector's share of regional gas use to 68 percent from today's 51 percent.

3. **Assume new pipelines serve a mix of additional gas power plant and existing non-power sector demand.** We note that existing gas power plants' gas import needs are met largely by existing pipeline capacity,⁹ and assume that continues into the future. We thus assume that gas imported via new pipelines will serve two demand sources:

- a. Incremental gas-fired power plant consumption on the margin of the region's current demand. In some cases, this is likely simplistic; for example, pipelines built into the Southeast from the Marcellus and Utica shale gas plays may offer lower-priced gas to regional utilities than presently existing pipeline capacity which imports from the Gulf Coast region. We explore the implications of this potential dynamic below.
- b. Demand for gas outside of the power sector. We note that existing pipelines are serving demand outside the power sector, and thus new pipelines would not necessarily have a ready market for their gas in these users. In the case of new demand (e.g., from LNG export) potentially arising in some regions of the country, some pipelines may have more ready access to demand outside the power sector. As a conservative assumption, we assume that new pipelines can sell to a non-power sector market for which gas demand remains largely unchanged from today's levels.

⁹ Or, in the cases where gas import capacity is nominally constrained, could be addressed by [gas demand response](#) programs with minimal impact on customer comfort.

Step 3 yields an estimate, at the region level, of the sector in which gas brought into the region will ultimately be used if proposed gas plants are built. We then use the outputs of the CEP model, described above, to determine whether gas use in proposed power plants is economic or not (i.e., whether gas plants are more expensive to build and/or run than new CEPs are to build) for each year from 2020 to 2045, and thus arrive at a new estimate of economic gas consumption from new pipelines.

In Step 3a, we noted a potential limitation of our assumption that new import capacity is marginal within the broader region's total import capacity, and thus serves only new gas-fired power plants. In such situations, our methodology implies slightly different interpretations:

- If new gas pipeline capacity imports gas at a lower basis price than currently shipped to a given region by existing pipelines (for example, lower-priced gas available in the Marcellus than from the Gulf Coast), then a decline in power sector demand would first reduce the need for transportation from pre-existing pipelines. In this case, our analysis would suggest that these pre-existing pipelines are at the most risk of throughput decline when CEPs outcompete gas power plants.
- If new gas pipeline capacity is proposed to serve existing power plants in addition to, or instead of, proposed new plants then the impact of CEP competition on demand for gas from the pipeline is largely the same or, more likely, accelerated. Specifically, our analysis estimates the decline in economic operation of gas-fired generators in each region using operating characteristics for proposed plants, which are generally more efficient and have lower operating costs than existing plants. In other words, older plants will be outcompeted sooner by CEPs than newer plants, with correspondingly faster declines in throughput for pipelines that serve them.

In short, even if new pipeline capacity into a given region is not associated with marginal gas-fired generation, our results still imply a loss of gas throughput for either new or existing pipelines into the region as a result of competition in the power sector from CEPs.

Implications for delivered price

The previous section outlined our approach for determining the likely declines in future demand for transportation services from new pipelines given the competitiveness of CEPs. Since gas pipeline capacity is typically secured using precedent agreements based on expected peak demand (i.e., where a shipper pays a reservation fee to ensure the right to ship gas through the pipeline), gas pipeline capacity is a sunk cost for most contract-holding shippers that is unaffected by declines in throughput. Rather, declines in throughput on the pipeline serve to increase the per-unit delivered cost of gas, by spreading sunk contract costs over fewer units of delivered fuel.

We capture this dynamic by estimating the change in throughput for new pipelines into each region on a percentage basis, and then calculating the implied multiplier on the per-unit delivered cost of fuel. For example, if CEPs outcompete gas plants in a region and drive down the level of economic gas use in a given year by 50 percent, then the sunk cost portion of gas delivered over that pipeline increases to 200 percent of the expected value. Several different stakeholders may be exposed to this increased price and bear associated financial risks, which we explore more fully in the Implications section below.

Conservative assumptions and limitations

Conservative assumptions and limitations of CEP approach

We use a fundamentally conservative model of the economics of CEPs versus new gas-fired power plants as a basis for this work. See the Appendix for discussion of all conservative assumptions used in this analysis, including limited expectations of future cost declines for renewables and storage, incremental value of CEPs relative to gas plants, a case-by-case rather than a system-level optimization framework, and no treatment of externality costs (e.g., cost of direct CO₂ emissions or upstream methane leakage) in the base case. In addition, we omit any accounting for the real costs imposed by gas price volatility, relative to the fixed costs of clean energy technologies.

We also note that our modeling approach assesses the economics of investment in new gas generation within the context of today's system, with adjustment made for future growth of renewables implied by current state-level renewable energy standards. However, we do not model the financial viability or system value of gas plants or CEPs in a system with very high (i.e., >50 percent) shares of wind and solar energy, a supply mix that would fundamentally reshape the set of resource attributes necessary to balance variable electricity generation. Thus, our results are best interpreted as consistent with near-term investment decisions that developers must make in assessing project viability over the next 10–20 years, and not necessarily reflective of the long-run role of gas-fired or other thermal generation resources as the grid moves to ever-higher shares of variable generation.

Conservative assumptions and limitations of estimated implications for pipelines

Our approach to assessing the implications of CEPs on pipeline economics contains several key conservative assumptions:

- **Access to demand in other sectors.** As outlined above, we conservatively assume that new pipelines can economically access existing customers outside the power sector, even though 90 percent of growth in domestic gas use in the past 20 years has come from the power sector. In short, we note that only the power sector's use of gas is growing, but assume that new pipelines can compete to serve existing demand across all sectors.
- **Demand trajectory in other sectors.** In addition to conservatively assuming that new pipelines can access existing non-power sector customers, we effectively assume that these sectors' demand stays at current levels through the study horizon. This is highly uncertain, especially for gas used for space and water heating, due to gas savings implied by building electrification as noted above in the *Market Snapshot* section. For some planned pipelines that would serve LNG export facilities (generally outside of our study region), sales to these new demand sources would offset demand declines in other sectors; we conservatively assume no net change from today.
- **Demand trajectory in the power sector.** We restrict our CEP analysis to only proposed power plants not yet under construction. However, there is already evidence of existing gas-fired power plants being outcompeted by clean energy and retired well in advance of their planned economic lifetimes. Our analysis does not capture this emerging dynamic and its implications on existing or new pipelines that would serve gas plants at risk of early retirement.

We also acknowledge that our analysis, performed at the regional level and focused exclusively on economics, does not capture all region- or project-specific factors associated with the net benefits of proposed pipeline investments. For example, we do not directly address fuel supply resilience benefits associated with pipeline investment—but we do note that CEPs require no fuel, and thus have no need for pipeline investments to increase resilience. We also do not directly address situations (outlined above) where new pipeline capacity can undercut pricing from existing pipelines—but note in that scenario that contract holders for existing pipelines will face stranded asset risks even if new pipelines capture their market share.



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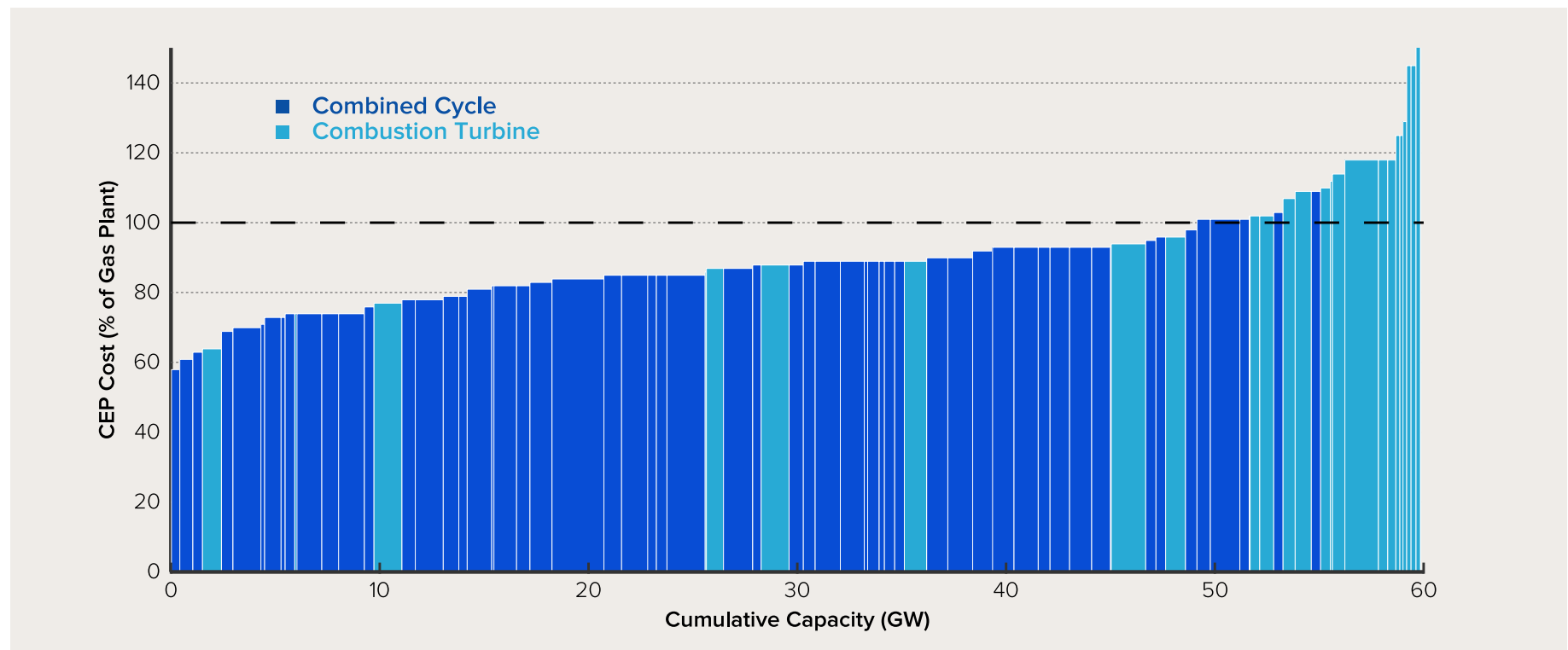
FINDINGS



FINDINGS

Our analysis implies four key findings about the economics of new gas plants proposed for construction in this study's focus regions, and implications for new pipelines.

FIGURE 10
COST SAVINGS ASSOCIATED WITH CEPS VERSUS NEW GAS POWER PLANTS



1. CEPs are lower cost than 81 percent of the proposed gas-fired power plant capacity in our focus regions, presenting an opportunity to save customers \$16 billion and prevent 83 million tons of CO₂ emissions each year

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

- At the proposed in-service date of planned gas-fired power plants, CEPs outcompete 49 GW, or 81 percent, of the 60 GW of proposed gas-fired power plants across the five focus regions of this study.
- There are \$16 billion dollars of available NPV savings over 20 years from CEPs that can be constructed and operated at lower costs than proposed gas plants.
- By building winning CEPs in place of proposed gas plants, we would reduce CO₂ emissions by 83 million tons per year, or approximately 5 percent of all 2017 US power sector emissions.

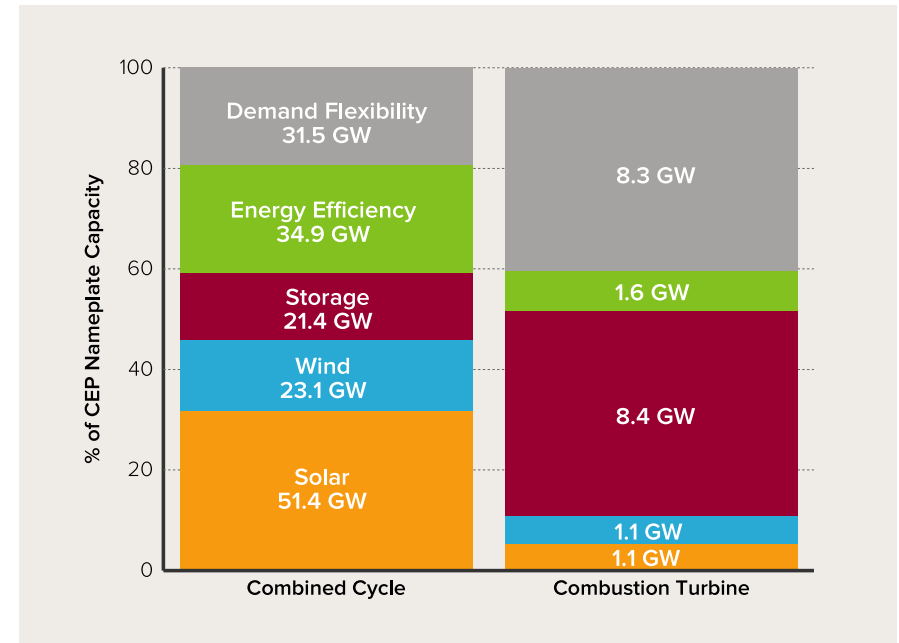
In Figure 10, we compare the total NPV costs of optimized CEPs with each proposed gas plant:

- Each bar shows the CEP NPV as a percentage of the gas plant NPV. When the bar height is below 100 percent, the CEP is lower-cost than the gas plant.
- Bar width indicates the gas plant nameplate capacity.
- Bar color indicates whether the plant is a combined-cycle or combustion turbine (CT).
- For clarity, we order the plants from most-to-least favorable for CEPs.

If all cost-effective CEPs were built, they would obviate 1.6 trillion cubic feet of gas demand and 83 million metric tons of carbon dioxide emissions each year in our focus regions—and significantly higher levels of CO₂-equivalent greenhouse gas emissions associated with leakage in gas production and transport.

FIGURE 11

COMPOSITION OF LEAST-COST CEPs IN FOCUS REGIONS



This alone would reduce US power sector CO₂ emissions by nearly 5 percent of present-day values, or approximately 20 percent of the total emissions budget of a US power sector with **80 percent lower emissions than 2005 levels**.

Figure 11 shows the contribution of individual CEP technologies to the aggregate portfolio. All five candidate technologies play significant roles. Storage and demand flexibility play larger roles in CEPs designed to replace CTs, where providing capacity during peak demand periods is most critical. In CEPs that replace combined-cycle plants, which are required to produce more energy, efficiency and solar are the most prominent resources, driven by their lowest cost per megawatt hour (MWh). These results are broadly consistent with our September 2019 findings from a nationwide sample of proposed gas plants.

As in the September 2019 companion study, we find that low-CF CT projects in most regions fare better in an economic comparison with CEPs than higher CF combined-cycle projects. The cost structure of CT projects is dominated by fixed costs, with relatively low fuel costs that could be avoided with CEP investment. In addition, these projects often serve peak demand at times when renewables are not available, which in our modeling approach implies a need for extensive battery storage. In practice, peaking gas plants are already being avoided and/or replaced with CEPs due to the less-conservative procurement approach undertaken by utilities across the country compared to the modeling approach used in this study; see the Appendix for further discussion.



2. If proposed gas plants are built, the falling costs of clean energy will likely render over 70 percent of planned capacity uneconomic by 2035

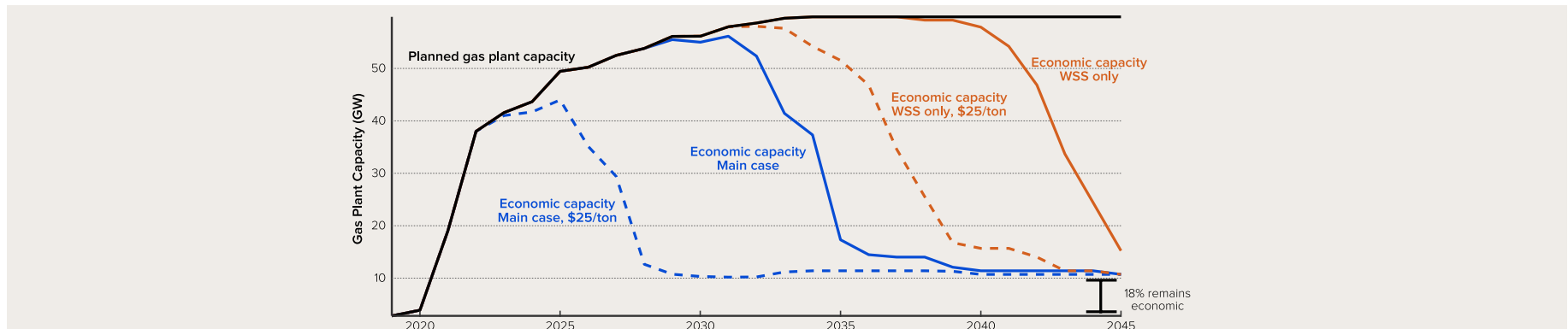
The falling cost of new CEPs threatens to force existing or proposed new gas plants (if built) into early retirement. Just as falling gas prices have undercut coal plant operating costs, clean energy technology price declines will soon undercut the costs to maintain and operate existing and proposed gas plants. Our analysis shows that by 2035, 71 percent of planned capacity would have higher go-forward operating costs if built than the new-build costs of an equivalent CEP.

Figure 12 summarizes the impacts of this economic trend across the proposed gas projects in our focus regions:

- Announcements and IRPs from gas plant developers in our focus regions suggest that our sample of planned new gas plant capacity would be fully built and operational by 2032 (black line).
- By 2035, 71 percent of planned new capacity could be economically retired and replaced with equivalent CEPs (blue line). The sharp declines in the mid-2030s reflects the crossover point where expected price declines in renewables and storage allow CEPs to systematically outcompete the operating costs of existing gas plants.
- Including a \$25/ton price on carbon advances the economic replacement timeline by 7 years (dashed blue line); excluding EE and demand flexibility from CEP technologies, and restricting our analysis to only combinations of WSS, delays economic replacement by 10 years (orange line).
- By 2045, approximately 80 percent of proposed gas capacity, if built, will be more expensive to operate than CEPs are to build under all scenarios.

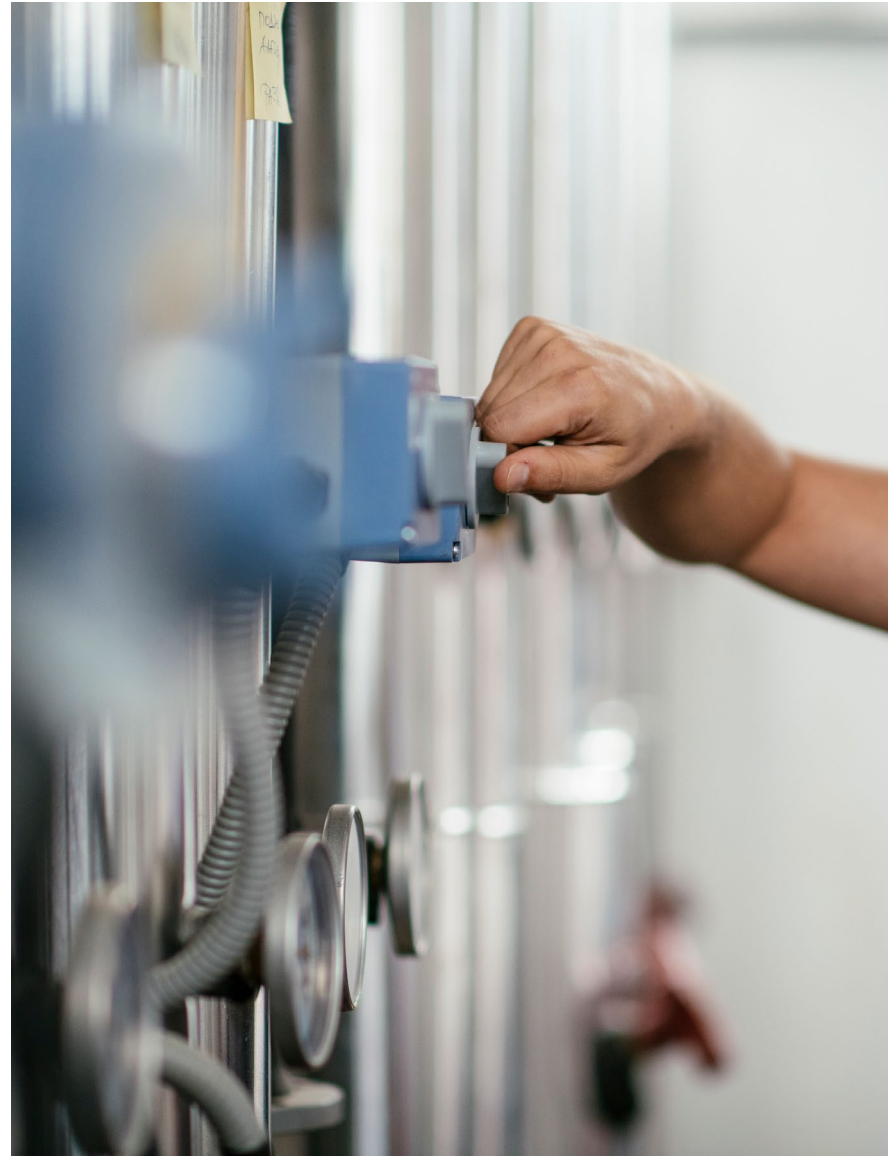
FIGURE 12

TIMELINE OF WHEN PLANNED GAS CAPACITY WOULD BE UNECONOMIC TO RUN GIVEN COMPETITION FROM CEPs



This changing economic picture for new gas plants will create risks for utilities or other investors who own the gas power plants. Consumer savings and/or market competition will dictate that the plants be shut down, even with significant book life remaining that investors have yet to recoup. This creates a “stranded asset” risk for investors, who may invest in proposed gas-fired projects that, sooner than expected, become uneconomic to run, and leave investors with significant, undepreciated asset value on their books, not offset by future revenues.

Of our sample considered in this study, just 18 percent of proposed power plant capacity, if built, would remain economic compared to new-build CEPs by 2045. This set of plants that would remain economic through 2045 is exclusively composed of CT projects, which together account for only 3 percent of fuel use for all proposed plants. With yearly average CFs ranging between 5 and 20 percent and operating almost exclusively to provide peak capacity, these CT projects have relatively low go-forward operating costs and are likely to remain competitive, once built, with new-build CEPs. However, that same lack of fuel costs means that CEPs will offset virtually all fuel use from proposed gas-fired power plants, as explored in the following finding.



3. Competition from clean energy will almost completely eliminate expected demand growth for gas from the power sector

As described above, CEPs, if considered fully in resource planning and procurement decisions, would outcompete over 80 percent of planned gas-fired power plant capacity across this study's focus regions. If these proposed gas plants are built despite the favorable economics of CEPs,

they are likely to stop running by the mid-2030s. In either case, by 2035, approximately 85 percent of expected fuel use from new gas-fired generation will likely be avoided by competition from clean energy. Figure 13 summarizes this outcome across all five focus regions.

FIGURE 13

IMPACT OF CEP COMPETITION ON FUEL USE IN PROPOSED POWER PLANTS, IF BUILT

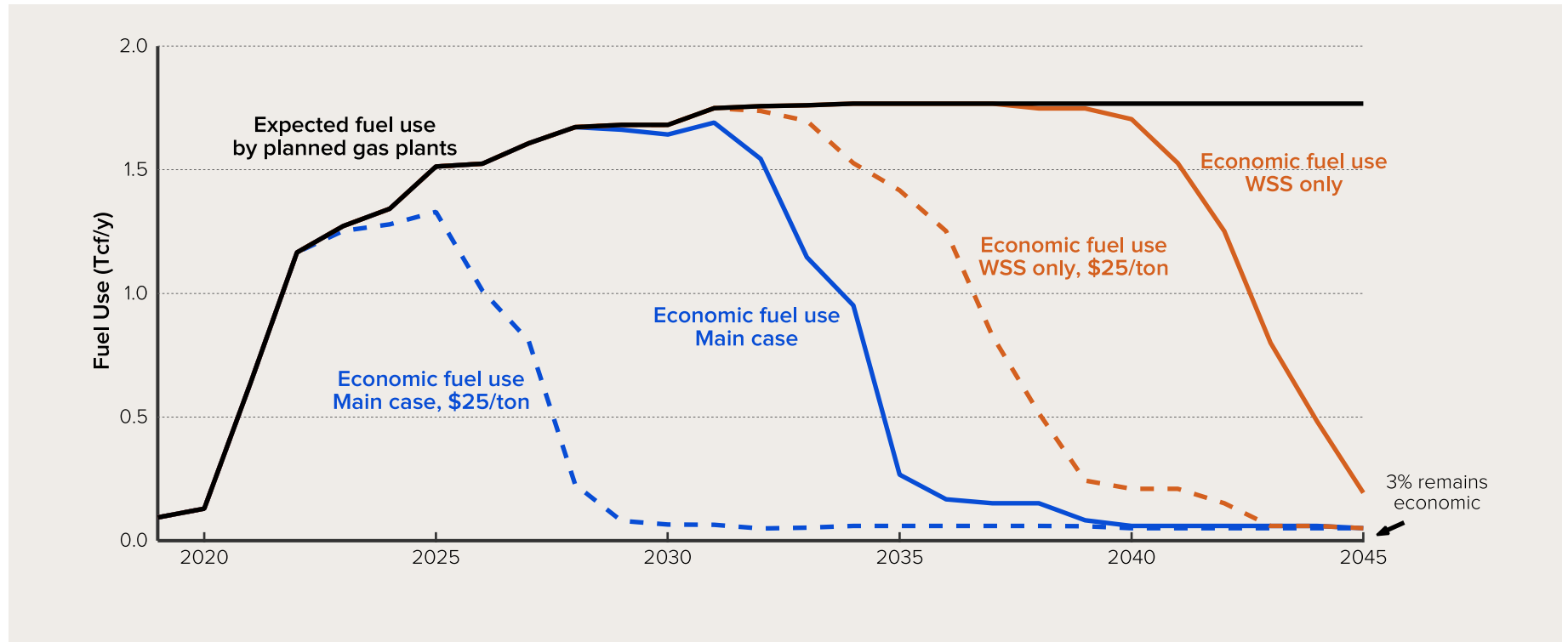
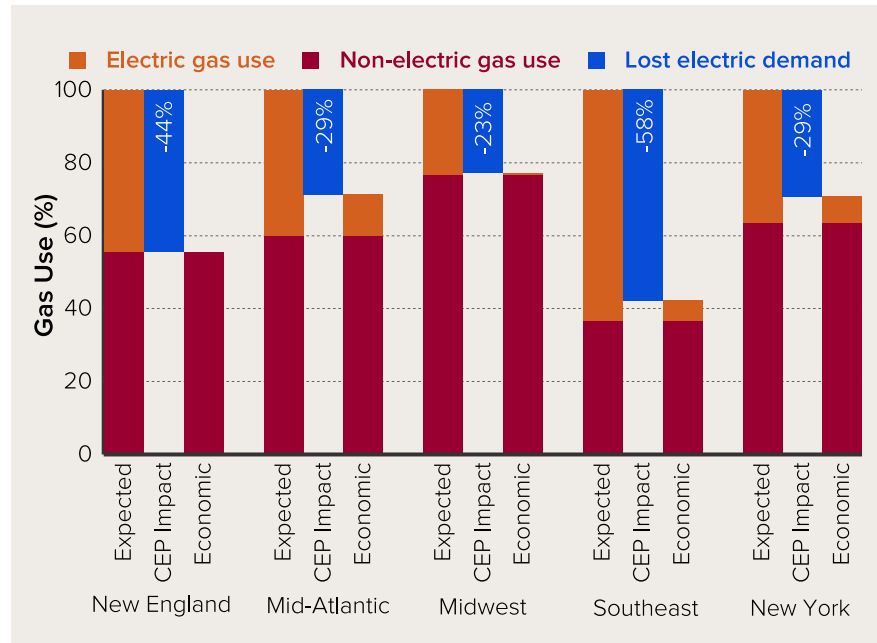


Figure 14 summarizes the implications for new proposed pipelines into each focus region in 2035. Across all regions, expected gas consumption from new power plants falls by 70 to 100 percent by 2035, leading to estimated loss of throughput on new pipelines of 20 to 60 percent, depending on the share of power plant demand to total regional demand and the share of proposed power plants out-competed by CEPs.

FIGURE 14

IMPLICATIONS OF CEP COMPETITION ON DEMAND SERVED BY NEW PIPELINES INTO EACH FOCUS REGION, 2035

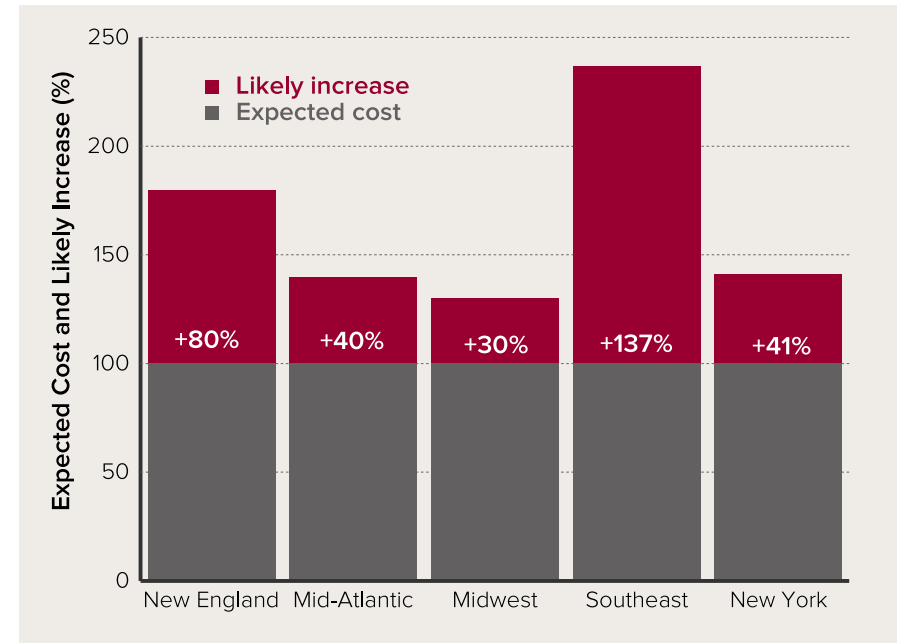


4. Lower-than-expected demand growth will significantly increase the per-unit cost of gas from newly built pipelines

Declining throughput for newly built gas pipelines will force sunk costs, borne by shippers under precedent agreements based on peak demand, to be recovered over fewer units of delivered fuel than expected. Estimated declines of 20 to 60 percent of pipeline throughput across the five regions (Figure 14) correspond to increases of 30 to 140 percent in per-unit delivered cost of fuel (Figure 15).

FIGURE 15

IMPACT OF CEP COMPETITION ON PER-UNIT DELIVERED COSTS FROM NEW GAS PIPELINES





An increase in unit cost of delivered fuel due to declining throughput is seen most immediately by whichever party bears a sunk cost for the pipeline (e.g., the investment in the pipeline, or a demand-based contract for pipeline capacity) but whose revenue or value depends on pipeline throughput. For example, a gas marketing company or gas utility who enters into a demand-based contract with a pipeline developer but expects to sell gas to electric utilities or independent power producers on a per-unit basis would have to adjust prices upward in order to recover sunk costs. Any price increase seen by gas generators would put further downward pressure on power sector demand; this dynamic risks setting up a reinforcing feedback loop, sometimes referred to as a “death spiral,” for gas pipelines whose unit costs rise as throughput declines, which in turn leads to further cost increases and further loss of throughput.

In cases where a single entity bears both the sunk cost and exposure to throughput risk, the risk of a death spiral is lower, but the same phenomenon of increasing unit costs still has dramatic effects on the economics of a new pipeline. For example, a regulated utility or holding company with a position in new pipeline capacity to bring gas to new power plants would pay approximately \$20 per MWh of gas generation for that pipeline capacity,¹⁰ using typical values for pipeline reservation costs, CFs, and gas unit efficiency. Increasing that amount by even 50 percent, let alone by over 100 percent, would cripple the economics of new gas-fired generation even more than the underlying economic advantage of clean energy resources, and call into question the presumed economic value of that pipeline and its associated gas plants in the first place.

¹⁰ Testimony of EDF in Massachusetts DPU 15-37 06-15-15, page 7.



IMPLICATIONS & RECOMMENDATIONS

The financial implications for gas pipelines of clean energy outcompeting gas power plants are dire, but where the ultimate risk lies depends on the contract and off-take structure for a specific pipeline. Table 2 lays out examples of and implications for the most common type of contract holders.

In many cases, captive customers of regulated utilities ultimately bear the financial risks of investment today in assets—pipelines and power plants—that are likely to become uneconomic sooner than anticipated.

TABLE 2
RISKS OF UNECONOMIC GAS PLANTS FOR DIFFERENT PIPELINE CONTRACT HOLDERS

CONTRACT HOLDER FOR PIPELINE CAPACITY	EXAMPLE	WHO BEARS THE RISK OF GAS POWER PLANTS BEING OUTCOMPETED BY CLEAN ENERGY?
VERTICALLY INTEGRATED, ELECTRIC UTILITIES	Utilities hold pipeline capacity contracts, or own the assets themselves, to ensure fuel delivery to owned power plants, and pass through fixed contract or asset costs to ratepayers.	Captive ratepayers of the electric utility bear the risk of pipeline capacity going unused and resulting escalation in per-unit sunk costs reflected in customer rates.
GAS DISTRIBUTION COMPANIES	Gas utilities hold pipeline capacity contracts to ensure fuel delivery to end-use customers during peak conditions (e.g., cold weather), and sell excess capacity in secondary markets to power sector buyers who lack contracted capacity.	Captive ratepayers of gas utilities bear the risk of secondary market sales failing to meet expectations due to falling demand for gas in the power sector, and thus average prices for fuel delivery rising significantly.
GAS MARKETERS	Gas marketers contract for pipeline capacity with the expectation of reselling to end-use customers across sectors, including power plants.	Shareholders of gas marketing companies bear the risk of sales to power sector failing to meet expectations, and thus revenue falling short of contract costs.
GAS PRODUCERS	Gas producers hold contracts for transportation capacity to move their product to market, including gas power plants.	Shareholders of production companies bear the risk of falling demand in power sector, and thus revenue falling short of contract costs.

As illustrated in Table 2, while the immediate risks of falling power sector demand for gas can fall on different groups, in many cases the risks are borne by captive utility customers—either electric, gas, or both. In other cases, private investors bear the risk of investment in and contracting for new pipeline capacity, but ultimately the risks are borne by society if these assets cease to provide value in advance of their assumed economic lifetimes.

We offer recommendations below that can help mitigate these risks.

For asset developers and investors: Carefully consider economics of new gas power plants and pipelines in light of clean energy competition

All gas plant and pipeline developers, and investors that provide them capital, should carefully assess the market and competitive position of contemplated gas-fired power or pipeline projects.

- ***For vertically integrated electric utilities and holding companies:*** Our analysis indicates that development of, direct investment in, or long-term contracting with new gas pipelines to serve expected demand for gas from new or existing power plants ignores the fundamental transition underway in the US electricity industry. Failing to account fully for the present and future economic potential of CEPs will likely lead to significant stranded asset risks imposed on future customers or shareholders if regulators disallow cost recovery for assets that become uneconomic ahead of proposed lifetimes. Utilities and holding companies considering a position in new pipeline capacity should carefully assess their risk tolerance for stranded costs, given the emerging dynamics and clear trajectory of the US electricity industry.

- ***For merchant power plant developers:*** Similar to electric utilities, merchant gas power plant developers should reconsider the competitiveness of gas-fired generation over the expected lifetime of the project, and contract for pipeline capacity accordingly—likely over much shorter durations than previously considered.
- ***For investors in pipeline projects or companies:*** The current rush to gas in the US power sector, combined with the negative economic outlook for new gas plant and pipeline capacity additions suggested by our analysis, suggests the real and growing potential of ongoing overbuild and future overcapacity of gas infrastructure. Such an imbalance of supply and demand presents a risk of lower returns for investors, who should carefully reassess the fundamentals of the industry and the competitive position of new projects in light of the economic advantages of clean energy resources in the near term.

For regulators: Assess likely future demand for gas pipelines when determining public benefit and allocating risk

Regulators for both electric and gas utilities have a role to play in shielding captive customers from risks imposed by utility investment in or contracting with new pipeline projects:

- ***For regulators of vertically integrated electric utilities:*** Our analysis indicates that utilities proposing to construct new gas-fired generation should first consider the economics of clean energy as a viable alternative, and only then determine the need for gas generation and pipeline capacity contracts to serve it. Electric utility regulators in vertically integrated markets, in turn, should first incentivize utilities to consider these non-traditional options, and then ensure that utilities use best practices in resource investment (i.e., market-based, all-source resource procurement that allows for demand-side resources), so that utility forecasts of gas pipeline capacity needs are robust and reflective of the ongoing transition in the power sector. Failing to recognize this transition exposes captive electric utility customers to the risks of paying for uneconomic assets for decades into the future. Regulators should consider a list of questions in assessing the justification for allowed cost recovery for regulated utilities associated with new pipeline capacity to serve new or existing gas plants, including:
 - » Given that utility planners, on average, over-forecast peak demand growth by 1 percentage point for each year that the forecast extends, does a resource plan accurately reflect a likely trajectory for peak demand growth that would necessitate new gas plant and/or pipeline capacity with multi-decade lifespans?
 - » If new capacity is justified by a robust peak demand forecast, does a utility resource plan take into account market-based data on the availability and costs of clean energy technologies that could provide peak capacity and other system needs?
 - » Does the utility modeling approach accurately represent the capabilities of clean energy resources to provide system reliability services?
 - » Does the resource plan and associated cost recovery proposal include a market-based outlook for a proposed gas-fired power plant's useful economic life, given expectations of clean energy cost declines?
 - » To what extent does the cost recovery proposal for new resource investment or pipeline capacity contract costs impose financial risks upon captive customers if utility forecasts of useful life for gas plants and associated new pipeline capacity are inaccurate?

- **For gas utility regulators:** Gas distribution companies are often the primary contract holder for new pipeline capacity, even though electric generators are increasingly the largest users of pipelines, because gas distribution companies resell their capacity rights to generators. Gas utilities rely on these revenues to keep costs low for their customers; a loss of revenue in the secondary market due to falling power sector demand will effectively raise the price paid by captive gas customers. Gas utility regulators considering proposed gas utility positions in new pipeline capacity should carefully assess the risks imposed on customers if expected electric sector demand fails to materialize, and allocate risks and incentives accordingly. Regulators should consider a representative list of questions in this determination, including:

- » To what extent does a gas utility's proposed investment in, or contract for new pipeline capacity rely on secondary market sales to electric power customers to bolster project economics for gas customers?
- » Does any expected revenue from secondary sales to the power market accurately reflect the declining economics of gas-fired generation relative to clean energy in the next 15 years?
- » Are risks passed on to captive retail customers if expected secondary market sales to power plants do not materialize?

- **For other federal- and state-level pipeline regulators:** The Federal Energy Regulatory Commission (FERC) issues certificates for new pipelines in part based on determination of need for new pipeline capacity. Our analysis indicates that, in the case of pipelines that may be presumed to support expanded use of gas in the power sector, that need has plateaued already and will soon decline. FERC has the opportunity to examine more holistically, and over a longer time horizon, the need for additional pipeline capacity, and adjust amortization periods and associated cost recovery rates accordingly.

At the state level, regulators that influence the construction of new pipelines should similarly evaluate the demonstrated need for new projects in the context of improving clean energy economics and likely demand sources for new pipeline capacity. As state-level clean energy goals proliferate and the economics increasingly suggest clean energy is the least-cost option for new grid capacity, state-level regulators have an opportunity to reassess the role that near-term gas infrastructure investment should play in their evolving energy supply mixes.

Our recommendations can help capture the economic opportunity at hand across much of the United States to prioritize investment in increasingly competitive clean energy resources, and in doing so mitigate the risks of investing today in over \$100 billion worth of assets that will likely be underutilized and uneconomic within the next 15 years.



TECHNICAL APPENDIX

CEP 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 capital expenditure and operational expenditure gas-fired power plants, capital expenditure and operational expenditure for wind, and operational expenditure for solar.
- We use Lazard [Levelized Cost of Storage v4](#) for storage operational expenditure, 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 capital expenditure as well as capital expenditure learning rates for wind, solar, and battery energy storage (WSS).
- We use LBNL's [Program Administrator Cost of Saved Energy \[PACSE\] 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 informs estimated 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 Electric Power Research Institute (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 Residential Energy Consumption Survey ([RECS](#)) and Commercial Buildings Energy Consumption Survey ([CBECS](#)) for the penetration of the various electricity end uses by region. We apply this data 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 United States, 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 in a typical year. 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 \(PSCO\) 120-day Report**](#) for transmission costs that we add to renewable costs.
- We use [**EIA**](#) for the carbon dioxide intensity of natural gas fuel.



Scenarios and Assumptions

In the analysis, we used our model to construct least-cost CEPs 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.

TABLE 3

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 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 plants, we disregard plants with CF <0.35, assuming that they are not representative of a new-build plant’s likely operating characteristics.

ISSUE	ASSUMPTION
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 <i>Reinventing Fire</i> and adjusting them to account for renewables deployment according to state-specific renewable energy targets and to renewables development implied by CEPs included in this study.
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.
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	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.

ISSUE	ASSUMPTION
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 expenditure costs by taking the present value of 20 years of that resource's annualized capital expenditure. 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, CA, NY, and NJ. In this study, distinct from our companion report on the growing market for CEPs, we do 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:

- **CEP 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 were historically systematically biased upward relative to observed cost declines. The average levelized costs of energy (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 CEPs:** 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, not on their overall profitability, net value, or contribution to broader reliability and other service requirements. By assessing just the marginal economics, rather than the net value in the context of broader grid economics, we over-constrain our optimization of CEPs relative to what might be expected in a system-level study.
- **Externality costs:** Our base results do not assume any value associated with reduced carbon emissions or other pollution reductions.
- **Plant-level versus system-level optimization:** We optimize CEPs to provide the same services as a proposed gas power plant, rather than to provide services needed across the entire power system. Were we to optimize across the entire power system, we would be able to include a broader set of resources and associated options from which to procure required grid services, and thus expect to find more cost savings from CEPs. For example, we may find that it is cheaper to provide services by better utilizing existing resources, downsizing need, or deferring investment, as has been shown in California and North Carolina. This conservatism has particular impact in driving our results for CT projects, which we find to be relatively more cost-effective compared to CEPs than combined-cycle projects, but in reality are being replaced or avoided by utility planners who are able to utilize a more holistic planning process than implied by our modeling approach.

Methodology

This analysis compares the 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 requirements model
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, the capacity additions necessary to meet the state's RPS (if one exists), and the capacity additions implied by winning CEPs designed to replace proposed gas plants as specified in this study.

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

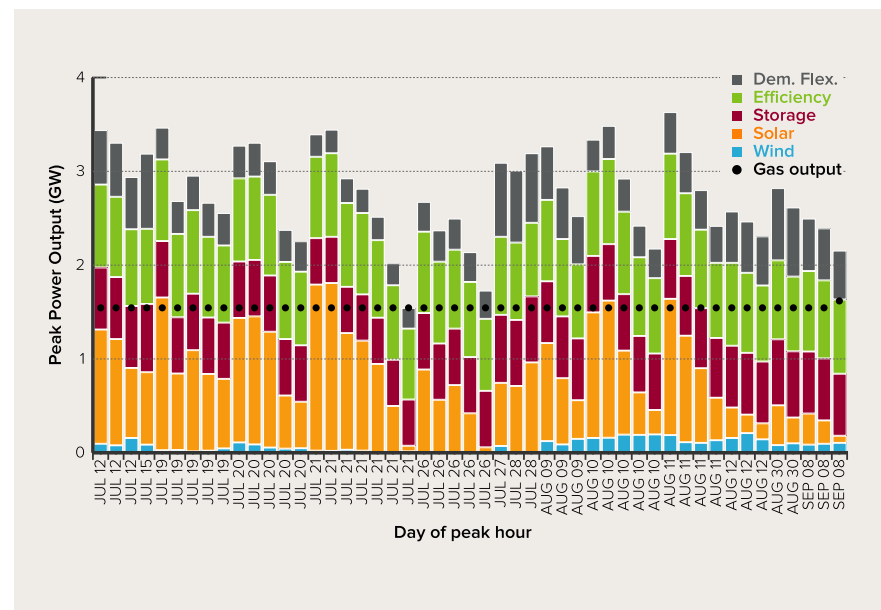
planning area's growth rate calculated from FERC 714's demand forecasts. We then apply that projected peak value to the plant region's normalized hourly load profile from *Reinventing Fire*. To determine projected hourly renewable production, we begin with the planning area's current annual renewable production, as reported in EIA Forms 923 and 860, 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), and add the amount of renewable generation implied by winning CEPs designed to replace proposed gas plants in the state. 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 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.

In Figure 16 and Figure 17, the black lines show the required peak hour capacity and monthly energy for an example combined-cycle gas plant in the Northeast.

FIGURE 16

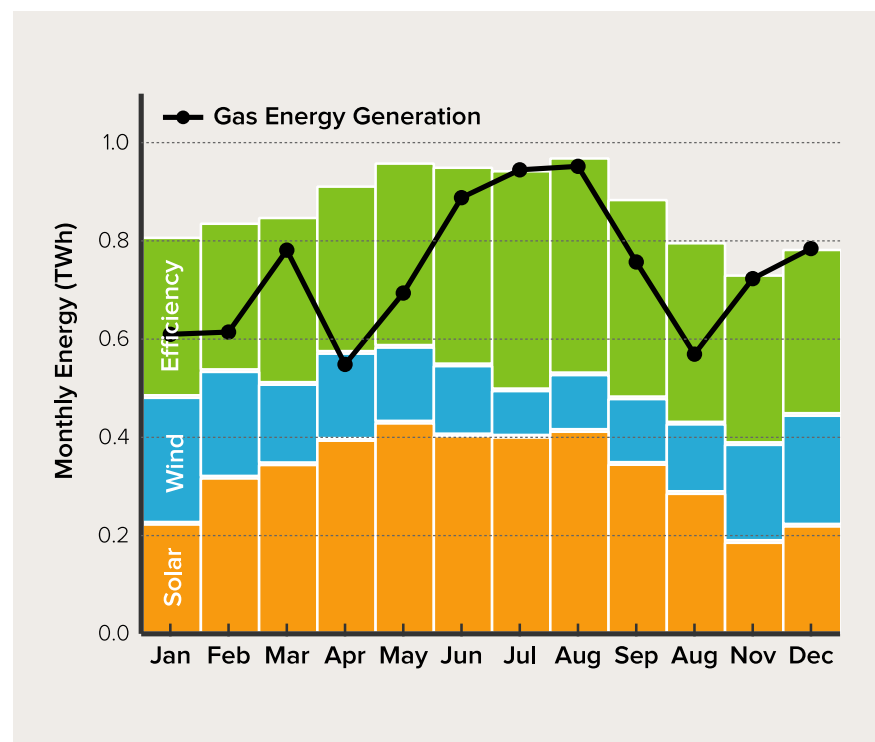
PEAK DEMAND REQUIREMENT OF THE EXAMPLE NORTHEAST COMBINED-CYCLE



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 be offset entirely 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.

FIGURE 17

MONTHLY ENERGY REQUIREMENT OF A NORTHEAST COMBINED-CYCLE



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 demand flexibility 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 demand flexibility resources available to the clean portfolio linear programming model. Bottom-up estimates for EE and demand flexibility 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 demand flexibility 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 capital expenditure and operational expenditure costs and annual capital expenditure declines are taken from Lazard LCOE v11, Lazard levelized cost of storage (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.

Capital expenditure 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 capital expenditure by annualizing it and then taking the present value of the first 20 cash flows. Operational expenditure 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 capital expenditure and operational expenditure 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 operational expenditure 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 CT 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 capital expenditure cost from incenting the deployment of EE measures but no operational expenditure costs. Capital expenditure 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 capital expenditure 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 demand flexibility program costs in EIA's Form 861. We assume 10 percent of that cost is for fixed annual operations and maintenance expenditures (O&M), and the remainder is capital expenditure that can be de-annualized into a first-year cost with a capital recovery factor. In addition to fixed O&M, demand flexibility operational expenditure includes variable O&M, which assumes use 25 times per year (10 times for CT 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 mathematically states 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., do not include more efficiency than we estimate is reasonable) the portfolio must satisfy.

Figure 17 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 and November; the model adds solar, wind, and efficiency to 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 16, all five technologies contribute to meeting peak demand. The most challenging day is July 21, where there are 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.

5. Gas plant cost assessment

The gas plant cost assessment includes capital expenditure, fixed O&M, variable O&M, fuel expenses, and carbon expenses (if any). Cost data used to determine gas plant capital expenditure, 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 sensitivity case, we include a price of \$25/metric ton of CO₂ emitted.

Gas plant capital expenditure is calculated by multiplying the per unit capacity cost of capital expenditure 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 capital expenditure to the current year for consistency.

Calculating CEP excess energy

As a post-optimization step, the model assesses how much energy the portfolio produces in excess of the service requirement and values this excess energy at \$15/MWh. This amount is much lower than typical wholesale market energy prices of **\$30–50/MWh**, and serves as a conservative estimate of the value of renewable energy during times when a gas-fired power plant would not be economically dispatched. This “excess energy” value is subtracted from the total lifetime cost of the CEP.

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 CT 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.

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

We define a cost metric for CEPs designed to replace combined-cycle plants, 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 plants, 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 CTs, 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 out-competed 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 metric tons of CO₂ per year as a function of the plant's annual energy production, heat rate, and CO₂ emissions factor.

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

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.

Key changes to approach used for this study

We augmented the CEP modeling approach used in our May 2018 study and the September 2019 update to better represent the region-wide interdependencies between the competitiveness of gas in the power sector and the economics of new pipelines:

- **Region-level impacts of CEP adoption:** Our core CEP modeling approach examines the economics of a CEP against a proposed gas-fired generator on the margin of the current system. To better estimate regional impacts on gas pipeline use from potentially replacing significant proposed gas-fired capacity with CEPs, we explicitly account for interactions between CEPs in each state under consideration by:
 - » including all expected wind and solar production from winning CEPs in our net load forecasts.
 - » subtracting the resource capacity of winning CEPs in each year from the available resource potential for all years thereafter.

With these changes, our CEPs are designed to provide the same grid services as gas plants even with higher (i.e., aligned with present RPS requirements) renewables penetration. This adjustment has the greatest effect in the Southeast and Mid-Atlantic regions of this study, where proposed gas plant capacity is equivalent to a significant fraction (~10–20 percent) of present-day peak demand.

- **Region definitions:** The regions used in this study are adjusted from those used in our previous and companion studies to better reflect electricity market regions and regions with significant proposed pipeline capacity additions.
- **Inclusion of IRP gas plants:** In this study, we include proposed gas plants announced in publicly available utility IRPs, even though they are less certain than plants announced by press release, to better reflect expected demand for gas in the power sector that, in some cases, proposed pipelines are presumably planning to meet.



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