HEADWINDS FOR US NATURAL GAS POWER

2021 Update on the Growing Market for Clean Energy Portfolios

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About RMI

RMI is an independent nonprofit founded in 1982 that transforms global energy systems through market-driven solutions to align with a 1.5°C future and secure a clean, prosperous, zero-carbon future for all. We work in the world's most critical geographies and engage businesses, policymakers, communities, and NGOs to identify and scale energy system interventions that will cut greenhouse gas emissions at least 50 percent by 2030. Boulder, Colorado; New York City; Oakland, California; Washington, D.C.; and Beijing.

Introduction and Context

Motivation

Many people still see natural gas as a "bridge" fuel. Across much of the United States, there is a pervasive belief that investing in new gas-fired power plants is a necessary "bridge" to a low-carbon grid. Utilities and other investors are anticipating investing more than $50 billion in new gas power plants over the next decade, locking in more than $140 billion in costs over their projected lifetimes.

Clean energy portfolios (CEPs) are gaining momentum as an alternative to building new gas plants. CEPs—combinations of wind, solar, energy efficiency, demand response, and battery energy storage—are increasingly being deployed to avoid the need for new gas investment. The components of CEPs, including wind, solar, and battery energy storage, represented over 90% of new capacity entering interconnection queues in 2020.

Proposed gas plants in 2021 face strong economic and policy headwinds. In addition to these trends, forecasts show the cost of renewable energy will continue to decline, and gas prices are likely to rise. The resilience of gas is front of mind in 2021 as extreme heat, deep freezes, and other weather events threaten gas supply and strain the grid more frequently due to climate change. The health burden that the legacy fossil fuel-based power system has imposed on communities is becoming clearer, and states are increasingly considering employment, health, and distribution of costs and pollution in their decisions to build new energy resources. CEPs are well positioned to strengthen their competitiveness because of these trends and make gas even less competitive moving forward.

About this study

In this report, we compare the costs and benefits of nearly every proposed gas plant in the country to a CEP that could provide the same grid services, building on the analytical approach used in our 2019 report *The Growing Market for Clean Energy Portfolios*. Our analysis assesses past, current, and future prospects for gas-fired power plants compared to CEPs:

- **Introduction** provides an overview of our modeling methodology and key metrics we use to assess the competitiveness of CEPs against proposed gas projects
- **Looking Back** provides a retrospective assessment of the declining gas build-out and increasing share of gas plant cancellations prior to construction
- **Current Situation** updates our economic analysis to show when and where gas plants are still proposed in 2021 and their current cost-competitiveness against CEPs
- **Looking Forward** assesses the headwinds on the horizon for proposed gas projects and quantifies the risk of trends that will continue to cause gas to be outcompeted or rendered a stranded asset by CEPs
- **Conclusions and Recommendations** provides a summary of messages for regulators and utilities and recommendations for actions that can enable real competition between gas and CEPs

Summary of Key Findings

Looking back

New gas power plant investment has declined since 2018.

- The falling costs of renewables and batteries have increased the competitiveness of CEPs—combinations of renewables, storage, and demand-side management that can provide the same reliability services as a gas-fired power plant.
- A combination of economics and advocacy has led to the cancellation prior to construction of more than 50% of proposed new gas plants in the past two years.

Current situation

Most of the 88-plus gigawatts (GW) of new gas plants proposed are uncompetitive against CEPs.

- At least 70 GW of proposed gas plants could be economically avoided with CEPs, saving $22 billion and 873 million metric tons (MMT) of CO_2 over project lifetimes.

Looking forward

New gas plant investments face at least six emerging risks.

- Economic risks including (1) declining renewable energy costs, (2) rising gas prices, and (3) expectations around firm gas supply could continue eroding gas project viability and render nearly all proposed gas projects uncompetitive against CEPs.
- In addition, policy-related risks including (4) the higher level of job creation associated with CEPs, (5) public health costs of gas power plant pollution, and (6) gas plants' impact on vulnerable communities threaten the viability of new gas projects.

These dynamics create significant stranded-cost risks for new gas plants.

- In our central analysis case, 40% of combined cycle (CC) gas plants proposed for construction would cost more to operate than a new CEP would cost to build within 10 years, making it likely that these plants would fail to secure revenue sufficient to keep operating well before their anticipated economic lifetimes.
- Under a variety of scenarios that reflect the economic risks noted, the percentage of plants with stranded-cost risks within 10 years could rise to 80%–90%.

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Introduction

About the modeling approach and key metrics for analysis in this report

Building the list of proposed gas plants

In this study, we assess the economics of each proposed gas project in the United States compared to a CEP that can perform the same services. We start by identifying a list of proposed gas plants across the country that have either had a construction site identified or have been described in utility investment plans.

Our plant list includes the majority of proposed gas capacity in the United States

Exhibit 1: Filtering process for proposed plants

113 GW	We begin with all proposed gas plants in the contiguous United States that have either been sited or described in utility plans.
104 GW	We limit our analysis to the two most common types of gas plants, CCs and CTs.
103 GW	We exclude plants smaller than 100 MW.
88 GW	We exclude plants scheduled to enter service after 2030 and focus our analysis on proposed plants with nearer-term operational timelines.

We focus our analysis on the two most common types of gas-fired power plants

- **Combined cycle gas turbines (CCs)** tend to be large and efficient plants, designed to run at high capacity factors.
- **Combustion turbines (CTs)**, often referred to as "peaker" plants, are less efficient and tend to be smaller, running less frequently during periods of high demand or when demand increases rapidly.

Our analysis reveals comparative economics of marginal additions

- Our modeling is intended to reveal the comparative economics of resources that could provide marginal capacity and generation to the grid.
- The analysis framework reflects the relative costs for gas plants and clean energy resources to contribute grid services in the near term, to inform imminent investment decisions across the United States.
- Other tools and approaches, such as long-run capacity expansion and production cost modeling, complement our study by assessing the role of gas and clean energy resources as the grid evolves.

Overview of the Clean Energy Portfolios Model

The modeling comparing the economics of CEPs to proposed gas plants is conducted using RMI's Clean Energy Portfolios Model (CEPM). A CEP is defined as a portfolio of wind, solar, battery energy storage, energy efficiency, and demand flexibility that can provide the same estimated services as a given proposed gas plant in a specific region.

Exhibit 2: High-level CEPM approach

Estimate the proposed gas plant's services

Service requirements: We estimate the services a proposed gas plant would provide to the grid that the CEP would be required to meet. There are three main service requirements used in the CEPM:

- **Monthly energy**: We estimate the proposed plant's monthly output assuming it would be run similarly to other plants in its region. The CEP is required to produce at least as much energy each month as the proposed gas plant.
- **Peak-hour capacity**: We identify the top 50 peak net load hours in each proposed plant's region, adjusted for expected renewable construction. The CEP must match or exceed the proposed plant's seasonally adjusted nameplate capacity for the identified hours.
- **Flexibility**: The total power output of the CEP in megawatts (MW) must meet the proposed gas plant's seasonally adjusted nameplate capacity during the hour of the region's largest increase in net load. Further, we estimate the largest four-hour ramp-down of solar generation in the CEP and require that total power output of the CEP be able to remain constant during that period. This constraint requires the CEP to not exacerbate ramping issues.

Build the optimal CEP that meets service requirements

Resource options and potential: All of the following options are considered in each CEP:

- **Energy efficiency (EE)**
- **Demand flexibility (DF)**
- **Wind**
- **Solar**
- **Battery energy storage (ES)**

We use modeled, regional production or load reduction estimates to characterize the potential for each resource type.

Resource cost assumptions: Resource costs are based on benchmark data for utility-scale wind, solar, and battery energy storage. Energy efficiency and demand flexibility costs are based on program costs for the region across residential, commercial, and industrial end uses. Sources are included in the Appendix.

Gas plant costs: Gas plant costs are modeled based on assumptions for proposed capital expenditures, operating costs, and region-specific fuel costs. Sources are included in the Appendix.

Output the portfolio and compare economics

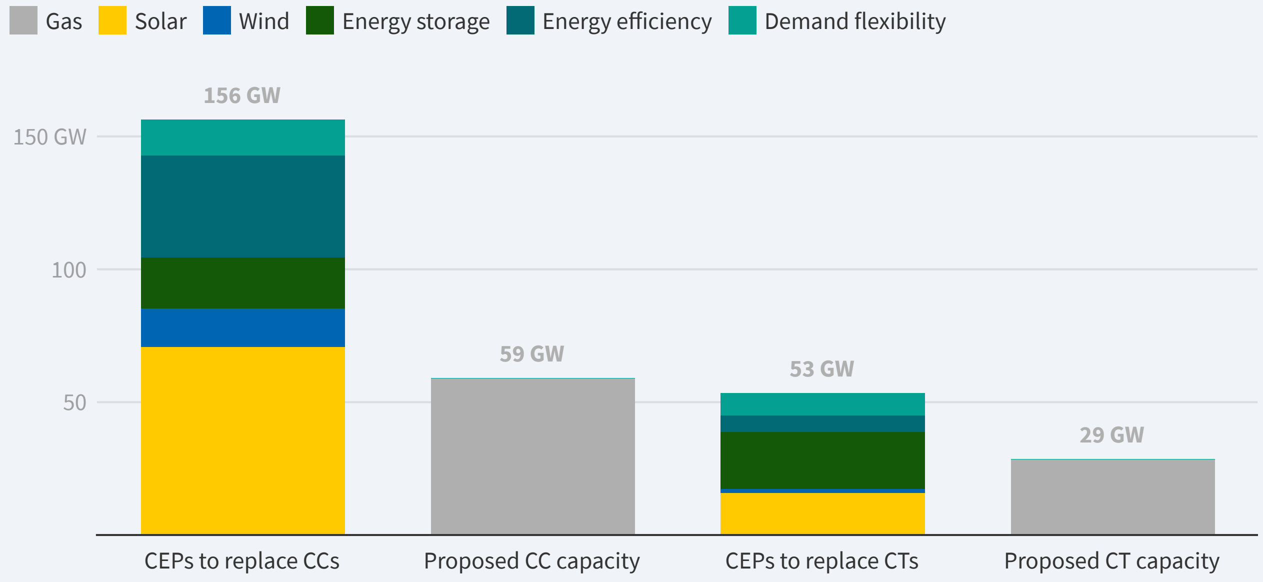
The CEPM uses linear optimization to choose the least-cost portfolio from the resource options that meets the service requirements of each proposed gas plant.

Overview of CEPM outputs

CEP composition to avoid all 88 GW of proposed gas plants in our analysis

CEPM outputs a least-cost portfolio for each proposed gas plant. Below, we show the aggregate composition of CEP resources chosen as part of these individual, plant-level optimization results.

Exhibit 3: Aggregate composition of CEPs across all 88 GW of proposed gas analyzed



- To avoid the 59 GW of new CC capacity proposed, nearly 160 GW of new CEP resources could be deployed.
- To avoid the 29 GW of new CT capacity proposed, over 50 GW of new CEP resources could be deployed.
- CEP nameplate capacity exceeds proposed gas capacity because capacity factors and peak capacity credit for clean energy resources are generally lower than for gas.

CEP economic metrics

Once optimized portfolios are output by CEPM, we compare them to proposed gas projects using the following economic metrics:

- **CEP and proposed gas levelized cost of energy (LCOE) ($/megawatt-hour [MWh]):** calculated as the present value of all costs divided by the lifetime energy of the proposed gas plant discounted to its present value
- **CEP net LCOE ($/MWh):** calculated as the present value of all CEP costs minus the present value of all revenues from energy produced in excess of the gas plant (CEP lifetime energy minus proposed gas lifetime energy), valued at the assumed additional energy price, divided by the present value of the lifetime energy of the proposed gas plant
- **Proposed gas marginal cost of energy (MCOE) ($/MWh):** the going-forward marginal cost of the proposed plant required to maintain and operate it once constructed, including fuel costs and both fixed and variable operations and maintenance costs

We assume a 20-year life for all resources. For resources with lifetimes other than 20 years, we adjust that resource's capital expenditures by annualizing it and taking the present value of the first 20 years of cash flows.

Main points of economic comparison

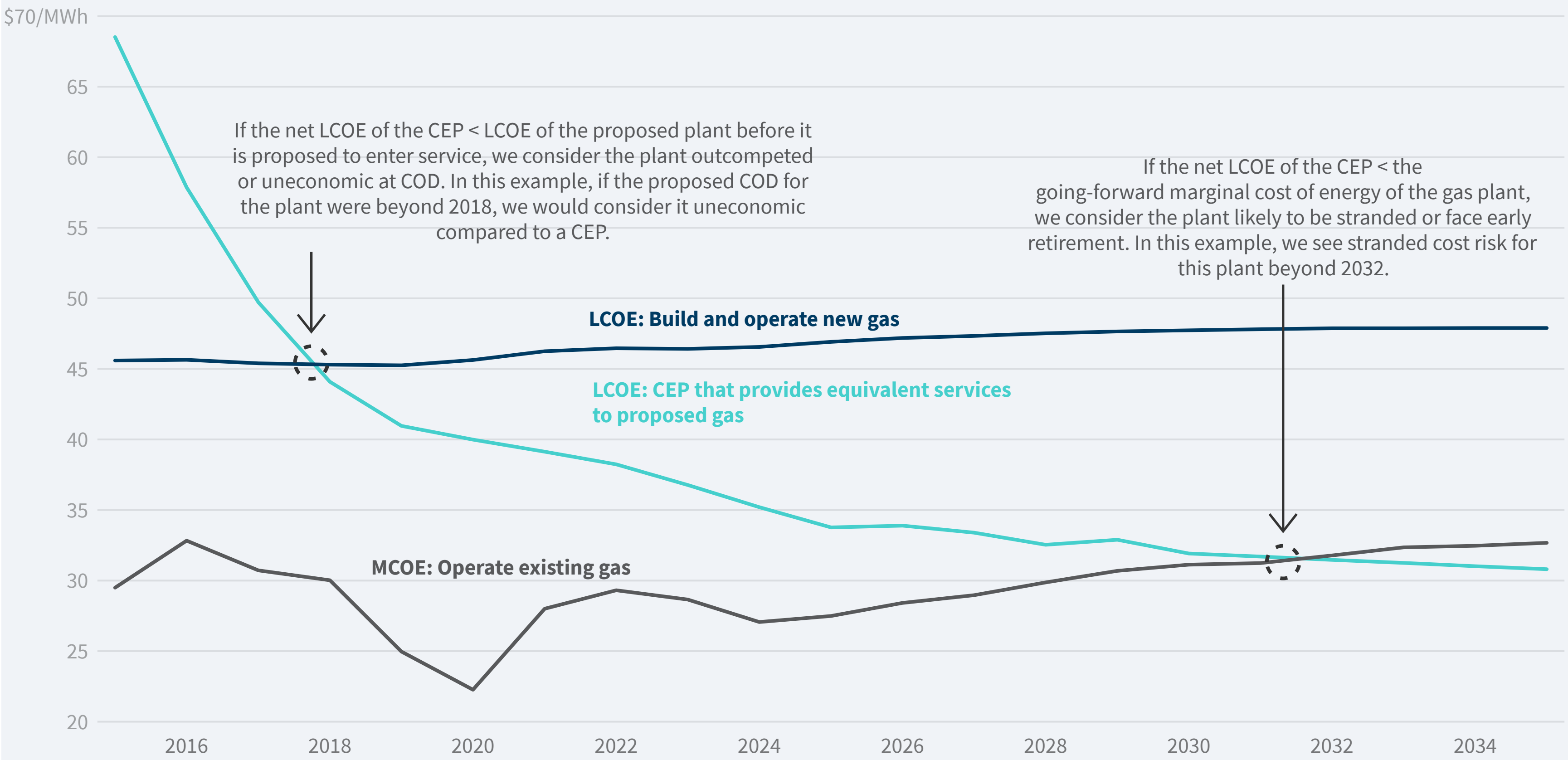
We use the metrics described on the previous slide to make two comparisons for each proposed gas plant: (1) whether the plant will be outcompeted by a CEP before its proposed in-service date, and (2) whether a gas plant will face stranded-cost risk after it is built.

1. A gas plant outcompeted by a CEP before its commercial operation date (COD) faces risks of uneconomic investment and potential cancellation.

2. Once built, gas plants face early retirement or stranded-cost risk if the going-forward costs of operating the plant exceed the cost of building a CEP.

Exhibit 4: Comparing the economics between CEPs and proposed gas plants

Example: Midwest combined cycle



This study reflects new data and improvements to the model since our 2019 report

Because of changes to how we compiled the plant list and changes to the model itself, the results of our 2019 study and this study are not directly comparable. The following are key changes across cost data and our methodology:

New cost data has affected the composition and competitiveness of CEPs

- **Renewables and storage:** The effective cost of solar and storage has declined as technologies, financing, and project development have improved. Wind technology costs have declined as well, though some of the decline has been offset by lower tax credits.

- **Gas prices:** While renewable energy costs declined, between 2019 and 2021, the Annual Energy Outlook (AEO) gas price projections declined as well, in some cases even more.

- **Demand-side management costs:** Our estimates for the cost of demand flexibility are higher than in our 2019 study, based on new data from the US Energy Information Administration (EIA).

Refined representation of energy storage improves estimated CEP competitiveness

An updated representation of storage in the model (see Appendix) better captures the ability of portfolios with solar and storage to meet capacity needs economically when multiple peak capacity hours occur on the same day and when solar output changes over those hours. In addition to making CEPs less costly by reducing the quantity of storage required to meet peak demand, this improved representation of storage means the resulting CEPs generate more energy, reducing their net cost and making them more competitive.

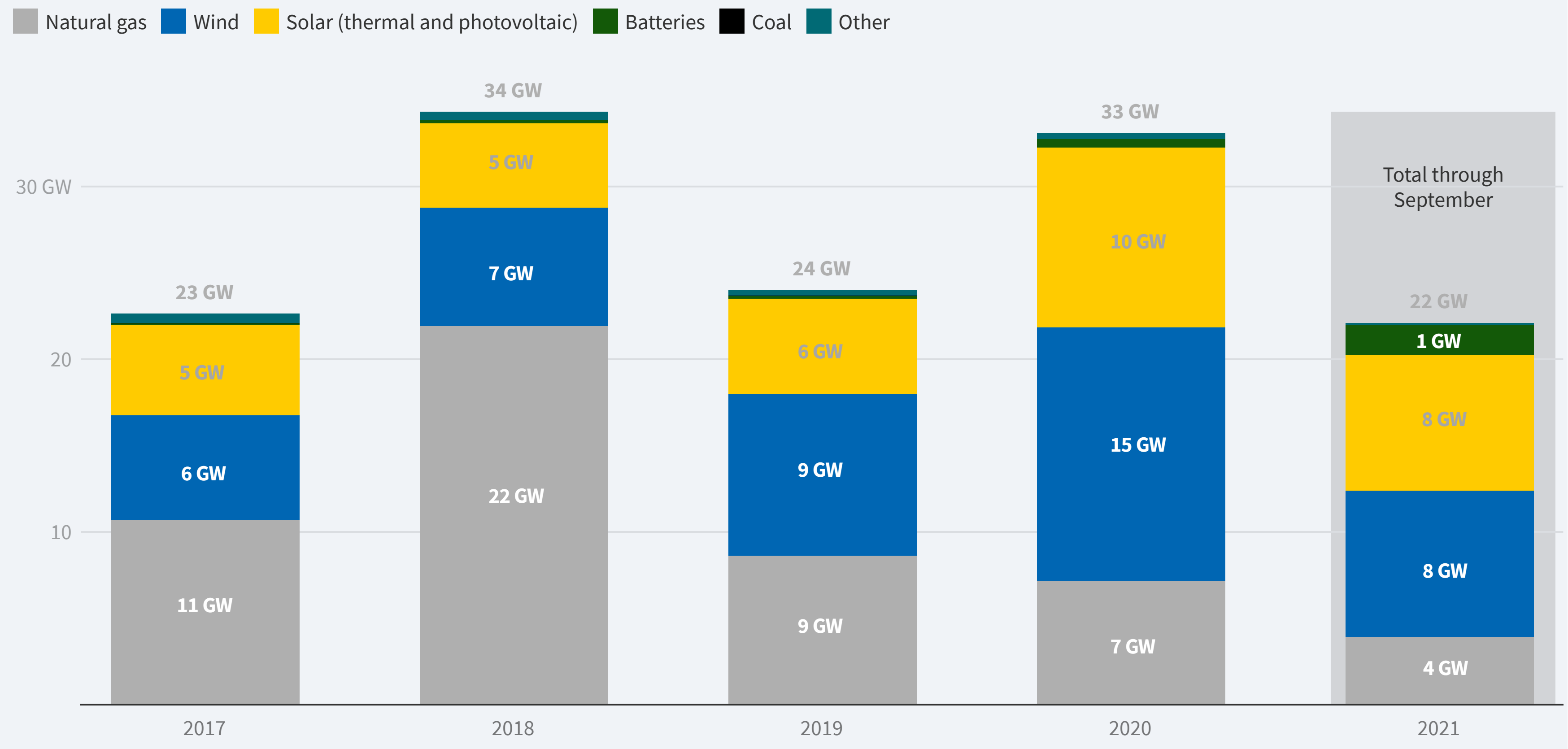
Chapter 1
Looking Back

An increasing share of gas plants have been canceled over the past several years, and trends point to a broader market shift

Since 2018, the total annual capacity of gas built has declined while solar and wind continue to rise

In the past five years, market dynamics have started to fundamentally shift against new investment in gas-fired power plants. While new gas additions increased annually from 2015 to 2018, 2019 represented a turning point. Since then, total annual nameplate capacity additions of clean energy have started to outpace new gas growth.

Exhibit 5: Annual nameplate capacity additions, by resource type



Source: RMI analysis of EIA 860-M, September 2021

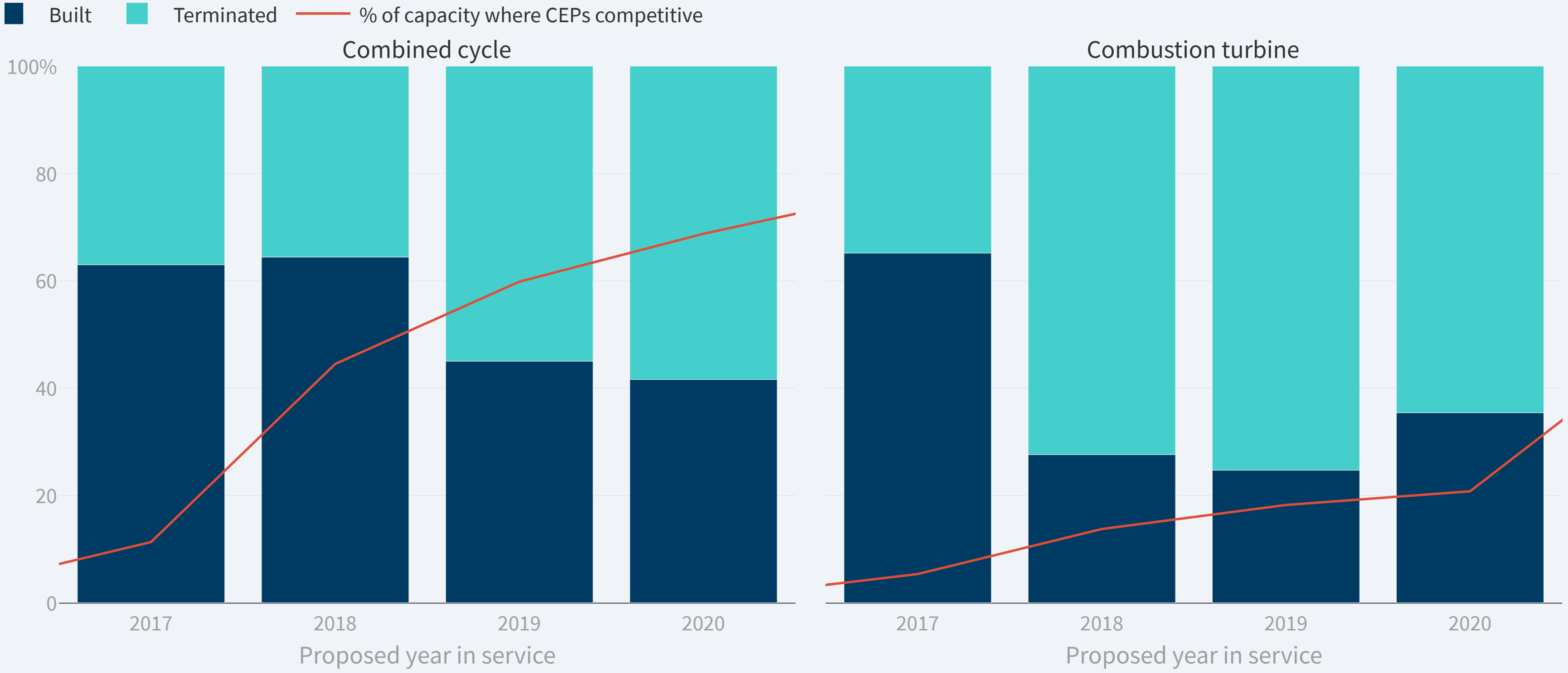
Exhibit 5 shows trends in new resource capacity over time:

- In 2018, gas made up 64% of new capacity additions in the United States, with 22 GW installed.
- Since 2018, gas's share of new capacity additions and absolute capacity additions has declined. Gas represented about 20% of new capacity additions in 2020.
- Renewable capacity, particularly wind and solar, has continued to rise in both total capacity additions and share of new capacity additions since 2018.

As clean energy prices have fallen, more proposed gas plants have been canceled before construction

In addition to fewer plants being built, the share of terminations of proposed gas prior to construction has increased. A plant may be canceled before construction if its financiers no longer determine it economic, or if regulators deny permits or cost recovery.

Exhibit 6: Annual share of proposed gas capacity terminated before construction compared to CEP competitiveness



- Over 50% of gas plants proposed to enter service in the past two years were terminated before construction.
- From 2017 to 2020, the percentage of CEPs that were able to economically compete with gas rose, and the overall capacity of gas plants built declined (as shown on the previous slide).
- The proportion of gas plants terminated versus built continued to rise for CCs.
- The trend for CTs is less clear.

Case studies point to a broader market shift

Over the next four slides, we highlight case studies of plants that were canceled or replaced with alternative portfolios after facing declining economics and extended advocacy between their proposal date and their target COD. We look at two merchant plants, planned to operate in wholesale markets, and two regulated plants, planned to be owned or operated by vertically integrated utilities. The patterns across these four case studies are indicative of a broader market shift—in economics, public opinion and advocacy, and policy—that has made competing against clean energy more difficult for gas plants and has led to the decline in capacity and increase in share of gas terminated before COD.

The economic data on the next four slides—for both proposed gas and CEPs—is modeled in CEPM using the methodology outlined in the introduction and data sources listed in the Appendix.

Exhibit 7: Regulated plants

Stakeholders' prioritization of alternative portfolio analysis is highlighting that CEPs often cost less than proposed gas plants.

Case study	Outcomes
Pinon Energy Center (CT)	Pinon Energy Center was proposed as a replacement for a retiring coal plant in New Mexico. In 2020, the New Mexico Public Regulation Commission (NMPRC) approved an alternative portfolio of clean energy in its place.
Sherburne County (SherCo) (CC)	Xcel Energy proposed the SherCo CC as a replacement for a retiring coal plant in Minnesota. After revisiting its analysis in 2021, Xcel proposed an alternative plan to build a large quantity of renewables and smaller CT units that will produce fewer emissions.

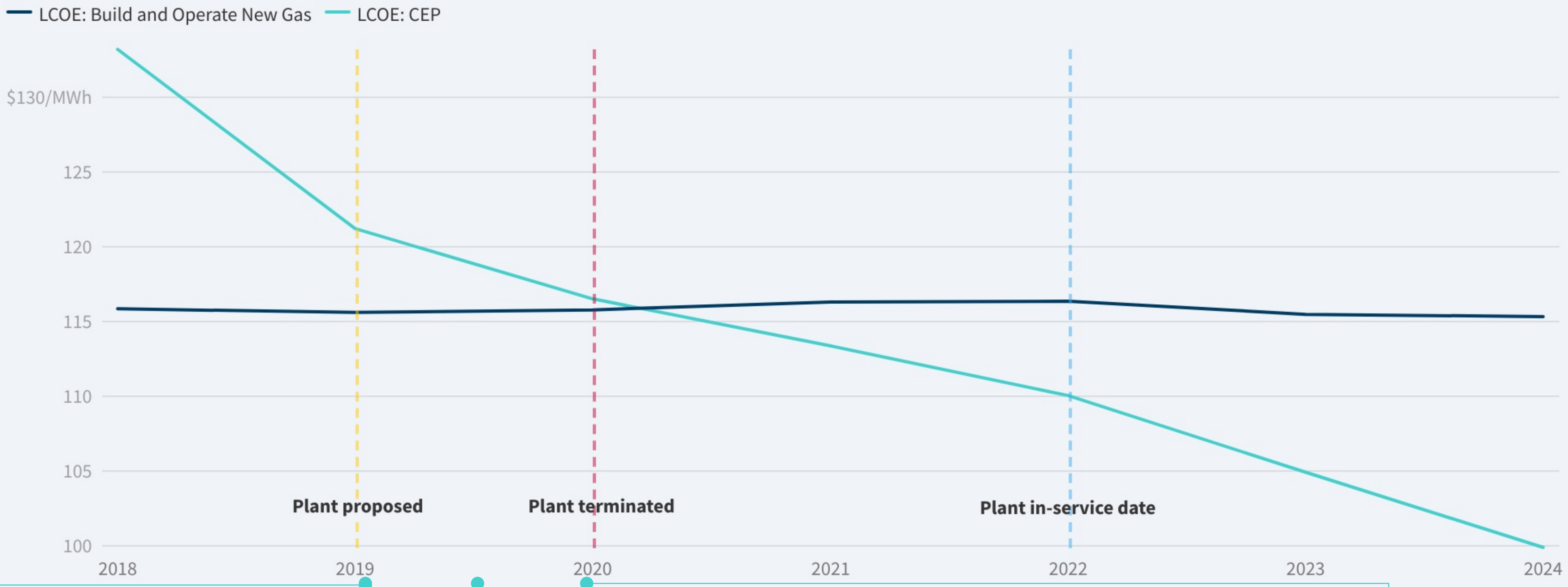
Exhibit 8: Merchant plants

Poor economics are compounding advocacy pressure and leading to cancellations of proposed merchant power plants.

Case study	Outcomes
Mattawoman (CC)	Mattawoman was proposed as a merchant plant in regional transmission organization PJM in 2013. It was canceled in 2021.
Palmdale (CC)	Palmdale was proposed as a merchant plant in the California Independent System Operator (CAISO) in 2008. It was canceled in 2020.

In New Mexico, NMPRC approved a stakeholder-driven portfolio of clean energy resources over proposed gas

Exhibit 9: Economics of Pinon Energy Center (combustion turbine)



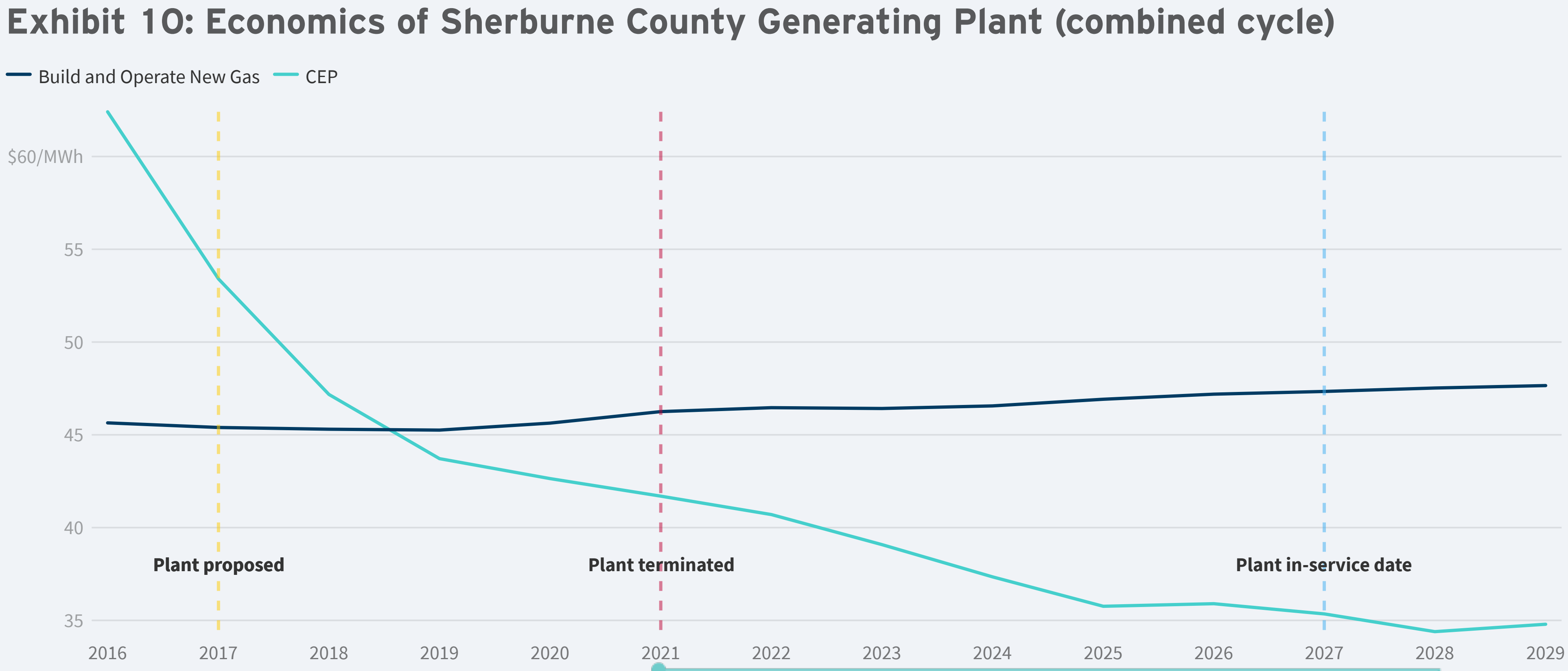
Public Service Company of New Mexico (PNM) proposed the Pinon Energy Center in 2019 among solar and storage projects in its preferred plan to replace capacity from San Juan Generating Station, which PNM plans to retire in 2022.

New Mexico passed the Energy Transition Act (2019), which defined a target for 100% carbon-free electricity by 2045.

Stakeholders pushed back on the plan for the new gas plant during public hearings, including conducting full reliability and cost modeling of a carbon-free clean energy portfolio as an alternative to the gas plant.

In July 2020, the commission approved an alternate 100% renewable and storage replacement for San Juan. The commission weighed costs, economic development, and the preference in the Energy Transition Act for carbon-free resources in its decision. In addition to being a leading example of clean energy providing reliability services, the CEP will bring jobs and tax revenue to the communities impacted by San Juan's closure.

In Minnesota, Xcel's second analysis revealed cost-effective, lower-emissions alternatives to the SherCo CC



Xcel first proposed building a CC gas generator in Sherburne County in its 2016–2030 resource plan after making the decision to retire the SherCo coal plant by 2026.

In 2018, the Minnesota Public Utilities Commission (PUC) approved the plan and the need for about 750 MW of new capacity as a result of SherCo's retirement—but stopped short of specifying that the need should be met with new gas.

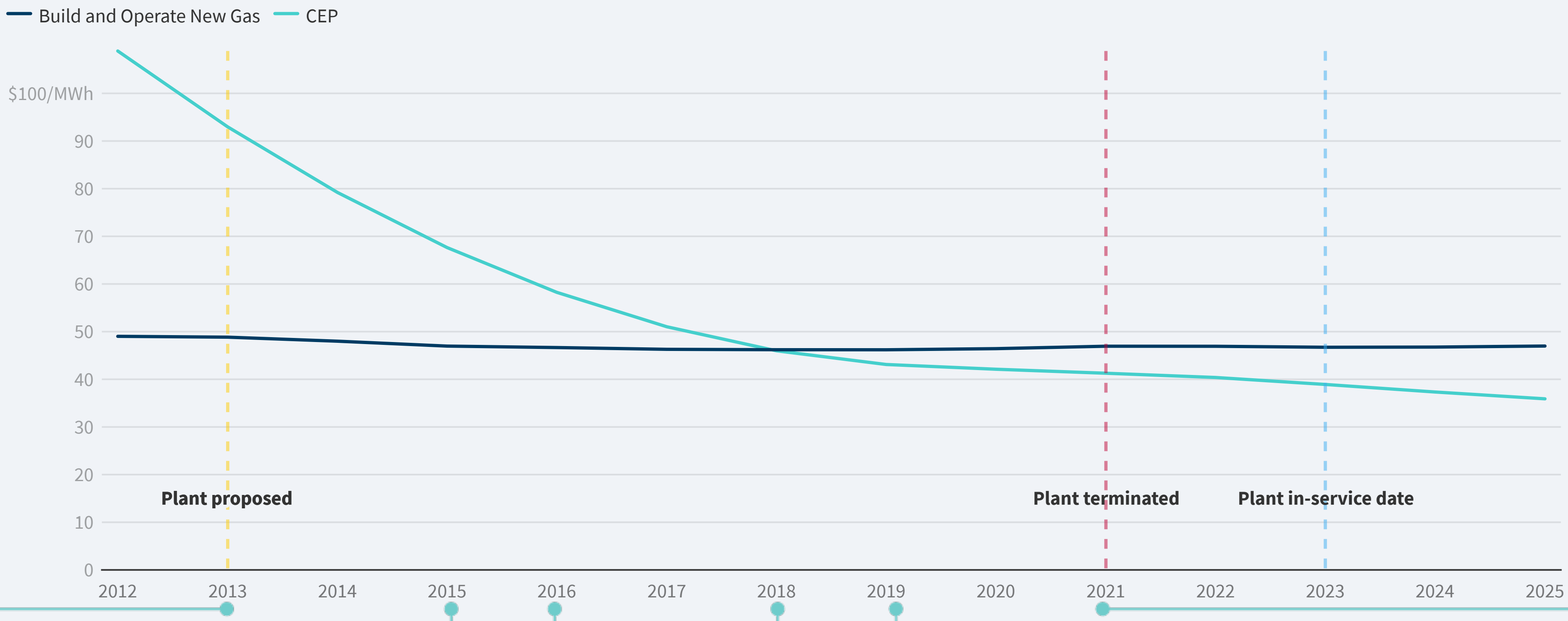
Based on our analysis of the cost of the proposed unit versus alternatives, in 2018, a CEP became the cheaper option.

The Minnesota legislature passed a bill authorizing Xcel to build a CC plant at the SherCo site, outside of the PUC's normal authorization process.

In the face of continuous stakeholder pushback and changing economics, Xcel decided to redo its analysis and reconsider alternatives. In its 2020–2034 resource plan, Xcel proposed a cost-effective alternative building smaller CTs and more renewables. The alternate plan includes an additional savings of $372 million in present value of societal costs and is expected to help Xcel reach an 86% CO_2 reduction by 2030, compared to its goal of 80%.

In Maryland, Mattawoman was canceled after facing compounding economic and advocacy pressure

Exhibit 11: Economics of Mattawoman Generating Station (combined cycle)



Mattawoman was proposed in 2013 as an 859 MW project in Prince George's County, Maryland, to participate in PJM.

The plant received approval as a 990 MW project in 2015.

Prince George's County is a majority-Black community with a cluster of existing power plants, and activism against Mattawoman included the filing of a federal civil rights complaint in 2016.

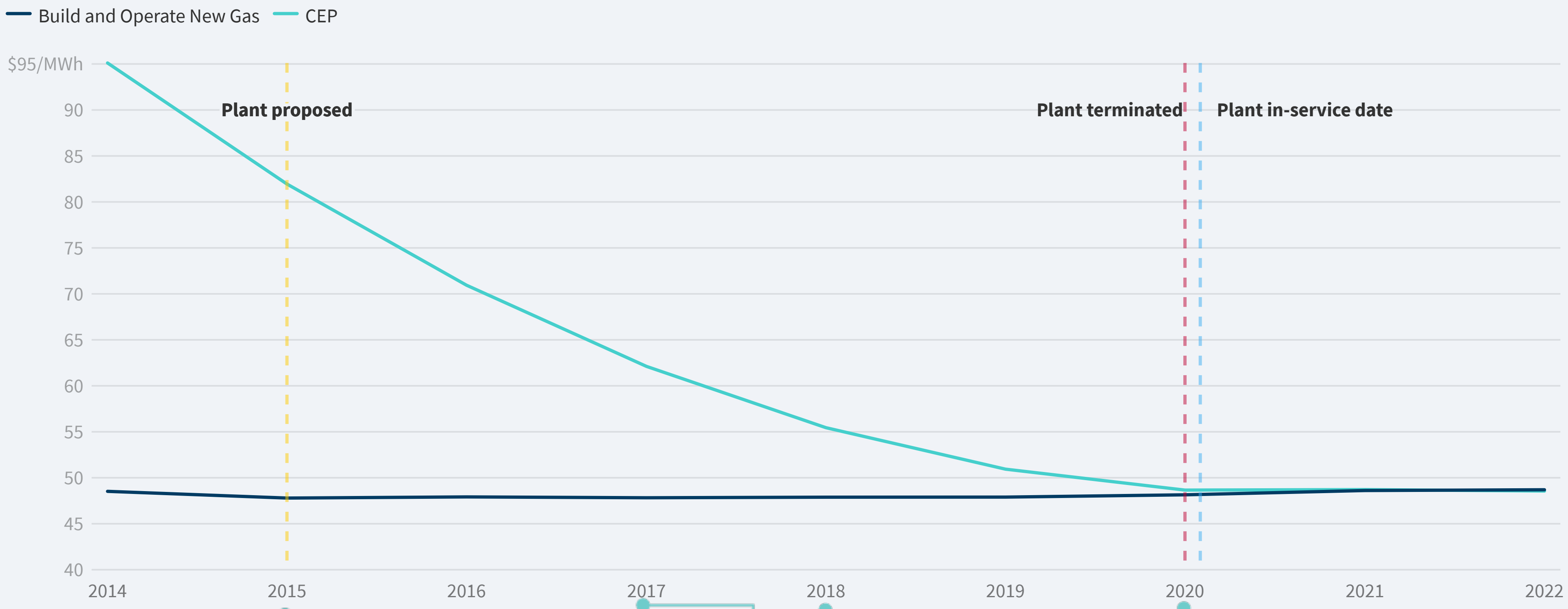
According to our analysis, the economics became favorable for a CEP in 2018. According to historical data, between 2016 and 2017, the interconnection queue in PJM went from majority gas to majority renewables.

Mattawoman has still not cleared the PJM capacity auction, a key project revenue stream. In addition, nearby pipeline and compressor station cancellations impacted gas transportation to Mattawoman in 2019.

Mattawoman Energy declared the project no longer feasible in 2021.

In California, Palmdale ultimately struggled to find off-takers

Exhibit 12: Economics of Palmdale Energy Project (combined cycle)



The Palmdale Energy Project was initially proposed in 2008 as a 570 MW hybrid solar and gas peaker project and approved by the California Energy Commission (CEC) in 2011.

In 2015, the City of Palmdale transferred ownership of the project to Palmdale Energy LLC, which evolved the proposal and permits into a 645 MW gas plant with no solar component.

The CEC approved the change in 2017.

By 2018, according to historical data, new proposed gas projects stopped entering the CAISO queue.

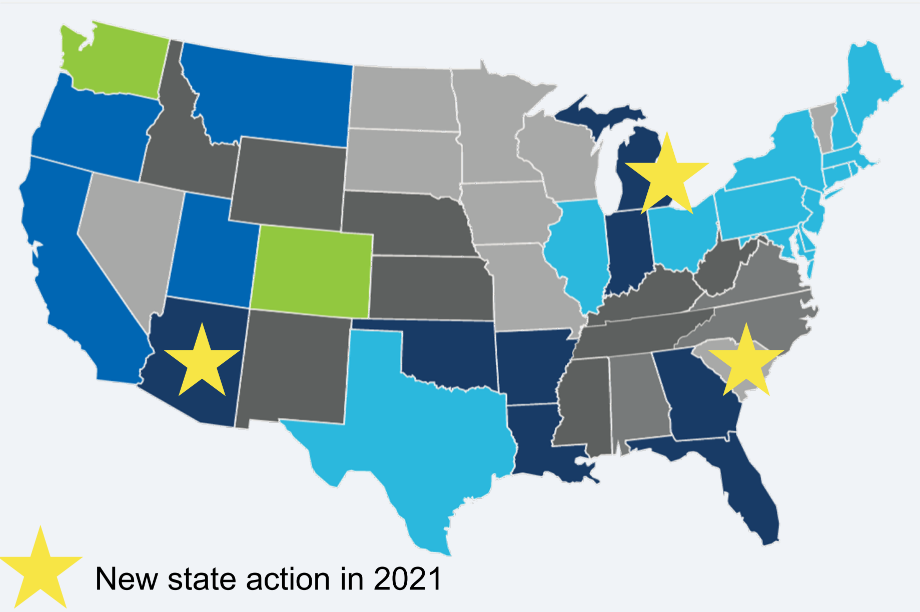
After facing over a decade of advocacy and permit challenges, the developer submitted a request to terminate the license for the plant in December 2019, citing a lack of interest in the state for contracting for new gas and an inability to secure an off-taker.

States are increasingly showing interest in implementing all-source procurement to assess new energy projects

In addition to the case studies, trends indicate a broader interest in testing market economics before procuring new resources. All-source procurement, described in our report *How to Build Clean Energy Portfolios*, is a promising tool for analyzing portfolios of clean energy resources as an alternative to new gas.

- In all-source procurement, utilities seek bids for all types of resources before determining the optimal set of supply- and demand-side assets to build—getting real-time cost and capability data to inform their investment decisions.
- This real-time data can be used to assess the current economics between CEPs and gas and avoid uneconomic procurement.

Exhibit 13: Status of competitive procurement rules and actions across the United States



Colorado and Washington had formal requirements in state statute or administrative rules requiring utilities to use all-source procurement to buy resources identified in their resource plans prior to 2021.

As depicted in Exhibit 13, recent state actions in 2021 indicate further interest in all-source procurement to assess the economics of CEPs against new gas and let market dynamics lead:

- The **South Carolina Public Service Commission** ordered Dominion Energy to develop an all-source procurement plan in all future planning cycles, which puts clean energy on a level playing field to meet future needs and compete with new gas.
- The **Michigan Public Service Commission** adopted new competitive procurement guidelines.
- The **Arizona Corporation Commission** continued to advance rules that would require utilities to use all-source procurement.

Less Competitive

- No formal requirement for competitive solicitations
- No formal requirement for competitive solicitations (requirement for limited competitive procurement of renewables)
- No formal requirement for competitive solicitations (requirement for demonstrated comparison of alternative options prior to resource aquisition)
- Requirement for competitive solicitations
- Requirement for competitive solicitations (statute or rules encourage all-source procurement)
- Requirement for all-source solicitations
- Procurement primarily driven by market competition

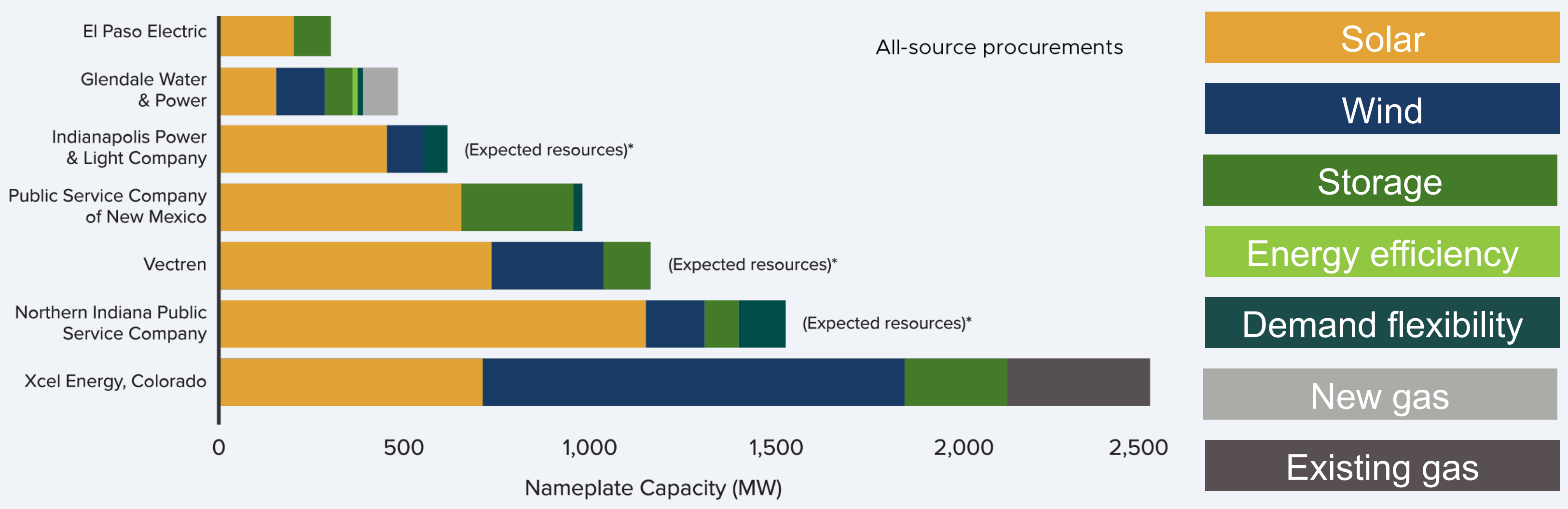
More Competitive

Recent all-source, competitive procurement processes have selected new gas for only 1% of total procured capacity

Utilities running all-source procurement processes have largely found portfolios of clean energy to be cheaper than building new gas to meet their future needs.

As we highlighted in *How to Build Clean Energy Portfolios*, all-source procurement processes that put clean energy on a level playing field with gas have generally resulted in investment decisions that prioritize carbon-free energy.

Exhibit 14: Results of recent all-source procurement processes



- Across seven recent all-source procurements surveyed in our report in which CEPs competed with new gas, only 93 MW of new gas was selected out of about 7,500 MW, representing just over 1% of all capacity procured.
- Glendale (California) Water & Power, the only procurement surveyed in which new gas was selected, faced significant transmission constraints that limited the ability of current-generation clean energy technologies to provide reliability services; the gas plant is anticipated to run at low capacity factors, significantly reducing pollution compared to previous gas investment proposals.
- El Paso Electric Company serves portions of Texas and New Mexico. In that procurement, gas was initially selected in a solicitation but denied approval by the NMPRC when it was found to be inconsistent with New Mexico's climate targets; the Public Utility Commission of Texas approved the investment, and it will serve Texas customers only.

Community-led advocacy and solutions have played a key role in driving utilities to consider clean alternatives

In addition to national trends toward all-source procurement, advocates across the country are asking for alternatives to building new gas in their communities. These efforts have resulted in several collaborations between utilities and communities to implement solutions that prioritize clean energy over new gas investment.

Oakland, California

In Oakland, community-led efforts by groups such as the West Oakland Environmental Indicators Project and local businesses led to proactive planning to avoid new fossil fuel generation, retire an existing generator, and meet reliability needs in a transmission-constrained area. As a result of the Oakland Clean Energy Initiative, PG&E and East Bay Community Energy released a solicitation to instead upgrade substation infrastructure and deploy local, clean energy resources.

Asheville, North Carolina

In Asheville, Duke Energy Progress proposed new gas-fired CC and peaker plants to replace a retiring coal plant. A collaboration among the utility, the City of Asheville, Buncombe County, and many active community members and organizations led to the formation of the Energy Innovation Task Force to find alternatives to the proposed peaker plant. In 2019, Duke announced that due to these efforts, the plant would be pushed out from 2023 to beyond 2032. The CC plant proposed at the Asheville site was built.

Oxnard, California

The City of Oxnard, with a coalition of environmental and clean energy groups and strong advocacy from Oxnard's youth and community groups like Central Coast Alliance United for a Sustainable Economy, prompted the state to initiate a review of clean alternatives to a proposed peaker plant. The California Energy Commission and CAISO concluded that Southern California Edison (SCE) could feasibly meet these local capacity needs with distributed energy resources. In 2019, SCE announced contracts for 181 MW of energy storage and 14 MW of demand response to meet the local capacity need.

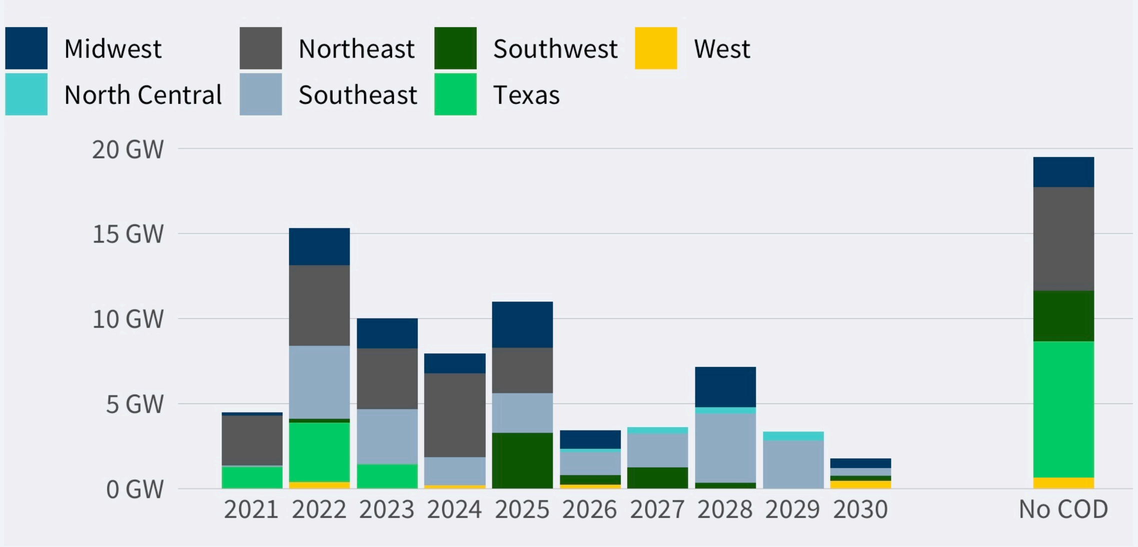
Chapter 2
Current Situation

There still are 88-plus GW of proposed gas plants in 2021, over 80% of which could be economically avoided by using CEPs

Despite changing economics, 88-plus GW of gas projects are proposed to come online in the United States before 2030

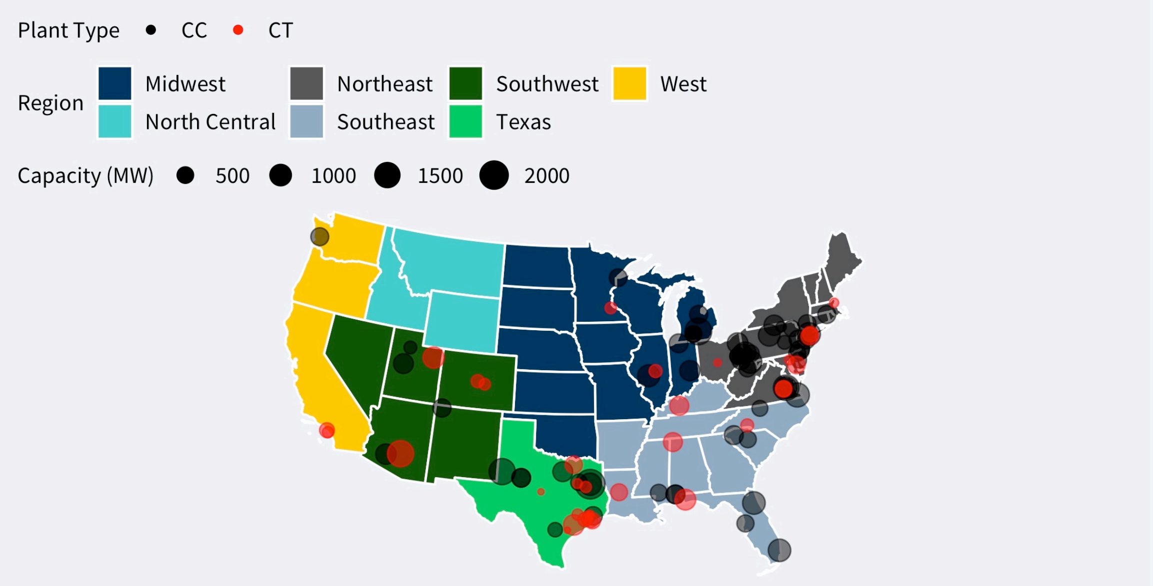
Despite changing economics and updated processes, utilities are proposing 88-plus GW of gas plants to come online before 2030, which represents about 7% of all currently installed generating capacity in the United States.

Exhibit 15: Capacity of planned gas by plant in-service year, by region



- Most proposed plants are in the Northeast, Southeast, and Texas.
- More plants are proposed to come online before 2025 than in the latter half of the decade. Nearly 20 GW of plants assessed do not have a specific in-service date.

Exhibit 16: Capacity of planned gas by 2030, for plants with a proposed location



- About 60 GW of the 88 GW of plants had a proposed location and are included in this map.
- Concentrations of plants can be seen in the Northeast and in Texas.

Source: RMI analysis of Sierra Club and S&P data

Over 80% of total gas capacity proposed could be economically avoided with CEPs, saving $22B and 873 MMT of CO_2 over a 20-year lifetime

CEPs are lower cost than 80% of utilities' proposed gas capacity.

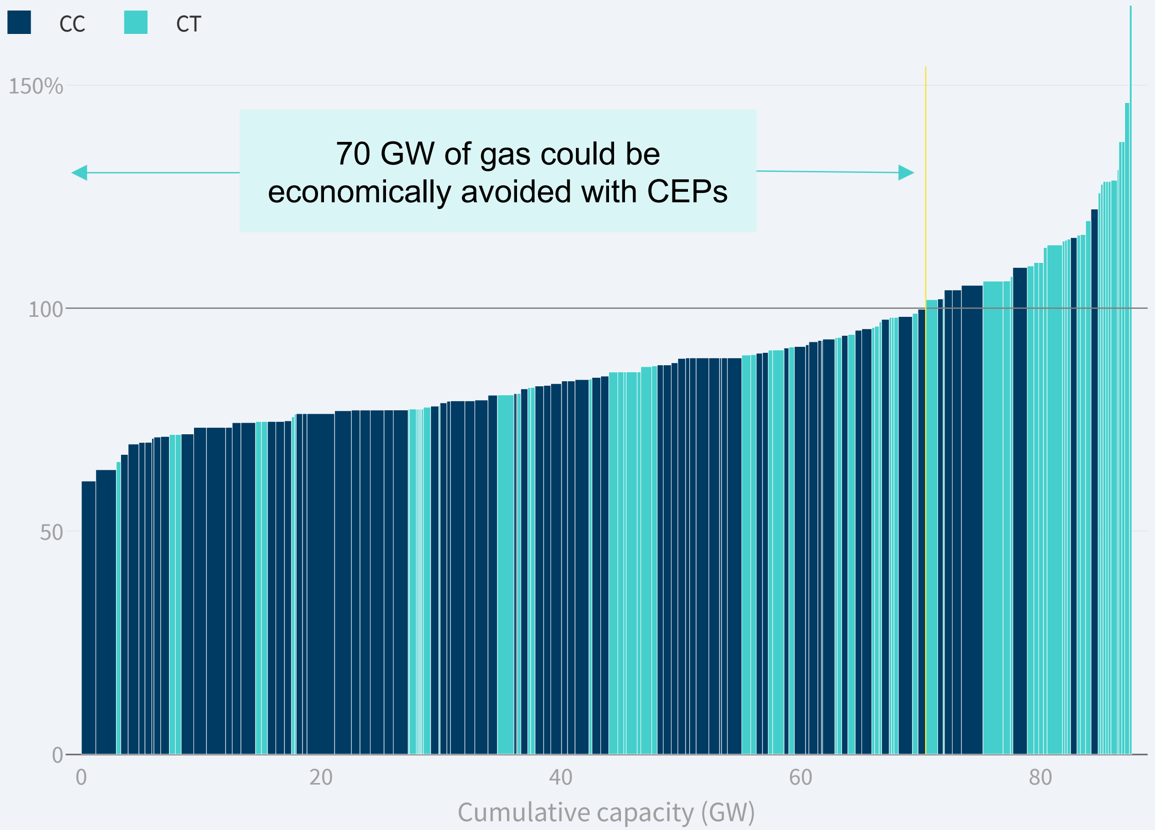
Investing in CEPs to avoid new gas capacity could:

- Save over $22 billion on a net present value basis
- Reduce emissions by 873 MMT over a 20-year period, based on expected gas plant operations—the equivalent of taking over 9 million vehicles off the road each year

In Exhibit 17, we show the costs of CEPs relative to the gas plants they are designed and optimized to avoid:

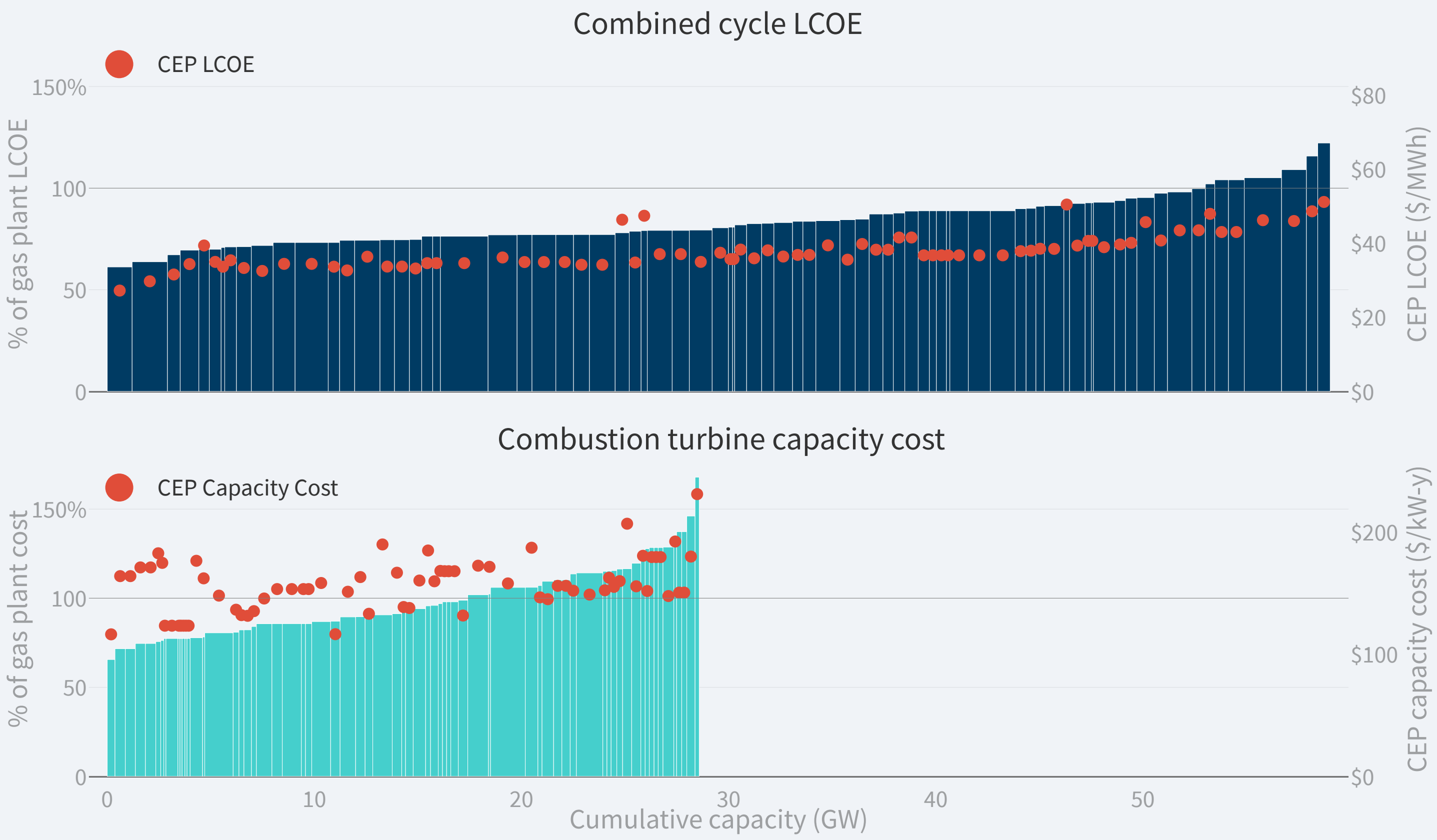
- The y-axis shows the net CEP cost as a percentage of gas plant costs. A percentage falling below 100% indicates that the CEP would cost less than its respective proposed gas plant.
- The x-axis indicates the cumulative capacity of plants analyzed, ordered by their competitiveness. The 100% line intersects with the cumulative capacity stack at about 70 GW, indicating the total quantity of uncompetitive gas plants proposed for construction prior to 2030.

Exhibit 17: Net CEP costs as a percentage of equivalent gas plant costs at planned gas in-service year



90% of CC capacity and 60% of CT capacity could be economically avoided by CEPs

Exhibit 18: Economics of CEPs needed to replace combined cycle and combustion turbine gas plants



CEPs that replace proposed CT plants tend to be less competitive than those that replace proposed CCGT plants and are more sensitive to the specific patterns of renewable generation and demand in a region.

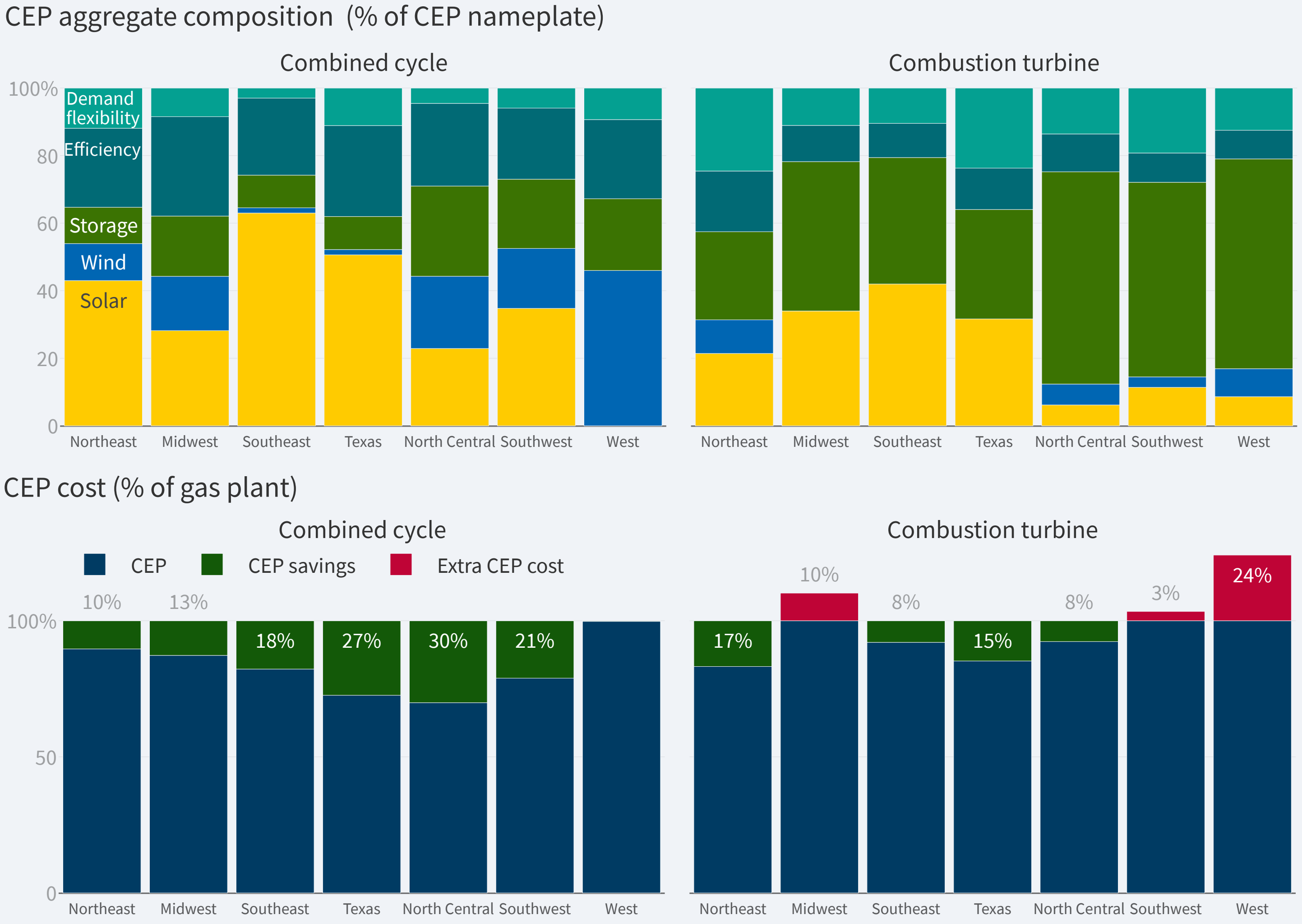
- CEPs are most competitive with CTs where combinations of renewables, efficiency, and demand flexibility can provide capacity during periods of high demand.
- In places where this isn't possible due to resource constraints or a mismatch between renewable generation and peak demand hours, large amounts of storage can be required, often making CEPs less competitive.

To the left, we show the costs of CEPs relative to the gas plants they are designed to avoid.

- For CC replacements (top panel), we show the LCOE of the CEP as a percentage of the LCOE of the CC, as well as the LCOE for the CEP in $/MWh.
- For CT replacements (bottom panel), we show the cost of the CEP as a percentage of the cost of the CT as well as the CEP capacity cost.

Least-cost CEP composition varies by region, reflecting local needs and resource potentials

Exhibit 19: Regional variation in average least-cost CEP composition and competitiveness



All five clean energy technologies play important roles in CEPs that can replace gas plants, though the combinations vary depending on the type of gas plant and its proposed location.

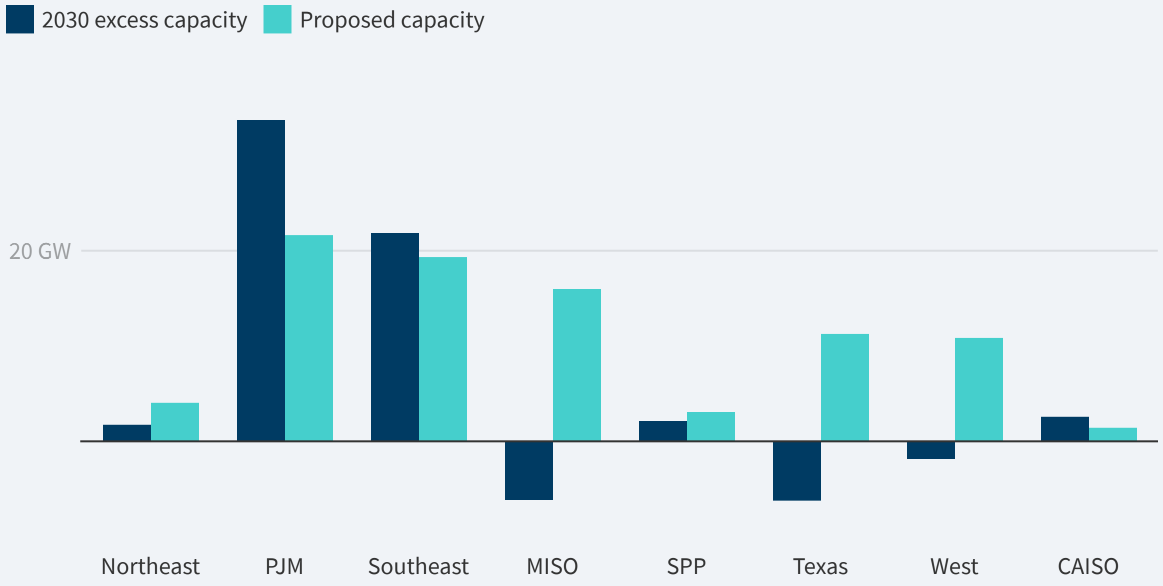
- The composition of CEPs that replace CCs is driven more by monthly energy needs, so these portfolios favor technologies that produce or save energy, i.e., solar, wind, and end-use energy efficiency.
- In contrast, CEPs that replace CTs have much lower energy requirements, so their composition is driven by capacity needs and includes more energy storage and demand flexibility.
- Regions where CEPs are more expensive relative to gas plants tend to have lower-quality renewable resources or have peak net load hours that occur when renewables are unavailable.

Exhibit 19 shows the composition and competitiveness of CEPs aggregated by region. A few key regions demonstrate how regional resources may impact CEP competitiveness:

- In the West, solar is largely absent from marginal CEPs because of the large amount of preexisting and already planned solar capacity, particularly in California. Wind is selected to help balance solar, but significant storage is still needed to meet all capacity needs. The relatively modest quality of wind in the West, relative to other regions, and the low capacity value of incremental solar leads to less-competitive CEPs in this region.
- In the Midwest, particularly for CEPs replacing CTs, a similar issue exists: the region’s highest-quality resource, wind, has relatively little incremental capacity value because of the large amount of wind already deployed in the Midwest and wind’s lower general coincidence with periods of high demand.

Nearly half of proposed gas is in regions with significant excess capacity expected through 2030

Exhibit 20: Anticipated excess capacity and proposed new gas capacity by region by 2030



Source: NERC 2020 Electricity Supply & Demand, January 2021

Reserve margin and excess capacity metrics are from NERC's 2020 Electricity Supply & Demand data released in January 2021. Reserve margin and excess capacity are based on NERC's anticipated resources; these are existing resources adjusted for firm capacity transfers, and formally approved capacity additions and retirements. We only show summer reserve margins and excess capacity; in all regions, winter reserve margins and excess capacity are greater. (In Exhibit 20, MISO stands for Midcontinent Independent System Operator; SPP represents the Southwest Power Pool.)

Reliability is often front of mind for utilities seeking to build new gas plants, yet 47% of proposed gas capacity is in PJM territories and the Southeast, both regions with substantial anticipated excess capacity beyond reserve margin targets.

- These regions are also expected to have excess capacity in 2030, including only some of these proposed capacity additions.
- A probabilistic analysis of reliability by the North American Electric Reliability Corporation (NERC) shows PJM territories and the Southeast face no significant reliability issues that would justify the amount of proposed capacity.

In regions that do have anticipated capacity shortfalls in the coming years, our analysis suggests that CEPs are a lower-cost approach than new gas capacity.

- In CAISO's territory and other parts of the West, resources and strategies beyond those included in our analysis may be required to support reliability.
- In these regions, transmission, multi-day storage, and geothermal energy could complement CEPs to provide reliable service at a lower cost and with less risk than gas; we do not assess these portfolios in this study.

Chapter 3
Looking Forward

Plants proposed today will be increasingly outcompeted before their in-service dates or face stranded-cost risks as clean energy portfolios become more competitive

Proposed gas plants face six key policy and market headwinds that may further undermine their competitiveness

In 2021, gas plants face additional risks beyond our baseline comparison. As technology continues to evolve and states and the federal government consider new energy policy, the trends outlined below in Exhibit 21 could further increase the risk of cancellation of proposed gas plants or lead to their early retirement.

Exhibit 21: Economic and policy risks for gas

	Economic or policy headwind	Description and key policy drivers	How we assess this risk in our analysis
1	Declining renewable energy costs	Renewable energy and storage prices have fallen faster than projected in most recent years. Federal policy that includes updated tax incentives for clean energy generation could accelerate renewables' cost declines.	We run a sensitivity that assumes cost declines continue at their current pace, rather than slowing as they are assumed to do in the base case.
2	Upside risk to gas prices	Since the advent of fracking, new supply exceeding new demand kept gas prices low. This was driven by easy access to leases, a permissive approach to regulating the gas supply chain, and abundant undemanding capital. With each of those drivers reversing, the risk to gas prices is asymmetric; it is much more likely that they increase than decrease.	We run a scenario using AEO gas price projections from 2019, which are effectively 22% higher than those used in our base case scenario and August and September 2021 market prices.
3	Incorporating the value of firm supply	Recent reliability events have shown that some gas plants struggle to provide capacity during periods of system stress because they do not have firm fuel supply.	We run a scenario including an estimated cost for securing firm gas supply for a proposed gas plant.
4	Including the value of jobs	As policymakers seek to prioritize job growth, recognition that CEPs provide more jobs than proposed gas could compound their economic advantage.	We compare the total job opportunities for CEPs to proposed gas.
5	Assessing health costs	Health impacts and their associated costs are increasingly being considered and quantified by state and national policymakers. Internalizing (e.g., through more stringent pollution control standards) or considering the potential health impacts of gas plants (e.g., in utility resource planning) poses additional risk.	We model the annual health costs associated with air pollution from proposed gas plants.
6	Prioritizing community risk	National and state-level initiatives prioritizing environmental justice and limiting impacts to low-income communities and communities of color add additional risks to proposed plants in those communities.	We identify plants with proposed locations in communities that are low-income or a community of color.

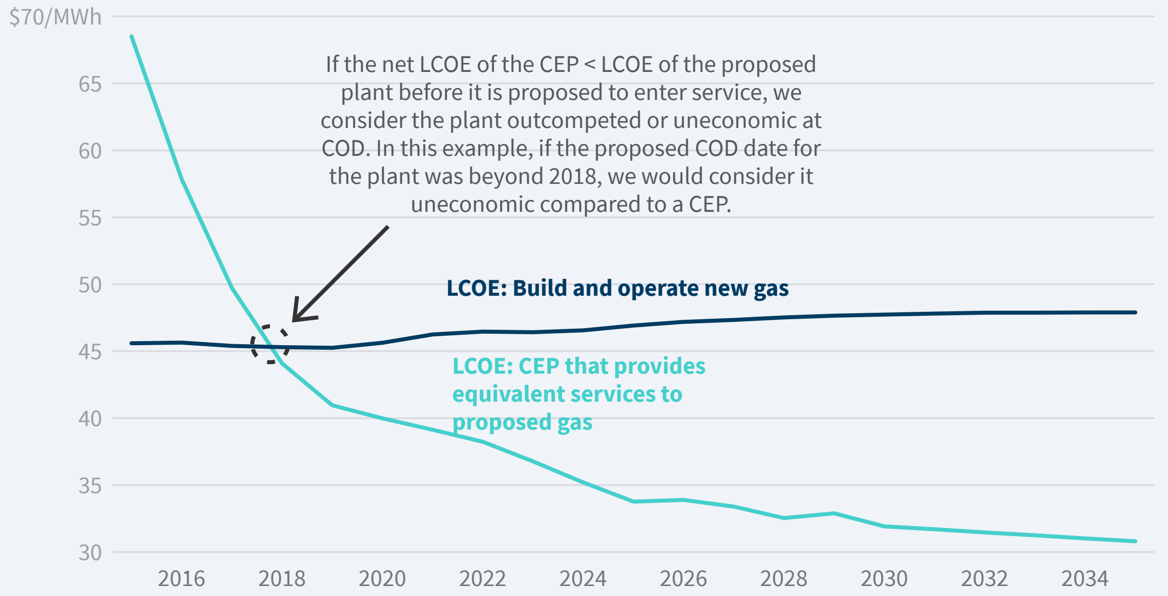
Approach: How risk factors affect competitiveness at a gas plant's proposed in-service date

In our base case scenario, 80% (70 GW) of plants are outcompeted by CEPs at their in-service date. If a gas plant is canceled before its in-service date, early-stage equity investors and development capital entities bear the risk for merchant plants. We assess further risk for gas plants at their in-service date for our six economic and policy headwinds.

Exhibit 22 shows how we assess the economic competitiveness of proposed gas plants at their target in-service date.

Exhibit 22: Assessing a gas plant's competitiveness at in-service date

Example: Midwest combined cycle



For declining renewable energy costs, upside gas price risk, firm supply, and health costs, we assess how each risk affects the comparative economics between CEPs and gas at the proposed plant's in-service date.

- Declining renewable energy costs
- Upside risk to gas prices
- Incorporating the value of firm supply
- Assessing health costs

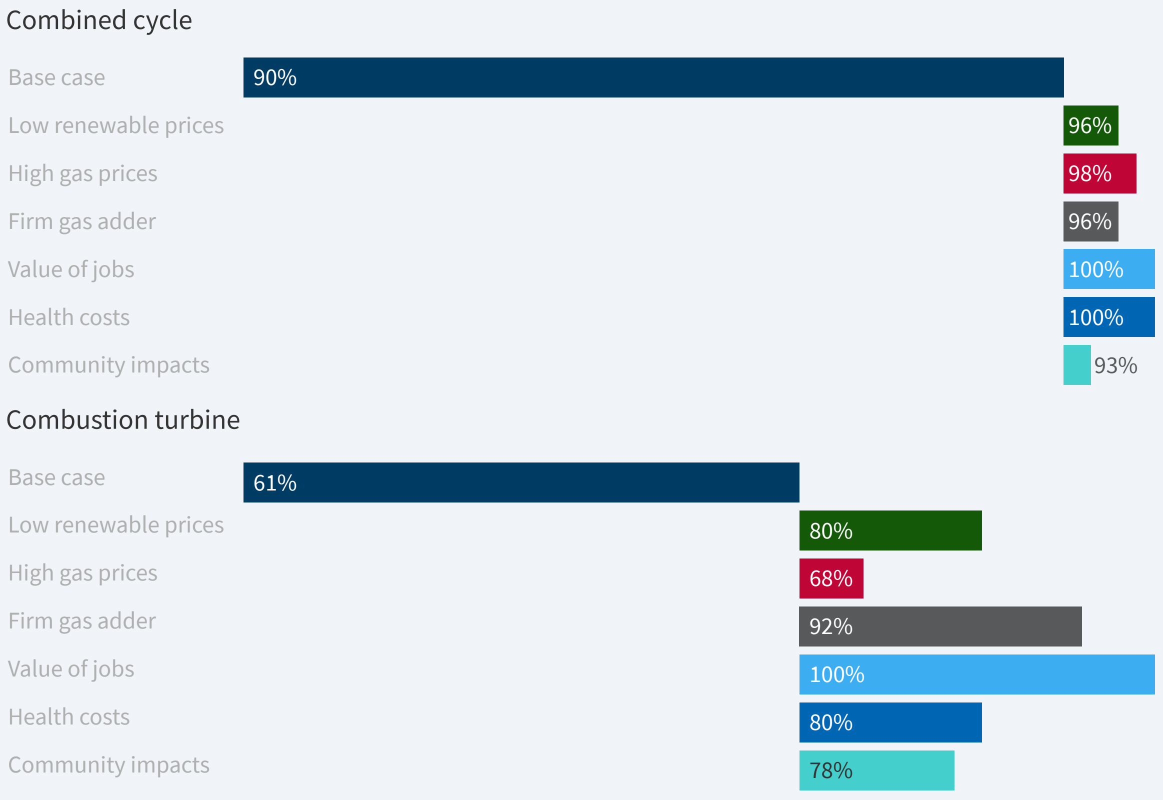
For jobs, we compare potential job-years created by CEPs versus proposed gas plants.

For community risk, we identify where plants are proposed in low-income communities or communities of color.

- Including the value of jobs
- Prioritizing community risk

All six key policy and market headwinds have the potential to further undermine the competitiveness of proposed gas at its in-service date

Exhibit 23: Summary of the impacts of six headwinds on the percentage of proposed gas capacity outcompeted at in-service date



If any headwinds materialize, nearly all CCs will be outcompeted. Low renewable energy prices, a firm gas adder, or valuing jobs could significantly impact CTs' competitiveness.

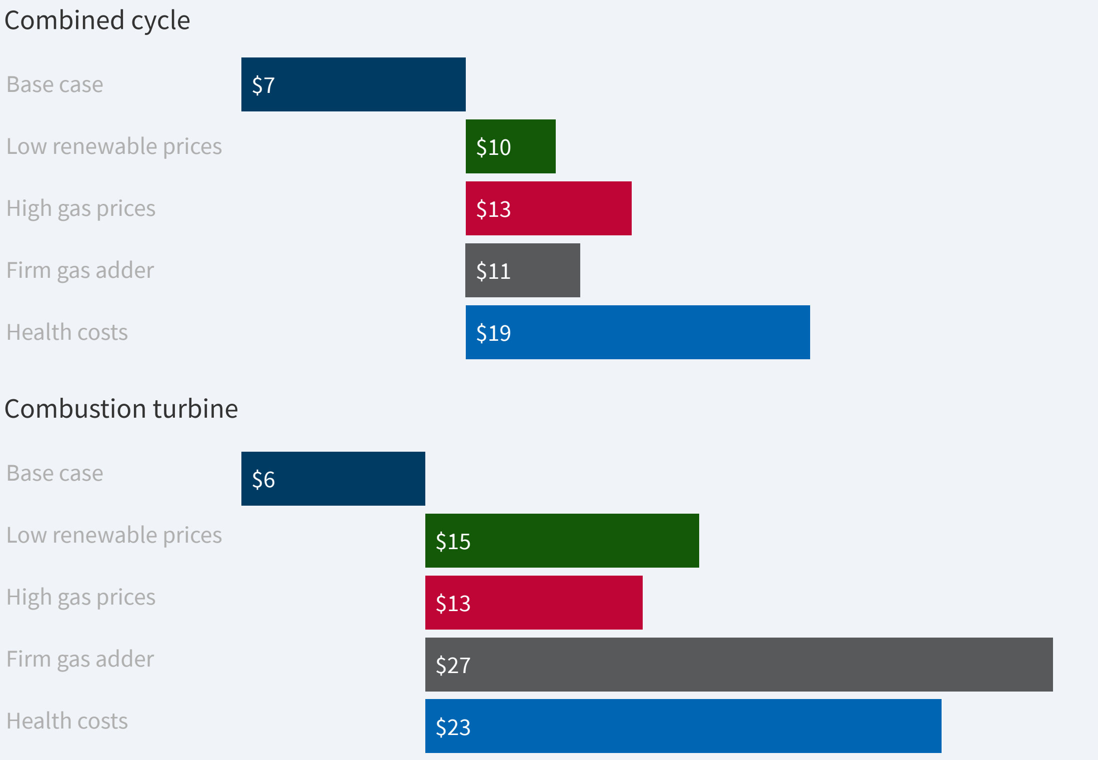
- Low renewable energy prices, high gas prices, and the firm gas adder are all interactive, with compounding effects on gas plant competitiveness.
- Increased risk due to health costs, community impacts, and jobs could be combined with others or each other if simultaneous policies are considered to internalize these values.

Exhibit 23 depicts the percentage of CEPs that outcompete gas in our base case for CCs and CTs, and the percentage that would be outcompeted if all six of the headwinds were realized.

- **Low renewable energy prices** could result in 96% of CCs and 80% of CTs being outcompeted.
- **High gas prices** could result in 98% of CCs and 68% of CTs being outcompeted. Gas prices have a greater impact on CCs due to their higher capacity factors.
- **A firm gas adder** could result in 96% of CCs and 92% of CTs being outcompeted. The firm gas adder affects CTs more than CCs, due to the fixed costs of gas supply being spread over less annual energy generation.
- **Internalizing health costs** could result in 100% of CCs and 80% of CTs being outcompeted.
- **Prioritizing minimizing harm in communities of color and low-income communities** could result in 93% of CCs and 78% of CTs being outcompeted.
- **Valuing jobs** puts all proposed gas plants at risk; every CEP that was less competitive than its proposed gas plant on economics alone resulted in more job creation.

Four headwinds have the potential to increase average CEP savings over proposed gas, widening the competitiveness gap

Exhibit 24: Summary of the impacts of four headwinds on average savings of CEPs over proposed gas at in-service date



- Three of the headwinds analyzed—low renewable energy prices, high gas prices, a firm gas adder—can be directly incorporated into an economic comparison between CEPs and proposed gas plants.
- Health costs of gas plant air pollution, if internalized by policy or in regulatory decision-making, can also be captured in an economic analysis.
- These four cost-quantifiable headwinds could increase the competitiveness of CEPs to a $10–$19/MWh advantage over proposed CCs or a $15–$27/MWh advantage over CTs.

Exhibit 24 shows that in our base case, CEPs cost less than equivalent gas plants by an average of $7/MWh for CCs and $6/MWh for CTs. Each of the four headwinds shown here increased CEPs' margin of economic competitiveness.

Declining renewable energy costs: 96% of CCs and 80% of CTs could be outcompeted

If renewable energy costs continue to decline at their current pace rather than slowing as predicted in our base case, CEPs will become even more competitive. There are indications that more steady cost declines could be realized—renewable and storage prices have fallen faster than they were projected to in most recent years. Federal policy that includes updated tax incentives could further accelerate renewable cost declines, even given the supply chain-related price increases observed in late 2021.

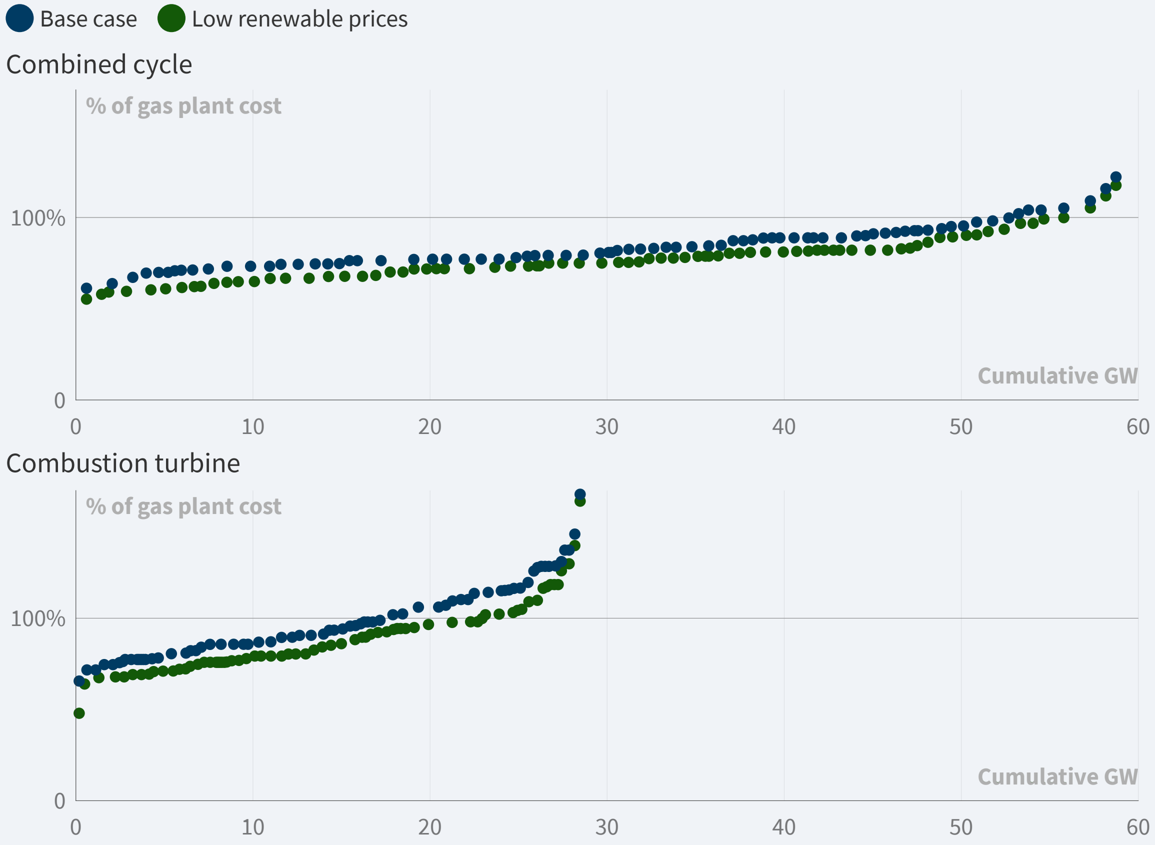
The renewable cost trajectories modeled reflect assumptions from the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB):

- The base case uses renewable and storage prices from NREL's 2021 Electricity ATB Moderate Scenario, which assumes broad adoption of leading practices and the realization of manufacturer improvement expectations but no new innovations.
- The low renewable energy prices scenario uses renewable and storage prices from NREL's 2021 Electricity ATB Advanced Scenario, which includes the development and adoption of known technology and planning innovations leading to price declines similar to those seen in recent years.

Exhibit 25 shows how the competitiveness curve shifts with declining costs of renewable energy. The whole curve shifts down from the base case curve, indicating that CEPs cost even less compared to their respective proposed gas plants.

- In the top panel, the percentage of CEPs competitive with CCs shifts from 90% to 96%.
- In the bottom panel, the percentage of CEPs competitive with CTs shifts from 61% to 80%.

Exhibit 25: Impact of declining renewable energy costs on CEPs' competitiveness with CCs and CTs at in-service date



Upside risk to gas prices: Higher gas prices would make CEPs competitive with nearly 90% of proposed gas plants

With expectations of higher future gas prices, CEPs are more competitive against proposed gas. Policy and market trends point to systematically higher gas prices:

- Higher transportation costs driven by the difficulty of building new oil and gas infrastructure, as shown with recent cancellations of the Keystone XL and Atlantic Coast pipelines, and the court decision instructing the Federal Energy Regulatory Commission (FERC) to consider the climate and environmental justice impacts of its decisions
- Less capital to develop new supply, driven by investor demand for profits from a sector that has not delivered them recently

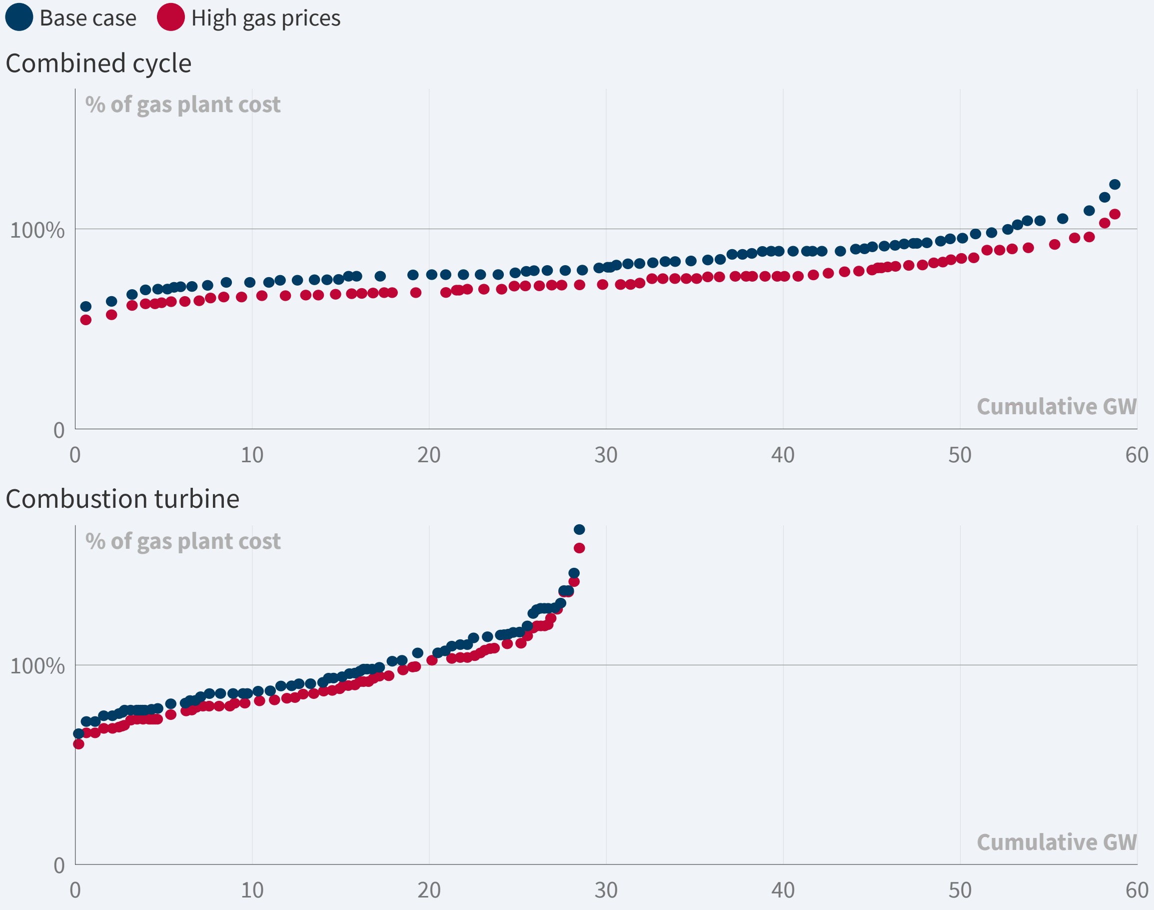
The base case uses benchmark forecasts from 2021, which are similar to futures market prices seen in August and September 2021 on a levelized basis. The high gas prices case uses forecasts from AEO 2019, which are about 22% higher.

Exhibit 26: Comparison of 2023–2033 levelized prices, the period that most affects CEP competitiveness	
Base case (power sector AEO 2021 reference case)	$3.44
High gas prices (power sector AEO 2019 reference case)	$4.21
October/November Henry Hub curve + AEO 2021 power sector delivery	$3.59

Exhibit 27 shows how the competitiveness curve shifts with higher gas prices, as defined in the table above:

- In the top panel, the percentage of CEPs competitive with CCs shifts from 90% to 98%.
- In the bottom panel, the percentage of CEPs competitive with CTs shifts from 61% to 68%.

Exhibit 27: Impact of higher gas prices on CEPs' competitiveness with CCs and CTs at in-service date



Incorporating the value of firm supply: Ensuring reliability with firm supply would render nearly all proposed gas plants uneconomic

Including a firm supply adder would make nearly all new-build CCs uneconomic and all but 2 GW of new-build CTs uneconomic. Recent blackouts during winter storm Uri highlight the consequences of outages at gas plants that planners assumed would be available during periods of system stress. As a result, having plants internalize more of the costs of firm supply is an active policy conversation.

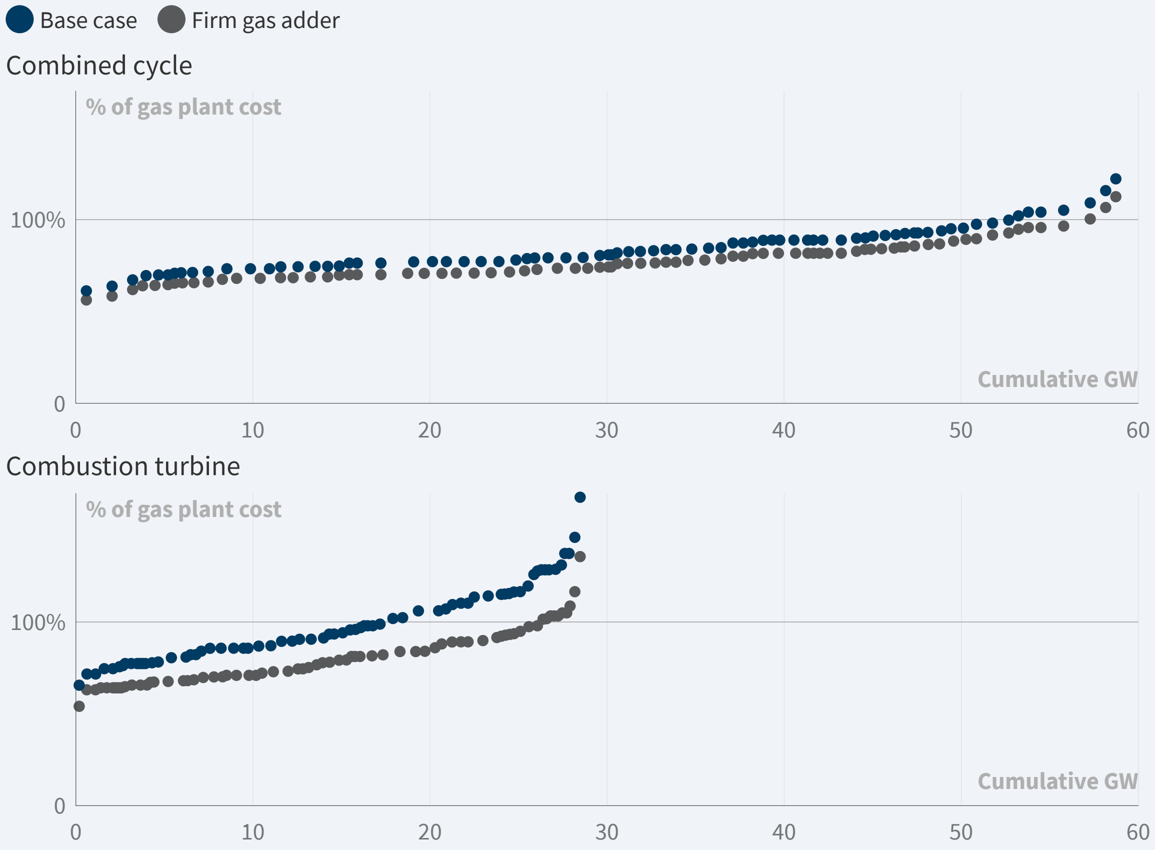
In times of system stress, research suggests that a substantial proportion of gas plant outages are associated with fuel supply issues, many of which could be addressed by firm fuel supply contracts and infrastructure. For a gas plant to provide capacity, or any other service to the grid, adequate fuel must be available and deliverable from the gas system to that plant. Historically, gas-fired power plants bear little of the cost for the infrastructure that delivers their fuel. Most of the cost of building gas pipelines and other upstream infrastructure falls to other gas users, such as buildings and industry. This can mean that power plants do not have guaranteed rights for gas supply and transportation.

The true cost of reliable gas power plant capacity includes the fixed costs of providing firm gas. We assume the cost of firm fuel supply is $0.33 per dekatherm per day based on the average reservation rate across a selection of pipeline tariffs (see Appendix).

Exhibit 28 shows how the competitiveness curve shifts with a firm gas adder:

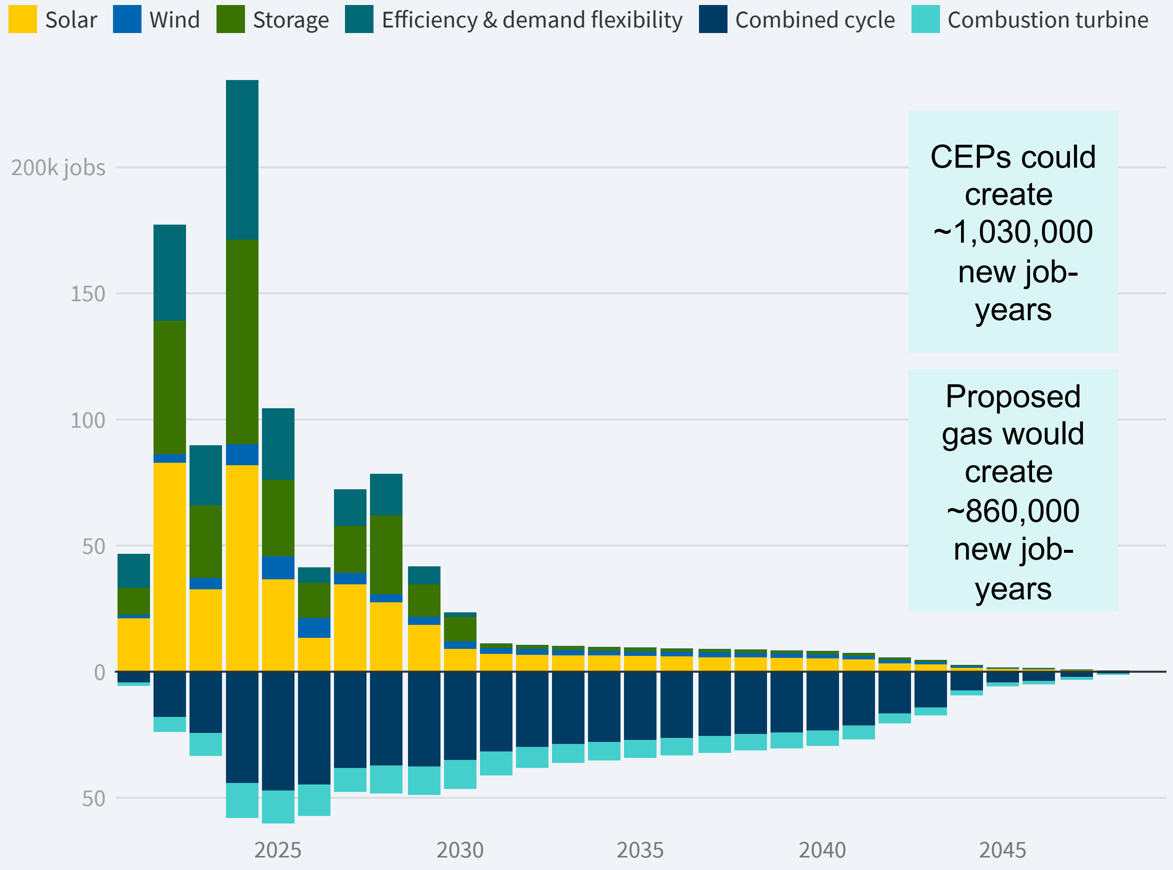
- In the top panel, the percentage of CEPs competitive with CCs shifts from 90% to 96%.
- In the bottom panel, the percentage of CEPs competitive with CTs shifts from 61% to 92%.

Exhibit 28: Impact of firm gas adder on CEPs' competitiveness with CCs and CTs at in-service date



Including the value of jobs: CEPs create more than 170,000 net new job-years relative to proposed gas plants

Exhibit 29: Net job-years created by pursuing CEPs over proposed gas projects



As policymakers seek to prioritize job growth, recognizing that CEPs provide more jobs than proposed gas could further limit the quantity of gas plants built. We used a custom input-output model to quantify the job-years associated with investment in and operation of CEP resources and proposed gas plants, including direct spending but omitting re-spending impacts.

Many of these jobs, like direct construction and ongoing operations and maintenance, will be inherently local to the communities where CEPs or gas plants are built. Given today's global manufacturing and supply chains, without deliberate stipulations from projects and policymakers, some upstream jobs may be created outside of the United States for both gas plants and CEP resources. A wide variety of policies and strategies from policymakers, regulators, utilities, and developers can help ensure localities can maximize the local economic benefits of energy resources and provide living wages to workers.

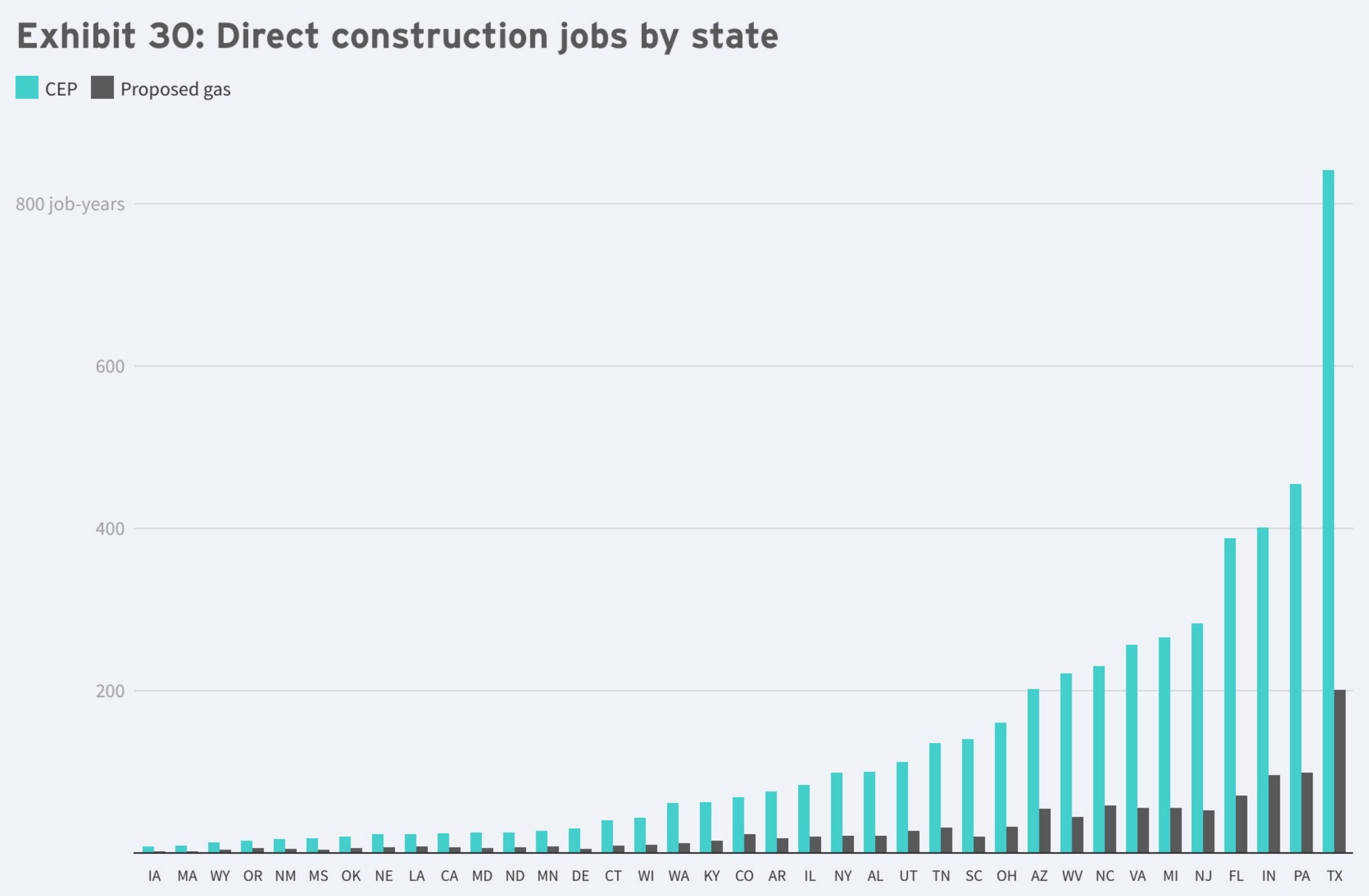
- CEPs could create 20% more job-years than the proposed gas plants over a 20-year horizon. Investment in CEPs over proposed gas will yield the most job-years in the battery and solar industries, given the composition of least-cost CEPs in our analysis.
- While CEP job-years overall exceed proposed gas job-years, CEPs result in fewer job-years for ongoing operations and maintenance due to the requirements for maintaining these renewable resources. Job-years that result from capital spending (construction and manufacturing) for both CEPs and gas far exceed jobs that result from ongoing operational and maintenance spending.

CEP direct construction job-years surpass those for proposed gas for all plants in every state

To capture the economic opportunity associated with direct construction jobs supported by CEPs, states can invest in additional in-state job-training resources for clean energy technologies, manufacturing infrastructure, and housing infrastructure to support this industry's growth and build local supply chains to deliver CEPs.

Exhibit 30 compares the direct construction jobs created by building CEPs versus proposed gas in 37 states.

- Investment in CEPs over gas would yield the most direct construction job-years in states like Texas and Pennsylvania where the most new gas is being proposed.
- In regions where our CEP model chooses resource mixes with higher labor requirements, such as wind, CEPs can yield up to four times more job-years than gas.
- This analysis assumes that both jobs from proposed gas plants and jobs from CEPs are direct construction jobs contained entirely within the state. Training programs can help build up the workforce in each state to support an industry capable of CEP development at scale.



Assessing health costs: Avoiding new gas with non-emitting CEPs could prevent $23 billion to $74 billion in health impacts over 20 years

Exhibit 31: Annual health benefits of avoiding proposed gas plants by investing in CEPs

Key health metrics underscore the risks to human health posed by building new gas plants. We used the US Environmental Protection Agency's CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA) model (see Appendix) to assess the impact of nitrogen oxides, sulfur dioxide, and particulate matter ($PM_{2.5}$). We found that combustion from proposed gas plants with a stated location (about 60 GW of the 80+ GW proposed), unabated, could be responsible for $1.6 billion to $3.7 billion in health impacts per year or $23 billion to $74 billion over their assumed 20-year lifetimes.

Adding the total estimated cost of health impacts to proposed gas plants further undermines their cost-competitiveness, increasing the percentages of CEPs that outcompete CCs and CTs from 90% and 61% to 98% and 68%, respectively. On average, adding health impact costs to proposed plants makes CEPs $7–$10/MWh more competitive than baseline (see Slide 26).

More stringent pollution control standards for new gas plants or policy that assigns a cost to criteria pollutants could force plants to internalize these costs.

Exhibit 31 depicts the potential human health impacts that could be avoided by building CEPs instead of proposed gas.

- Opting for CEPs in lieu of proposed gas plants could avoid 152 to 346 pollution-related deaths across the continental United States every year. This is equivalent to 3,040 to 6,920 deaths over the next 20 years.
- Further damaging air quality with pollution from proposed gas plants could result in 76,540 additional asthma exacerbations nationwide over the next 20 years, compounding asthma risks already exacerbated by climate change-driven wildfires and COVID-19.
- Our analysis conservatively included only the health impacts of avoiding proposed gas. Opting for equivalent CEPs would displace fossil fuel generation from other existing coal- and gas-fired plants, resulting in higher avoided health impacts per year.

Health impacts will be highest in host communities but borne nationwide

Investment in CEPs over gas would avoid harmful health impacts in a majority of US states, with higher potential impacts concentrated in states with higher population densities and unfavorable wind patterns.

Health impacts would be concentrated in areas surrounding the proposed plant locations but are present nationwide. Each proposed plant would cause health damages in regions beyond its proposed locality.

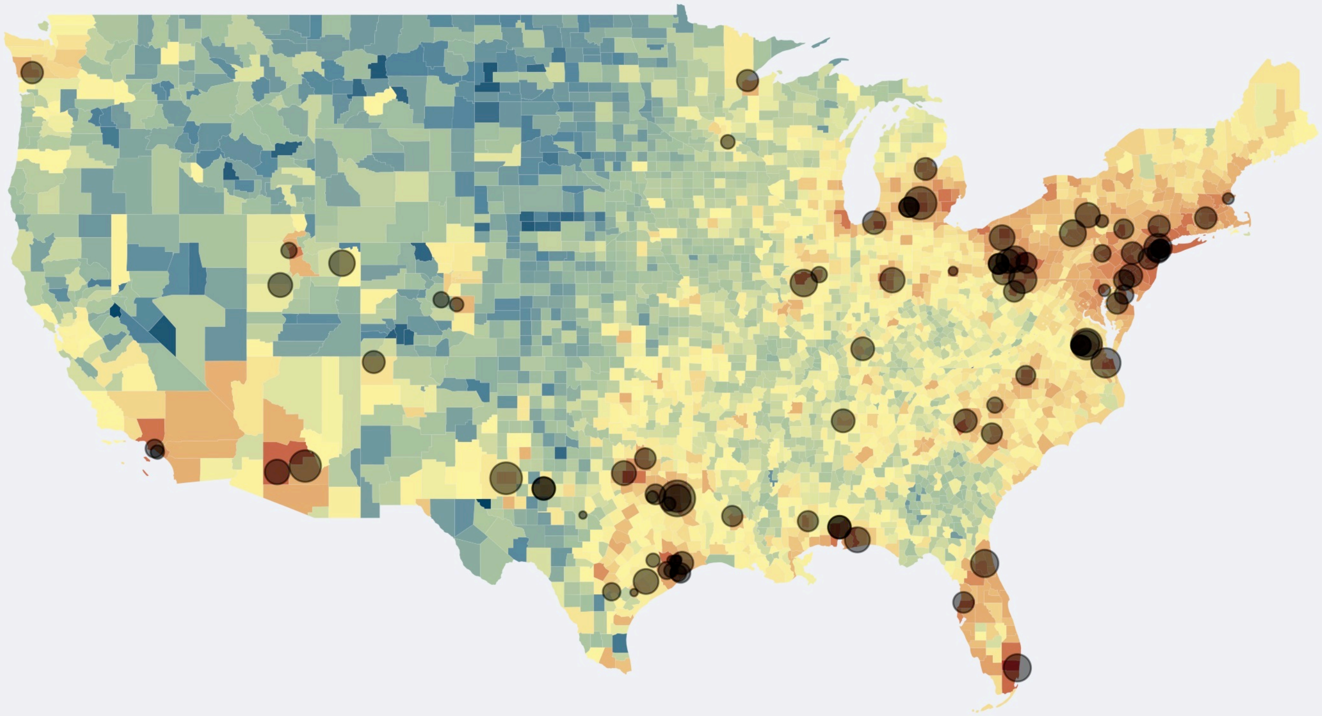
Exhibit 32 depicts the distribution of annual healthcare costs avoided by building CEPs over gas, in COBRA's low estimate.

- The Northeast could experience the highest negative health impacts from proposed gas due to the concentration of proposed plants and the population density of the region.
- Proposed gas plants could cost New Jersey alone over $180 million over a 20-year period.
- States including Georgia, Vermont, New Hampshire, and Maine could experience an increase in health costs of at least $2 million without physically hosting any proposed gas plants.

Exhibit 32: Annual cost of healthcare impacts avoided by building CEPs

Health impacts ($ / year): $60 | $100 | $1,000 | $10,000 | $100,000 | $1,000,000 | $10,000,000 | $64,500,822

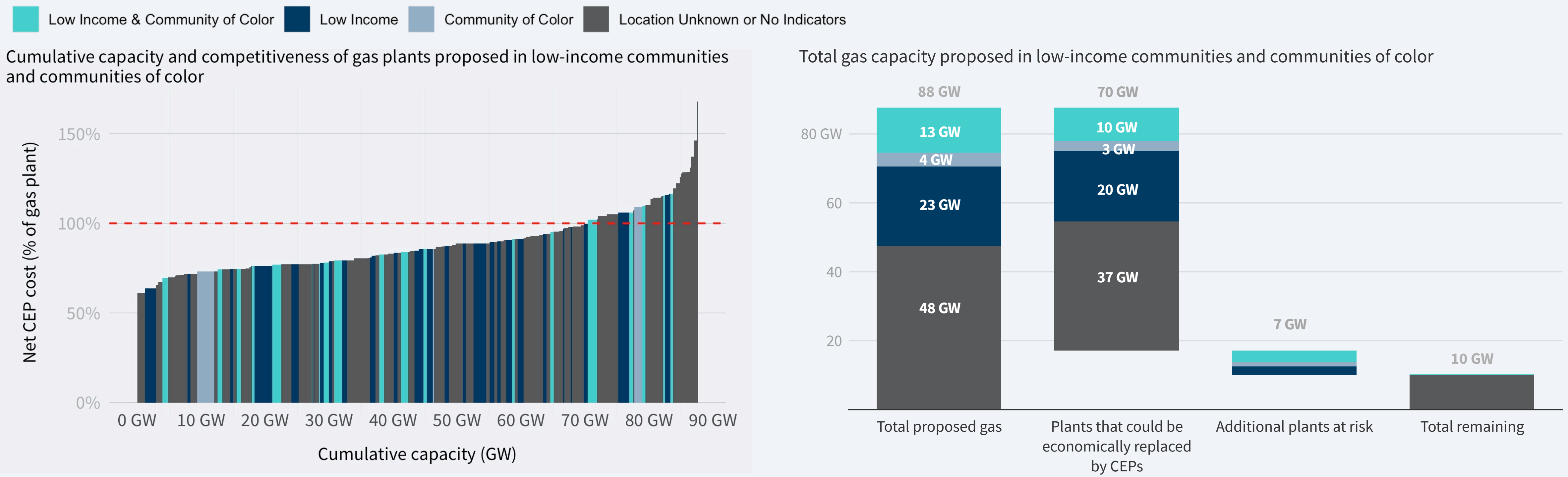
Capacity (MW): 500 | 1000 | 1500 | 2000



Prioritizing community risk: CEPs could avoid 40 GW of gas in low-income communities and communities of color

CEPs have the potential to economically avoid 33 GW of gas in low-income communities (defined as communities with more than 30% of individuals below 200% of the federal poverty line) and communities of color (defined as areas in which the percentage of minority persons is greater than the state average). State and national policies that prioritize minimizing impacts to these communities would put an additional 7 GW of gas plants at risk, despite favorable economics.

Exhibit 33: The potential for CEPs to avoid gas plants in low-income communities and communities of color



- The chart on the left highlights plants in the proposed plant cost-competitiveness stack that are located in communities of color or low-income communities.
- The chart on the right adds up values from the chart on the left to show that 40 GW of plants are proposed for locations in low-income communities or communities of color, 33 GW could be avoided by economic CEPs, and 7 GW would be at risk by being located in communities of color or low-income communities despite favorable economics.

Health costs from proposed gas plants would disproportionately burden low-income communities and communities of color

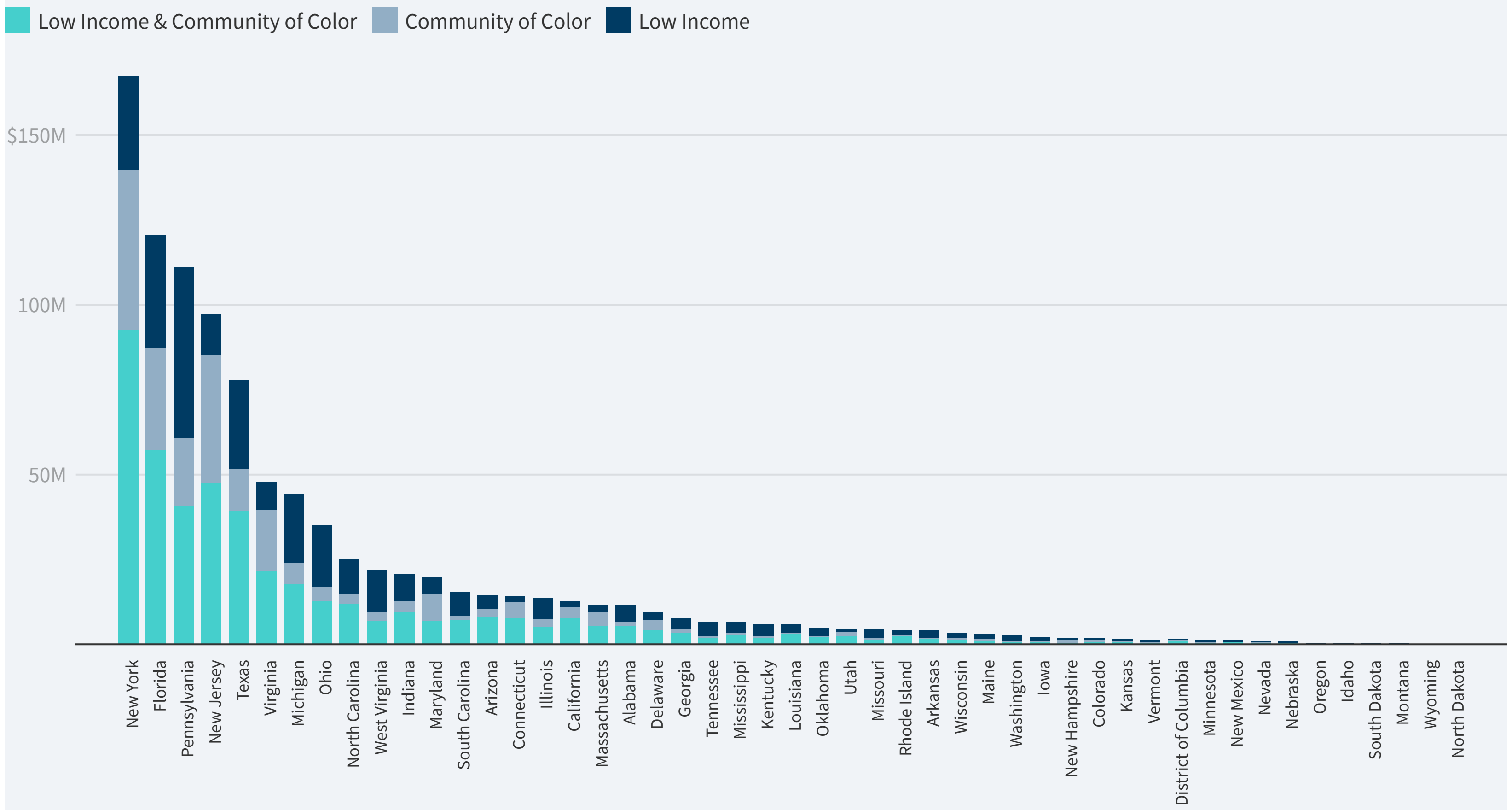
About 60% of the health impacts depicted on the two previous slides associated with proposed gas plants would be borne by low-income communities and communities of color, estimated based on the underlying demographics of each county. For low-income communities in particular, additional health costs have the potential to exacerbate poverty.

Proposed plants that would exacerbate health burdens in low-income communities and communities of color face risk from policy that prioritizes limiting harm in those communities, as well as risk from heightened air pollution standards.

Exhibit 34 shows the total annual health costs that could be avoided in low-income communities and communities of color by investing in CEPs instead of proposed gas plants.

- Communities in densely populated states where a significant quantity of gas is proposed in the region, such as New York, Florida, and Pennsylvania, have the most to gain.
- The potential savings add up to nearly $1 billion per year in avoided health costs in low-income communities and communities of color, 59% of total avoided health costs.

Exhibit 34: Annual healthcare impacts that could be avoided by building CEPs, by state and community status



Source: RMI analysis using EPA's COBRA, low estimate

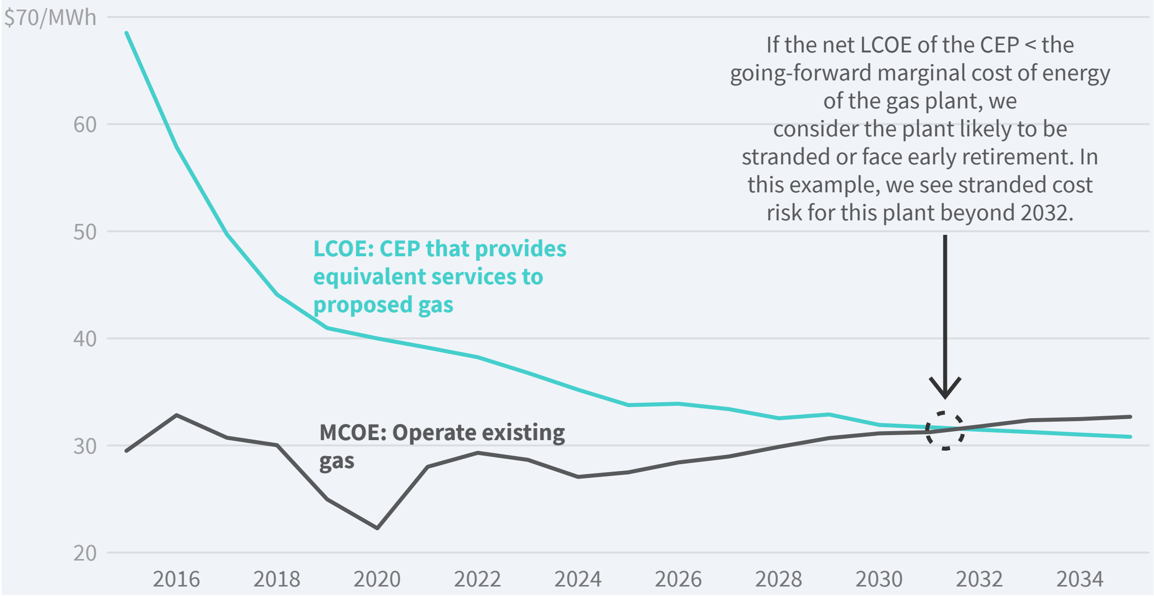
Approach: How market headwinds create stranded-cost risks for proposed gas plants that do get built

Gas plants, even after construction, are at risk of not being able to operate economically as planned, creating stranded-cost risk. If a merchant gas plant becomes stranded, equity and debt holders could face lower returns if not outright losses on their investments. For rate-regulated assets, ratepayers may bear the risk of uneconomic plants.

Exhibit 35 shows how we assess the stranded-cost risk of a CEP compared to a gas plant after the gas plant's construction.

Exhibit 35: Assessing the stranded-cost risk of proposed gas plant

Example: Midwest combined cycle



For declining renewable energy costs and the upside risk to gas prices, we assess how each risk impacts the comparative economics between new-build CEPs and the going-forward cost of gas in each year from 2021 to 2050:

- Declining renewable energy costs
- Upside risk to gas prices

Gas plants that do get built need low gas prices and the end of significant cost improvements for renewables and storage to be economically competitive

Continued price declines for renewables and storage will allow CEPs to undercut gas plants' operating costs in the 2030s, much like the falling price of shale gas has allowed gas plants to undercut coal plants' operating costs since the 2010s. In our base case, by 2035, over half of proposed CC capacity, if built, would cost more to operate than building new CEPs.

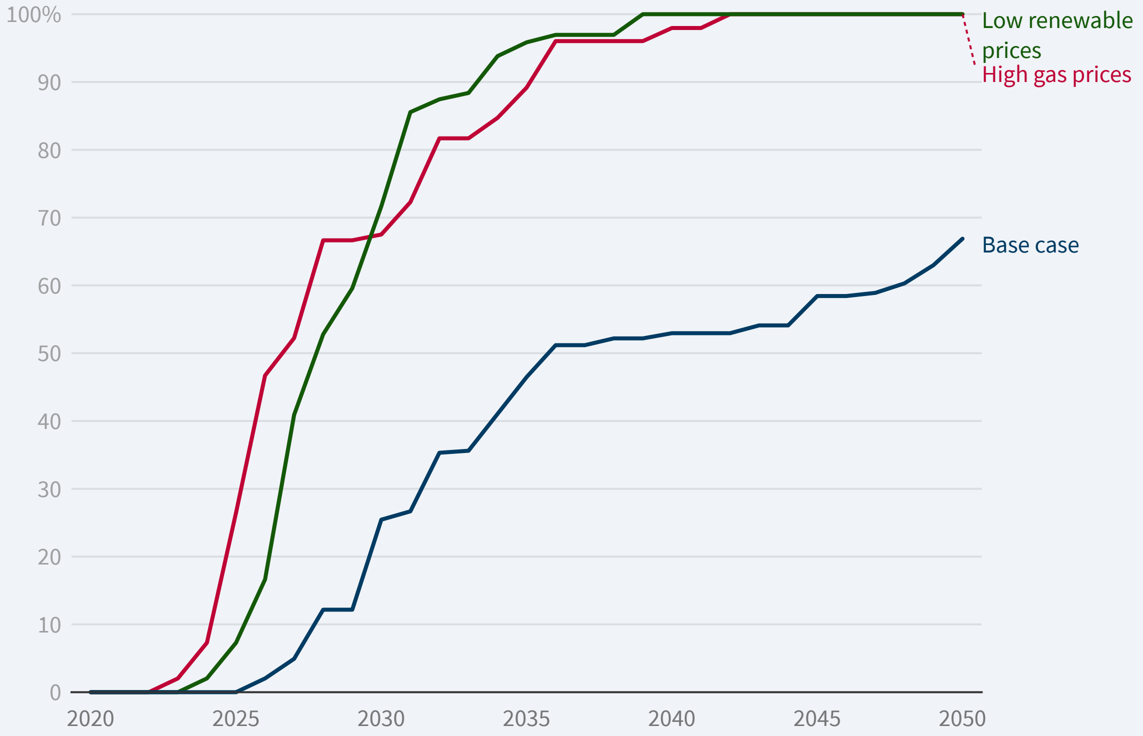
Without both higher renewable and storage costs and low gas prices, well over 90% of proposed CC capacity, if built, would cost more to operate than building new CEPs by 2035. This cuts the economic life of these plants in half, leaving them only 10 years to operate as they would today and imposing significant stranded-cost risk on investors and/or regulated customers.

Exhibit 36 depicts how the percentage of proposed gas plants facing stranded-asset risk increases with low renewable energy prices or high gas prices.

- In the base case, over half of plants face stranded-cost risk by 2035.
- In both the low renewable energy prices and high gas prices cases, about 90% of plants face stranded-cost risk by 2035.

Exhibit 36: Impact of higher gas and lower renewable prices on when proposed combined cycle capacity risks being stranded

% of proposed combined cycle capacity facing stranded asset risk



Chapter 4
Conclusions and Recommendations

Key Takeaways and Implications

The window for building new gas is rapidly closing.

CEPs have continued to become more competitive compared to gas, and the economic and policy-related risks faced by new gas plants continue to strengthen. The total capacity of gas plants built is declining as the proportion of plants canceled before construction has continued to rise. Declining renewable energy costs, rising gas prices, and expectations around firm gas supply will erode proposed gas plant economics. As policymakers and advocates prioritize human health, job creation, and impacts to low-income communities and communities of color, proposed gas projects will face additional hurdles.

Plants that do get built today will face stranded-cost risk.

Gas plants that do get built will still face salient future risks, including stranded-cost risk when renewables become cheaper to build than existing gas plants cost to operate. Economic trends today—rising gas prices and falling costs of renewables—stand to accelerate stranded-cost timelines, further shortening the economic life of plants. Many of the policy risks that are present prior to construction will continue to pose risks post-construction. Risks of tighter environmental controls and the enforcement of climate targets could also leave plants with little headroom to recover costs.

These findings have implications for several stakeholders.

Utilities	Utilities have an opportunity to use market-based cost and capability data to assess alternatives to building new gas before proceeding with a decision to build. Assessments can factor in economic and policy risks that could leave ratepayers with stranded costs over plant lifetimes.
Regulators	Regulators can ask utilities for a robust assessment of alternative options with economic and non-economic tradeoffs when facing a decision to build new gas, given the risks of leaving ratepayers with stranded costs.
Independent power producers and financiers	Independent power producers and financiers can reevaluate whether the market structures that support new gas today are likely to last for the next 10 to 20 years, and whether hedging against declining power prices can be borne long term. With increasing environmental, social, and governance scrutiny, and expectations from investors around climate alignment, there is increasing risk that gas may be incompatible with long-term portfolios.

Recommendations and Resources

Test the market through a competitive bidding process before assuming that gas will be the cheapest or only option to meet emerging grid needs.

- Competitive bidding processes can make real-time costs and capabilities of resources transparent, enabling utilities and regulators to more accurately assess the costs of renewables compared to new gas.
- For projects that have been in the queue over a year, reassess economic risks and market conditions, as they are rapidly changing.

Resources:
- How to Build Clean Energy Portfolios
- Making the Most of the Power Plant Market
- All-Source Competitive Procurement Rules from Washington State

Consider non-economic factors when making decisions to procure new resources.

- Use non-economic criteria, such as health, emissions, and job creation, to make comparisons between gas and new resources where those criteria are priorities within the state and deemed in the public interest.

Resources:
- New Mexico's San Juan Replacement Decision, where economic development and alignment with state energy goals in the Energy Transition Act were used in a plant investment decision

Include an assessment of economic and policy risk over the plant lifetime to understand the potential for stranded costs.

- Consider risk in the decision-making process, including both economic and non-economic factors that could further erode the competitiveness of gas and strand a plant before the end of its useful life.

Resources:
- Carbon Stranding: Climate Risk and Stranded Assets in Duke's Integrated Resource Plan
- A Nationwide Push for Green Energy Could Strand $68B in Coal, Gas Assets
- Risks Outweigh Rewards for Investors Considering PJM Natural Gas Projects

Appendix
Analysis Methodology

Key updates to the Clean Energy Portfolios Model

Our optimization methodology remains largely unchanged from the approach in our 2018 and 2019 studies; see the Appendices of those reports for detailed methodology and mathematical formulations.

We made the following improvements to the model used in this analysis:

Methodology updates	Data source updates
• **Storage:** We improved the way storage is represented in capacity constraints to reduce the amount of excess storage that is selected. The original representation derated storage's capacity value on a given day based on the number of peak hours on that day, without considering whether storage was actually needed during each hour. The new representation gives storage full capacity credit during all peak hours. Separately, it requires that total energy provided during peak hours be at least the amount required on each day on which peak hours occur. After the optimization is complete, we check that there was enough storage to serve all peak hours; if there was not, we add enough two-hour storage to ensure all capacity constraints are met. • **Renewable capacity:** We now use BloombergNEF's US Power Plant Stack to derive the capacity of renewables currently in each balancing area and planned for each balancing area through 2030. This data is used in the calculation of net load, which determines the set of peak hours used in the capacity constraints. The former method estimated future renewable deployments based on state renewable portfolio standard targets. • **Renewable costs:** For renewable resources, rather than calculate their total costs based on capital expenditures and fixed operating and maintenance costs, we use LCOEs calculated by NREL in the 2021 ATB market case. For solar resources, we extend the investment tax credit three years from the market case default to account for developers' use of the safe harbor.	• We use NREL's 2021 Electricity ATB for most cost and performance metrics for renewable, storage and gas-fired resources, except as described below. Except where otherwise specified, we use the market case's financial assumptions and the moderate scenario's cost trajectories. • We use Lazard's Levelized Cost of Storage Analysis, v. 6 for the degradation rate of Li-ion batteries. • We use EIA Annual Energy Outlook 2021 for regional natural gas price projections. • We use EIA Form 861 (2019) for our estimates of the cost of demand flexibility resources. • We also use EIA Form 860 (2019) to identify plants comparable to proposed plants to estimate future monthly energy generation and to calculate the planning areas' current renewable capacity. • We also use EIA Form 923 (2019) to estimate existing power plants' monthly energy generation. • We use BloombergNEF's 2021–02–01—US Power Plant Stack Raw Data for planned renewables by balancing area. The solar data includes some distributed solar as included by BloombergNEF. • We use Sierra Club's gas tracker to identify planned gas-fired power plants in the continental United States, excluding Alaska. The plants in this analysis are from the tracker as of July 2021. The list is screened to only include CC and CT plants larger than 100 MW, and which are not combined heat and power units.

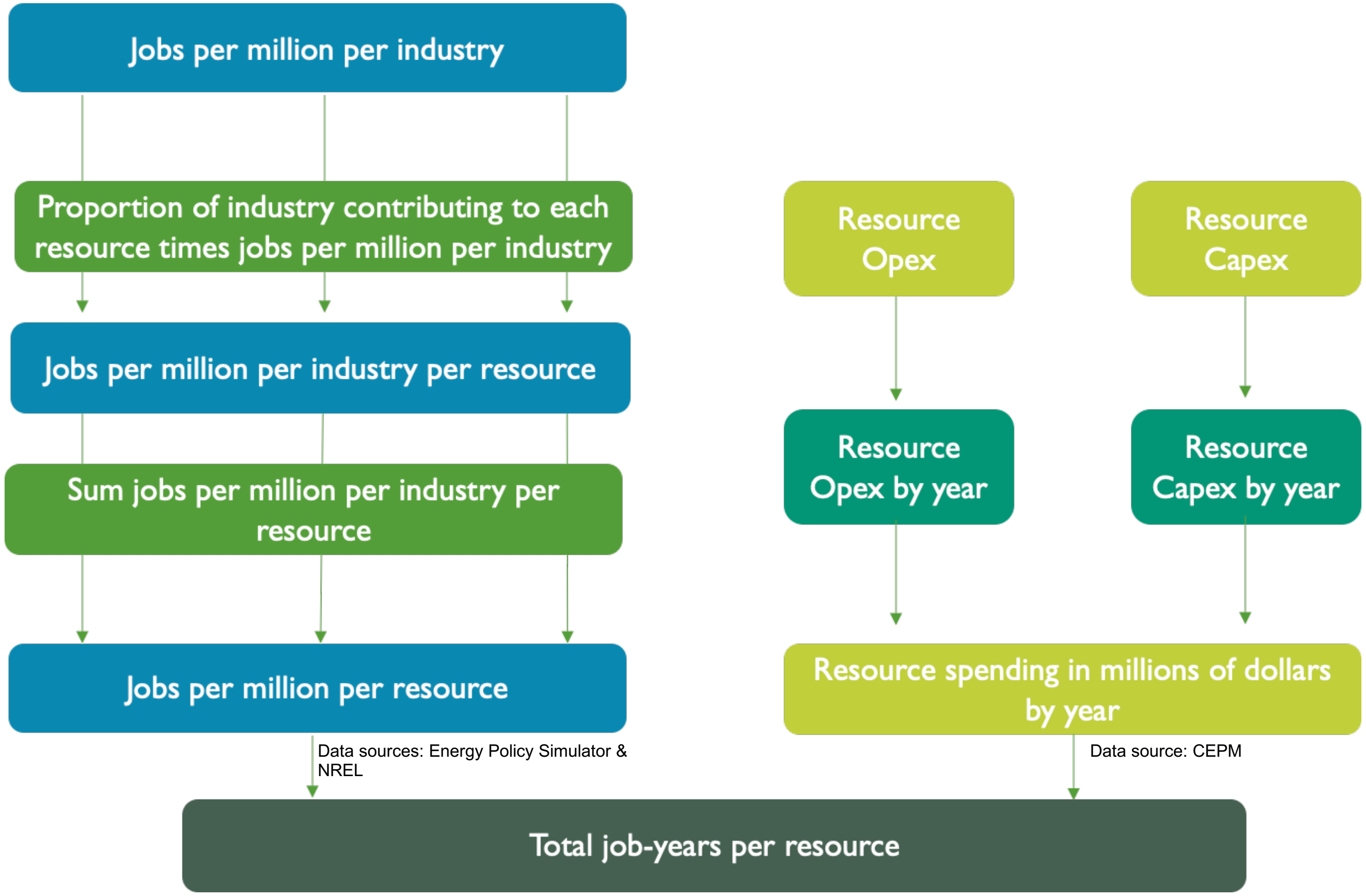
Methodology for calculating the cost of firm gas supply

- We assume that the cost of firm gas is equivalent to a pipeline's firm transportation reservation rate. We also assume that a gas plant must reserve sufficient delivery capacity from the pipeline to operate at its peak output continuously. This cost is meant to represent the cost of both firm transportation capacity (i.e., transmission and distribution pipelines and other midstream infrastructure) and firm upstream supply.
- We use $0.33 per dekatherm per day as the cost of firm gas supply. This is an average of the values found in two FERC tariffs (Tallgrass Interstate Gas Transmission and Viking Gas Transmission) and expiring contracts reported by S&P in "Major gas pipelines face 1.6 million Dth/d of expiring contracts in Q3."

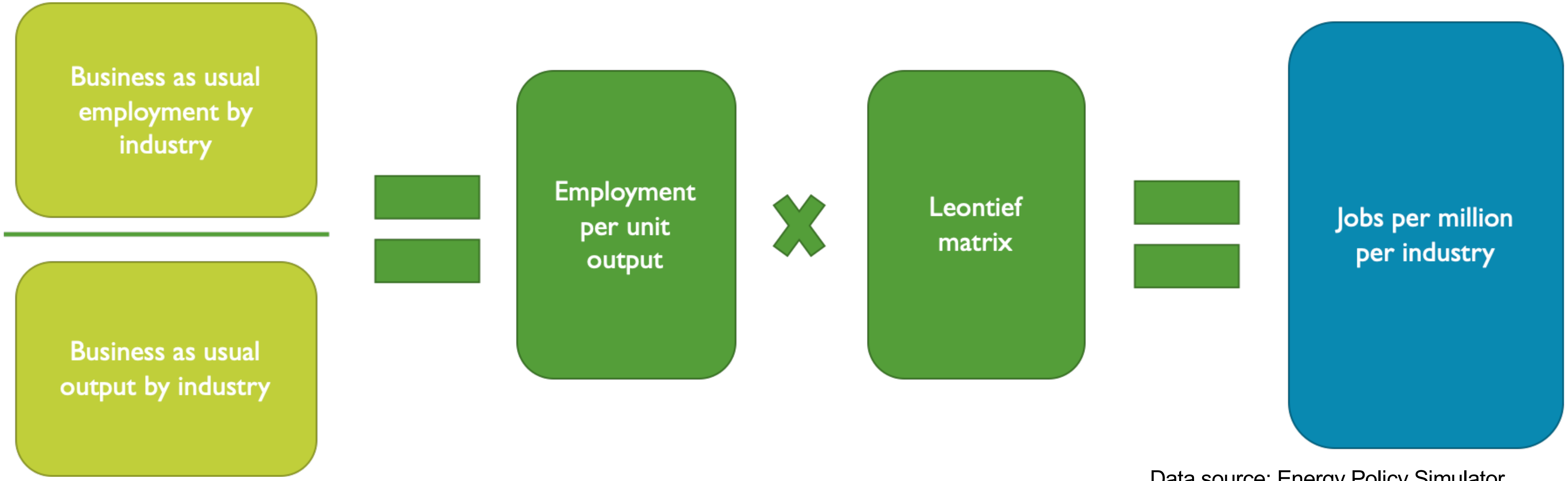
Cost of firm gas supply ($0.33/Dthm/day) × Plant heat rate (MMBtu/MWh) equivalent to (Dthm/MWh) × 8,760 hours/year (convert to annual cost) = Plant's annual cost of firm supply ($/MW-year)

Methodology for calculating job-years (1/2)

- The CEPM outputs the total investment (capital expenditures, operating expenditures) in each resource needed to avoid the proposed gas plant.
- Our analysis relies on job multipliers by ISIC industry from the Energy Policy Simulator (EPS).
  - The most current version of these multipliers is provided by state.
  - The multipliers assume each state acts as its own island, not counting for trade out of state or out of country. Therefore, impacts include direct and indirect job additions, without accounting for possible job loss to trade.
- We then calculate the proportion each CEP resource contributes to each industry, broken out using capital expenditures and operating expenditures, using NREL JEDI data and data from the EPS.
- Job-years were calculated by dividing investment in each resource by expected resource lifetime using a discount rate of 3% and 2019 as the base year. Investment by year was then multiplied by job multipliers year on year to find job-years per resource.
- Our analysis does not include re-spending impacts due to lack of a complete public data set for calculating the direct impacts of each industry.



Methodology for calculating job-years (2/2)



Data source: Energy Policy Simulator

- Much of our analysis relies on the jobs multipliers by industry. Our analysis replicates the methodology employed by the EPS, and the data in the diagram is sourced from that tool.
- This input-output analysis, specifically use of the Leontief Matrix, allows us to understand the impacts of a change in investment in one sector on that sector as well as on all other sectors, enabling the analysis to include upstream impacts.
- The final output of jobs per million per industry enables us to calculate the anticipated jobs (direct and upstream) from change in investment per $1 million. However, the inability to separate these impacts prevents us from being able to calculate re-spending impacts.

Methodology for calculating health impacts

COBRA
Co-Benefits Risk Assessment
Health Impacts Screening and Mapping Tool

Using COBRA to generate health impact results

- Using yearly plant emissions anticipated from proposed gas plants, we constructed a new emissions baseline.
- We employed the advanced scenario capabilities of the EPA COBRA tool for the year 2023 to model a scenario that included the proposed gas plant emissions as the baseline and a control scenario removing those potential emissions, as the CEP alternative would contribute no emissions to the atmosphere during operation.
- COBRA results include county-level impacts of many health indicators including total health savings, mortality, exacerbated asthma, and more. For mortality impacts, COBRA provides a low and high estimate.
- Impacts shown beyond the 2023 model year are extrapolated from the original model year and given a 6% discount every year removed from the model year.

Methodology for assessing health costs borne by communities

- We merged county-level health outputs from COBRA results with county-level demographic data from the EPA's Environmental Justice Screening and Mapping Tool (EJSCREEN) to identify the health costs in each state that would be borne by low-income communities and communities of color as defined on the next slide.

Methodology for assessing community impact

- First, we pulled EPA's EJSCREEN data from 2020 for each planned gas plant in our inventory that had latitude and longitude coordinates. We pulled demographic data using the EJSCREEN API using each plant's coordinates with a three-mile buffer. The three-mile radius parallels the approach used to assess community demographics near existing fossil plants in the EPA's Power Plants and Neighboring Communities Tool.
- Once we had EJSCREEN data corresponding to each plant, we developed definitions for low-income communities and communities of color. We roughly used interim definitions included in the White House Environmental Justice Advisory Council's memo on a new screening tool for the Justice40 initiative:

> For purposes of this Order. (a) The term "community of color" means a geographically distinct area in which the population of any of the following categories of individuals, individually or in combination, is higher than the average population of that category for the State in which the community is located: (i) Black; (ii) African American; (iii) Asian; (iv) Pacific Islander; (v) Other Non-White race; (vi) Hispanic; (vii) Latino; (viii) Indigenous or members of a Tribe; and (ix) Linguistically isolated.

Given this definition and the current data in EJSCREEN, we considered a community to be a community of color if the percentage of minority persons in our area of interest (three-mile radius around the plant) was greater than the statewide average of minority persons.

> (h) The term "low-income community" means any census block group in which 30 percent or more of the population are individuals with an annual household income equal to, or less than, the greater of: (i) an amount equal to 80 percent of the median income of the area in which the household is located, as reported by the Department of Housing and Urban Development; or (ii) 200 percent of the Federal poverty line.

Given this definition and the current data in EJSCREEN, we considered a community to be low-income if more than 30% of the people in the area of interest (three-mile radius around the plant) had incomes less than or equal to 200% of the federal poverty line.

- Finally, we added up the capacity of plants that were proposed in each category of community.