The Nuclear Power Dilemma

Declining Profits, Plant Closures, and the Threat of Rising Carbon Emissions

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[EXECUTIVE SUMMARY]

For decades, nuclear power has provided most of the nation's carbon-free electricity. However, the owners have shut down many nuclear plants in the last five years or announced plans to close them well before their operating licenses expire, generating a discussion among policymakers and regulators about the impact of early retirements. The primary reasons for these early closures are the economic challenges brought on by cheap natural gas, diminished demand for electricity, falling costs for renewable energy, rising operating costs, and safety and performance problems. The possibility that the nation will replace existing nuclear plants with natural gas and coal rather than low-carbon sources raises serious concerns about our ability to achieve the deep cuts in carbon emissions needed to limit the worst impacts of climate change.

As of the end of 2017, 99 reactors at 60 power plants provided 20 percent of US electricity generation. The owners have retired six reactors at five plants since 2013, slated seven reactors at five more plants to retire over the next eight years, and threatened to close five reactors at four more plants in the next few years if they do not receive new financial support.[1] In addition, Illinois, New Jersey, and New York now provide financial support to keep 10 reactors at seven plants operating for at least 10 more years.

The economic challenges facing nuclear plants are part of a historic transition in the US electricity sector. Over the last decade, natural gas generation and renewable energy generation from wind and solar have grown rapidly as their prices have fallen. Combined with investments in energy efficiency, these energy sources have largely replaced generation from retiring coal plants, resulting in a 28 percent reduction in US power-sector emissions of carbon dioxide (CO_2) below 2005 levels in 2017. While nuclear power's share of electric power production has remained relatively flat over the past decade, most analysts project that share to decline in the future without additional financial or policy support.

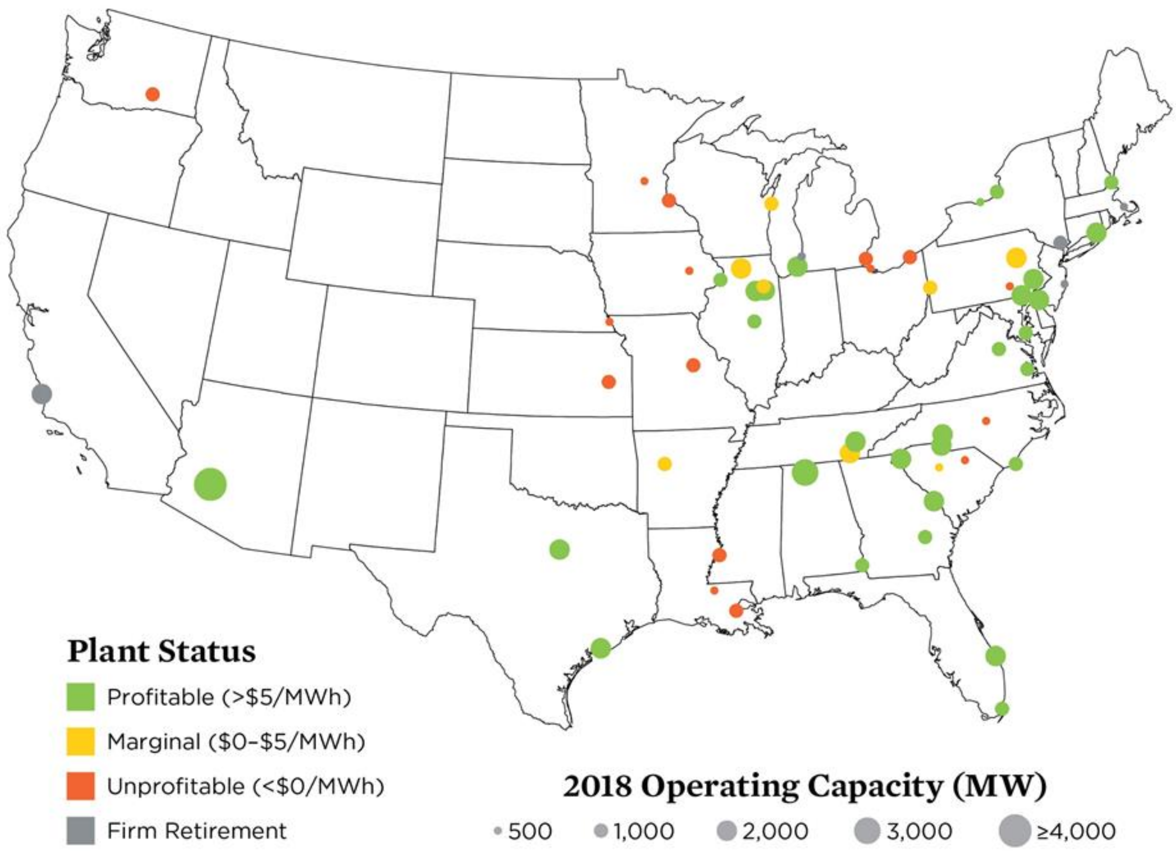
The transition already has resulted in many benefits, including lower electricity prices, technological innovation, a cleaner environment, and increased customer control over energy use. However, in the absence of national policy to reduce carbon emissions, the transition has undervalued all types of low-carbon sources of electricity and underpriced natural gas and coal relative to their damage to the climate.

The Union of Concerned Scientists (UCS) has assessed the economic viability and performance of most of the nuclear power plants operating in the United States, analyzing which ones are most at risk of early retirement and evaluating the main factors that affect competitiveness. We also identified reactors that have been safe, reliable performers and those with troubled performance records. In addition, using a national model of the electricity sector, UCS has analyzed the impacts on the US electricity mix, CO_2 emissions, and consumer electricity bills of three scenarios for retiring nuclear plants early and two scenarios based on the introduction of national policies to reduce carbon emissions.

Assessing the Profitability of Today's Nuclear Power Reactors

Using projections from S&P Global Market Intelligence,[2] UCS estimated the annual operating margins (revenues minus costs) for 92 nuclear reactors at 55 plants, excluding from the analysis seven reactors at five plants slated to close in the next eight years. The plants derive revenue in three ways: selling electricity into regional wholesale power markets; providing capacity to ensure the availability of adequate generation during times of peak demand;

FIGURE ES-1. **US Nuclear Power Plants at Risk of Early Closure or Slated for Early Retirement**



More than one-third of existing plants, representing 22 percent of US nuclear capacity, are unprofitable or scheduled to close.

and, in the case of seven plants, receiving financial support for their zero carbon–emissions attributes from three states. The costs, which cover fuel, capital expenses, and fixed and variable operations and maintenance, are based primarily on annual data collected by the Electric Utility Cost Group for the Nuclear Energy Institute. Profitability is assessed based on the average annual operating margin over the five-year period from 2018 to 2022. The analysis covers plants owned by regulated, investor-owned utilities and public power utilities, as well as merchant generators, which are not regulated by state public utility commissions. The analysis does not reflect additional revenue collected from consumers through rates.

The UCS analysis found that:

More than one-third of existing plants, representing 22 percent of total US nuclear capacity, are unprofitable or scheduled to close (Figure ES-1). On average, projected operating costs exceed revenues between 2018 and 2022 for 16 nuclear plants in addition to five plants scheduled for retirement. These 21 plants accounted for 22.7 gigawatts (GW) of operating capacity in 2018. The annual average cost of bringing unprofitable plants to the breakeven point is $814 million, for a total of more than $4 billion over five years. Merchant plants are more susceptible to market forces and have a higher risk of retirement, but regulated and public power plants are not immune from these pressures. Ten of the 21 plants are merchant plants (10.5 GW), including four (4.2 GW) that are slated to close and six (6.3 GW) that have a higher risk of closing in the future. Eleven of the 21 plants are regulated plants (12.3 GW), including one (2.2 GW) that is slated to close by 2025 and 10 that have a lower risk of closing because they currently receive cost recovery from ratepayers. Eight additional plants are marginally profitable (15 GW), including five merchant plants (9.8 GW) and three regulated plants (5.2 GW).

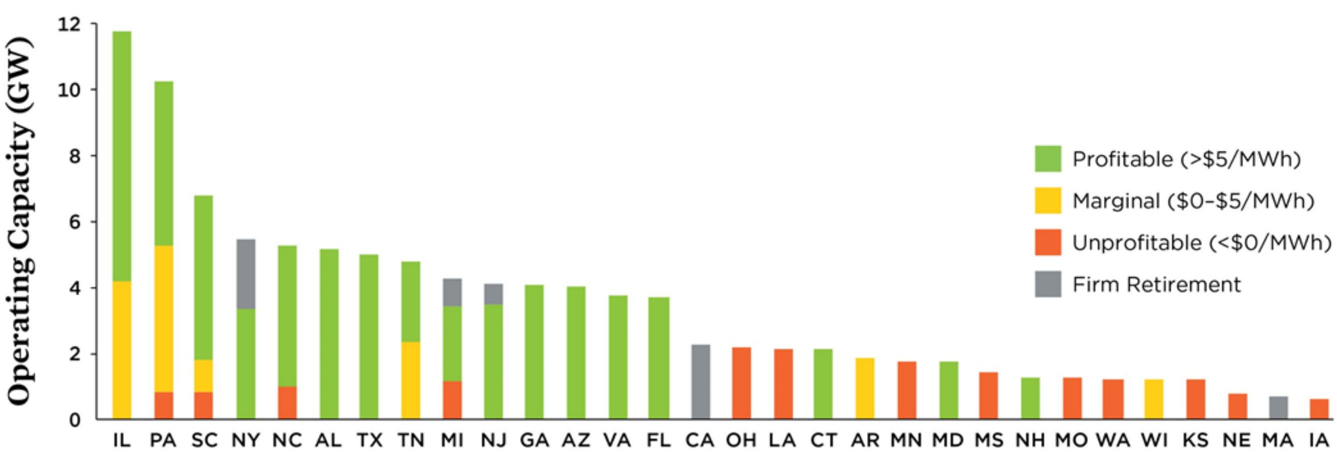
Single-reactor plants are more at risk than multiple-reactor plants. More than three-quarters of the total capacity from smaller, single-reactor plants is unprofitable or marginal compared with 20 percent from larger, multiple-reactor plants, which have greater economies of scale.

The Midwest and Mid-Atlantic states have the most plants at risk of early retirement. The Midcontinent Independent System Operator has the greatest unprofitable nuclear capacity (8.3 GW, 63 percent of its total nuclear capacity) due to lower-than-average wholesale electricity prices and a higher concentration of single-reactor plants. PJM Interconnection in the Mid-Atlantic states has the most marginal capacity (8.6 GW, 25 percent of its total nuclear capacity).

Seventeen states have plants that are unprofitable or scheduled to close (Figure ES-2). Ohio, Louisiana, and Minnesota have the highest amount of unprofitable capacity. Pennsylvania, Illinois, and Tennessee have the most marginal capacity. California and New York have the most capacity scheduled to close. Financial support has helped make five unprofitable or marginal plants in Illinois, New Jersey, and New York profitable. Such support also has boosted the revenues of one plant in New York and one in New Jersey even though the UCS analysis suggests that these were already profitable.

Most plant owners have reactors that are unprofitable or scheduled to close. Exelon owns the most US nuclear capacity (20 GW) by far; about one quarter of that capacity is unprofitable or marginal. Entergy is retiring 40 percent of its nuclear capacity with the pending closure of three plants in Massachusetts, Michigan, and New York, and its remaining

FIGURE ES-2. **Nuclear Capacity at Risk of Early Closure or Slated for Early Retirement, by State**



Of the 30 states with nuclear power plants, 17 states have nuclear capacity that is unprofitable or scheduled to close.

capacity is unprofitable or marginal. More than half of FirstEnergy's nuclear capacity is unprofitable, with the remainder categorized as marginal. Notably, all of the assets of a few companies that own only one or two nuclear plants, like Xcel Energy, are unprofitable compared with cheaper alternatives available in the market.

Natural gas prices, nuclear costs, and CO_2 prices have the biggest impact on profitability. The amount of unprofitable nuclear capacity could increase from 16.3 GW under our reference case assumptions to 42.7 GW (42 percent of total US nuclear capacity) with higher nuclear costs and 28.7 GW with lower natural gas prices over the next five years. In contrast, the amount of unprofitable capacity could decline to 10.6 GW with lower nuclear costs, 7 GW with higher natural gas prices, and 1.4 GW with a national CO_2 price of $25 per ton in 2020, rising 5 percent per year.

Because most plant-level cost data are proprietary, and because factors not included in our analysis can affect profitability and retirement decisions, owners of distressed plants should be required to submit detailed economic data to regulators to demonstrate financial need. Our analysis estimates the profitability of specific nuclear plants based on the best available data and cannot substitute for a careful financial review of each facility.

Analyzing the Impact of Carbon Reduction Policies and Retiring Reactors Early

Using the National Renewable Energy Laboratory's Renewable Energy Deployment System model, UCS analyzed the impact of early plant retirements and carbon-reduction policies on the US electricity mix, CO_2 emissions, and consumer electricity bills through 2035. We chose that date to assess the potential near-term impacts from retiring unprofitable or marginal reactors before their operating licenses expire, which occurs for most US reactors between 2030 and 2050. We examined six main scenarios:

Reference Case: No new policies are enacted and no nuclear reactors are retired early beyond the five plants already slated to close.

Three Early Retirement Cases: No new policies are enacted, and early retirements range from 13.7 GW to 26.8 GW over the next eight years. These cases assume the early retirement of plants that fail our economic screening test based on the profitability assessment described above. Two cases use our reference case assumptions: early retirement case 1 only includes merchant plants; early retirement case 2 includes a mix of merchant and regulated plants. Early retirement case 3 assumes lower natural gas prices and only includes merchant plants.

National Carbon Price Case: New policies set a $25 per ton price on CO_2 in 2020, increasing 5 percent per year.

National Low-Carbon Electricity Standard (LCES) Case: The LCES increases from 45 percent in 2020 to 60 percent by 2030 and 80 percent by 2050.

The UCS analysis found that:

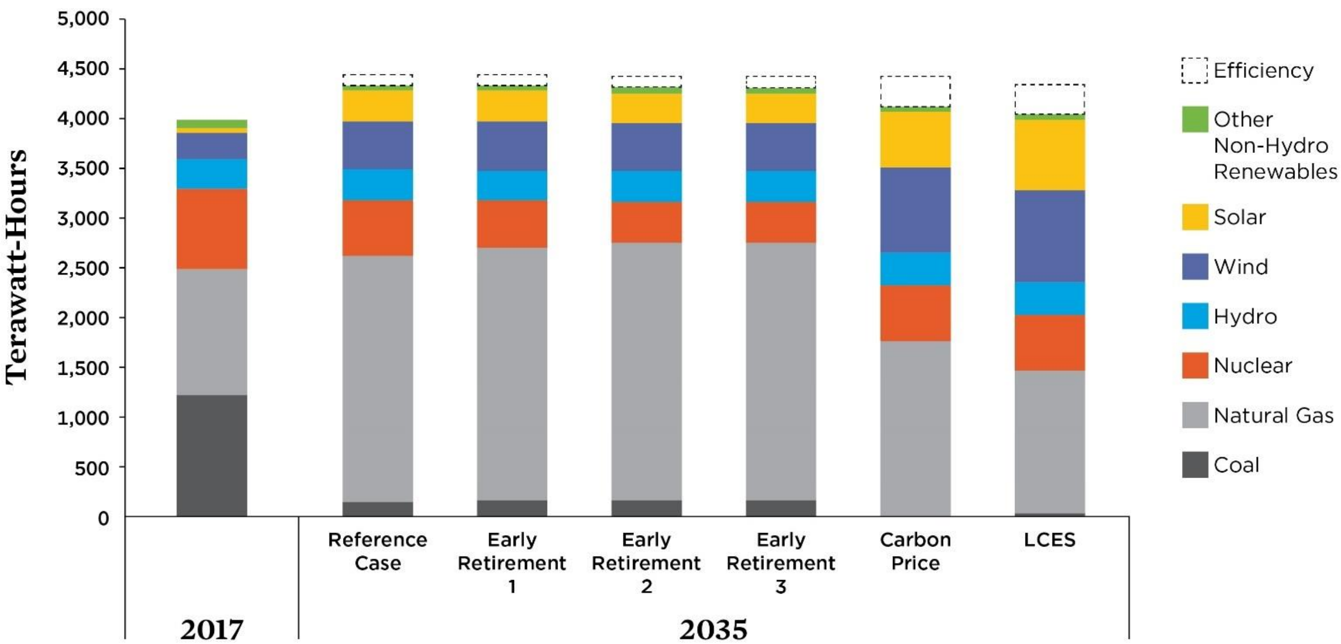
Without new policies and with low natural gas prices, early nuclear retirements are replaced primarily with natural gas and coal. Closing the at-risk plants early could result in a cumulative 4 to 6 percent increase in US power sector carbon emissions by 2035 (0.7 to 1.25 billion metric tons) from burning more natural gas and coal. This pathway would make it more difficult for the United States to achieve deep cuts in carbon emissions.

State and national carbon-reduction policies would help preserve existing nuclear generation and diversify our nation's electricity mix. Nuclear and hydropower stay at reference case levels and non-hydro renewable energy generation (primarily wind and solar) more than triples from 10 percent of total US power generation in 2017 to 36 percent by 2035 under the carbon price case and 41 percent by 2035 under the LCES case. Energy efficiency reduces generation by nearly 9 percent by 2035 under both cases (Figure ES-3).

Carbon-reduction policies can prevent an overreliance on natural gas. Under the two scenarios with new policies to encourage low-carbon energy sources (carbon price and LCES), natural gas generation is 31 percent to 44 percent lower than in early retirement case 1.

A national carbon price, an LCES, or other policies that preserve existing nuclear generation and

FIGURE ES-3. **The US Electricity Generation Mix, 2017 and 2035**



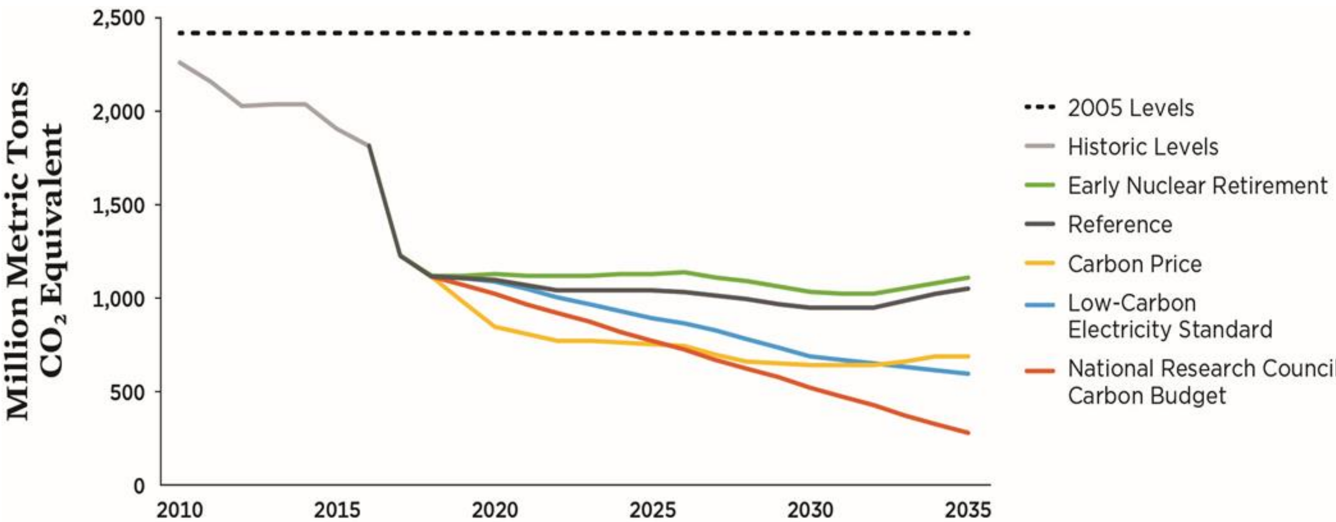
Carbon-reduction policies would diversify the US electricity mix by maintaining existing nuclear generation, increasing investments in energy efficiency and renewable energy and preventing an overreliance on natural gas.

Note: Early retirement case 1 only includes 9 merchant plants (13.7 GW). Early retirement case 2 includes a mix of 21 merchant and regulated plants (26.8 GW) under our reference case assumptions. Early retirement case 3 assumes lower natural gas prices and only includes 15 merchant plants (26.3 GW).

increase investments in renewable energy and energy efficiency significantly reduce CO_2. Cumulative CO_2 emissions from the US power sector are 19 percent (4 billion metric tons) lower in the LCES case and 28 percent (5.7 billion metric tons) lower in the carbon price case through 2035 compared with early retirement case 1 (Figure ES-4). A National Research Council study found that US power-sector emissions would need to fall more than 90 percent below 2005 levels by 2040 to meet US climate goals. Achieving that requires a cumulative reduction in power-sector CO_2 emissions of 33 percent by 2035 (6.6 billion metric tons) compared with early retirement case 1. Both the carbon price and LCES cases take the US power sector most of the way toward meeting these targets.

Carbon-reduction policies reduce NO_x and SO_2 emissions, leading to tangible health and economic benefits. Primarily by reducing coal generation, the carbon-price and LCES policy cases help cut other air pollutants: sulfur dioxide (SO_2) emissions are 61 to 68 percent lower than the early retirement case 1 in 2035; nitrogen oxides (NO_x) are 41 to 42 percent lower. NO_x and SO_2 contribute to smog and soot, both of which exacerbate asthma and other heart and lung diseases and can result in significant disability and premature death. CO_2 emissions contribute to global warming and other climate impacts that can impair human health and safety. The climate and public health benefits average $22 billion each year, adding up to a total of $132 billion under the LCES case to $227 billion under the carbon price case cumulatively from 2018 through 2035 compared with early retirement case 1.

FIGURE ES-4. **US Power Plant CO_2 Emissions**



Under a reference case with low natural gas prices and no new policies, closing at-risk nuclear plants before their operating licenses expire could result in a cumulative increase in US power-sector CO_2 emissions of up to 6 percent by 2035 from burning more natural gas and coal. The carbon-policy cases reduce CO_2 emissions by 19 to 28 percent cumulatively by 2035. A National Research Council study found that to meet US climate goals, power-sector emissions would need to fall to more than 90 percent below 2005 levels by 2040.

The emissions reductions and increases in clean energy spurred by the two carbon-reduction policies are affordable. Savings from investments in energy efficiency offset most of the cost increases from investments in low-carbon technologies. Average monthly electricity bills for a typical household under the two policy cases are only 1.0 to 1.4 percent higher in 2035 than in the early retirement case 1, amounting to a modest electricity bill increase of \$0.74 to \$1.03 per month. The carbon price case could offset most of those costs by returning to consumers a portion of the \$28 billion in average annual carbon revenues between 2020 and 2035. Overall, the benefits exceed the costs of implementing the policies, resulting in cumulative net benefits of \$61 billion under the LCES case and \$234 billion under the carbon price case by 2035.

Evaluating Reactor Safety Performance

While an accident or terrorist attack at a US nuclear reactor could severely harm public health, the environment, and the economy, it would also jeopardize the prospects for US nuclear energy for decades and limit available options to meet near-term carbon reduction targets. It is thus essential that policymakers and other stakeholders consider financial support only for nuclear reactors that meet or exceed current safety standards.

UCS proposed using information from the Reactor Oversight Process (ROP) of the Nuclear Regulatory Commission (NRC), which rates the safety performance of each reactor on a quarterly basis. Only reactors with the highest safety rating—indicating they meet all safety regulations—would be eligible for financial support. Between 2000 and 2018, the NRC gave reactors its top rating 80 percent of the time, and its second highest rating 15 percent of the time. When a reactor dropped out of the top category, it took an average of one year for it to return to that category.

However, the industry's trade organization, the Nuclear Energy Institute (NEI), has proposed that the NRC change the ROP, including merging the highest and second-highest safety ratings, which would effectively render it meaningless. Under this scheme, all US reactors today would have the highest safety rating. If the NRC makes this change, we could no longer recommend that reactors with the highest rating qualify for support.

To lower operating costs, US reactor owners and the NEI have been pressuring the NRC for decades to reduce inspections and weaken safety and security standards. For example, in response to this pressure, the NRC has made its security inspections far less challenging, reducing its mock terrorist attacks from three scenarios to one. And after the 2011 Fukushima accident, the NRC required less rigorous safety upgrades than its own task force recommended. It also refused to require the transfer of spent nuclear fuel from overcrowded pools to safer dry storage casks.

Economic assistance to at-risk plants would help alleviate financial pressures—and could reduce industry pressure on the NRC to cut corners. However, policymakers will need to monitor the situation and adjust their subsidy policies accordingly if the NRC weakens its standards.

Recommendations

New public policies are needed to properly value low-carbon energy and prevent the replacement of nuclear plants with large quantities of natural gas. Failure to put such policies in place will set back state and national efforts to achieve needed emissions reductions. In today's market, the prices of fossil fuels are artificially low in most regions because they do not reflect the cost to society of harmful carbon emissions. Strong climate and clean-energy policies will address this market failure and ensure that low-carbon energy sources replace nuclear plants when they eventually retire. Until such policies are in place or natural gas prices rise significantly, owners of economically at-risk nuclear reactors will continue asking policymakers for financial assistance.

To address this challenge, policymakers should consider the following recommendations for designing effective state and national policies and conditions:

ADOPT STRONG STATE AND FEDERAL POLICIES THAT SUPPORT ALL LOW-CARBON TECHNOLOGIES

Adopt carbon pricing. A robust, economy-wide cap or price on carbon emissions would address a key market failure and provide a level playing field for all low-carbon technologies. A national carbon cap or price could achieve the greatest carbon reductions for the lowest cost, but states can also adopt such policies. Two examples are the Regional Greenhouse Gas Initiative capping carbon emissions from power plants in nine Northeastern states and California's economy-wide, cap-and-trade program, which is a key component of the state's broader strategy to reduce total global warming emissions 40 percent below 1990 levels by 2030.

Further, states can use revenue from carbon-pricing policies to support investments in energy efficiency, advanced low-carbon technologies, and consumer protections, such as energy rebates for low-income families. State public utility commissions should also require regulated utilities to include an increasing price on carbon in their resource plans to reflect the possibility of future regulation of CO_2 emissions at the federal and state levels.

Adopt low-carbon electricity standards. A well-designed LCES could help prevent the early closure of nuclear plants while allowing renewable energy technologies, new nuclear plants, and fossil fuel plants with carbon capture and storage to compete for a growing share of low-carbon generation. Existing nuclear plants should be included in a separate tier, as New York State has done, to limit costs to ratepayers and avoid market-power issues due to limited competition among a small number of large plants and owners. New York also has combined an LCES with a zero-energy credit program to provide financial support only to existing nuclear plants that need it, with support adjusted as market conditions change. Along with an LCES, states should adopt complementary policies that encourage investments in energy efficiency.

CONDITION FINANCIAL SUPPORT ON CONSUMER PROTECTION, SAFETY

REQUIREMENTS, AND INVESTMENTS IN RENEWABLES AND EFFICIENCY

Policies that value the low-carbon attributes of nuclear power, renewable energy, energy efficiency, grid modernerization, and all other low-carbon technologies are critical for state and national efforts to significantly reduce emissions and help limit climate impacts. However, where policymakers are considering temporary financial support aimed exclusively at mitigating the early closing of nuclear plants to prevent carbon emissions from rising, that support must be coupled with strong clean energy policies, efforts to limit rate increases to consumers, and strong requirements around safety, security, transparency, and performance.

Require plant owners to open their financial books and demonstrate need. States should require plant owners requesting financial support to open their books to state regulators and the public. Transparent regulatory proceedings help minimize the cost to ratepayers. Profitable nuclear plants should not receive financial assistance; doing so would give their owners a windfall profit while overcharging consumers without significantly reducing emissions.

Limit and adjust financial support for unprofitable nuclear plants. To protect consumers and avoid windfall profits, make financial support for distressed plants temporary. Further, periodically assess whether continued support is necessary and cost effective, adjusting it to account for changes in market and policy conditions. To the extent possible, base adjustments on competition across all low-carbon sources, including energy efficiency. If this type of competition is not feasible, rigorously apply least-cost planning principles reflecting a reasonable cost of carbon. Programs that make only nuclear plants eligible for financial support for an arbitrary number of years could misallocate funds toward relatively expensive ways to reduce CO_2 emissions.

Ensure that qualifying plants maintain strong safety performance. To help ensure that financial support to the owners of existing nuclear reactors yields the intended benefits, states should consider it only for reactors that meet the NRC's highest safety rating, indicating they meet all safety requirements. For reactors that drop in safety performance, continued financial support should depend on a return to the NRC's highest performance rating within 18 months (the average time plus a 50 percent margin).

Strengthen renewable energy and efficiency standards. States that provide financial assistance to existing nuclear plants also should strengthen policies that stimulate the growth of low-carbon renewable energy—for example, renewable electricity standards—as well as energy efficiency programs and policies. While providing financial support for distressed nuclear plants, New Jersey and New York have increased renewable standards to require that 50 percent of all electricity sales to consumers come from renewable sources by 2030 and Illinois strengthened its 25 percent by 2025 renewable standard. These states also strengthened energy efficiency standards to require minimal annual electricity savings of 2 to 3 percent.

Develop transition plans for affected workers and communities. Nuclear power plants are an important source of local jobs and tax revenues. Plant owners can work with states and communities to attract new businesses, helping replace lost jobs and tax revenues. For example, 2018 legislation in California includes a $350 million employee-retention fund and an $85 million community impact–mitigation fund for Diablo Canyon, which is slated to close in 2025. Because the spent fuel produced during the lives of operating reactors has no place to go, it is likely to remain on site for a considerable period. This alone justifies substantial payments to host communities, which must store spent fuel for many years, something never contemplated when the plants were licensed.

Address other state and local issues. Nuclear plants affect resources subject to state jurisdiction, such as the use of local water supplies for cooling and the impact of cooling-water discharges. Some plants are involved in state regulatory proceedings around such issues, and the results could cost enough to lead to a plant's closure. Such requirements need to be vigorously enforced.

[CHAPTER 1]

Introduction

For decades, nuclear energy has provided most of the nation's carbon-free electricity, with the number of nuclear power reactors peaking at 112 in 1990. In the 1990s, several reactors closed, largely in anticipation of the economic stresses of electric industry restructuring and the introduction of competing ways to generate electric power. However, the remaining reactors withstood the competition, and no reactors closed for more than a decade.

In the last five years, closures have resumed, chiefly due to low prices for natural gas but also due to safety and performance problems, rising costs for operating nuclear power plants, falling costs for some renewable energy technologies, stagnant demand for electricity, and the absence of nationwide policy controlling carbon emissions. In 2013, Duke Energy closed the Crystal River nuclear power plant in Florida and Southern California Edison retired two reactors at the San Onofre plant after steam-generator replacements failed (Dietrich 2013; Franke 2013). Dominion Energy closed the Kewaunee plant in Wisconsin in 2013, and Entergy retired the Vermont Yankee plant in 2014; both owners claimed the plants were unprofitable (Perlto 2013; Stoddard 2013). In 2016, Omaha Public Power District permanently shut the Fort Calhoun nuclear power plant in Nebraska primarily for economic reasons following several years of extended outages and damage due to flooding and expensive repairs (Burke 2016).

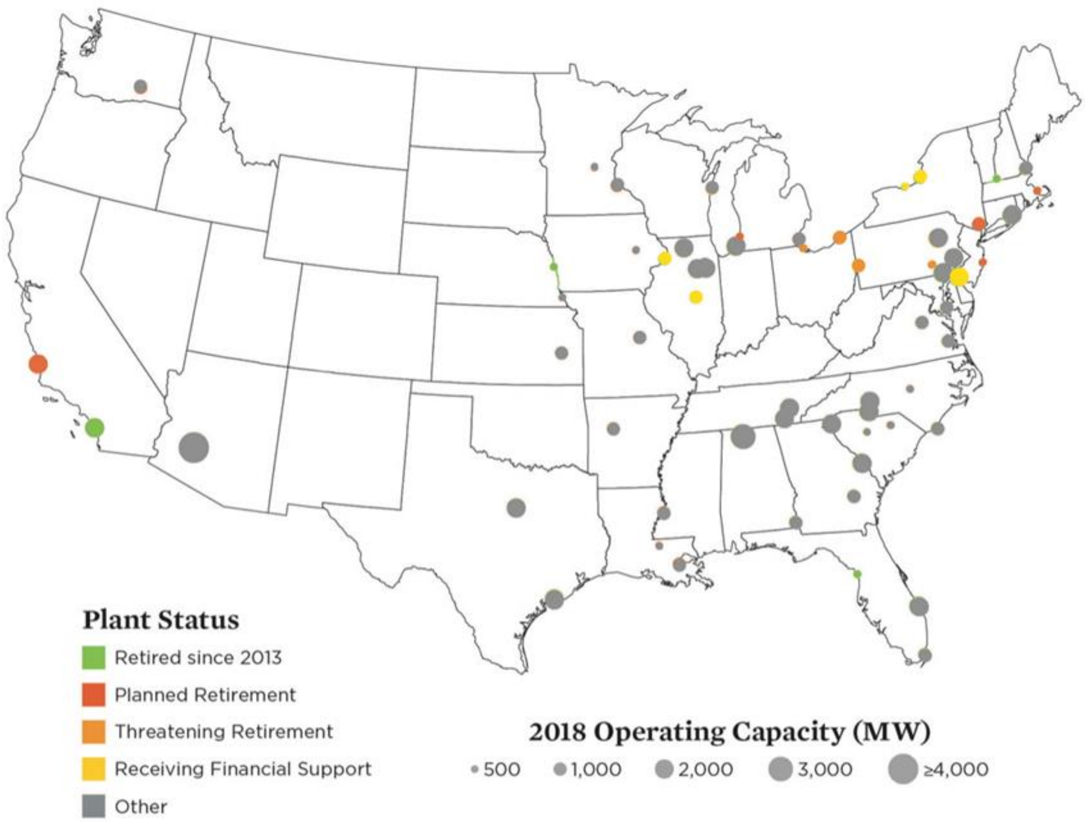
At the end of 2017, 99 reactors were operating at 60 plants[1] in the United States, providing 20 percent of the country's electricity generation (Figure 1 and Box 1) (NEI 2018a). The owners of five more plants have announced plans to retire at least seven reactors over the next eight years in California, Massachusetts, Michigan, New Jersey, and New York. Illinois, New Jersey, and New York are providing financial support to keep 10 reactors at seven other nuclear plants operating for at least another decade. And owners are threatening to retire five reactors at four nuclear plants in Pennsylvania and Ohio in the next few years if they do not receive additional financial support.

The Union of Concerned Scientists (UCS) has assessed the economic viability and performance of most of the nuclear power plants operating in the United States. We analyzed which plants are most at risk of retiring reactors early, evaluated the main factors that affect competitiveness, and identified reactors that have been safe, reliable performers as well as those with troubled performance records. In addition, using a national model of the electricity sector, UCS analyzed the impact on the US electricity mix, carbon dioxide (CO_2) emissions, and consumer electricity bills under several early nuclear retirement scenarios and two national carbon-reduction policies.

Why Nuclear Plants Are Closing Early

Most US nuclear reactors have 60-year operating licenses, expiring between 2030 and 2050 (NRC 2018a). However, many reactors have retired early. Nineteen reactors closed before 2013 for a variety of reasons, including poor management, costly repairs, safety and performance problems, electric industry restructuring, and market factors. More recently, low natural gas prices and, to a lesser extent, increasingly affordable renewable energy technologies, flattening demand for electricity, and increased operating costs have also contributed to early closures and put

FIGURE 1. **US Nuclear Power Plants in 2017**



At the end of 2017, 99 reactors were operating at 60 plants in the United States, providing 20 percent of the country's electricity generation.

additional plants at risk of early retirement (EIA 2018a; Jenkins 2018; Haratyk 2017).

The economic challenges surrounding nuclear plants are part of a historic transition in the US electricity sector. Over the last decade, natural gas and renewable energy generation from wind and solar have grown rapidly as their prices have fallen. For the most part, these energy sources have replaced generation from coal plants (Figure 2), resulting in a 28 percent reduction below 2005 levels in emissions of CO_2 from the US power sector (EIA 2018b). According to reports by UCS and other analysts, these trends are likely to continue (Houser, Bordoff, and Marsters 2017; Richardson et al. 2017; Rogers and Garcia 2017; Deyette et al. 2015).

This transition has yielded numerous benefits, including lower prices, innovative technologies, a cleaner environment, and increased customer control over energy use. However, in the absence of a national policy to reduce carbon emissions, this transition has undervalued low- and zero-carbon energy sources of all types and underpriced natural gas and coal relative to their damage to the climate.

Nuclear power generation has remained relatively flat over the past decade; increased generation at other nuclear power plants and from a reactor that began operating in Tennessee in 2016 have more than made up for the lost generation from recently retired plants. However, analysts project nuclear power's share of US generation to decline without additional financial support as the plants face continued economic challenges. In addition to plants at risk of closing early, others are nearing the end of their operating licenses; only one new nuclear plant is under construction in the United States—and it is experiencing significant cost overruns and delays.

Nuclear Power's Role in Addressing Climate Change

Addressing global warming requires a rapid transformation of how we produce and consume energy. Rising seas, damaging extreme weather events, severe ecological disruption, and the related toll on public health and the economy—these impacts of climate change demand that we consider all possible options for limiting heat-trapping emissions, including consideration of the respective costs and timelines for implementation of each option.

To help prevent the worst consequences of climate change, the United States must achieve net-zero heat-trapping emissions across the economy by mid-century (IEA 2017; DOE 2016a). Swiftly decarbonizing the electric sector, one of the largest sources of US carbon emissions, is among the most cost-effective steps for limiting heat-trapping gases, and it can help decarbonize other sectors through increased electrification (Cleetus, Clemmer, and Bailie 2016; DOE 2016a; Williams et al. 2014).

What role nuclear power should play in decarbonizing the power sector is the subject of much debate. According to several studies, continued growth in renewable energy and energy efficiency, with enough planning and strong public policies, could replace almost all nuclear and coal generation in the United States by 2050 (Lovins et al. 2018; Gowrishankar and Levin 2017; Jacobson et al. 2017; Lovins 2017; Cleetus, Clemmer, and Bailie 2016; Makhijani 2007). However, many of these analyses assume that most existing US nuclear reactors will continue to run until their 60-year operating licenses expire, and that new nuclear plants are too expensive to build when compared with other low-carbon technologies. On the other hand, several studies suggest that nuclear power will make a meaningful contribution to decarbonizing the US power sector by 2050 (Sepulveda et al. 2018; Clack et al. 2017; Jenkins and Thernstrom 2017; DOE 2016a; Williams et al. 2014). Most of those studies assume that existing plants will operate for 60, or even 80, years, and that the costs of new nuclear plants will decline significantly with the development of advanced technologies.

That said, past forecasts of nuclear power in terms of cost reductions, technological innovation, and

BOX 1.

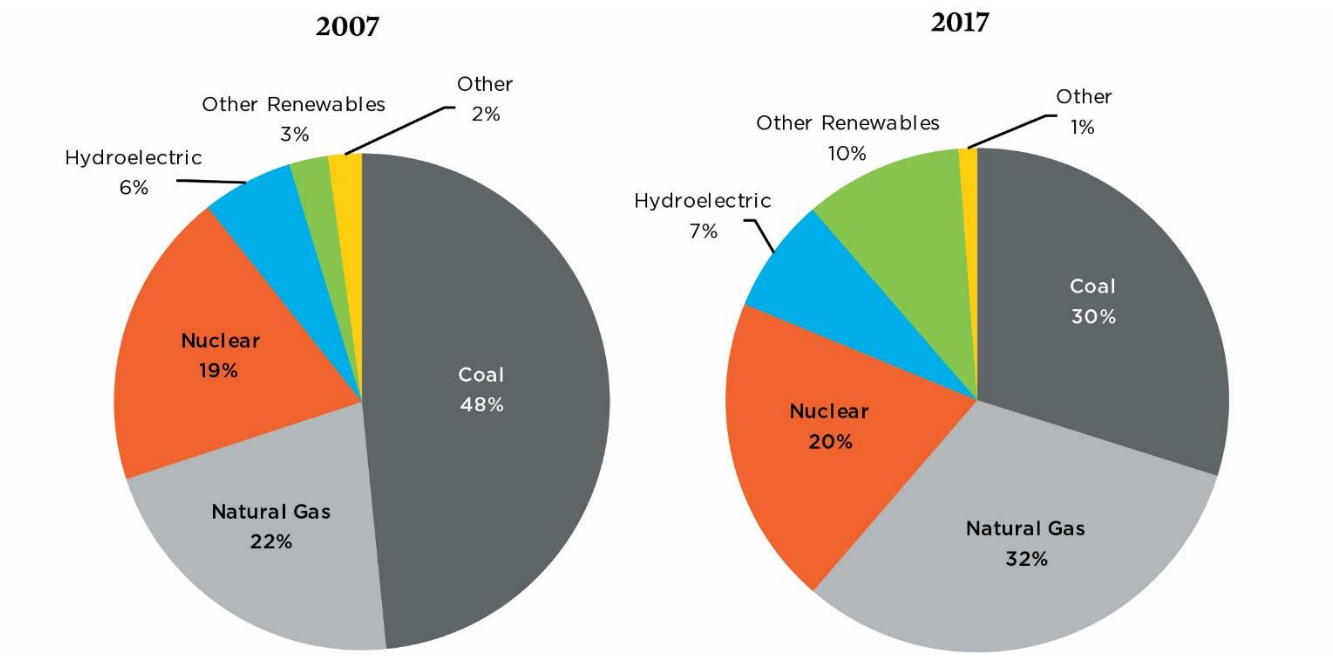
Plants and Reactors

Two closely related terms—reactor and plant—complicate discussions of nuclear power. A nuclear reactor consists of the components necessary to use the energy released by splitting atoms to generate electricity. A nuclear plant consists of one or more nuclear reactors.

Some nuclear plants have both operating and closed reactors. Also, some generating plants have both nuclear reactors and generators operating on other fuels such as coal, natural gas, or oil. Here are a few examples:

- Nuclear plants with a single reactor: Davis-Besse (Ohio), Clinton (Illinois), Grand Gulf (Mississippi)
- Nuclear plants with multiple reactors: Beaver Valley (Pennsylvania), Palo Verde (Arizona), Catawba (South Carolina)
- Nuclear plants with an operating reactor and a permanently closed reactor: Dresden (Illinois), Millstone (Connecticut)
- Nuclear plants with nuclear reactors and generating units using other fuels: H.B. Robinson (South Carolina), Turkey Point (Florida)

FIGURE 2. **Changes in US Electricity Generation, 2007 to 2017**



Over the past decade, the United States has made a historic transition away from coal and toward natural gas, wind, and solar, while the market share of nuclear has remained flat.

SOURCE: EIA 2018B.

growth have proved far more wrong than right. Forecasts predicting nuclear power would be "too cheap to meter," a "nuclear renaissance" of some 50 new US reactors by 2020, or natural gas prices that are three to four times higher than current prices are a stark warning of the need for technologies and policies that can respond quickly when reality contradicts predictions. Many of the recent technological innovations in the energy sector have happened very quickly, such as improvements in wind, solar, and energy-storage technologies; the rapid penetration of LED lighting; advanced electronic controls for grid management; and new technologies for producing and burning natural gas. In short, the design of any system of support for existing technologies must encourage competition and not lock in the current market share of an energy source for longer than is necessary to keep the United States on track for achieving deep emissions reductions.

Given the uncertainty around how nuclear power and other low-carbon technologies will evolve over the next three decades, combined with the enormous challenge and urgency of achieving deep cuts in heat-trapping emissions, nuclear power cannot be dismissed as a potential part of a long-term climate solution. Nevertheless, its role in combating climate change will depend on overcoming important economic, safety, human health, and environmental risks (UCS n.d.; Lochbaum, Lyman, and Stranahan 2014; Rogers et al. 2013; Koplow 2011).

Without assessing the potential role of new nuclear plants in meeting *long-term* emissions-reduction targets, UCS explored the possible role of existing nuclear plants in reducing US carbon emissions by 2035. We chose this date to assess the potential near-term impacts from retiring at-risk reactors before their operating licenses expire, which occurs for most US reactors between 2030 and 2050.

While nuclear power provided 53 percent of America's low-carbon electricity in 2017, renewable energy is the fastest-growing source, increasing from 30 percent of the total in 2007 to 47 percent in 2017. Most of this growth in low-carbon electricity has come from wind and solar power. Although natural gas was the nation's leading source of new electric-generating capacity over the past five years, wind and solar combined for a total of 56 percent of all new capacity (AWEA 2018). Electricity savings from state and utility energy-efficiency programs have also grown over the past decade, reducing total US electricity use by an estimated 6 percent in 2016 (Weston et al. 2017).

Continued growth in renewable energy and energy efficiency could replace a significant portion of the lost generation from retiring nuclear plants. However, replacing one source of low-carbon generation with another does not go far enough. We must significantly reduce heat-trapping emissions by adding more low-carbon generation and reducing fossil fuel use. It will be challenging to ramp up energy efficiency and renewable energy technologies fast enough in the next decade to not only replace the generation from retiring coal plants but also prevent a further increase in natural gas generation and increase the electrification of transportation and buildings. All of these will be necessary to put the nation on a path to achieving deep cuts in carbon emissions (Cleetus, Clemmer, and Bailie 2016; DOE 2016a; Williams et al. 2014).

Without new policies, the nation might replace abruptly closed nuclear plants primarily with natural gas (EIA 2018a; Vine 2018; EIA 2016). While cleaner than coal, natural gas still emits unacceptably large amounts of heat-trapping emissions, especially taking into account methane leaks from pipelines and other infrastructure. To the extent that electricity from natural gas or coal replaces a nuclear plant's output, the resulting increase in heat-trapping emissions would set back national and state efforts to reduce emissions.

To ensure they don't lose a vital source of low-carbon electricity, states such as Illinois, New York and New Jersey have adopted policies that provide temporary financial assistance for at-risk plants. Experience in these states demonstrates the importance of predicating such support on a showing of financial distress and adjusting support as market and policy conditions change to limit costs to ratepayers.Policymakers in those states also have tied support for nuclear to a broader strategy of reducing carbon emissions, including state policies designed to increase investments in energy efficiency and renewable energy that could eventually replace existing nuclear plants over a longer timeframe. With strong climate and clean energy policies, California is working to ensure that zero-carbon resources replace its nuclear plants, while the state continues to drive down emissions. *(See Appendix A for details on these state policies.)*

Key Drivers of Early Nuclear Power Retirements

The declining price of wholesale power, due primarily to declining natural gas prices, has been the main driver of early nuclear retirements over the past decade (EIA 2018a; Jenkins 2018; Haratyk 2017; Shea and Hartman 2017). Other factors have played a more modest role, including flat or declining demand for electricity, the rapid deployment and falling costs of renewable energy, increased operating costs and costly repairs for some nuclear plants, and plant ownership and market structure.

Low Natural Gas Prices

The rapid growth in domestic production of natural gas, due to advances in hydraulic fracturing and horizontal drilling techniques, pushed down prices for natural gas and wholesale power by 50 to 70 percent between 2008 and 2017 (Figure 3) (EIA 2018c; Jenkins 2018; Wiser and Bolinger 2018). In contrast, the national average for the operating costs of existing nuclear plants increased 41 percent between 2002 and 2012 before falling 19 percent between 2012 and 2017 (NEI 2018a).

Market Structure

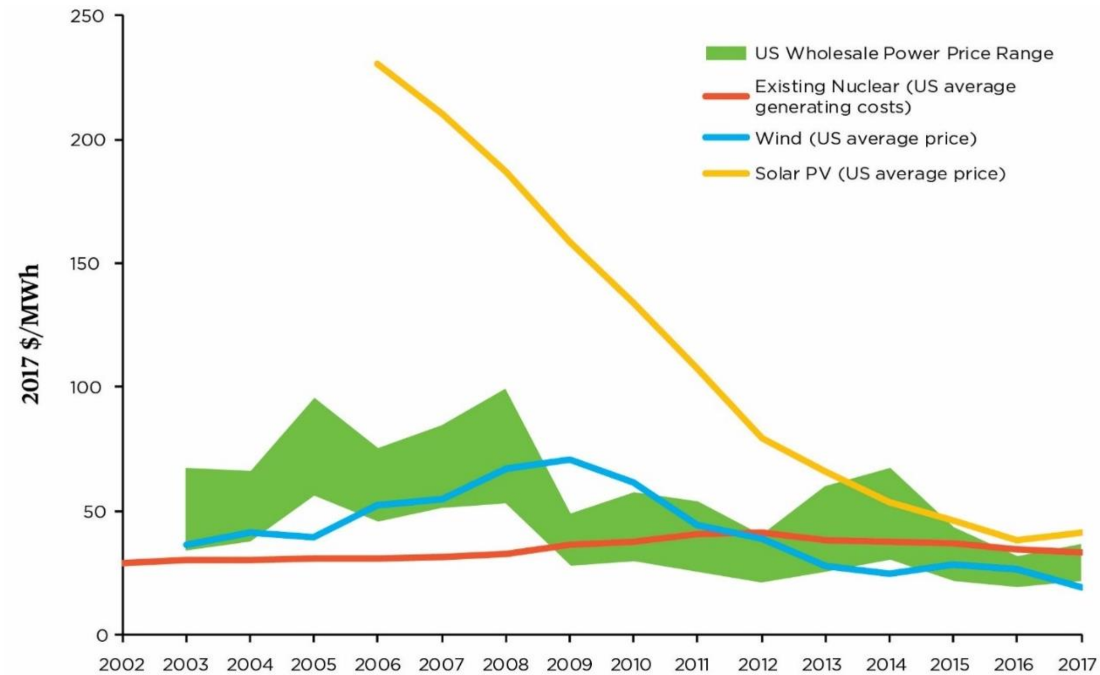
Most of the nuclear plants that have retired recently, announced a shutdown, or threatened to close early are merchant plants and located in states with restructured electricity markets or regions with competitive wholesale power markets. Merchant plants, which are not owned by utilities, are more vulnerable to market pressures than are plants owned by regulated, investor-owned utilities. The latter typically can recover their capital and operating costs from ratepayers, plus earn a return on investment, subject to approval from state public utility commissions. Like regulated utilities, nuclear plants owned by public power entities typically recover plant costs from their customers, but they have access to lower-cost financing and do not earn a profit.

While the relative risks are higher for merchant plants and the decisionmaking process differs, plants owned by regulated and public utilities are not immune from current economic pressures. For example, the need for expensive equipment repairs at the Fort Calhoun, San Onofre, and Crystal River plants played a significant role in closure decisions by their public and regulated utility owners. And while merchant generators own the Duane Arnold plant in Iowa and the Palisades plant in Michigan, regulated utilities purchase most of the power from these plants through power purchase agreements (PPAs). Utilities in Iowa and Michigan recently ended those PPAs early, largely because of the availability of lower-cost alternatives; the result was the announced closure of those plants (Patane and Schmidt 2018; Parker 2016). The Minnesota legislature recently rejected a proposal to preapprove $1.4 billion in new investments for Xcel Energy’s regulated Monticello and Prairie Island nuclear plants over the next 17 years, with a potentially significant impact on future decisions to refurbish or replace those plants (Hughlett 2018).

Declining Electricity Demand and Renewable Energy Growth

Declining demand for electricity due to investments in energy efficiency, along with the growth in wind and

FIGURE 3. **Declining Natural Gas and Renewable Energy Prices Pose Economic Challenges to Existing Nuclear Plants**



Over the past decade, the decline in natural gas prices has been the main driver for declining wholesale electricity prices. Wind and solar prices, which include federal tax credits set to expire in the next few years, have also fallen, in this case by more than two-thirds. These costs reductions have made all these energy sources competitive with existing nuclear plants.

Note: Prices for wind and solar are based on power purchase agreements between renewable energy developers and utilities.

SOURCES: BOLINGER AND SEEL 2018; NEI 2018A; WISER AND BOLINGER 2018.

solar due to falling costs and state federal policies, have contributed to decisions to retire nuclear plants early. Since 2009, the average price of wind power nationally has fallen by more than two-thirds, while the average price of utility-scale solar photovoltaics has fallen more than 75 percent (Figure 3) (Bolinger and Seel 2018; Wiser and Bolinger 2018). In some parts of the country, the reductions have made wind and solar projects less expensive than building natural gas plants or operating nuclear plants.

In the Mid-Atlantic and Midwest states, where many of the nation's nuclear power plants are located, such factors have played a much smaller role in reducing wholesale power prices than the decline in natural gas prices (Jenkins 2018; Haratyk 2017). The growth in wind had an order of magnitude smaller cumulative effect than natural gas prices in the Mid-Atlantic states, where cheap natural gas is available from the Marcellus shale deposit and the deployment of renewable energy is relatively modest (Jenkins 2018). Other studies report similar results, refuting claims by the nuclear and coal industries that subsidies for wind and solar are distorting electricity markets and the main cause of wholesale electricity prices falling below zero when high and inflexible generation appears during periods of low electricity demand. (Goggin 2017a; Goggin 2017b; Houser, Bordoff, and Marsters 2017; Goggin 2014).

Aging, Safety, and Performance

Poor safety, weak performance, and the high costs of repairing or replacing aging equipment have played a role in decisions to retire some nuclear plants early.

For example:

- The Crystal River plant in Florida and the San Onofre plant in California shut down in 2013 due to failed steam generator replacements. The Fort Calhoun plant in Nebraska shut down in 2016 after experiencing extended outages and damage due to flooding and expensive repairs.
- The Pilgrim plant in Massachusetts, slated to close in 2019, has shut down temporarily multiple times due to ongoing safety and performance issues.
- Indian Point in New York is set to close in 2021 due to safety concerns related to its proximity to New York City, as well as to avoid investing in a new closed-cycle cooling system to reduce water withdrawals and impacts on aquatic species (EIA 2018a).
- Diablo Canyon in California, scheduled to shut down by 2025, would have needed to invest in a new cooling system and is located near earthquake fault lines.

BOX 2.

Early Nuclear Retirements Do Not Threaten Electricity Reliability and Resilience

Deeply flawed Trump administration proposals, citing concerns over reliability, national security, and resilience, would force grid operators and consumers to buy power from uneconomical coal and nuclear power plants (Tierney and Palmer 2018a; Lovins 2017). How-ever, grid operators have shown no reliability problem from retiring nuclear plants that would affect national security. Moreover, the administration ignores several weaknesses in coal and nuclear power that make the grid less resilient. If implemented, the proposals could increase costs to consumers by an estimated $17 billion to $35 billion per year (Celebi et al. 2018; Natter 2018).

The administration plan to use emergency authorities to bail out uneconomic coal and nuclear plants is unprecedented. The federal government has used such authorities primarily to address major power outages and shortages, such as the California energy crisis in 2000, the Northeast blackout in 2003, and major hurricanes (Moore and Giannetti 2018; Tierney and Palmer 2018b). Those short-term actions did not include widespread increases in the cost of electricity. Reliable power depends on many system attributes, among them adequate reserve margins, careful and sufficient maintenance, secure fuel supplies, and a diversity of generation sources. Almost all power outages occur at the transmission or distribution level and not at the generator level (Houser, Larsen, and Marsters 2017). Planning for a sudden outage at large power plants and transmission facilities mean that grid operators already have additional generation and transmission reserves on hand to replace them immediately. The most recent assessment from the North American Electricity Reliability Corporation projects that reserve margins will be considerably higher than needed in 2022 in almost every region of the country (NERC 2018).

Regional grid operators do not believe there is a reliability crisis from retiring uneconomic coal and nuclear plants that warrants federal intervention. "Our analysis of the recently announced planned deactivations of certain nuclear plants has determined that there is no immediate threat to system reliability," according to a June 2018 statement by PJM Interconnection (PJM), the grid operator in the Mid-Atlantic states. "Markets have helped to establish a reliable grid with historically low prices. Any federal intervention in the market to order customers to buy electricity from specific power plants would be damaging to the markets and therefore costly to consumers" (PJM 2018).

The 2017 proposal of the US Department of Energy (DOE) to pay coal and nuclear plants an electricity resilience benefit for having a 90-day fuel supply was also rejected by the Federal Energy Regulatory Commission and most grid operators.

All technologies have strengths and weaknesses and contribute to reliability and resilience in different ways, which is why markets are critical for delivering these services in a technology-neutral way (Goggin 2017a). The DOE's proposal ignores several risks that coal and nuclear plants pose to grid resilience, including cyber risks and a lack of flexibility, as well as vulnerability to the impact of heat and drought on cooling water temperatures and availability, faults that have caused plants to shut down.

While the retirement of uneconomic coal and nuclear plants is not a reliability, resilience, or national security crisis, the increase in the frequency and severity of climate impacts is. The effects of climate change on US society, the nation's security interests internationally, and the civilian, electricity, and military infrastructure are significant and well documented (DOD 2018; Jacobs 2018; Werrell and Femia 2017; Spanger-Siegfried et al. 2016; McNamara et al. 2015, Melillo et al. 2014). Addressing these impacts warrants consideration of policy or financial support that values the attributes of low-carbon technologies. It does not justify support for coal.

Methodology

Our analysis consisted of three parts. First, we assessed the profitability of existing nuclear power plants in the United States using the best available data. Next, we analyzed the impacts of potential early nuclear power plant retirements and carbon reduction policies on the electricity system. Finally, we evaluated the safety performance of each nuclear reactor using data from the Nuclear Regulatory Commission.

TABLE 1. **US Nuclear Plants with Firm Plans to Close**

Plant Name	State	No. Reactors	2018 Operating Capacity (MW)	Retirement Year
Diablo Canyon	CA	2	2,240	2024, 2025
Indian Point	NY	2	2,071	2020, 2021
Oyster Creek	NJ	1	635	2018
Palisades	MI	1	820	2022
Pilgrim	MA	1	683	2019
Total		**7**	**6,449**	

The owners of seven nuclear reactors at five plants have firm plans to close them over the next seven years. The UCS profitability analysis excludes these reactors.

Assessing the Profitability of Existing Nuclear Power Plants

Of the 99 reactors operating at 60 power plants across the United States at the end of 2017, our economic analysis focused on 92 units at 55 plants and excluded seven reactors at five plants scheduled for closure between 2018 and 2025 (Table 1).[3] We used a similar methodology as most previous studies and projected the annual operating margin (revenues minus expenses) on a dollar-per-megawatt-hour basis for all 92 reactors from 2018 through 2032, with a focus on the five years from 2018 to 2022. (*See Appendix B for more detail on the assumptions used in this analysis.*)

We based projections of annual operating revenues for each reactor on estimates from S&P Global Market Intelligence (S&P).[4] S&P developed its estimates using near-term market data and projections from the Aurora model, a widely used tool for forecasting electricity market prices, valuing resources, and analyzing market risk (SNL Energy n.d.). Revenue projections include both energy (or money received from selling electricity) and capacity (or money received to ensure the availability of adequate generation at times of peak demand). The analysis of operating margins does not reflect the revenues collected from consumers through rates that help insulate regulated and public power utility-owned plants from lower-cost alternatives available in the market. Costs include fixed and variable operations and maintenance (O&M) costs, fuel costs, and capital costs, based on reports from the Electric Utility Cost Group and the annual survey of costs for existing US nuclear plants that it conducts for the NEI (NEI 2018a; NEI 2017). To benchmark costs from the Aurora

TABLE 2. **US Nuclear Plants Receiving State Financial Support**

Plant Name	State	No. Reactors	2018 Operating Capacity (MW)
Clinton	IL	1	1,078
Quad Cities	IL	2	1,819
Hope Creek	NJ	1	1,172
Salem	NJ	2	2,307
Ginna	NY	1	582
Fitzpatrick	NY	1	853
Nine Mile Point	NY	2	1,928
Total		**10**	**9,739**

Ten nuclear reactors at seven plants in Illinois, New Jersey, and New York receive or will receive financial support to keep them operating for at least 10 years.

model projections, we combined all this information with publicly available cost inform-ation for some regulated plants.

The analysis took into account current carbon prices in California and the nine states participating in the Regional Greenhouse Gas Initiative, which improves the economics of nuclear plants by making fossil resources more expensive to run. We included estimates based on recent legislation in Illinois, New Jersey, and New York that provide financial support for selected nuclear plants (Table 2).

We used the average annual operating margin to evaluate the profitability of each reactor, aggregated to the plant level. The profitability assessment did not consider regulatory status. Merchant generators are much more susceptible to changing market dynamics and more likely to retire unprofitable plants early. Plants owned by regulated and public utilities typically can recover above-market costs from their customers, but they are not immune to market pressures from lower-cost alternatives, particularly if they seek to make major capital investments in nuclear plants. Most other economic analyses of existing nuclear plant profitability have included both merchant and regulated plants.

We categorized plants as profitable, unprofitable, or marginal. Unprofitable plants have average annual operating margins below $0. Marginal plants have operating margins between $0 and $5 per megawatt-hour (MWh). We deemed plants above $5 per MWh as profitable. That cutoff is equivalent to 16 percent of the average annual total generating cost for all US reactors from 2018 to 2022.[5] A new natural gas combined-cycle plant would need operating margins of $10 to $20 per MWh to be sure of covering debt and equity financing costs (Piper 2018). The $5 per MWh cutoff for existing plants is reasonable because most nuclear plants are fully depreciated (Rhodes 2018).

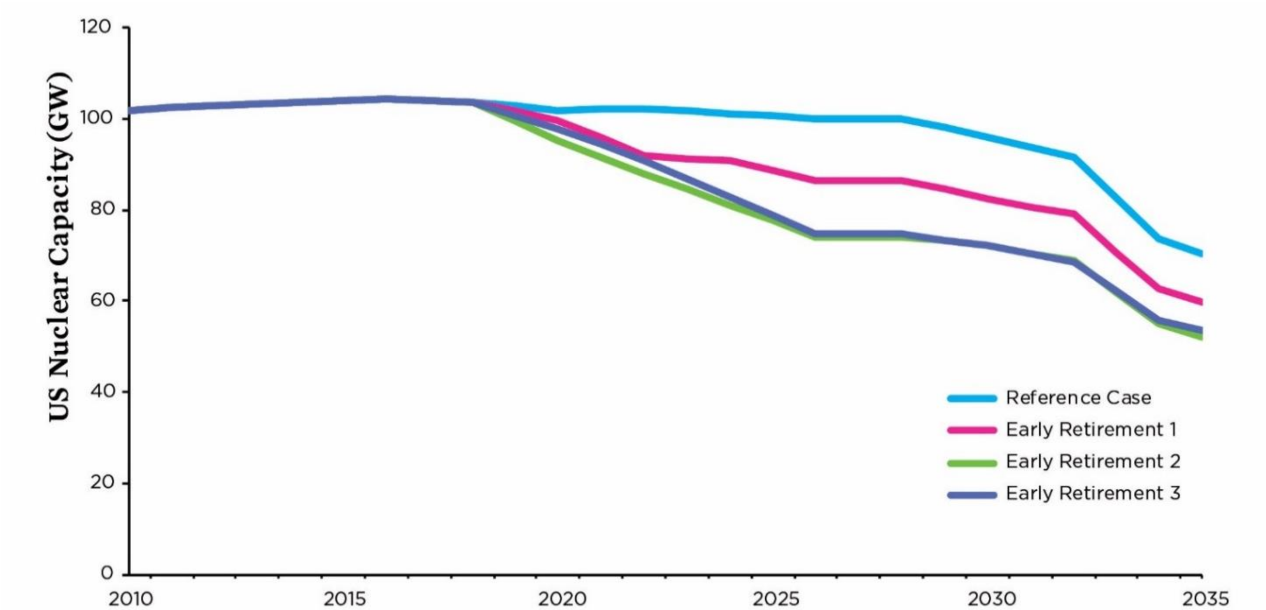
The identification of marginal plants suggests that a significant number of nuclear plants may be close to the edge and could face financial troubles due to relatively small changes in assumptions about plant-specific operating costs or projected revenues. Because of this uncertainty, we evaluated the sensitivity of our results to changes in key assumptions, including natural gas prices, nuclear operating costs, and the level of a presumed national carbon price. (*See results from our sensitivity analysis in Appendix E.*)

We presented the findings in five-year averages of the annual operating margin for each nuclear plant to be in line with the business cycles for nuclear power plants (Cameron 2017). We focused on the near-term profitability over the initial five years, 2018 to 2022, given near-term discussions about the future of nuclear power plants and because of the greater uncertainty inherent in longer-term price projections.

Analyzing the Impacts of Early Retirements and Carbon Reduction Policies

The UCS analysis used a modified version of the Regional Energy Deployment System (ReEDS) model of capacity expansion for the power sector. Developed by the National Renewable Energy Laboratory, ReEDS simulates the electricity supply mix that would meet demand in the future throughout the contiguous

FIGURE 4. **US Nuclear Capacity in the Reference Case and Three Early Nuclear Retirement Cases**



Nuclear generating capacity is projected to drop 13 to 26 percent below current levels by 2026 under our modeled early retirement cases, compared with a decrease of 6 percent during the same period under the reference case. After 2026, nuclear generating capacity declines similarly across all cases as existing reactors retire after their operating licenses expire.

Notes: The ReEDS Reference Case assumes that all existing nuclear reactors will operate until their operating licenses expire (after 60 years) except for the seven nuclear reactors at five plants that have firm plans to retire over the next seven years. It includes two reactors under construction at the Vogtle plant in Georgia. Early retirement case 1 only includes merchant plants. Early retirement case 2 includes a mix of merchant and regulated plants under our reference case assumptions. Early retirement case 3 assumes lower natural gas prices and only includes merchant plants.

United States at the lowest overall system cost while meeting reliability, environmental, and other legal requirements. Using the modified model, we projected impacts on the nation's electricity generation mix, CO_2 emissions, and electricity prices through 2035 under various scenarios.

We based the assumptions in our version of the ReEDS model on information the Energy Information Administration (EIA) uses for its *Annual Energy Outlook 2018*, supplemented by data from NREL's 2017 Standard Scenarios report (EIA 2018d; NREL 2017). For natural gas prices, we used the EIA's low projection from its 2018 "High oil and gas resource and technology" side case to be consistent with our plant-level analysis. We also updated the model's data for existing power plants to include recent and announced retirements, plants under construction, and current state-level energy efficiency programs. We included the seven nuclear reactors at five plants that have firm plans to retire over the next eight years in California, Massachusetts, Michigan, New Jersey, and New York.[6] We also included two reactors under construction at the Vogtle plant in Georgia.

Scenarios Modeled in the UCS Analysis

The UCS analysis focused on six main scenarios: a reference case with no new state or federal policies beyond those in place as of June 2018, three early-nuclear-retirement cases, and two national carbon-reduction policy cases.

TABLE 3. **EARLY RETIREMENT CASES**

	Reference Case, Merchant Only (early retirement case 1)	Reference Case, All Plants (early retirement case 2)	Low Gas Price, Merchant Only (early retirement case 3)
Number of Plants	9	21	15
Number of Reactors	13	27	25
Total Operating Capacity	**13.7 GW**	**26.8 GW**	**26.3 GW**

The early retirement cases represent about 13 to 26 percent of total nuclear capacity currently operating in the United States. The seven reactors at five plants that have firm plans to retire over the next seven years are not included in these numbers.

EARLY NUCLEAR RETIREMENT CASES

The early nuclear retirement case combines a series of cases reflecting the sensitivity of our results to various assumptions. We prescribed retirement dates for existing nuclear power plants that we determined to be at risk based on the results of the plant-level analysis. We selected these plants through an economic screening test using projected operating margins from the plant-level analysis to identify which reactors might face premature retirement. The screening test focused on plants that showed up as unprofitable or marginal in the three five-year periods between 2018 and 2032.

We repeated this screening test for the profitability analysis reference case and the low gas price case, which represents projections from S&P that are slightly lower than the low gas price case of the Energy Information Administration. Recognizing that merchant generators are more susceptible to market changes than are regulated plants, we constructed three early retirement cases (Figure 4 and Table 3). Two cases use our reference case assumptions: early retirement case 1 only includes merchant plants; early retirement case 2 includes a mix of merchant and regulated plants. Early retirement case 3 assumes lower natural gas prices and only includes merchant plants.

NATIONAL CARBON PRICE POLICY CASE

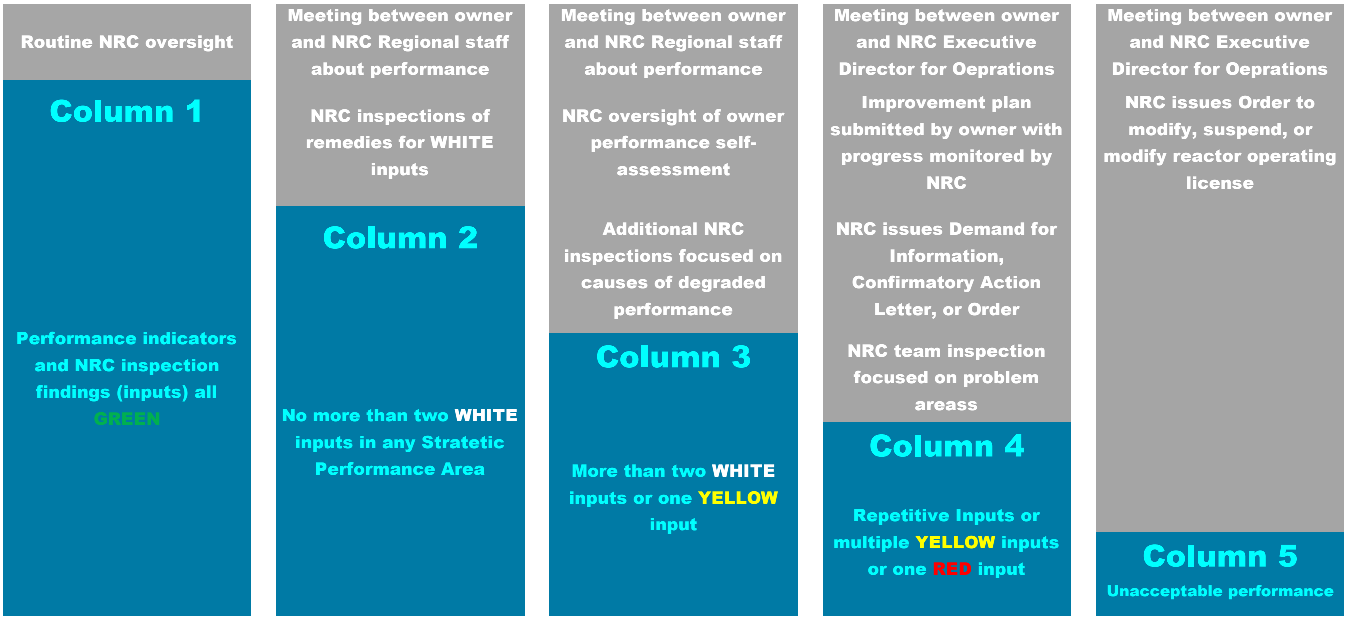
This scenario is based on the EIA's *Annual Energy Outlook 2018* economy-wide CO_2 price of $25 per ton in 2020, increasing at 5 percent per year (EIA 2018a). While UCS believes a higher economy-wide carbon price would be needed to achieve deep cuts in global warming emissions consistent with the Paris Climate Agreement, we modeled this more modest power sector–only carbon price specifically and solely to analyze the price that would be sufficient to make most unprofitable nuclear plants economically viable.

We also analyzed the impact of a national energy efficiency standard, assuming that all states achieve a modest reduction in electricity sales of at least 1 percent per year from 2022 to 2030 and that states with stronger energy efficiency standards continue meeting their respective targets (Deyette et al. 2016). Leading states currently meet energy efficiency targets of 2 to 3 percent per year (Weston et al. 2017). This energy-efficiency policy is modeled as a reduction in electricity demand in ReEDs, with the costs of implementing the policy and net savings on consumer electricity bills estimated outside the model. To achieve these targets, states could use a portion of the carbon revenues to provide incentives for consumers to invest in energy efficiency.

NATIONAL LOW CARBON ELECTRICITY STANDARD (LCES) CASE

The LCES case assumes that the share of US electricity generation represented by low-carbon generation will increase from 45 percent in 2020 to 60

FIGURE 5. **NRC Reactor Oversight Process Action Matrix Columns and Associated NRC Responses**



SOURCE: NRC 2018B.

percent in 2030 and 80 percent by 2050. We estimated the share of generation in 2020 based on the results of the ReEDS reference case and assumed LCES targets would ramp up 1.5 percent per year through 2030 and 1 percent per year from 2031 to 2050. We assumed that several technologies would be eligible to meet the standard, including new and existing nuclear plants, renewable energy technologies (from hydro, wind, solar, biomass, and geothermal), and natural gas and coal plants equipped with carbon capture and storage (CCS), with carbon-capture rates of 90 percent or more. We assumed that nuclear and renewable energy facilities would get full credit toward the standard and that CCS projects would receive partial credit based on their capture rate (e.g., a CCS project that captures 90 percent of CO_2 emissions would be credited at 90 percent of its generation). We assumed that all states meet a national energy efficiency standard of at least 1 percent per year from 2022 to 2030, as in the carbon price case.

Evaluating Reactor Safety Performance

An accident or terrorist attack at a US nuclear reactor could severely harm public health, the environment, and the economy. For example, the 2011 Fukushima reactor meltdowns in Japan released large amounts of radioactive material into the air and water, requiring more than160,000 people to leave their homes and causing an estimated $200 billion worth of damage to the economy. Moreover, the accident led to the shutdown of the entire Japanese nuclear power sector for years, and it is unlikely to fully recover.

Similarly, such an accident at a US nuclear reactor would jeopardize the prospects for nuclear energy for decades to come and limit available options to meet near-term carbon reduction targets. It is thus essential that policymakers and other stakeholders consider financial support only for nuclear reactors that meet or exceed current safety standards.

UCS evaluated the safety performance of the nation’s operating nuclear power reactors to provide a metric that would help policymakers and other stakeholders consider economic support for individual nuclear facilities. This safety analysis complements the economic and low carbon–generation analyses to provide a fuller picture of whether financial support is warranted to achieve carbon-reduction objectives.

The performance measures in this evaluation were the quarterly assessments that the NRC has conducted for nearly two decades as part of its Reactor Oversight Process (ROP). Available for the same time periods for all reactors, these assessments have a known track record. Just as important, they were developed by an independent federal government organization less susceptible to biases than assessments by an industry group or groups actively working to shut down reactors.

Every three months, the NRC classifies each operating reactor into one of five columns of the ROP's Action Matrix depending on the performance indicators and inspection findings (Figure 5). Reactors in Column 1, the License Response column, meet or exceed the NRC's expectations (i.e., all performance indicators and NRC inspection findings are green). Columns 2, 3, and 4 list reactors where performance indicators or NRC inspection findings indicate declining safety performance. Generally, placement in Column 2 reflects minor problems in an isolated area; placement in Columns 3 and 4 reflects problems suggesting systemic breakdowns. As performance declines, the NRC's oversight response increases to stem the decline and guide performance back into the expected band. When performance drops too far, the NRC puts a reactor into Action Matrix Column 5. The owner must shut down the reactor until remedying enough of the problems for the NRC to approve a restart.

However, policymakers will need to monitor the situation and adjust their subsidy policies accordingly if the NRC weakens its safety and security standards.

To lower operating costs, US reactor owners and the NEI have been pressuring the NRC for decades to weaken safety and security standards. More recently they have proposed cutbacks in critical inspection and enforcement activities (NEI 2018b).

Due to industry pressure, the NRC has:

- **Required inadequate measures to upgrade protection against extreme natural disasters.** After Fukushima, an NRC task force found multiple problems with current regulations and made 12 recommendations to strengthen safety requirements. However, due in part to vigorous lobbying by the NEI, the NRC implemented watered-down versions of some of these recommendations and rejected others (Lyman 2016). For instance, following the accident, reactors in France and Japan were required to install filters on reactor containment vents to trap radiation. The NRC task force recommended that the NRC adopt the same requirement for the more than two dozen US Fukushima-type reactors, but the NRC did not. As a result, the NRC's post-Fukushima requirements were far weaker than those of some other countries, allowing U.S. reactor owners to spend 10 to 20 times less on new safety measures than reactors in France and Japan.
- **Weakened oversight of its security measures.** Security measures are designed to protect nuclear reactors and spent nuclear fuel from terrorist attacks which could cause radiological releases comparable to or even greater than those at Fukushima—which was not a worst-case accident. To assess the ability of reactor security forces to repel an attacking force, the NRC conducts mock attack exercises every three years. It has recently reduced the attack scenarios used in these exercises from three to one, making reactor operators less prepared for—and reactors more vulnerable to—the diverse attack strategies terrorists could pursue.

The NRC is also considering further rollbacks:

- **Reducing security forces at reactors.** The NRC is considering an NEI proposal that it should assume greater involvement of local law enforcement in protecting nuclear plants and allow plant owners to reduce their own on-site security forces (NRC 2018c).
- **Changing the Reactor Oversight Process.** The NEI has been pushing the NRC to change

the ROP in ways that would greatly diminish the ROP's effectiveness and present a misleading picture of the nuclear fleet's safety performance (NEI 2018a). For instance, the NEI has proposed merging the highest and second-highest safety ratings, which would effectively render the rating meaningless—under this scheme, all US reactors operating today would have the highest safety rating. As NRC Commissioner Jeff Baran pointed out in a recent meeting, even the Pilgrim plant—which currently has the second-worst safety rating—would be reclassified as a top performer (NRC 2018d).

In addition, the NEI has proposed replacing some of the NRC safety inspections on which the ROP is based with "self-assessments," putting the proverbial foxes in charge of the henhouses.

If the NRC adopts either of these measures, we could no longer recommend that reactors with the highest rating qualify for support, as the safety assessments on which our recommendations are based would no longer indicate that reactors provided meaningful protection to people and the environment.

Results

This section presents the results of our economic assessment of most of the nuclear power plants operating in the United States, analyzing which ones are most at risk of early retirement at the state, regional, and national levels, and evaluating the main factors that affect competitiveness. Using a national model of the electricity sector, we also highlight the impacts on the US electricity mix, CO_2 emissions, and consumer electricity bills of early nuclear retirement scenarios and national policies to reduce carbon emissions. Finally, we examine the safety and performance of US nuclear reactors to differentiate between strong safety performers and underperformers.

TABLE 4. **Summary Results of Unprofitable Plants and Firm Retirements**

	All	Unprofitable (2018–2022)	Firm Retirements	% US Total
Number of Plants	60	16	5	35%
Number of Reactors	99	17	7	24%
Operating Capacity (GW)	101.8	16.3	6.4	22%
2018 Generation (million MWh)*	797.1	126.2	50.4	22%

In 2018, 99 operating nuclear reactors at 60 nuclear power plants accounted for nearly 102 GW of capacity and were expected to produce 797 million MWh of power. The unprofitable portion represents those that were projected to have a negative average annual operating margin from 2018 to 2022.

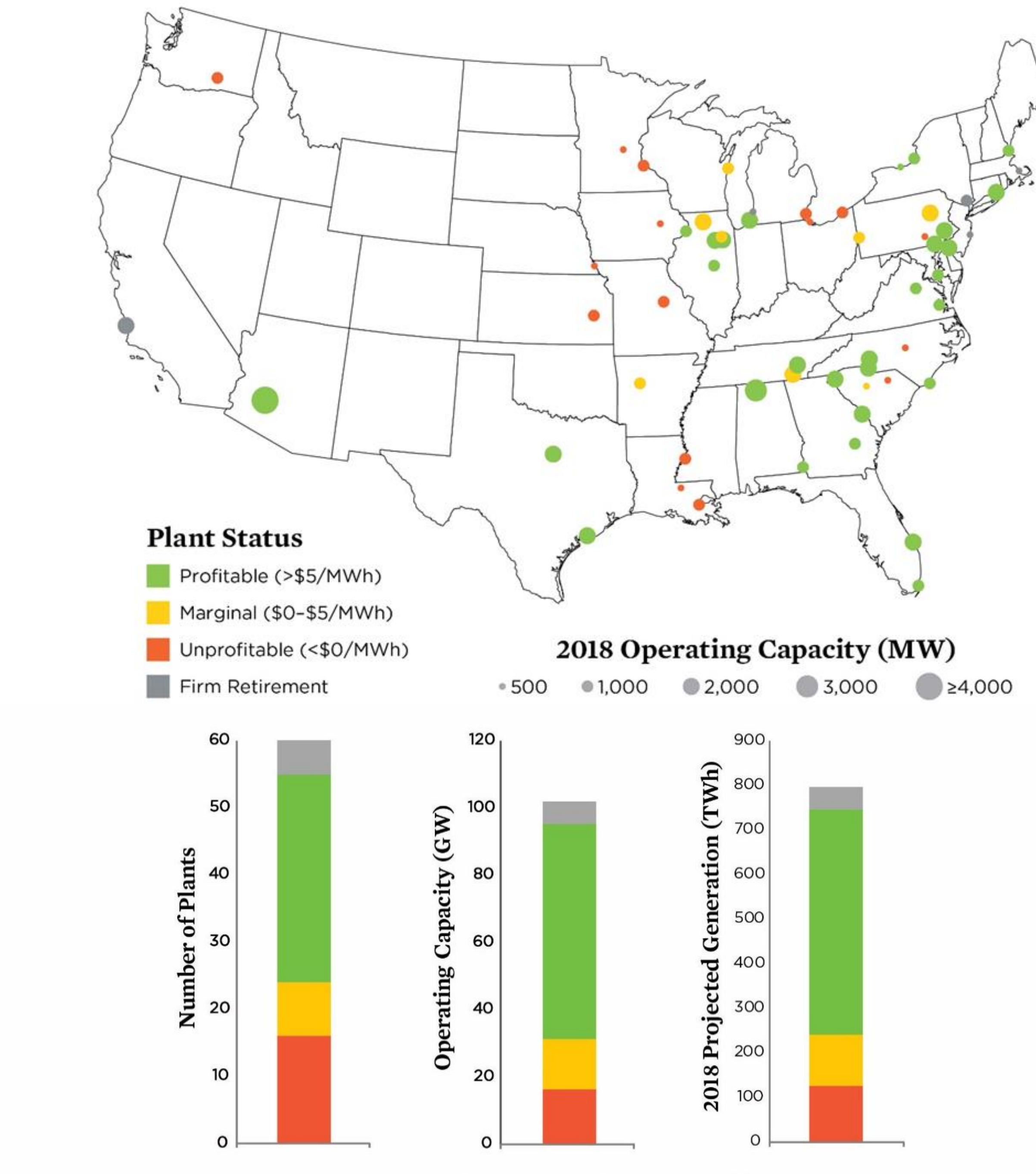
*2018 geneation is estimated.

Assessing the Profitability of the Existing Nuclear Fleet

More than one-third of US nuclear plants, representing 22 percent of the nation's nuclear capacity, are unprofitable or scheduled to close. UCS assessed the profitability of every nuclear power reactor in the United States regardless of regulatory status and aggregated the results to the plant level. We present the results for the plant-level average annual operating margins for five years, 2018 to 2022 (Table 4). Operating costs exceed revenues for 16 nuclear power plants in addition to the five scheduled for retirement. These 21 nuclear plants accounted for 22.7 gigawatts (GW) of operating capacity in 2018, or 22 percent of the total operating capacity. Figure 6 summarizes the results for all US nuclear power plants.

Table 5 lists plants the analysis categorized as unprofitable, marginal, or firm retirements. Ten of the 21 plants are merchant plants (10.5 GW), including four (4.2 GW) that have announced they are closing and six (6.3 GW) that have a higher risk of closing in the future (Table 6). Eleven plants are regulated (12.3 GW), including one (2.2 GW) that is slated to close by 2025 and 10 that have a lower risk of closing because they receive cost recovery from ratepayers. Eight additional plants are marginally profitable (15 GW), including five merchant plants (9.8 GW) and three regulated plants (5.2 GW).

FIGURE 6. **US Nuclear Power Plants at Risk of Early Closure or Slated for Early Retirement**



More than one-third of existing plants, representing 22 percent of US nuclear capacity, are unprofitable or scheduled to close. The map illustrates the location of each US nuclear power plant, color coded to show the results for profitability in the reference case and sized by operating capacity.

TABLE 5. **Unprofitable and Marginal Plants, Plus Those with Firm Retirement Plans**

Plant Name	Reactors	State	2018 Operating Capacity (MW)	Status (2018 – 2022)
Rate-Regulated Plants				
Callaway	1	MO	1,236	Unprofitable
Cooper Nuclear Station	1	NE	772	Unprofitable
Fermi	1	MI	1,161	Unprofitable
H.B. Robinson	1	SC	797	Unprofitable
Monticello	1	MN	646	Unprofitable
Prairie Island	2	MN	1,092	Unprofitable
River Bend	1	LA	968	Unprofitable
Shearon Harris Nuclear Power Plant	1	NC	973	Unprofitable
Waterford 3	1	LA	1,177	Unprofitable
Wolf Creek	1	KS	1,205	Unprofitable
Arkansas Nuclear One	2	AR	1,854	Marginal
Sequoyah	2	TN	2,333	Marginal
V.C. Summer	1	SC	992	Marginal
Diablo Canyon	2	CA	2,240	Firm Retirement
Merchant Plants				
Columbia Generating (WNP-2)	1	WA	1,210	Unprofitable
Davis-Besse	1	OH	908	Unprofitable
Duane Arnold Energy Center (DAEC)**	1	IA	622	Unprofitable
Grand Gulf	1	MS	1,428	Unprofitable
Perry	1	OH	1,268	Unprofitable
Three Mile Island	1	PA	827	Unprofitable
Beaver Valley	2	PA	1,867	Marginal
Byron Generating Station	2	IL	2,346	Marginal
Dresden	2	IL	1,805	Marginal
Point Beach	2	WI	1,206	Marginal
Susquehanna Nuclear	2	PA	2,593	Marginal
Indian Point	1	NY	2,071	Firm Retirement
Oyster Creek	1	NJ	635	Firm Retirement
Palisades	1	MI	820	Firm Retirement
Pilgrim Nuclear Power Station	1	MA	683	Firm Retirement

These plants are unprofitable or marginal in our reference case profitability assessment or have firm retirement dates. Plants are grouped based on whether they are owned by merchant generators or rate-regulated utilities.

Notes: We categorized plants owned by public power utilities as rate-regulated. Duane Arnold's owner announced the firm retirement of the plant after completion of this analysis.

The analysis sought to get a sense of what minimum level of financial support might be required for the 16 unprofitable plants. We calculated the amount each plant would need for projected revenues to equal projected costs, which would advance those plants to the marginal category. We found that these 16 plants would require a total of $814 million per year on average to break even, or more than $4 billion over the five years (Table 7). This translates to a cost of $7.7 per MWh, on average, to move the 16 unprofitable plants into marginal territory. If we assume that the unprofitable plants would be retired and replaced by existing natural gas combined-cycle plants, the level of financial support needed to prevent their closure would imply a cost of almost $19 per ton of avoided CO_2.

While the revenue gap is an important metric for understanding how much financial support might be needed, the annual generating costs of these plants is important for understanding of how much money could be available to invest in other alternatives if the unprofitable plants were closed. We estimated average annual generating costs of $5.4 billion between 2018 and 2022 for the 16 unprofitable plants.

Our analysis estimated the profitability of specific nuclear plants based on the best available data and cannot substitute for a careful financial review of each facility. Because most plant-level cost data are proprietary, and because factors not included in our analysis can affect profitability and retirement decisions, owners of distressed plants should be required to submit detailed economic data to regulators to demonstrate financial need.

More Challenging Economics at Single-Reactor Plants

Smaller nuclear plants tend to be unprofitable more often than do larger ones: 77 percent of operating capacity from single-reactor plants is either unprofitable or marginal, compared with 20 percent of capacity from multiple-reactor plants (Figure 7). This reflects the higher operating costs on a per-megawatt-hour basis for single-reactor plants; multiple-reactor plants can capture economies of scale (NEI 2017).

Most At-Risk Plants Are in the Midwest and Mid-Atlantic Regions

The regional results represent a mix of Regional Transmission Organizations (RTOs), Independent System Operators (ISOs), and regions outside of RTOs and ISOs that generally contain vertically integrated and rate-regulated utilities and public power (the Southeast and the West) (Figure 8). The Midcontinent

TABLE 6. **Summary of Total Unprofitable, Marginal, and Retiring Operating Capacity (MW), by Plant Type**

	Unprofitable Plants	Marginal Plants	Firm Retirements
Rate-Regulated	10,026	5,179	2,240
Merchant	6,263	9,817	4,209
Total	**16,289**	**14,996**	**6,449**

The operating capacity from rate-regulated and merchant plants that are scheduled to retire or identified as unprofitable or marginal in the profitability assessment totals more than 37,000 MW.

TABLE 7. **Cost Summary of Unprofitable Nuclear Reactors**

	Cost
Total Annual Revenue Gap, 2018-2022 (million $)	$814.1
Average Revenue Gap, 2018-2022 ($/MWh)	$7.7
Equivalent Estimated $/ton of CO_2 Avoided	$18.9

Sixteen unprofitable plants would require a total of $814 million per year, on average, to break even, or more than $4 billion over the five years.

Note: The equivalent dollars per ton of CO_2 avoided is based on an average existing natural gas combined-cycle plant.

Independent System Operator (MISO) has the largest amount of unprofitable nuclear capacity: 8.3 GW, 63 percent of its total. In part, this reflects relatively low wholesale power prices in the region; also, the region has many smaller, single-reactor plants. PJM has the largest amount of marginal capacity: 8.6 GW, or a quarter of its total capacity. MISO and PJM each have more than 11 GW of unprofitable or marginal capacity.

Plants in 17 States are Unprofitable or Scheduled to Close

UCS analyzed the impact of recently enacted state subsidies for selected nuclear plants in Illinois, New Jersey, and New York through 2030 (Figures 9 and 10). Financial support from Illinois pushed the Quad Cities plant up from marginal and Clinton up from unprofitable. However, more than one-third of Illinois nuclear capacity remains marginal, according to the analysis. Excepting firm retirements (Indian Point and Oyster Creek), nuclear plants in New York and New Jersey are all profitable, implying that the policies in those states boost the economics of the remaining plants. Indeed, our analysis suggests that the Nine Mile Point and Salem plants were already profitable in the 2018 to 2022 timeframe without financial support in those states. It also suggests that the support for many of these plants may have been higher than what was actually needed to keep them operating.[7]

The unprofitable and marginal categories in several states reflect state-level discussions surrounding possible policy support for at-risk nuclear plants. For Pennsylvania, with the second-highest installed nuclear capacity, the analysis found Three Mile Island to be unprofitable. Exelon, the plant's owner, has threatened to close the plant in 2019 unless it receives financial support. We also found Susquehanna and Beaver Valley to be marginal. Ohio's two nuclear plants, Davis-Besse and Perry, show up as unprofitable; both are merchant generators. FirstEnergy, the owner of these Ohio plants and Beaver Valley in Pennsylvania, has threatened to shut down all three by 2021 unless they receive financial assistance. Minnesota's nuclear plants, Monticello and Prairie Island, are unprofitable compared with cheaper alternatives available in the market. Both are rate-regulated facilities, and Xcel Energy has approached the legislature seeking up-front approval for $1.4 billion in additional funds for repairs and maintenance over the next 17 years (Hughlett 2018).

Most Owners Have Plants That are Unprofitable or Scheduled to Close

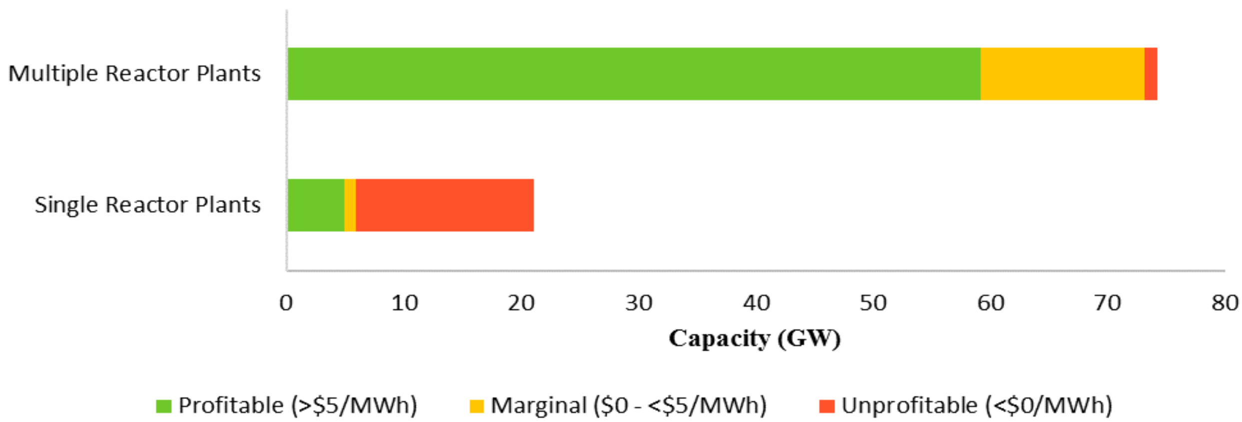
Exelon, FirstEnergy, Public Service Enterprise Group, and Xcel Energy have all advocated for state-level financial support for struggling nuclear plants. The profitability analysis for the 20 companies owning the greatest nuclear operating capacity in 2018 suggests why (Figure 11). With just over 20 GW, Exelon owns the greatest nuclear capacity by far, and about one-quarter of that capacity is unprofitable or marginal. With the expected closure of Indian Point, Palisades, and Pilgrim, Entergy is shutting down 40 percent of its nuclear capacity; the remainder is unprofitable (almost 40 percent) or marginal (about 20 percent). More than half of FirstEnergy's nuclear capacity is unprofitable, with our analysis categorizing the remainder as marginal. A few companies that own only one or two nuclear plants have no nuclear assets that appear profitable.

Natural Gas Prices, Nuclear Costs, and CO_2 Prices: The Major Factors for Profitability

To test the sensitivity of our results, we evaluated the profitability of the nuclear fleet under a variety of assumptions, including the price of natural gas, nuclear costs, assumed carbon prices, and assumed capacity revenues (Figure 12). These tests enabled us to compare our results with other studies that have used different assumptions (Box 3). (*See the Appendix E for further detail.*)

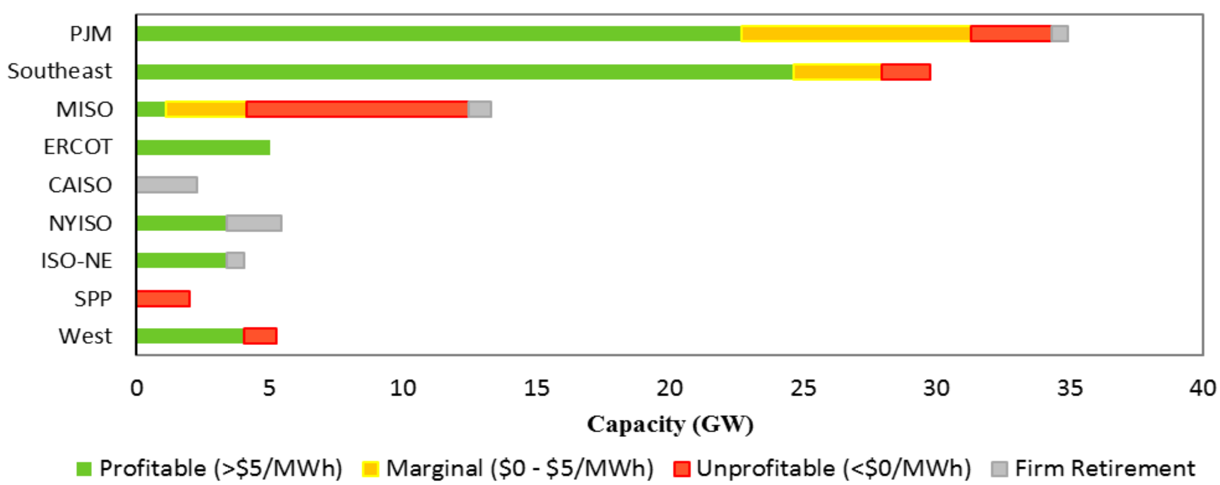
The reference case shows 16.3 GW of unprofitable nuclear capacity (16 percent of the total operating nuclear capacity). The amount of unprofitable capacity ranges from 7.0 GW in the higher-price natural gas case (which reflects the EIA's AEO 2018 reference

FIGURE 7. **Higher-Risk of Early Retirement at Single-Reactor Plants**



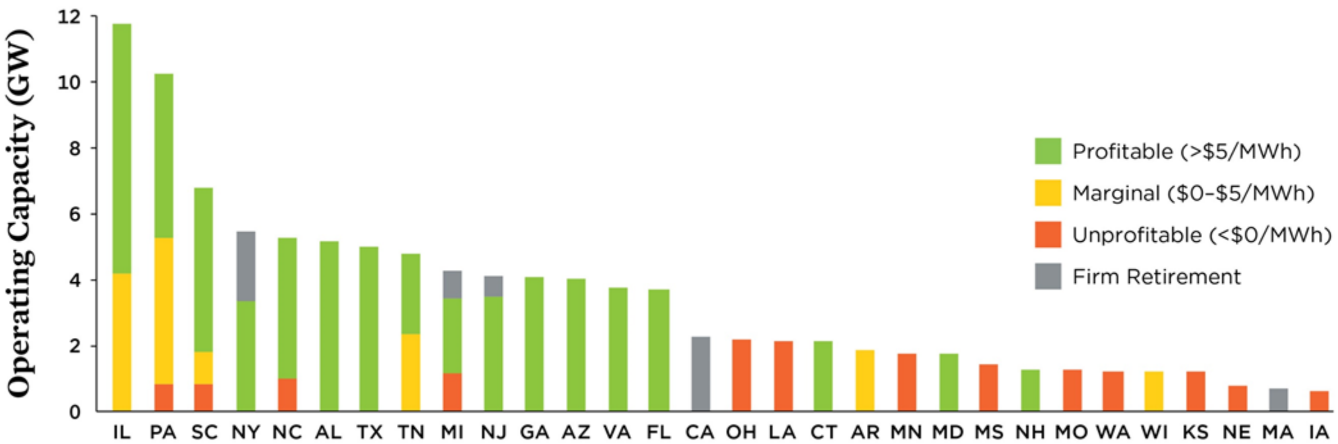
Most single-reactor plants in the United States are unprofitable. Prairie Island in Minnesota is the only multiple-reactor plant projected to have a negative average annual operating margin from 2018 to 2022.

FIGURE 8. **Nuclear Capacity at Risk of Early Closure, by Region**



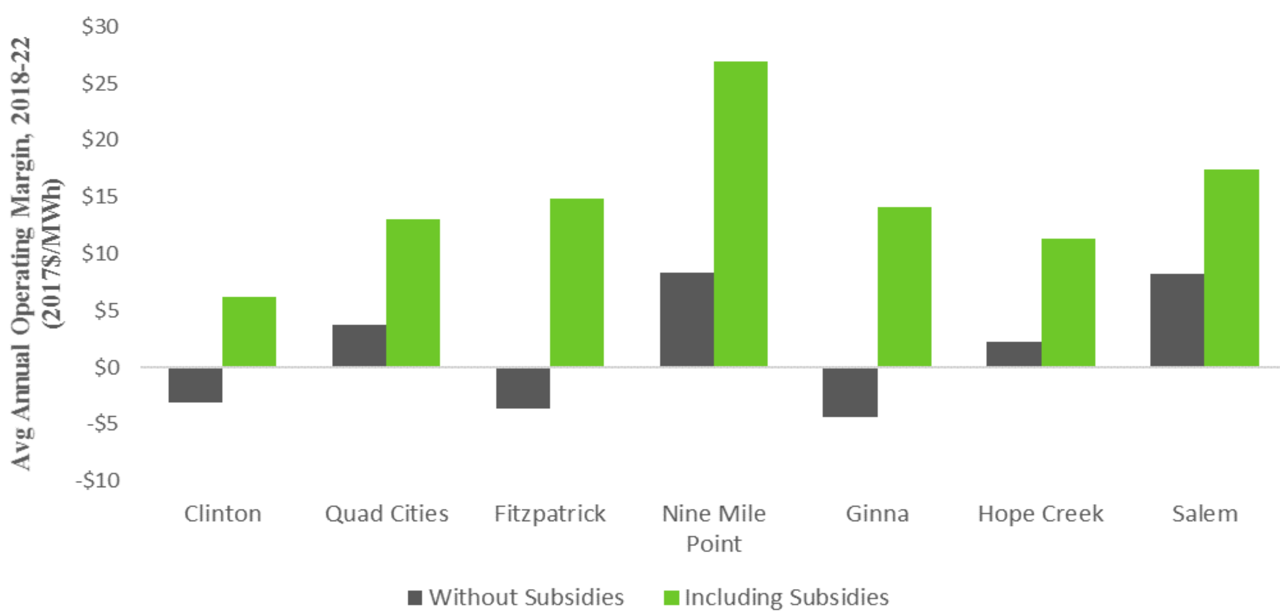
MISO has the largest amount of unprofitable nuclear capacity: 8.3 GW, 63 percent of its total. PJM has the largest amount of marginal capacity: 8.6 GW, or a quarter of its total capacity. MISO and PJM each has more than 11 GW of unprofitable or marginal capacity.

FIGURE 9. **Nuclear Capacity at Risk of Early Closure or Slated for Early Retirement, by State**



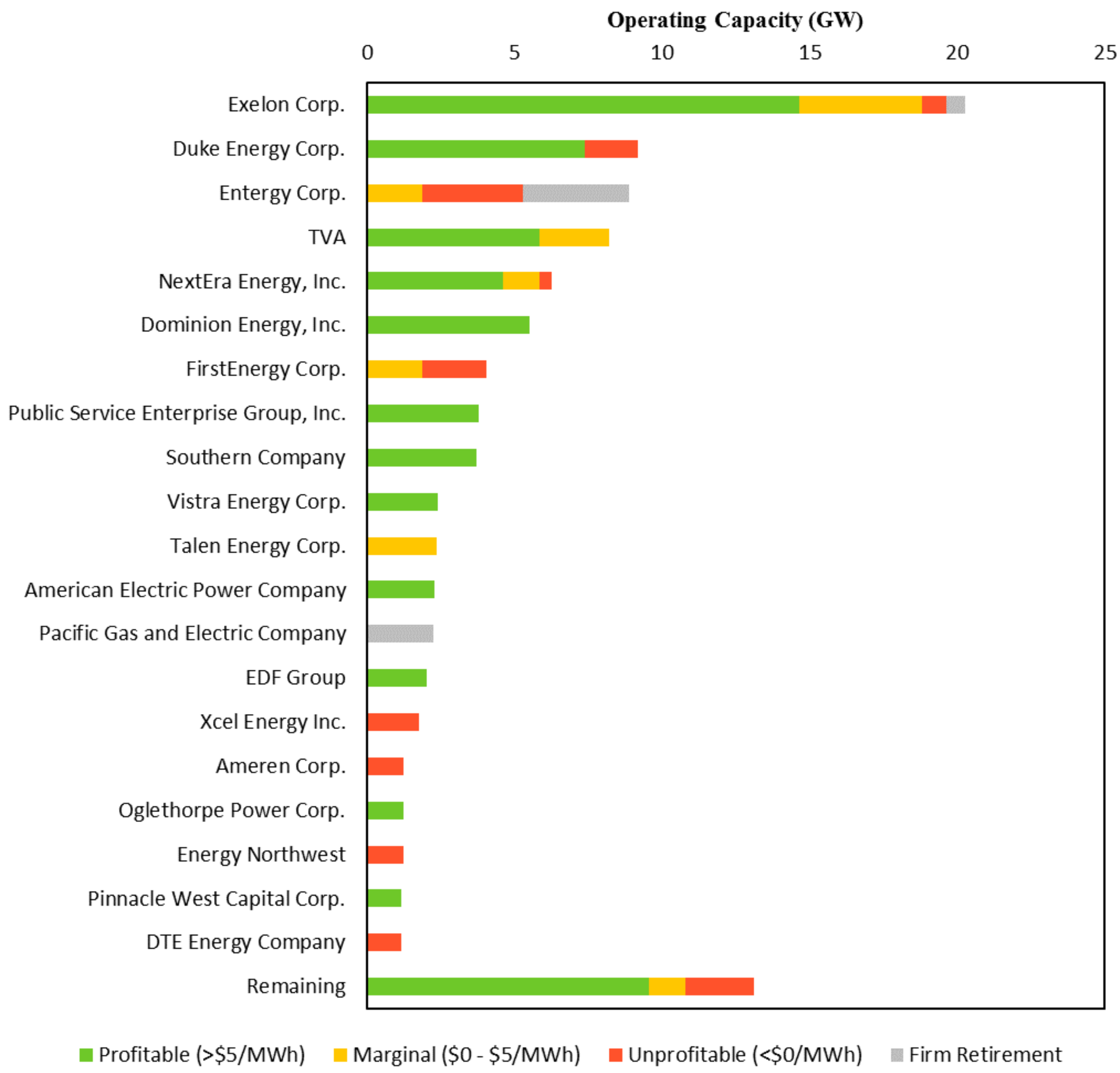
Of the 30 states with nuclear power plants, 17 states have nuclear capacity that is unprofitable or scheduled to close.

FIGURE 10. **Nuclear Plants Receiving State Financial Support**



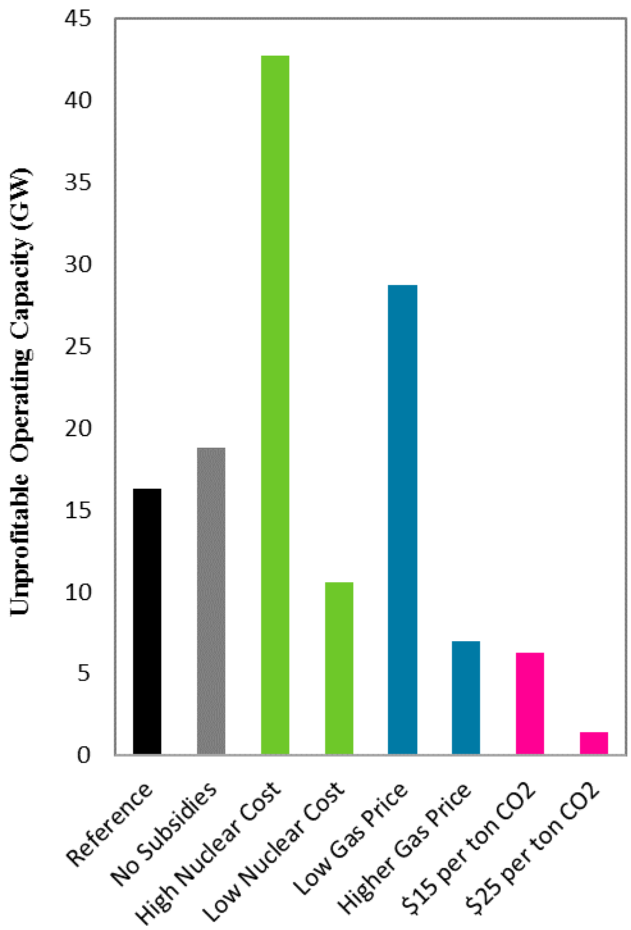
Of the seven nuclear plants receiving state-level financial support, at least two—Nine Mile Point and Ginna—were profitable even before receiving the support. Two others—Quad Cities and Hope Creek—were marginal.

FIGURE 11. Nuclear Capacity at Risk of Early Closure, Top 20 Owners of Nuclear Assets



Entergy and FirstEnergy have the most unprofitable capacity. Exelon, TVA, and Talen have the most marginal capacity. Entergy and Pacific Gas and Electric have the most capacity scheduled to close.

FIGURE 12. **Unprofitable Nuclear Operating Capacity, Selected Scenarios**



Projections of profitability change under different assumptions. For example, 16.3 GW of operating capacity is unprofitable in the reference case, rising to 18.8 GW without the inclusion of existing state subsidies. Assumed nuclear costs (orange bars) have a strong impact on the results, ranging from 10.6 GW of unprofitable capacity in the low-cost case to 42.7 GW in the high-cost case.

case) to 28.7 GW in the lower-price natural gas case (which reflects S&P's near-term projection for natural gas prices). The amount of unprofitable capacity declines to 10.6 GW in the low nuclear costs case, which assumes the industry meets the NEI's goal of a 30 percent reduction in costs beginning in 2018 (NEI 2016). The figure rises to 42.7 GW in the high nuclear costs case, which uses EIA assumptions for additional capital expenditures due to aging.

Our analysis suggests that a modest carbon price would make most at-risk nuclear power plants profitable. In the $15 per ton CO_2 case, only 6.3 GW of capacity is unprofitable (82 percent of capacity is profitable). In the $25 per ton CO_2 case, which we modeled as a national policy case, 88 percent of the fleet is profitable. While Monticello in Minnesota and Cooper in Nebraska would continue operating in the red through 2022 under this case, revenues would exceed costs starting in 2023 and gradually increase over time as carbon prices increase. For those two cases, the carbon price becomes effective in 2020, while we calculated the profitability over the period 2018 to 2022.

All existing plants become profitable when assuming a higher carbon price based on the social cost of carbon (Interagency Working Group 2016, NAS 2017). Illinois and New York used that cost to determine the levels of financial support for at-risk plants.

The Impacts of Early Reactor Retirements and Policies to Reduce CO_2 Emissions

With no new policies and continued low natural gas prices, the UCS analysis suggests that retiring uneconomic nuclear reactors before their operating licenses expire would result in a net increase in natural gas and coal generation and higher carbon emissions. However, the US power sector is in the midst of a major transition. Electric utilities are shifting from coal toward cleaner energy sources as advances in technology, decreases in costs, and strong state and regional policies drive investments in renewable energy and energy efficiency. Coal-fired power is declining as aging, inefficient, and polluting power plants struggle to remain competitive. With the sharp fall in natural gas prices, many power providers are also investing in natural gas to replace coal-generated electricity. However, the nation would also need to replace lost generation from nuclear plants that close early.

BOX 3.

Comparing the UCS Analysis with Other Studies

A number of recent reports have evaluated the economics of nuclear power, largely concluding that market dynamics—specifically low prices for natural gas—are putting pressure on the long-term economic viability of nuclear power plants. These studies have reported a range of figures for unprofitable nuclear capacity. Our reference case results—21 plants that are unprofitable or scheduled to retire, representing 22.7 GW of operating capacity in 2018—fall on the low end of this range. However, our low natural gas price and high nuclear cost sensitivities show results (summarized in Appendix E) more in line with studies that have estimated higher levels of unprofitable nuclear capacity. For example:

- In a 2018 study, 24 plants representing 32.5 GW of generating capacity were either scheduled to close or losing money through 2021; $1.3 billion per year would be needed to fill the revenue gap for these plants (Loh 2018).
- A 2016 Rhodium Group study estimated that 24 GW could close through 2030 (Larsen and Herndon 2016).
- A 2017 Idaho National Lab study found two-thirds of nuclear power plants to be unprofitable (Szilard et al. 2017). However, that analysis focused on 2016, a year of historically low natural gas prices.
- A 2017 MIT report found that about two-thirds of US nuclear reactors would be unprofitable between 2017 and 2019, assuming low natural gas prices (Haratyk 2017).
- In a Brattle Group study, 41.2 GW to 73.7 GW of nuclear capacity faced a revenue shortfall in 2017 (Celebi et al. 2018).
- The EIA's 2018 Nuclear Power Outlook projected nuclear capacity in 2030 to fall by 12.4 GW in the reference case and 26 GW in the low natural gas price case (EIA 2018a). With an assumed 20 percent increase in nuclear costs, nuclear capacity falls by 27 GW in the reference case and 46 GW in the low gas price case.

CHANGES IN US ELECTRICITY GENERATION

Under our early retirement case 1, which assumes the early closures of the nine at-risk merchant plants representing 13.7 GW of capacity, a mix of coal and natural gas generation replaces most of the loss in nuclear generation in the early years, with natural gas gradually playing a large role (Figure 13). Most of the increase in natural gas and coal generation results from increased dispatch of existing plants in the states where the retired plants are located. The increase in natural gas and coal generation is nearly twice as high in early retirement cases 2 and 3 to replace the loss of more than 26 GW of nuclear capacity.

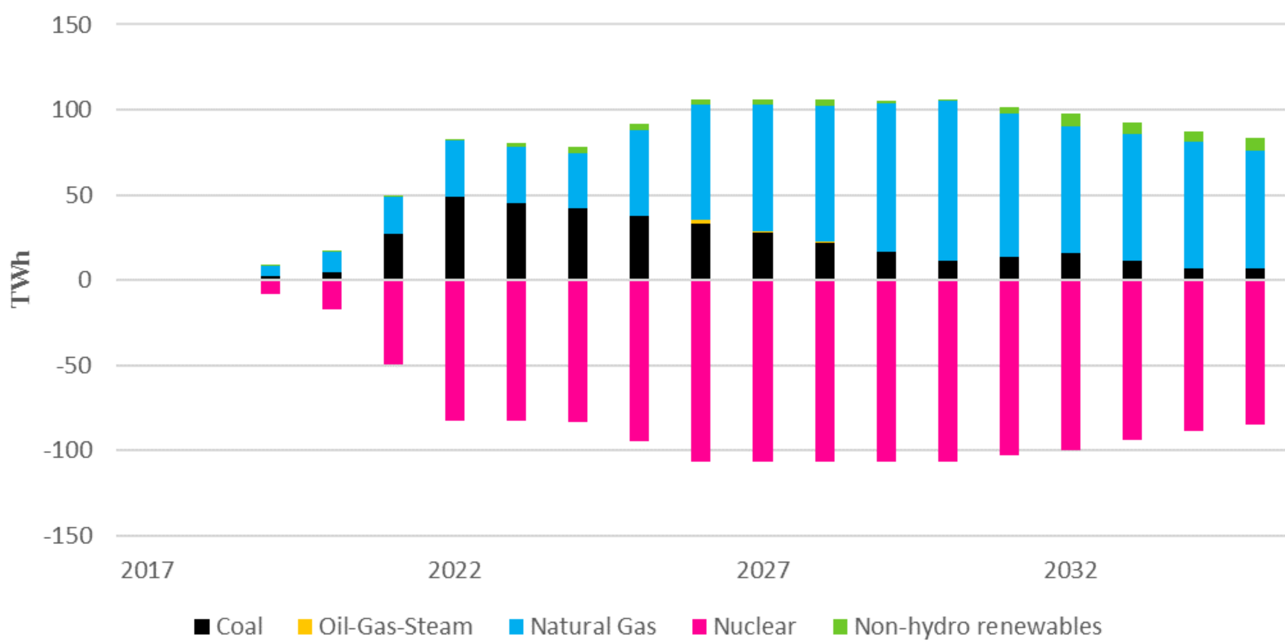
Renewable energy capacity is built in the ReEDS reference case and all of the early retirement cases to satisfy existing state renewable policies and take advantage of federal tax credits for renewables (Figure 14). However, it plays a relatively small role in replacing the generation from uneconomic nuclear plants in the early retirement cases after tax credits expire in the early 2020s.

In contrast, national policies that put a price on carbon or value the low-carbon attributes of existing nuclear plants, renewable energy sources, and fossil fuels with carbon capture and storage would diversify our nation's electricity mix and help keep the United States on a path to decarbonizing the electric sector by 2050. By accounting for the cost of CO_2 emissions, such policies would also help prevent the retirement of existing nuclear plants. Our analysis suggests that a modest carbon price pushes most at-risk nuclear power plants into profitable.

Under the carbon price case, nuclear power would stay at reference case levels while non-hydro renewable energy sources would more than triple from

10 percent of total US power generation in 2017 to 36 percent by 2035; energy efficiency would reduce US generation increases to 41 percent in 2035; energy efficiency reduces generation by nearly 9 percent by

FIGURE 13. **Change in U.S. Electricity Generation, Early Retirement Case 1 vs. Reference Case**



Compared with a reference case that includes five nuclear plants slated to retire by 2025, early retirement case 1 assumes additional closures of nine at-risk merchant plants representing 13.7 GW of capacity. Initially, a mix of coal and natural gas generation replaces most of the lost nuclear generation in early retirement case 1, with natural gas increasing over time. Most of the increase in natural gas and coal generation results from increased dispatch of existing plants in the states where the retired plants are located. The increase in natural gas and coal generation is nearly twice as high in early retirement cases 2 and 3.

generation nearly 9 percent by 2035 (Figure 14). In contrast, natural gas generation is 31 percent lower than in the early retirement case 1 by 2035 and coal generation is phased out, resulting in a 37 percent reduction in power-sector CO2 emissions in 2035 compared with the early retirement case 1 (Figure 15).

A low-carbon electricity standard is another example of a carbon-reduction policy that could help limit the early closure of existing nuclear plants. Under the LCES case, the share of US low-carbon generation increases from 45 percent in 2020 to 60 percent in 2030 and 80 percent by 2050. Like the carbon price case, valuing zero-carbon nuclear generation under an LCES keeps most nuclear plants profitable. Under this LCES scenario, nuclear power maintains its current market share while non-hydro renewable energy 2035. Natural gas generation is 44 percent lower in 2035 compared with the early retirement case 1 while coal generation is almost completely phased out. Keeping natural gas power generation in check is critical for limiting the serious consumer, health, and climate risks associated with it as the nation continues to transition away from coal (Deyette et al. 2015).

POWER PLANT CO_2 EMISSIONS

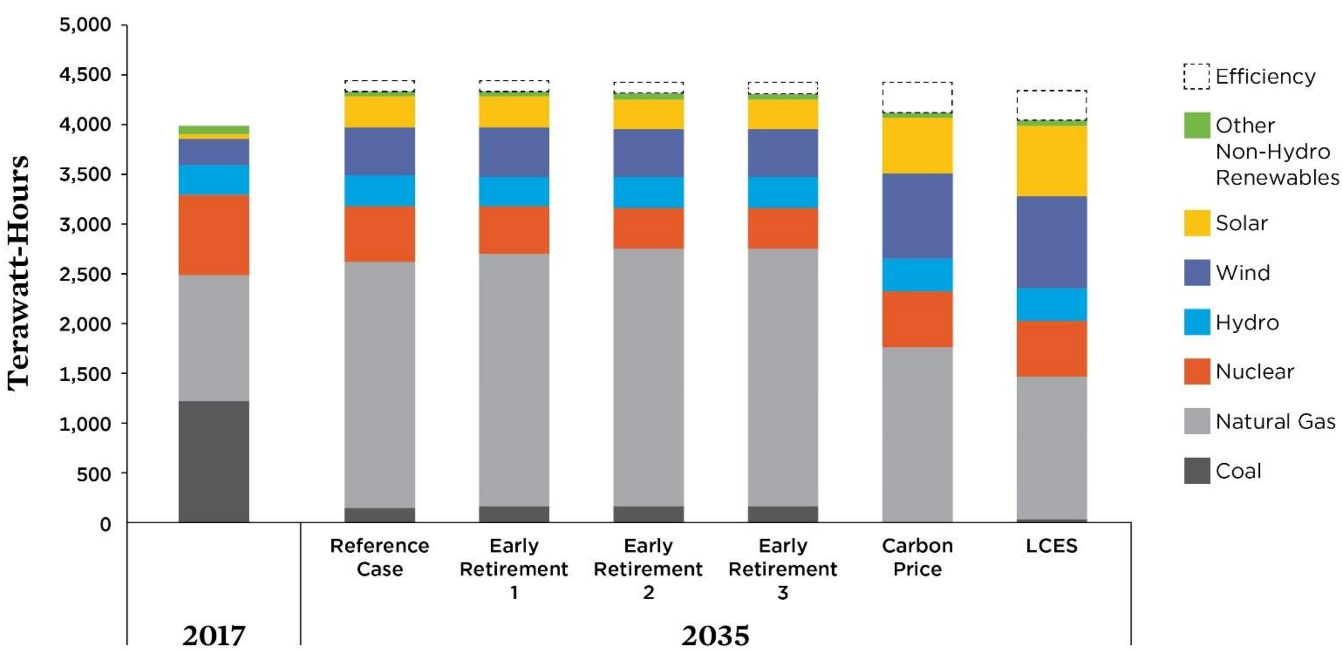
Preserving existing nuclear generation and increasing renewable energy development in both the carbon price and LCES policy cases help to reduce CO_2 emissions earlier, so that the cumulative reductions from 2016 to 2035 are much greater than without these policies. The net increase in fossil generation under the early retirement cases results in a cumulative increase in power sector emissions of CO_2 of 4 to 6 percent (equivalent to 0.7 billion to 1.25 billion metric tons) over the reference case by 2035 (Figure 15). The gap in emissions between the reference case and early retirements cases declines by 2035 due to our assumption that all US reactors would be retired after their 60-year operating licenses expire, which occurs for most reactors between 2030 and 2050. The carbon-reduction policies curb CO_2 emissions by an additional 19 to 28 percent cumulatively (equivalent to 4 billion to 5.7 billion metric tons) through 2035 compared with the early retirement case 1.

A National Research Council study found that power sector emissions would need to fall by more than 90 percent below 2005 levels by 2040 for the nation to meet its climate goals (National Research Council 2010). Achieving that would require a cumulative reduction in power sector CO_2 emissions of 33 percent by 2035 (6.6 billion metric tons) compared with the early retirement case 1. While the carbon price and LCES cases would take the US power sector most of the way toward meeting the targets, the early retirement cases would take us in the wrong direction.

The model takes advantage of federal tax credits for renewables in the carbon price case, with heavy investments in renewable energy in the early years resulting in a large emissions reduction by 2020. Emissions in this case continue to decline slowly over the next decade and increase slightly by 2035 as more nuclear capacity retires as reactor licenses expire.

The main reason why the carbon price case results in greater emission reductions than the LCES case in the early years of the forecast is the ramp-up rates and relative stringency of the policies over time. For example, the carbon price case has a starting point at $25 per ton in 2020, ramping up at 5 percent per year. The LCES targets start out at projected reference case levels of low-carbon generation in 2020 (45 percent), increasing more gradually at 1.5 percent per year through 2030 and 1 percent per year through 2050. Thus, modeling a carbon price with a lower starting point or an LCES with higher targets and faster ramp-up rates could show similar results over time from these policies.

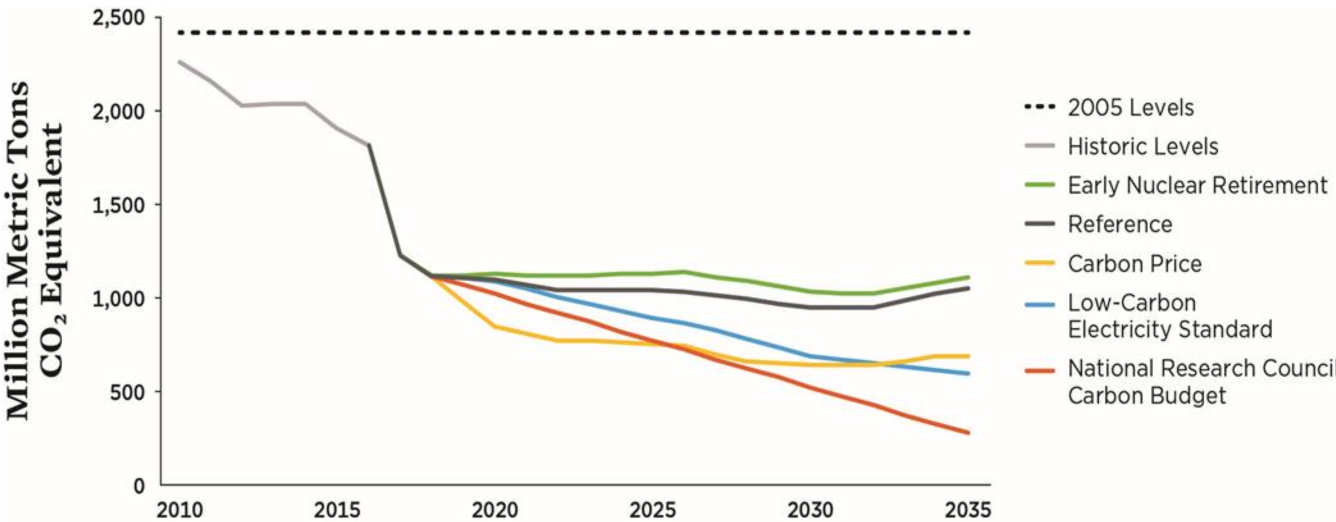
FIGURE 14. **The US Electricity Generation Mix, 2017 and 2035**



Carbon-reduction policies would diversify the US electricity mix by maintaining existing nuclear generation, increasing investments in energy efficiency and renewable energy, and preventing an overreliance on natural gas.

Note: Early retirement case 1 only includes 9 merchant plants (13.7 GW). Early retirement case 2 includes a mix of 21 merchant and regulated plants (26.3 GW) under our reference case assumptions. Early retirement case 3 assumes lower natural gas prices and only includes 15 merchant plants (26.3 GW).

FIGURE 15. **US Power Plant CO_2 Emissions**



Under a reference case with low natural gas prices and no new policies, closing at-risk nuclear plants before their operating licenses expire could result in a cumulative increase in US power-sector CO_2 emissions of up to 6 percent by 2035 from burning more natural gas and coal. The carbon-policy cases reduce CO_2 emissions by 19 to 28 percent cumulatively by 2035. A National Research Council study found that to meet US climate goals, power-sector emissions would need to fall to more than 90 percent below 2005 levels by 2040.

ECONOMIC AND HEALTH BENEFITS EXCEED THE COSTS

The emissions reductions and increases in clean energy spurred by carbon-reduction policies are affordable. Those outcomes of public policies, including investments in renewable energy and energy efficiency, lead to small bill increases over the early retirement cases. In the analyses, average monthly electricity bills for a typical household are only 1.0 to 1.4 percent higher in 2035, amounting to a monthly increase of $0.74 to $1.03.

UCS also examined several broader financial impacts of carbon-reduction policies on the nation's electricity system, including net effects on electricity bills for all customer classes, investments by participants in energy efficiency programs, and net costs for power generators and distributors. For 2035, the analysis suggests a small increase of $5.3 billion to $7 billion or 1.2 to 1.6 percent of total electricity system costs (not including the carbon revenue from the carbon price case) compared with the early retirement case 1. Cumulatively from 2016 through 2035, the policy cases lead to an increase of $71 billion to $211 billion or 2 to 5 percent in total cumulative electricity system costs (not including carbon revenue).

From 2020, when the carbon price begins, to 2035, the average annual carbon revenue under the carbon price case is $28 billion. Cumulatively, carbon revenues reach $218 billion by 2035. This revenue could be used in many ways. For example, it could offset the slightly higher electricity bills for consumers. It also could be used in deploying additional renewable energy or provided to communities to promote environmental justice and equity. It could be invested in energy efficiency, power-grid infrastructure improvements, making buildings and infrastructure more climate-resilient, and

TABLE 8. **Public Health and Climate Economic Benefits, Carbon Price and LCES Cases, 2018–2035**

	Difference in Cumulative Benefits (billion 2017$)	
	Carbon Price	LCES
Early Retirement Case 1	$227	$132
Early Retirement Case 2	$250	$154
Early Retirement Case 3	$245	$150

The UCS carbon-policy cases show billions of dollars of public health and economic benefits from reducing CO_2, NO_x, and SO_2 emissions compared with the early retirement scenarios, exceeding the costs of implementing the policies.

improving worker training and other transition support for communities adversely affected by the nation's shift away from coal (Deyette et al. 2016).

UCS also estimated the monetary savings resulting from reducing emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x). We used the same methodology applied by the Environmental Protection Agency in its impact assessment for the Clean Power Plan. Under the two policy cases, NO_x emissions are 41 to 42 percent lower in 2035 than the early retirement case 1, while SO_2 emissions are 61 to 68 percent lower, primarily through the reduction in coal generation from older and inefficient plants.

Reducing NO_x, SO_2, and CO_2 emissions would lead to tangible health and economic benefits. NO_x and SO_2 contribute to smog and soot, which exacerbate asthma and other heart and lung diseases and can result in significant disability and premature death (EPA n.d.). CO_2 emissions contribute to global warming and other climate impacts that can impair human health and safety. Under the policy cases, the climate and public health benefits average $22 billion each year, adding up to a total of $132 billion to $250 billion in benefits cumulatively from 2018 through 2035 (Table 8). These benefits exceed the costs of implementing the policies, resulting in $61 billion to $257 billion in cumulative net benefits by 2035.[8]

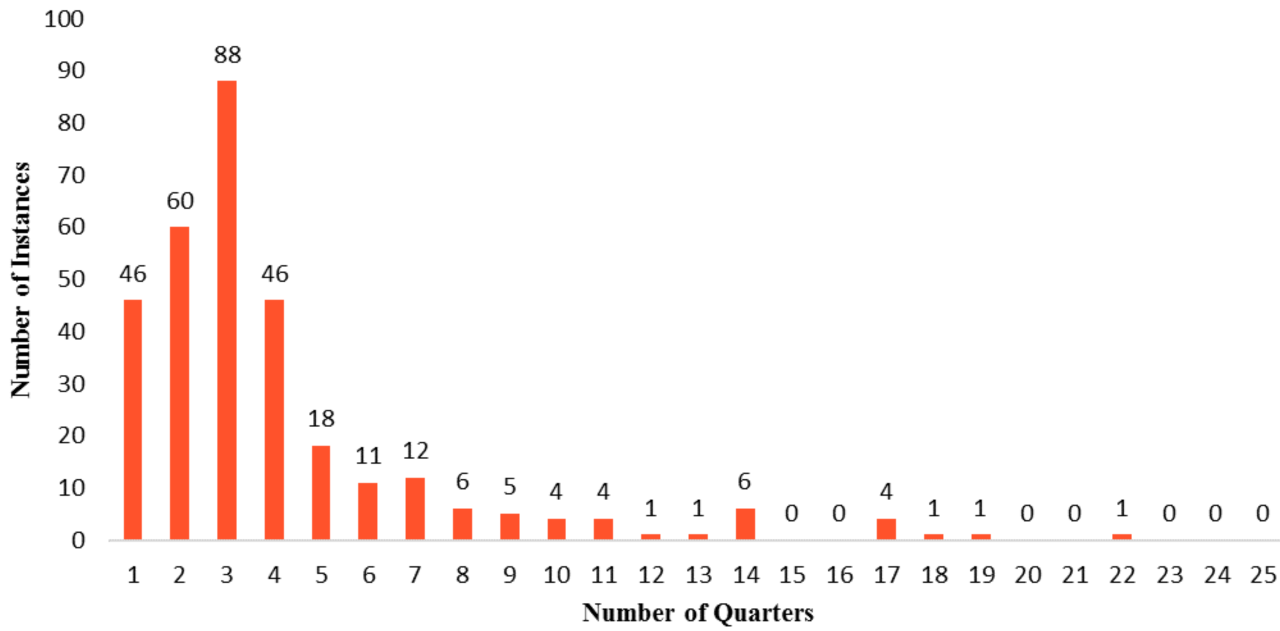
Reactor Safety Performance Evaluation

UCS analyzed the safety performance of nuclear plants to differentiate between strong safety performers and underperformers. To restore safety levels, 52 US nuclear reactors have had to shut down for longer than a year (UCS 2015). The intended benefit of continued low-carbon emissions sought by financial support to a nuclear plant would be lost if safety problems forced a lengthy shut down or contributed to a serious accident.

The nuclear reactors operating today met or exceeded the NRC's safety and performance standards in 5,532 of the 6,870 quarterly ratings (80.5 percent) issued by the NRC between 2000 and 2018—that is, they were rated in the NRC's Action Matrix Column 1.[9] The NRC issued ratings reflecting minor problems 14.6 percent of the time (Column 2). The agency issued ratings reflecting the need for additional inspections and NRC oversight of owner performance self-assessments 2.9 percent of the time (Column 3). It issued a demand for information and confirmation of remedial action 1.8 percent of the time (Column 4) and ratings requiring a shutdown 0.2 percent of the time (Column 5).

When a reactor's performance dropped it out of Column 1, the operators took an average of four quarters (one year) to remedy shortcomings and return the reactor to Column 1 (Figure 16). The longest it has taken is 22 quarters. Indeed, reactors returned to Column 1 within four quarters 76.2 percent of the time. A nuclear industry consultant reported that it cost plant owners $1 million to $2 million to correct the performance shortcomings needed to return to Column 1 from Column 2, $10 million to $20 million to return to Column 1 from Column 3, and $100 million to $300 million to return to Column 1 from Column 4 (Conger 2009).

FIGURE 16. **Time Needed for Reactors to Return to Meeting or Exceeding NRC Safety and Performance Standards, 2000–2018**



When a reactor's performance level dropped it out of Column 1, the operators took an average of four quarters to remedy performance shortcomings and the NRC to return the reactor to Column 1.

[CHAPTER 5]

Recommendations and Conclusions

The UCS analysis shows that, without new policies, up to 26 percent of total US nuclear capacity could close in the next decade. Early closure of the at-risk plants could increase US power-plant carbon emissions by up to 6 percent by 2035 as a result of burning more natural gas and coal. New public policies are needed to properly value low-carbon energy and prevent the replacement of nuclear plants with large quantities of natural gas. Failure to put such policies in place will set back state and national efforts to achieve needed emissions reductions.

In today's market, the prices of fossil fuels are artificially low in most regions because they do not reflect the cost to society of harmful carbon emissions. Strong climate and clean-energy policies will address this market failure and ensure that low-carbon energy sources replace nuclear plants when they eventually retire. Until such policies are in place or natural gas prices rise significantly, owners of economically at-risk nuclear reactors will continue asking policymakers for financial assistance. Who pays for that assistance will differ depending on the policy and whether the federal government or individual states implement it.

No financial assistance to existing nuclear power plants should come at the expense of incentives for energy efficiency, grid modernization, or renewable resources such as wind and solar. Financial support for unprofitable nuclear plants should go only to distressed plants and only while such support is the lowest-cost way of achieving carbon-reduction goals. Assistance programs should require periodic assessments of the need and cost effectiveness of continued support. Support should not extend for more than a few years unless justified in part by processes demonstrating that the same funds could not procure more low- or zero-carbon electricity in ways other than by supporting unprofitable reactors. Further, policymakers should couple support with strong clean energy policies and strong safety and performance requirements. Finally, any financial or policy support for existing nuclear plants should be part of a broader strategy to reduce carbon emissions.

Adopt State and Federal Policies That Support All Low-Carbon Technologies

CARBON PRICING

A robust, economy-wide cap or price on carbon would be an effective, market-based approach to addressing a key market failure and leveling the playing field for all low-carbon technologies. It would send a clear market signal rewarding cuts in heat-trapping CO_2 emissions and driving innovation and private investments in low-carbon technologies, including existing nuclear generation. It should include such critical features as a mechanism for setting and adjusting emissions-reduction targets to match the latest science, incentives to support investments in energy efficiency and advanced low-carbon technologies, and consumer protections that maintain the policy's overall effectiveness (for example, energy rebates for low-income families). A national carbon cap or price could achieve the greatest amount of carbon reductions for the lowest cost. However, states can also adopt climate policies like the Regional Greenhouse Gas Initiative, which caps CO_2 emissions from power plants in nine Northeastern states, and California's cap-and-trade program, which is a key component of the state's broader strategy to reduce total heat-trapping emissions 40 percent below 1990 levels by 2030. State public utility commissions should also require utilities to include an increasing price on carbon in their resource plans to reflect the risk of future regulation of CO_2 emissions at the federal and state levels (Luckow et al. 2016).

LOW-CARBON ELECTRICITY STANDARD

A well-designed LCES could help prevent the early closure of existing nuclear plants while allowing renewable energy technologies, new nuclear plants, and fossil fuel plants with carbon capture and storage to compete for a growing share of low-carbon generation. Existing nuclear plants should be included in a separate tier with other existing low-carbon energy sources, such as large hydropower facilities, to avoid market issues due to limited competition between a relatively small number of large plants and owners. The other tier would be reserved for developing new low-carbon generation to encourage competition across many technologies, projects, and companies to deliver the most low-carbon electricity at the lowest cost, with an ongoing incentive to drive down costs. Technologies included in the new tier would be eligible to compete in the existing tier to help ensure that the most cost-effective low-carbon energy sources replace any retiring nuclear plants. An LCES could be combined with a zero-energy credit program, as New York State has done, with financial support provided only to existing nuclear plants that need it to continue operating and adjusted to account for changing market conditions. Complementary policies that encourage investments in energy efficiency should be adopted along with an LCES.

Condition Financial Support on Consumer Protection, Safety Requirements, and Investments in Renewables and Efficiency

Where policymakers are considering temporary financial support aimed exclusively at mitigating the early closing of nuclear plants to prevent carbon emissions from rising, that support must be contingent on meeting the following conditions.

Require companies to open their financial books and demonstrate need. All plant owners requesting financial support should be required to open their books to state regulators and the public to provide for effective regulation while minimizing the cost to ratepayers. In Illinois, New Jersey, and New York, the owners notified the NRC and regional grid operators that they would be closing financially distressed plants by a certain date, and they opened their books to state regulators to help determine the level of public support. Connecticut hired a consultant to conduct an economic analysis of the Millstone plant because the owner refused to make a disclosure. The study found that the plant was profitable under a range of conditions and did not need subsidies (Levitan & Associates 2018), which is consistent with our analysis and other studies (Loh 2018; Haratyk 2017). Profitable nuclear plants should not receive financial assistance, which would give owners a windfall profit while overcharging consumers.

Limit and adjust financial support for unprofitable nuclear plants. To protect consumers and avoid windfall profits, financial support for distressed plants should be temporary and adjusted to account for changes in market and policy conditions, with periodic assessments of the need for and cost effectiveness of continued support. The laws in New York and Illinois provide financial support for 10 to 12 years, adjusted every few years to account for changes in wholesale electricity prices and carbon prices. However, some have argued that the costs are too high and the duration of the programs are too long (Pyper 2017). The New Jersey legislation, which balances the value of the low-carbon resource against concerns about consumer impact, sets the zero-energy credit at a fixed price of approximately $10 per MWh, substantially lower than in Illinois or New York. Illinois includes a cap on the overall level of financial support.

Before approving financial support for existing plants, policymakers should look at major equipment replacement or retrofit costs and any projected increases in operating costs due to aging, safety, and performance issues. To help them invest public money wisely, states should conduct or commission independent cost-benefit analyses that compare providing financial support for distressed nuclear plants with supporting other low-carbon alternatives. Policymakers should consider the magnitude and timing of carbon reduction for each option, the respective costs, and the extent to which each option will spur technology innovation.

Financial support for existing nuclear plants should be limited to the amount needed to preserve the carbon emissions benefits of distressed plants because most plants have already received significant subsidies, while also making large profits when natural gas and wholesale electricity prices were high. Nuclear and fossil fuels have received far more subsidies than renewables over the past 70 years (Goggin 2017b). Many of the subsidies for nuclear and fossil fuels are permanent, while subsidies for renewables are temporary and scheduled to phase out in the next few years. A 2011 UCS analysis found that subsidies for existing nuclear plants have cost taxpayers more than the market price of power they helped generate, and these plants continue to receive subsidies ranging from 1 to 6 cents per kilowatt-hour (Koplow 2011). Existing plants in several states also received large subsidies from consumers in the form of "transition assistance" when the electricity sector was restructured in the late 1990s and early 2000s.

Ensure that qualifying plants maintain strong safety performance. Due to unfavorable economics, owners have permanently closed many nuclear reactors with little to no advance notice years before the operating licenses would have expired. Frequently, the cost of fixing safety problems exacerbated the economic challenges. For nearly 20 years, the Nuclear Regulatory Commission has assessed the safety performance of all reactors every quarter. The UCS analysis shows that reactor performance has met all NRC safety requirements and standards more than 80 percent of the time. Plant owners that have not met these standards have addressed safety and performance issues within a year more than 75 percent of the time. To help ensure that financial support to existing nuclear power reactors reaps the intended benefits, policymakers should consider it only for reactors that meet the NRC's highest safety rating, indicating they meet all safety requirements and standards. This condition further protects against the use of financial support to correct safety problems caused by bad management.

For reactors that drop in safety performance, continued financial support should depend on a return to the NRC's highest performance rating within 18 months (the average time plus a 50 percent margin).

Strengthen renewable energy and efficiency standards. If policymakers provide financial assistance to existing nuclear plants, they should simultaneously strengthen renewable electricity standards and other policies that stimulate the growth of low-carbon renewable energy and promote energy efficiency. For example, when New Jersey and New York provided financial support for distressed nuclear plants, they also increased the states' renewable standards to 50 percent by 2030, making significant new commitments to develop offshore wind and energy storage, and strengthened energy efficiency standards requiring minimal annual savings of 2 to 3 percent. Similarly, while providing financial support for two distressed nuclear plants, Illinois strengthened its renewable standard of 25 percent by 2025 and increased its energy efficiency standard. California also has set a renewable standard of 60 percent by 2030 (and a goal of 100 percent zero-carbon electricity by 2045) and enacted strong energy efficiency policies that will enable the state to replace the generation from the Diablo Canyon nuclear plant over the next eight years while continuing to reduce natural gas use and carbon emissions. States with relatively weak renewable and efficiency standards, such as Pennsylvania and Ohio, should strengthen those standards as part of any legislation providing financial support to existing nuclear plants. Financial assistance to existing nuclear power plants should not dilute or otherwise come at the expense of incentives for energy efficiency, renewable energy, or grid modernization.

Develop worker and community transition plans. Nuclear power plants are an important source of local jobs and tax revenues. Plant owners can work with states and communities to develop worker and community transition plans to attract new businesses and help replace lost jobs and taxes. For example, recent California legislation includes a $350 million employee-retention fund and an $85 million community impact–mitigation fund for the closure of Diablo Canyon in 2025 (Maloney 2018a; Miller 2018). The bill includes a commitment that the closure will not increase heat-trapping emissions. Plant employees could transition to work decommissioning retired plants, which can take up to 60 years (Bryk and Morris 2017). Plant owners can also transfer employees to other facilities or positions within their companies, as Entergy is considering doing for up to 180 employees at its Palisades nuclear plant in Michigan (Parker 2016). Illinois provides $30 million for broader job-training programs. New York has a clean energy job-training program (NYSERDA 2018a) and a statute to provide temporary, transitional, tax-base relief to communities that face the retirement of power plants (NYSERDA 2018b). States can also provide incentives for new economic development.

Because the spent fuel produced during the lives of the operating reactors has no place to go, it is likely to remain on site for many, many years. This alone justifies substantial payments to host communities, which must function as *de facto* spent fuel storage facilities, something never contemplated when the plants were licensed.

Address other state and local issues. Nuclear plants affect resources subject to state jurisdiction, such as the use of local water supplies for cooling and the acceptable thermal impact of their cooling-water discharges. Some plants are involved in state regulatory proceedings around these issues, and the results could be costly enough to lead to a plant's closure.

Conclusions

Many nuclear plants are at risk of retiring early primarily because of low prices for natural gas, with a more modest role for other factors, such as declining demand for electricity, falling costs for wind and solar, and rising operating costs for repairs and other needs. Most of the at-risk plants are merchant plants located in competitive state and regional markets in the Mid-Atlantic states. However, many plants owned by regulated utilities and public power agencies, located primarily in the Midwest and Plains states, are more expensive than market prices and competing technologies and could be at risk of closing before their operating licenses expire.

The UCS analysis shows that 22 percent of total US nuclear capacity is scheduled to close or unprofitable and at risk of closing in the next decade. The estimated national cost of closing the revenue gap for these at-risk plants would be $814 million per year on average, or more than $4 billion over the next five years. This translates to a cost of $7.7 per MWh or $19 per ton of CO_2 avoid-ed from an average existing natural gas combined-cycle plant.

Without new policies, closing the unprofitable plants early could result in a net increase in US natural gas and coal generation—and hence increase CO_2 emissions. This would make it much harder to keep the nation on a path to the deep cuts in heat-trapping emissions needed to limit the impacts of climate change. However, strong national and state climate and clean energy policies can prevent or limit these impacts at a reasonable cost to consumers, while providing a worthwhile investment for society.

In particular, a meaningful, economy-wide price on carbon would be a sound policy to address a key market failure and level the playing field for all low-carbon technologies. It would help ensure that when nuclear plants are eventually retired, low-carbon energy sources will replace them in the most cost-effective way.

Where policymakers are considering financial support to avoid the early closure of unprofitable nuclear plants and prevent carbon emissions from rising, that support must be temporary and adjusted over time to limit rate increases to consumers. Moreover, it must be coupled with strong clean energy policies, stringent safety and performance standards, and requirements for owners to develop worker and community transition plans to prepare for the plant's eventual retirement. Unlike the Trump administration's deeply flawed proposals to bail out uneconomic coal and nuclear plants, policies that value the low-carbon attributes of nuclear power, renewable energy, energy efficiency, electricity storage, and other technologies are critical for state and national efforts to significantly reduce emissions and help limit climate impacts.

[ENDNOTES]

[1] On July 30, 2018, NextEra Energy announced plans to retire the 615 MW Duane Arnold plant in Iowa in 2020, five years before the scheduled expiration of its power purchase agreement with Iowa utilities. Exelon also shut down the Oyster Creek plant in New Jersey on September 17, 2018. Because both of these events occurred after we had completed our analysis, we included Duane Arnold in our economic analysis rather than listing it as a firm retirement and we listed Oyster Creek as a firm retirement instead of as a closed plant.

[2] S&P Global Market Intelligence is a division of S&P Global, which provides news, data, and analysis for individuals, companies, and government entities.

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[4] S&P Global Market Intelligence is a division of S&P Global, which provides news, data, and analysis for individuals, companies, and government entities.

[5] This is similar to an earlier analysis that defined this cutoff as 10 percent of total generating costs (Chupka, Celebi, and Graves 2014).

[6] As noted earlier, we included Duane Arnold in our economic analysis rather than listing it as a firm retirement, because the announcement was made after this analysis was complete.

[7] Connecticut has authorized financial support for its sole nuclear plant (Millstone), but our analysis does not consider that because state agencies have yet to evaluate the merit of the plant owner’s request. Even without additional financial support, Millstone is among the most profitable plants in the nation across a range of assumptions, according to our analysis and others (Levitan & Associates 2018; Loh 2018; Haratyk 2017).

[8] The higher end of this range is for the national carbon price case and assumes the $218 billion in carbon allowance revenues would be recycled back into the economy.

[9] This evaluation excluded performance results for permanently closed reactors.

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[APPENDIX A]

Four State Policy Approaches to the Nuclear Power Dilemma

Recent experience in four states—California, Illinois, New Jersey, and New York—illustrate different policy approaches to ensuring existing nuclear power plants are not closed abruptly and replaced with fossil fuels. With strong climate and clean energy policies, California is working to ensure that zero-carbon resources replace its nuclear plants, while the state continues to drive down emissions. The other three states are providing financial support to delay the closure of unprofitable plants but are predicating such support on a showing of financial distress. To limit costs to ratepayers, financial support is temporary and adjusted as market and policy conditions change. Policymakers in those states also have tied support for nuclear to a broader strategy of reducing carbon emissions, including state policies designed to increase investments in energy efficiency and renewable energy that could eventually replace existing nuclear plants over a longer timeframe.

California

In June 2016, Pacific Gas & Electric (PG&E) announced plans to retire the 2,200 MW Diablo Canyon nuclear power plant by 2025 as part of a proposed joint settlement with labor and environmental groups (PG&E 2016). With strong climate and clean energy policies, California is working to ensure that zero-carbon resources replace Diablo Canyon, while the state continues to drive down emissions.

PG&E estimated that it would be more expensive to refurbish, relicense, and operate the plant's two reactors for 29 to 49 more years than to invest in energy efficiency, renewable energy, and other zero-carbon sources. PG&E also decided to retire the plant because of its location near earthquake fault lines, its large size and lack of operating flexibility for integrating increasing levels of renewable energy, and the projected loss of customer load to community choice aggregation (CCA) providers.

In January 2018, the California Public Utilities Commission (CPUC) approved PG&E's proposal to close the plant by 2025, but it rejected the proposed joint settlement to replace the plant's capacity with specified levels of energy efficiency and renewable energy (Bade 2018; CPUC 2018). Instead, the commission ordered PG&E to explore replacement options that would minimize potential increases in power-sector emissions of heat-trapping gases in its next Integrated Resource Planning (IRP) proceeding.

The CPUC also rejected the settlement's proposal to provide ratepayer funding for local communities currently receiving property tax revenues from the plant, which the commission argued would require legislative approval. Instead, in September 2018, Governor Jerry Brown signed bipartisan legislation (SB 1090) that includes a $350 million employee-retention fund and restores the full $85 million for local communities and school districts from the original joint proposal to help make up for the lost property taxes. The legislation includes a commitment by the state that the planned closure of Diablo Canyon in 2025 will not increase heat-trapping emissions (Maloney 2018b; Miller 2018).

The governor also signed landmark legislation (SB 100) to increase California's Renewable Portfolio Standard (RPS) to 50 percent by 2025 and 60 percent by 2030 and achieve 100 percent zero-carbon electricity by 2045 (Alvord 2018). To further ensure that California combats global warming beyond the electric sector, the governor also issued an executive order directing the state to achieve carbon neutrality by 2045 and net negative heat-trapping emissions after that. This will help ensure that California removes as much carbon dioxide from the atmosphere as it emits—the first step to reversing the potentially disastrous impacts of climate change.

Illinois

Enacted in Illinois in December 2016, the comprehensive Future Energy Jobs Act (FEJA) includes a Zero Emission Standard to provide direct financial support for two of Exelon's nuclear power plants (Clinton and Quad Cities), while strengthening the state's renewable energy and energy efficiency policies (Collingsworth 2016; IPA 2018; Maloney 2016).

The previous June, Exelon had filed notices with the Nuclear Regulatory Commission to retire these facilities in 2017 and 2018 (Exelon 2016). Exelon claimed the two plants had lost $800 million over the past seven years. Analyses by several state agencies, regional transmission operators, and UCS all showed that if Exelon shut these facilities abruptly in the absence of new state or federal policies, the generation would be replaced primarily with natural gas and coal (Clemmer 2016; ICC et al. 2015).

The Zero Emission Standard enables Exelon to earn credits based on the economic value of the avoided carbon emissions from these facilities using the federal social cost of carbon, which represents the avoided economic damages from climate change. The total number of credits is capped according to a yearly budget formula—the cap is about $235 million for 2018–2019—and the program lasts for 10 years. The value of the credits is $16.50 per MWh in 2017, increasing to $27.50 per MWh in 2027, with adjustments when wholesale electricity prices exceed $34.40 per MWh. To limit costs to ratepayers, the legislation included a cost cap of 1.65 percent of 2009 retail electricity costs.

FEJA also fixed flaws in Illinois's 25 percent by 2025 RPS, providing more than $200 million per year to procure additional solar and wind power in Illinois (Collingsworth 2016; Maloney 2016). The law requires at least 3,000 MW of new solar power and 1,300 MW of new wind power to be built in the state by 2030. Most of this development has been fast-tracked to take advantage of federal renewable energy tax credits that are set to expire in the next few years.

Further, FEJA created the state's first community solar program, allowing consumers who cannot install solar on their rooves the opportunity to subscribe to a shared project in their community. And it created the Illinois Solar for All Program, providing a comprehensive, low-income, solar deployment and job training program that will open up access to the solar economy for millions of low-income families.

FEJA increased Illinois's Energy Efficiency Portfolio Standard. This requires Commonwealth Edison to achieve a 21.5 percent reduction and Ameren to achieve a 16 percent reduction in energy use by 2030, with a focus on deep, long-lasting savings. Ameren Illinois modified its four-year energy efficiency and demand response plan in March 2018 to lower its targets. To ensure that these benefits are accessible to all communities, these utilities will spend a minimum of $33 million per year on energy efficiency programs for low-income customers (Elevate Energy 2018).

New Jersey

In May 2018, New Jersey enacted comprehensive legislation (S. 2314) that establishes a Zero Emissions Credit (ZEC) program to provide financial support to two nuclear power plants (Hope Creek and Salem), while strengthening the state's renewable energy and energy efficiency policies (State of New Jersey 2018). The law requires PSE&G, the owner of the plants, to demonstrate that they are risk of closure within three years and not receiving funding from any other federal, regional, or state source. The law allows the

New Jersey Board of Public Utilities and outside experts to review the plants' financial information and to adjust ZEC payments based on changing market conditions. The ZEC program will provide $10 per MWh in direct financial support, or $300 million per year. The legislation did not specify a sunset date, and the ZEC program does not include New Jersey's Oyster Creek plant, which officially shut down on September 17, 2018.

In addition to providing financial support for existing nuclear plants, the legislation increases New Jersey's RPS to 35 percent by 2025 and 50 percent by 2030, making it one of the nation's strongest. It mandates structural improvements to the state's solar program and establishes a community solar energy program, scheduled to result in 2,000 MW of new solar by 2030. It includes a commitment to develop 3,500 MW of offshore wind by 2030 and reinstates an expired program to provide tax credits for offshore wind manufacturing activities. It also codifies Governor Phil Murphy's goal of deploying 600 MW of energy storage by 2021 and 2,000 MW by 2030.

The law requires each utility, through investments in energy efficiency, to reduce electricity usage by 2 percent per year and natural gas usage by 0.75 percent per year. These higher efficiency targets are projected to quadruple energy savings and save consumers $200 million per year (Bryk 2018).

When the governor signed the legislation in May 2018, he also signed an Executive Order directing state agencies to develop an updated Energy Master Plan providing a path to 100 percent clean energy by 2050. The governor also signed an executive order in January 2018, directing the state to rejoin the Regional Greenhouse Gas Initiative (RGGI) (Maloney 2108b). Since New Jersey withdrew from RGGI in 2012, the state has fallen behind in its emissions reduction targets and foregone $279 million in revenue from RGGI auction proceeds (State of New Jersey 2018).

New York

In August 2016, the New York Public Service Commission (PSC) adopted a Clean Energy Standard that includes the nation's first zero-emissions credit (ZEC) program exclusively for nuclear power (NYSERDA 2018c). The program provides direct financial support to avoid the early closure of three upstate facilities: James A. FitzPatrick Nuclear Power Plant, R.E. Ginna Nuclear Power Plant, and Nine Mile Point Nuclear Generating Station.

While the licenses for these plants expire in 2029 (Ginna and Nine Mile Point) and 2034 (FitzPatrick) (NRC 2018a), the PSC reviewed their financial data and determined they were losing money and at risk of abruptly retiring under current market conditions (DPS 2016). For the near-term, closures were projected to increase generation primarily from natural gas and oil because it takes time to scale up renewable resources and energy efficiency and integrate them into the electric grid.

The ZEC program requires electricity providers to purchase credits from the upstate nuclear power plants until 2030. ZEC prices increase from $17.48 per MWh in 2017 to 29.15 per MWh in 2027 based on the federal social cost of carbon. Through 2030, prices are adjusted based on RGGI CO_2 prices and when wholesale electricity prices exceed $39 per MWh. The PSC will undertake a public biennial review of the ZEC program and make any necessary adjustments.

The Clean Energy Standard requires electricity providers to deliver 50 percent of their electricity from renewable energy sources by 2030. The ZEC program is structured as a component of the standard, but it is separate and distinct from the renewables program. No electricity generated from nuclear facilities will count toward the renewables target. The PSC kept the ZEC program separate to avoid market power issues due to limited competition among relatively few large plants and owners.

More recently, New York has made a commitment to develop 2,400 MW of offshore wind by 2030 and 1,500 MW of energy storage by 2025. It also increased its energy efficiency targets to reduce consumer electricity use by 3 percent per year by 2025. Achieving these targets will help the state meet one-third of its goal to reduce heat-trapping emissions 40 percent by 2030.

New York's ZEC program does not include the Indian Point Energy Center, a 2,000 MW, two-unit facility. The state has negotiated an agreement to close the facility, based in part on its proximity to New York City—making emergency evacuation all but impossible—and on the decades-long series of safety and operational problems that have plagued the plant. Under the agreement, Indian Point's remaining Unit 2 reactor will close in 2020 and Unit 3 will close in 2021. The agreement does not specify a plan for replacement power, but Governor Andrew Cuomo has made a commitment that the closure will not cause an appreciable increase in carbon emissions (State of New York 2017). A 2017 study showed that New York's strong renewable energy and energy efficiency policies and participation in the RGGI will help the state meet this commitment, while maintaining reliability (Morris 2017).

[APPENDIX B]

Methodology for Profitability Analysis

This appendix provides additional details on the methodology UCS used to conduct the profitability analysis for the existing nuclear reactors in the United States.

We based projections of annual operating revenues for each reactor on estimates from S&P Global Market Intelligence (S&P). We used near-term market data and projections from the Aurora model, a common tool for electricity market price forecasting, resource valuation, and market risk analysis (SNL Energy n.d.). Revenue projections include energy (or money received from selling electricity) and capacity (or money received to ensure the availability of adequate generation at times of peak demand). We based revenues from electricity sales on projections of wholesale electricity and natural gas prices at key hubs. The projected value of capacity reflects regional differences in market structure, analogous to cleared capacity auction prices in regions with capacity auctions. We did not include capacity revenues for years that certain plants failed to receive revenue from recent forward-capacity market auctions.

The analysis took into account existing carbon prices in California and the nine states participating in the Regional Greenhouse Gas Initiative, which serves to improve the economics of nuclear plants in those states by making fossil resources more expensive. We included estimates for recently enacted policies in Illinois, New York, and New Jersey that provide financial support for selected nuclear plants.

The costs included fixed and variable operations and maintenance (O&M) costs, fuel costs, and capital costs. Cost information, frequently considered proprietary, is often difficult to obtain for specific nuclear plants. Therefore, we based costs on reports from the Electric Utility Cost Group and the annual survey of costs for existing US nuclear plants it conducts for the Nuclear Energy Institute (NEI 2018a; NEI 2017). We aggregated the survey data to the company level, aggregated for single-reactor and multiple-reactor plants and by plant size to calculate industry averages. We combined this information with publicly available cost information for some regulated plants to benchmark costs from the Aurora model projections.

We used the average annual operating margin to evaluate the profitability of each reactor, aggregated to the plant level. The profitability assessment did not consider regulatory status. Merchant generators are much more susceptible to changing market dynamics and more likely to retire unprofitable plants early. Plants owned by regulated and public utilities typically can obtain cost recovery for above-market costs from their customers, but they are not immune to market pressures from lower-cost alternatives, particularly if they seek to make major capital investments in nuclear plants. Most other economic analyses of existing nuclear plant profitability have included both merchant and regulated plants. The operating margins analysis does not reflect the revenues collected from consumers through rates that helps insulate regulated and public power utility-owned plants from lower cost alternatives available in the market.

Our analysis estimated the profitability of specific nuclear plants based on the best available data, but it does not substitute for a careful financial review of each facility. Because most plant-level cost data are proprietary and other factors not included in our analysis can affect profitability and retirement decisions, owners of distressed plants should be required to submit detailed economic data to regulators to demonstrate financial need.

Sensitivity Analysis

Establishing the cutoff value for marginal units at $5 per MWh is somewhat subjective, but it represents a conservative view of how many plants might be at risk because many more plants fall in the $5 to $10 per MWh range. In short, our identification of marginal plants demonstrated that a significant number of nuclear plants are close to the edge and could face financial troubles due to relatively small changes in assumptions about reactor-specific operating costs or revenues.

Because of this uncertainty, we evaluated the sensitivity of our results to changes in assumptions. Key assumptions include projections of natural gas prices, nuclear operating costs, and the level of a presumed national carbon price.

Natural gas prices have a strong impact on the results of the analysis, which is expected given that the nuclear fleet has been challenged in recent years by historically low gas prices (Haratyk 2017; Szilard et al. 2017; Szilard et al. 2016). Our reference case assumed natural gas prices from the Energy Information Administration (EIA) and its high oil and gas resource and technology case (i.e., low gas price case); these prices are more in line with recent near-term prices from EIA's Short-term Energy Outlook and projections from Market Intelligence and other independent financial analysts (Larsen et al. 2018). Our reference case also includes the subsidies in Illinois, New York, and New Jersey, as well as the results of the PJM capacity auction for 2021 to 2022. To test the sensitivity of our results to changes in natural gas price projections, we considered cases from the 2018 AEO reference case as well as projections from Market Intelligence.

We considered three different CO_2 price cases. Two represented EIA test cases ($15 per ton and $25 per ton beginning in 2020 and escalating by 5 percent per year) (EIA 2018b). The third was based on the social cost of carbon, which is used in the subsidy calculations for New York and Illinois (Interagency Working Group 2016).

Lower nuclear costs were based on meeting industry cost-reduction goals (NEI 2016). Higher nuclear costs were estimated using cost adders for aging plants from EIA (EIA 2018a).

[APPENDIX C]

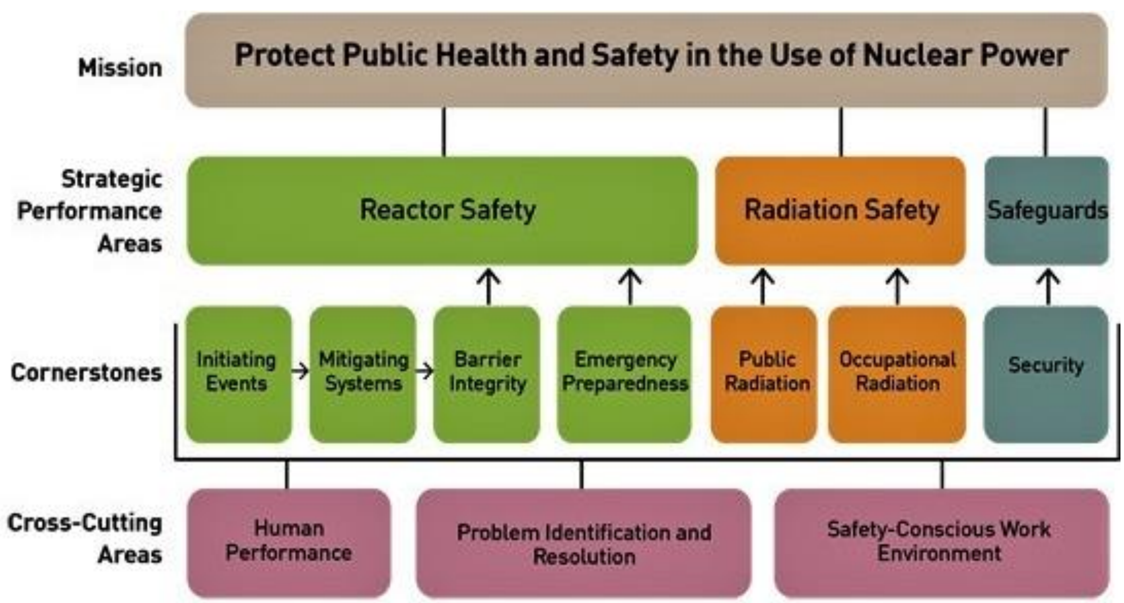
Methodology for Evaluating Reactor Safety Performance

In the 1980s and 1990s, the NRC used the Systematic Assessment of Licensee Performance (SALP) process to evaluate safety at operating reactors and inform the agency's level of oversight. Responding to growing evidence that SALP was more subjective than necessary, the NRC initiated a broad review of the inspection, assessment, and enforcement components of its oversight regime. That effort culminated in the Reactor Oversight Process (ROP), adopted in 2002 (Figure C-1).

The ROP builds on seven cornerstones: four relate to reactor safety, two are associated with radiation exposure to the public and plant workers, and one deals with plant security. When practical, performance indicators gauge safety.

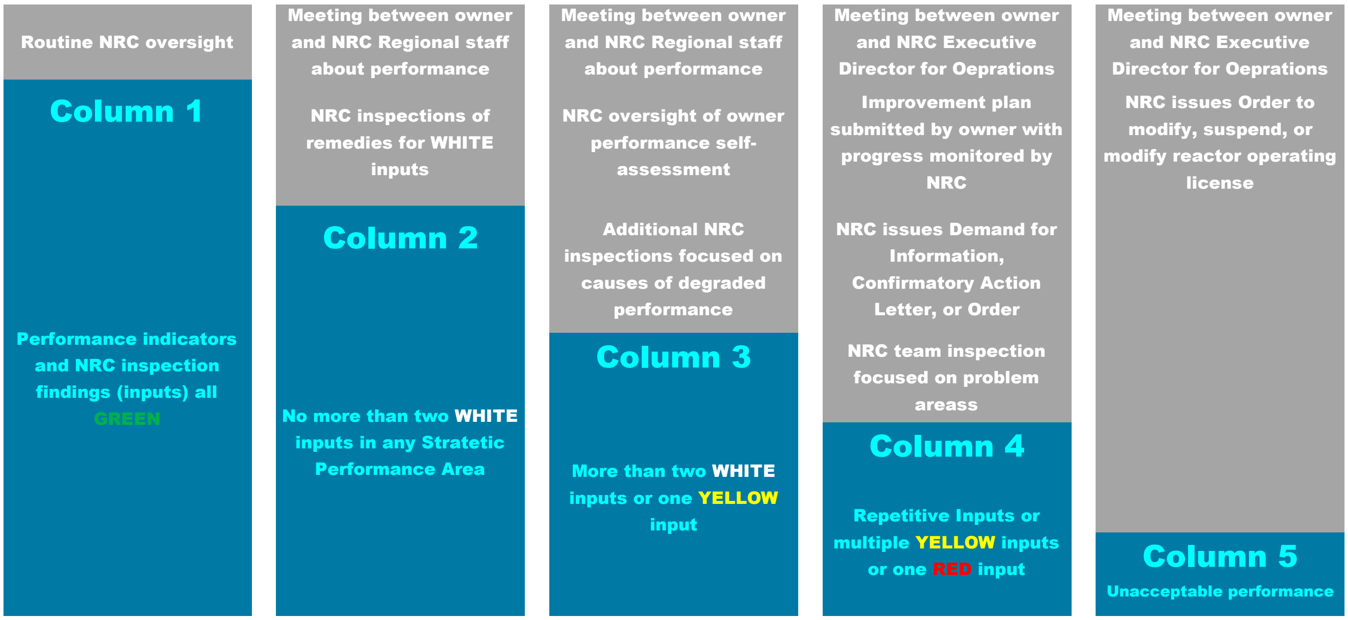
Overall, the ROP uses nearly two dozen performance indicators. For example, the Barrier Integrity cornerstone features two performance indicators. One tracks the integrity of the metal rods encasing the nuclear fuel. The other tracks the integrity

FIGURE C-1. **NRC Reactor Oversight Process Framework**



SOURCE: NRC 2018E.

FIGURE C-2. **NRC Reactor Oversight Process Action Matrix Columns and Associated NRC Responses**



SOURCE: NRC 2018B

of the metal vessel and connected piping that contain the reactor core. When the integrity of these barriers is breached, pathways open for radioactivity to get places it should not go.

NRC inspectors, who determine whether regulatory requirements are being met, supplement reported data on the performance indicators. The performance indicators and inspector findings are color-coded based on their safety significance: green, white, yellow, and red in order of increasing significance.

Every three months, the NRC classifies each operating reactor into one of five columns of the ROP's Action Matrix depending on the performance indicators and inspection findings (Figure C-2). Reactors in Column 1, the License Response column, meet or exceed the NRC's expectations (i.e., all performance indicators and NRC inspection findings are green). Columns 2, 3, and 4 list reactors where performance indicators or NRC inspection findings indicate declining safety performance. Generally, placement in Column 2 reflects minor problems in an isolated area; placement in Columns 3 and 4 suggests systemic breakdowns. As performance declines, the NRC's oversight response increases to stem the decline and guide performance back into the expected band. When performance drops too far, the NRC puts a reactor into Action Matrix Column 5. The owner must shut down the reactor until remedying enough of the problems for the NRC to approve a restart.

The NRC's ratings system differentiates between bad luck and poor performance. The owner need only repair or replace a component that fails despite the owner's properly conducting all required tests, inspections, and maintenance activities. However, when ineffective testing or inadequate maintenance cause a component's failure, the owner must remedy that performance deficiency in addition to repairing or replacing the broken component. The owner must also determine whether the performance deficiency may have impaired other components and implement corrections as applicable.

Reactors listed in Column 1 receive the NRC's baseline inspection. Inspection procedures cover worker training, the operation and maintenance of safety equipment, security, fire protection, plant modifications, refueling of the reactor core, and many other areas. Some procedures are performed once or more each year. Others take place every other year. The least frequent take place once every three years. The NRC expends nearly 5,200 inspection hours annually at the average nuclear plant.

Every quarter, the NRC posts its current Action Matrix column placements on its website, at *www.nrc.gov/reactors/operating/oversight/actionmatrix-summary.html*. It also maintains an online archive of ROP results dating back to 2000, at *www.nrc.gov/reactors/operating/oversight/prevqtr.html.*

[APPENDIX D]

Electricity Generation Share by Source, States with Nuclear Plants, 2017

TABLE D-1. **Electricity Generation Share by Source for States with Nuclear Plants, 2017**

State	Nuclear	Coal	Natural Gas	Hydro	Wind	Solar	Biomass	Geothermal	Other
Alabama	31%	23%	38%	7%	0%	0%	2%	0%	0%
Arkansas	20%	42%	28%	6%	0%	0%	2%	0%	0%
Arizona	31%	30%	28%	7%	1%	4%	0%	0%	0%
California	9%	0%	43%	21%	7%	11%	3%	6%	1%
Connecticut	48%	1%	46%	1%	0%	0%	2%	0%	2%
Florida	12%	16%	68%	0%	0%	0%	2%	0%	2%
Georgia	26%	25%	41%	2%	0%	2%	4%	0%	0%
Iowa	9%	45%	6%	2%	37%	0%	0%	0%	1%
Illinois	53%	32%	8%	0%	6%	0%	0%	0%	0%
Kansas	21%	38%	5%	0%	36%	0%	0%	0%	0%
Louisiana	16%	13%	60%	1%	0%	0%	3%	0%	8%
Massachusetts	16%	4%	67%	3%	1%	3%	4%	0%	3%
Maryland	44%	25%	20%	6%	1%	1%	2%	0%	1%
Michigan	29%	37%	23%	1%	4%	0%	2%	0%	3%
Minnesota	23%	39%	12%	2%	18%	1%	3%	0%	1%
Missouri	10%	81%	5%	2%	2%	0%	0%	0%	0%
Mississippi	12%	8%	78%	0%	0%	0%	2%	0%	0%
North Carolina	32%	26%	30%	4%	0%	4%	2%	0%	1%

State	Nuclear	Coal	Natural Gas	Hydro	Wind	Solar	Biomass	Geothermal	Other
Nebraska	19%	60%	2%	4%	15%	0%	0%	0%	0%
New Hampshire	57%	2%	20%	7%	2%	0%	10%	0%	1%
New Jersey	46%	2%	49%	0%	0%	2%	1%	0%	1%
New York	33%	1%	38%	23%	3%	0%	2%	0%	1%
Ohio	15%	58%	24%	0%	1%	0%	1%	0%	1%
Pennsylvania	41%	24%	30%	1%	2%	0%	1%	0%	1%
South Carolina	58%	19%	17%	3%	0%	0%	3%	0%	0%
Tennessee	40%	35%	13%	10%	0%	0%	1%	0%	0%
Texas	9%	30%	45%	0%	15%	0%	0%	0%	1%
Virginia	32%	11%	49%	2%	0%	0%	4%	0%	1%
Washington	7%	5%	8%	72%	6%	0%	2%	0%	0%
Wisconsin	15%	55%	21%	4%	2%	0%	3%	0%	0%

DATA SOURCE: EIA 2018B.

[APPENDIX E]

Supplemental Data and Results from the Profitability Analysis

This appendix provides additional details on the data and results from the profitability analysis of all 99 US nuclear reactors and operating at 60 plants at the end of 2017.

TABLE E-1. **Basic Statistics of US Nuclear Reactors**

Plant Name	Reactor Number	State	RTO/Region	Regulatory Status	Parent Company	2018 Operating Capacity (MW)	Operating License Expiration Date	Age
Alvin W. Vogtle Nuclear Plant	1	GA	Southeast	Regulated	Southern Company	1,150	1/16/2047	31
Alvin W. Vogtle Nuclear Plant	2	GA	Southeast	Regulated	Southern Company	1,152	2/9/2049	29
Arkansas Nuclear One	1	AR	MISO	Regulated	Entergy Corporation	852	5/20/2034	44
Arkansas Nuclear One	2	AR	MISO	Regulated	Entergy Corporation	1,002	7/17/2038	38
Beaver Valley	1	PA	PJM	Merchant	FirstEnergy Corp.	939	1/29/2036	42
Beaver Valley	2	PA	PJM	Merchant	FirstEnergy Corp.	928	5/27/2047	31
Braidwood Generating Station	1	IL	PJM	Merchant	Exelon Corporation	1,208	10/17/2046	30
Braidwood Generating Station	2	IL	PJM	Merchant	Exelon Corporation	1,176	12/18/2047	30
Browns Ferry	1	AL	Southeast	Public Power	TVA	1,132	12/20/2033	44
Browns Ferry	2	AL	Southeast	Public Power	TVA	1,135	6/28/2034	43
Browns Ferry	3	AL	Southeast	Public Power	TVA	1,134	7/2/2036	41
Brunswick	1	NC	Southeast	Regulated	Duke Energy Corporation	975	9/8/2036	41

Plant Name	Reactor Number	State	RTO/Region	Regulatory Status	Parent Company	2018 Operating Capacity (MW)	Operating License Expiration Date	Age
Brunswick	2	NC	Southeast	Regulated	Duke Energy Corporation	953	12/27/2034	43
Byron Generating Station	1	IL	PJM	Merchant	Exelon Corporation	1,188	10/31/2044	33
Byron Generating Station	2	IL	PJM	Merchant	Exelon Corporation	1,158	11/6/2046	31
Callaway	1	MO	MISO	Regulated	Ameren Corporation	1,236	10/18/2044	34
Calvert Cliffs	1	MD	PJM	Merchant	Exelon Corporation	872	7/31/2034	43
Calvert Cliffs	2	MD	PJM	Merchant	Exelon Corporation	862	8/13/2036	41
Catawba	1	SC	Southeast	Regulated	Duke Energy Corporation	1,199	12/5/2043	33
Catawba	2	SC	Southeast	Regulated	Duke Energy Corporation	1,180	12/5/2043	32
Clinton Power Station	1	IL	MISO	Merchant	Exelon Corporation	1,078	9/29/2026	31
Columbia Generating (WNP-2)	2	WA	West	Merchant **	Energy Northwest	1,210	12/20/2043	34
Comanche Peak	1	TX	ERCOT	Merchant	Vistra Energy Corp.	1,205	2/8/2030	28
Comanche Peak	2	TX	ERCOT	Merchant	Vistra Energy Corp.	1,195	2/2/2033	25
Cooper Nuclear Station	1	NE	SPP	Public Power	Nebraska Public Power District	772	1/18/2034	44
Davis-Besse	1	OH	PJM	Merchant	FirstEnergy Corp.	908	4/22/2037	41
Diablo Canyon	1	CA	CAISO	Regulated	Pacific Gas and Electric Company	1,122	11/2/2024	33
Diablo Canyon	2	CA	CAISO	Regulated	Pacific Gas and Electric Company	1,118	8/26/2025	32
Donald C. Cook	1	MI	PJM	Regulated	American Electric Power Company, Inc.	1,081	10/25/2034	43
Donald C. Cook	2	MI	PJM	Regulated	American Electric Power Company, Inc.	1,198	12/23/2037	40

Plant Name	Reactor Number	State	RTO/Region	Regulatory Status	Parent Company	2018 Operating Capacity (MW)	Operating License Expiration Date	Age
Dresden	2	IL	PJM	Merchant	Exelon Corporation	902	12/22/2029	48
Dresden	3	IL	PJM	Merchant	Exelon Corporation	903	1/12/2031	47
Duane Arnold Energy Center (DAEC)	1	IA	MISO	Merchant	NextEra Energy, Inc.	622	2/21/2034	43
Edwin I Hatch	1	GA	Southeast	Regulated	Southern Company	876	8/6/2034	43
Edwin I Hatch	2	GA	Southeast	Regulated	Southern Company	883	6/13/2038	39
Fermi	2	MI	MISO	Regulated	DTE Energy Company	1,161	3/20/2045	30
Grand Gulf	1	MS	MISO	Merchant	Entergy Corporation	1,428	11/1/2024	33
H.B. Robinson	2	SC	Southeast	Regulated	Duke Energy Corporation	797	7/31/2030	47
Hope Creek	1	NJ	PJM	Merchant	Public Service Enterprise Group Incorporated	1,172	4/11/2046	32
Indian Point 2	2	NY	NYISO	Merchant	Entergy Corporation	1,030	9/28/2013	44
Indian Point 3	3	NY	NYISO	Merchant	Entergy Corporation	1,041	12/12/2015	42
James A. FitzPatrick	1	NY	NYISO	Merchant	Exelon Corporation	853	10/17/2034	43
Joseph M Farley	1	AL	Southeast	Regulated	Southern Company	874	6/25/2037	41
Joseph M Farley	2	AL	Southeast	Regulated	Southern Company	877	3/31/2041	37
LaSalle County Generating Station	1	IL	PJM	Merchant	Exelon Corporation	1,147	4/17/2022	34
LaSalle County Generating Station	2	IL	PJM	Merchant	Exelon Corporation	1,159	12/16/2023	34
Limerick	1	PA	PJM	Merchant	Exelon Corporation	1,191	10/26/2044	32
Limerick	2	PA	PJM	Merchant	Exelon Corporation	1,195	6/22/2049	28

Plant Name	Reactor Number	State	RTO/Region	Regulatory Status	Parent Company	2018 Operating Capacity (MW)	Operating License Expiration Date	Age
McGuire	2	NC	Southeast	Regulated	Duke Energy Corporation	1,187	3/3/2043	34
McGuire	1	NC	Southeast	Regulated	Duke Energy Corporation	1,199	6/12/2041	37
Millstone	2	CT	ISO-NE	Regulated	Dominion Energy, Inc.	868	7/31/2035	43
Millstone	3	CT	ISO-NE	Regulated	Dominion Energy, Inc.	1,234	11/25/2045	32
Monticello	1	MN	MISO	Regulated	Xcel Energy Inc.	646	9/8/2030	47
Nine Mile Point	1	NY	NYISO	Merchant	Exelon Corporation	628	8/22/2029	49
Nine Mile Point	2	NY	NYISO	Merchant	Exelon Corporation	1,300	10/31/2046	31
North Anna	1	VA	PJM	Regulated	Dominion Energy, Inc.	982	4/1/2038	40
North Anna	2	VA	PJM	Regulated	Dominion Energy, Inc.	976	8/21/2040	38
Oconee	1	SC	Southeast	Regulated	Duke Energy Corporation	865	2/6/2033	45
Oconee	2	SC	Southeast	Regulated	Duke Energy Corporation	872	10/6/2033	44
Oconee	3	SC	Southeast	Regulated	Duke Energy Corporation	881	7/19/2034	44
Oyster Creek	1	NJ	PJM	Merchant	Exelon Corporation	635	4/9/2029	49
Palisades	1	MI	MISO	Merchant	Entergy Corporation	820	3/24/2031	47
Palo Verde	1	AZ	West	Regulated	Pinnacle West Capital Corporation	1,333	6/1/2045	32
Palo Verde	2	AZ	West	Regulated	Pinnacle West Capital Corporation	1,336	4/24/2046	32
Peach Bottom	2	PA	PJM	Merchant	Exelon Corporation	1,296	8/8/2033	44
Peach Bottom	3	PA	PJM	Merchant	Exelon Corporation	1,288	7/2/2034	44
Perry	1	OH	PJM	Merchant	FirstEnergy Corp.	1,268	3/18/2026	31
Pilgrim Nuclear Power Station	1	MA	ISO-NE	Merchant	Entergy Corporation	683	6/8/2032	46

Plant Name	Reactor Number	State	RTO/Region	Regulatory Status	Parent Company	2018 Operating Capacity (MW)	Operating License Expiration Date	Age
Point Beach	1	WI	MISO	Merchant	NextEra Energy, Inc.	602	10/5/2030	48
Point Beach	2	WI	MISO	Merchant	NextEra Energy, Inc.	604	3/8/2033	46
Prairie Island	1	MN	MISO	Regulated	Xcel Energy Inc.	546	8/9/2033	45
Prairie Island	2	MN	MISO	Regulated	Xcel Energy Inc.	546	10/29/2034	44
Quad Cities	1	IL	PJM	Regulated	Exelon Corporation	908	12/14/2032	46
Quad Cities	2	IL	PJM	Regulated	Exelon Corporation	911	12/14/2032	46
R.E. Ginna/Ontario Sta. 13	1	NY	NYISO	Merchant	Exelon Corporation	582	9/18/2029	48
River Bend	1	LA	MISO	Regulated	Entergy Corporation	968	8/29/2025	32
Salem	1	NJ	PJM	Merchant	Public Service Enterprise Group Incorporated	1,154	8/13/2036	41
Salem	2	NJ	PJM	Merchant	Public Service Enterprise Group Incorporated	1,153	4/18/2040	37
Seabrook	1	NH	ISO-NE	Merchant	NextEra Energy, Inc.	1,251	3/15/2030	28
Sequoyah	1	TN	Southeast	Public Power	TVA	1,177	9/17/2040	37
Sequoyah	2	TN	Southeast	Public Power	TVA	1,155	9/15/2041	36
Shearon Harris Nuclear Power Plant	1	NC	Southeast	Regulated	Duke Energy Corporation	973	10/24/2046	31
South Texas Project	1	TX	ERCOT	Regulated		1,286	8/20/2027	30
South Texas Project	2	TX	ERCOT	Regulated		1,295	12/15/2028	29
St. Lucie	1	FL	Southeast	Regulated	NextEra Energy, Inc.	1,003	3/1/2036	42
St. Lucie	2	FL	Southeast	Regulated	NextEra Energy, Inc.	1,010	4/6/2043	35
Surry	1	VA	PJM	Regulated	Dominion Energy, Inc.	879	5/25/2032	46

Plant Name	Reactor Number	State	RTO/Region	Regulatory Status	Parent Company	2018 Operating Capacity (MW)	Operating License Expiration Date	Age
Surry	2	VA	PJM	Regulated	Dominion Energy, Inc.	879	1/29/2033	45
Susquehanna Nuclear	1	PA	PJM	Merchant	Talen Energy Corporation	1,296	7/17/2042	35
Susquehanna Nuclear	2	PA	PJM	Merchant	Talen Energy Corporation	1,296	3/23/2044	33
Three Mile Island	1	PA	PJM	Merchant	Exelon Corporation	827	4/19/2034	44
Turkey Point Nuclear	3	FL	Southeast	Regulated	NextEra Energy, Inc.	826	7/19/2032	46
Turkey Point Nuclear	4	FL	Southeast	Regulated	NextEra Energy, Inc.	826	4/10/2033	45
V.C. Summer	1	SC	Southeast	Regulated	SCANA Corporation	992	8/6/2042	34
Waterford 3	3	LA	MISO	Regulated	Entergy Corporation	1,177	12/18/2024	33
Watts Bar Nuclear	1	TN	Southeast	Public Power	TVA	1,179	11/9/2035	22
Watts Bar Nuclear	2	TN	Southeast	Public Power	TVA	1,270	10/22/2055	2
Wolf Creek	1	KS	SPP	Regulated		1,205	3/11/2045	33

Basic statistics on each reactor operating in the United States at the end of 2017. Parent company represents the company with the largest ownership stake by capacity for each reactor. License expiration date from the Nuclear Regulatory Commission, combined with the date of first operation, is used to calculate each reactor's age in 2018.

Notes: (1) Public power" refers to a power plant or unit that is owned primarily by a government entity (such as the Tennessee Valley Authority or a municipal government). Reactors listed as public power are treated as rate-regulated in our analysis. This is because they are characterized as "regulated" in the S&P's database, and because owners of these reactors typically recover costs from ratepayers similar to rate-regulated power plants (Szilard et al. 2017). (2) Columbia Generating Station is listed in the S&P database as a merchant generator and treated as such in the analysis. However, we note that is under contract to provide most of its output to a federal government entity, the Bonneville Power Administration, meaning that it could be considered public power as well.
DATA SOURCE: S&P 2018; NRC 2018a.

TABLE E-2. **Plant-Level Results of the Profitability Analysis, by Scenario**

Plant Name	Reference	No Subsidies	High Nuclear Cost	Low Nuclear Cost	Low Gas Price	Higher Gas Price	$15 per ton CO2	$25 per ton CO2	Social Cost of Carbon
Alvin W. Vogtle Nuclear Plant	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable
Arkansas Nuclear One	Marginal	Marginal	Unprofitable	Marginal	Unprofitable	Profitable	Profitable	Profitable	Profitable
Beaver Valley	Marginal	Marginal	Unprofitable	Marginal	Unprofitable	Profitable	Profitable	Profitable	Profitable
Braidwood Generating Station	Profitable	Profitable	Unprofitable	Profitable	Marginal	Profitable	Profitable	Profitable	Profitable
Browns Ferry	Profitable	Profitable	Unprofitable	Profitable	Marginal	Profitable	Profitable	Profitable	Profitable
Brunswick	Profitable	Profitable	Marginal	Profitable	Marginal	Profitable	Profitable	Profitable	Profitable
Byron Generating Station	Marginal	Marginal	Unprofitable	Profitable	Unprofitable	Profitable	Profitable	Profitable	Profitable
Callaway	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Marginal	Marginal	Profitable	Profitable
Calvert Cliffs	Profitable	Profitable	Marginal	Profitable	Marginal	Profitable	Profitable	Profitable	Profitable
Catawba	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable
Clinton Power Station	Profitable	Unprofitable	Unprofitable	Profitable	Marginal	Profitable	Profitable	Profitable	Profitable
Columbia Generating (WNP-2)	Unprofitable	Unprofitable	Unprofitable	Marginal	Unprofitable	Marginal	Profitable	Profitable	Profitable
Comanche Peak	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable
Cooper Nuclear Station	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Profitable

Plant Name	Reference	No Subsidies	High Nuclear Cost	Low Nuclear Cost	Low Gas Price	Higher Gas Price	$15 per ton CO2	$25 per ton CO2	Social Cost of Carbon
Davis-Besse	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Marginal	Profitable
Diablo Canyon	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement
Donald C. Cook	Profitable	Profitable	Unprofitable	Profitable	Marginal	Profitable	Profitable	Profitable	Profitable
Dresden	Marginal	Marginal	Unprofitable	Profitable	Unprofitable	Profitable	Profitable	Profitable	Profitable
Duane Arnold Energy Center (DAEC)	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Marginal	Profitable
Edwin I Hatch	Profitable	Profitable	Marginal	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable
Fermi	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Marginal	Profitable	Profitable
Grand Gulf	Unprofitable	Unprofitable	Unprofitable	Marginal	Unprofitable	Marginal	Profitable	Profitable	Profitable
H.B. Robinson	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Marginal	Profitable
Hope Creek	Profitable	Marginal	Marginal	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable
Indian Point 2	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement
James A. FitzPatrick	Profitable	Unprofitable	Profitable	Profitable	Profitable	Profitable	Unprofitable	Profitable	Profitable
Joseph M Farley	Profitable	Profitable	Marginal	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable
LaSalle County Generating Station	Profitable	Profitable	Unprofitable	Profitable	Marginal	Profitable	Profitable	Profitable	Profitable
Limerick	Profitable	Profitable	Marginal	Profitable	Marginal	Profitable	Profitable	Profitable	Profitable
McGuire	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable
Millstone	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable
Monticello	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Profitable
Nine Mile Point	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable

Plant Name	Reference	No Subsidies	High Nuclear Cost	Low Nuclear Cost	Low Gas Price	Higher Gas Price	$15 per ton CO2	$25 per ton CO2	Social Cost of Carbon
North Anna	Profitable	Profitable	Marginal	Profitable	Marginal	Profitable	Profitable	Profitable	Profitable
Oconee	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable
Oyster Creek	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement
Palisades	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement
Palo Verde	Profitable	Profitable	Marginal	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable
Peach Bottom	Profitable	Profitable	Marginal	Profitable	Marginal	Profitable	Profitable	Profitable	Profitable
Perry	Unprofitable	Unprofitable	Unprofitable	Marginal	Unprofitable	Marginal	Profitable	Profitable	Profitable
Pilgrim Nuclear Power Station	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement	Firm Retirement
Point Beach	Marginal	Marginal	Unprofitable	Profitable	Unprofitable	Profitable	Profitable	Profitable	Profitable
Prairie Island	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Marginal	Profitable
Quad Cities	Profitable	Marginal	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable
R.E. Ginna/Ontario Sta. 13	Profitable	Unprofitable	Profitable	Profitable	Profitable	Profitable	Unprofitable	Marginal	Profitable
River Bend	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Marginal	Profitable	Profitable
Salem	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable
Seabrook	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable
Sequoyah	Marginal	Marginal	Unprofitable	Profitable	Unprofitable	Profitable	Profitable	Profitable	Profitable
Shearon Harris Nuclear Power Plant	Unprofitable	Unprofitable	Unprofitable	Marginal	Unprofitable	Marginal	Profitable	Profitable	Profitable
South Texas Project	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable
St. Lucie	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable

Plant Name	Reference	No Subsidies	High Nuclear Cost	Low Nuclear Cost	Low Gas Price	Higher Gas Price	$15 per ton CO2	$25 per ton CO2	Social Cost of Carbon
Surry	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable
Susquehanna Nuclear	Marginal	Marginal	Unprofitable	Profitable	Marginal	Profitable	Profitable	Profitable	Profitable
Three Mile Island	Unprofitable	Unprofitable	Unprofitable	Marginal	Unprofitable	Marginal	Profitable	Profitable	Profitable
Turkey Point Nuclear	Profitable	Profitable	Marginal	Profitable	Profitable	Profitable	Profitable	Profitable	Profitable
V.C. Summer	Marginal	Marginal	Unprofitable	Profitable	Unprofitable	Profitable	Profitable	Profitable	Profitable
Waterford 3	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Marginal	Marginal	Profitable	Profitable
Watts Bar Nuclear	Profitable	Profitable	Marginal	Profitable	Marginal	Profitable	Profitable	Profitable	Profitable
Wolf Creek	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Unprofitable	Marginal	Marginal	Profitable	Profitable

All 60 nuclear power plants are shown along with identifying information such as number of reactors and projected 2018 operating capacity. The results of the profitability analysis are shown for each scenario considered. Unprofitable plants are those with an average annual operating margin over the period 2018–2022 of less than $0. Marginal plants are those between $0 and $5 per MWh. Profitable plants are greater than $5 per MWh. All scenarios except the "No Subsidies" case include the financial support for the Clinton and Quad Cities plants in Illinois; the Nine Mile Point, Fitzpatrick and Ginna plants in New York; and the Salem and Hope Creek plants in New Jersey based on the laws adopted in each of these states.

Notes: (1) For the purposes of the profitability analysis, "public power" is equivalent to "regulated" for regulatory status. (2) Columbia Generating Station is listed as a merchant generator in the S&P database but is more appropriately categorized as public power. For the purposes of this analysis, it is listed as a merchant generator.

DATA SOURCE: S&P 2018; UCS Analysis.

TABLE E-3. **US Nuclear Power Operating Capacity, by Profitability and Scenario**

	Reference	No Subsidies	High Nuclear Cost	Low Nuclear Cost	Low Gas Price	Higher Gas Price	$15 per ton CO2	$25 per ton CO2	Social Cost of Carbon
Operating Capacity in 2018 (GW)									
Unprofitable	16.3	18.8	42.7	10.6	28.7	7.0	6.3	1.4	0.0
Marginal	15.0	18.0	23.4	9.4	27.1	9.3	5.7	4.0	0.0
Profitable	64.1	58.6	29.3	75.4	39.6	79.1	83.4	90.0	95.4
Operating Capacity as Percentage of U.S. Total Nuclear									
Unprofitable	16.0%	18.5%	42.0%	10.4%	28.2%	6.8%	6.2%	1.4%	0.0%
Marginal	14.7%	17.7%	23.0%	9.3%	26.6%	9.2%	5.6%	3.9%	0.0%
Profitable	62.9%	57.5%	28.8%	74.0%	38.9%	77.7%	81.9%	88.3%	93.7%

This table shows the total projected operating capacity in 2018 that falls into each category (profitable, marginal, or unprofitable) for each scenario considered. Unprofitable plants are those with an average annual operating margin over the period 2018–2022 of less than $0. Marginal plants are those between $0 and $5 per MWh. Profitable plants are greater than $5 per MWh. The lower half of the table casts these values in terms of the total operating capacity for all US reactors, which in 2018 is projected to be 101.8 GW. Firm retirements, not shown in this table, represent 6.4 GW. All scenarios except the "No Subsidies" case include the financial support for the Clinton and Quad Cities plants in Illinois; the Nine Mile Point, Fitzpatrick, and Ginna plants in New York; and the Salem and Hope Creek plants in New Jersey based on the laws adopted in each of these states.

DATA SOURCE: S&P 2018; UCS ANALYSIS.

TABLE E4. **Summary of Early Nuclear Retirement Cases Included in Modeling Runs**

Plant Name	# of Reactors	State	2018 Operating Capacity (MW)	Regulatory Status	Year Plant Assumed to Retire		
					Reference Case, Merchant Only	Reference Case, All Plants	Low Gas Price Case, Merchant Only
Arkansas Nuclear One	2	AR	1,854.0	Regulated		2025	
Beaver Valley	2	PA	1,866.9	Merchant	2021	2021	2021
Braidwood Generating	2	IL	2,384.0	Merchant			2024
Byron Generating Station	2	IL	2,346.0	Merchant	2022	2022	2022
Callaway	1	MO	1,236.0	Regulated		2024	
Calvert Cliffs	2	MD	1,734.0	Merchant			2025
Columbia (WNP-2)	1	WA	1,210.0	Merchant **		2022	
Cooper Nuclear Station	1	NE	771.5	Public Power		2020	
Davis-Besse	1	OH	908.0	Merchant	2020	2020	2020
Dresden	2	IL	1,805.0	Merchant	2022	2022	2022
Duane Arnold Energy Center	1	IA	622.1	Merchant	2025	2025	2025
Fermi	1	MI	1,161.0	Regulated		2024	
Grand Gulf	1	MS	1,428.0	Merchant	2020	2020	2020
H.B. Robinson	1	SC	797.0	Regulated		2020	
LaSalle County Gen. Station	2	IL	2,305.7	Merchant			2025
Limerick	2	PA	2,386.0	Merchant			2024
Monticello	1	MN	646.0	Regulated		2022	
Peach Bottom	2	PA	2,584.0	Merchant			2025
Perry	1	OH	1,268.0	Merchant	2021	2021	2021
Point Beach	2	WI	1,206.4	Merchant			2020
Prairie Island	2	MN	1,092.0	Regulated		2026	
River Bend	1	LA	967.5	Regulated		2020	
Shearon Harris	1	NC	973.0	Regulated		2024	
Susquehanna Nuclear	2	PA	2,593.0	Merchant	2024	2024	2024
Three Mile Island	1	PA	826.7	Merchant	2019	2019	2019
Waterford 3	1	LA	1,177.0	Regulated		2026	
Wolf Creek	1	KS	1,205.0	Regulated		2026	

Summary information for the three early nuclear retirement cases included in ReEDS modeling runs. Dates indicate when each nuclear plant is assumed to retire; blanks indicate that the plant was not included in a particular case. Case 1 represents the merchant plants that fail the screening test for the reference case profitability analysis. Case 2 adds on the regulated and public power plants. Case 3 represents the merchant plants that fail the screening test under the low gas price assumption.

Notes: For the purposes of the profitability analysis, "public power" is equivalent to "regulated" for regulatory status. Columbia Generating Station is listed as a merchant generator in the S&P database but is more appropriately categorized as public power. For the purposes of this analysis, it is listed as a merchant generator.

SOURCE: S&P 2018; UCS ANALYSIS

[APPENDIX F]

Methods and Assumptions for ReEDS Modeling

This document describes the methodology and assumptions that the Union of Concerned Scientists (UCS) used for developing the analysis in *The Nuclear Power Dilemma*.

Regional Energy Deployment System (ReEDS)

The UCS employed the National Renewable Energy Laboratory's (NREL) Regional Energy Deployment System (ReEDS) to analyze the effects of early nuclear power plant retirements and carbon reduction policies in the United States. ReEDS is a capacity-planning model for the deployment of electric power-generation technologies in the contiguous United States through 2050.

ReEDS is designed to analyze in particular the impact of state and federal energy policies, such as clean energy and renewable energy standards, for reducing carbon emissions. ReEDS provides a detailed representation of electricity generation and transmission systems. It specifically addresses issues, such as transmission, resource supply and quality, variability, and reliability, related to renewable energy technologies (NREL 2016a).

UCS used the 2016.RE.TaxExt.P1 version of ReEDS for our analysis. Based on project-specific data and estimates from recent studies, we made a few adjustments to NREL's assumptions on renewable and conventional energy technologies, as described in more detail in "Overall Model Assumptions." Our assumptions for the policies being tested in our analysis are described in "Policy Assumptions for Scenarios."

Modeling Limitations and Uncertainties

The intent of this modeling is not to predict the future generation mix but rather to consider a range of possible futures to better understand key drivers and important implications around the timing and impacts of potential nuclear plant retirements and national carbon-reduction policies. These modeling scenarios are not forecasts, and we make no claim that the scenarios will predict the future accurately. The goal is to illustrate the potential impacts of the scenarios to build on analyses conducted by other organizations using models and assumptions developed by credible, independent sources and informed by real-world data. The value of the analysis lies more in the difference between scenarios rather than the absolute values of the projections. Other modeling and analytic frameworks will have different emphases, strengths, and weaknesses.

No discussion of the future cost of and need for nuclear units would be complete without an acknowledgment that such forecasts have historically proved far more wrong than right. One does not need to go back decades to good-faith forecasts like "too cheap to meter," "one thousand reactors by the year 2000," or "$300 per barrel oil by 2010" to demonstrate this. The forecasts of 15 years ago predicting a "nuclear renaissance" of some 50 new US nuclear reactors by 2020 or natural-gas prices three to four time higher than those presently in effect are a stark warning of the need for technologies and policies that can respond quickly when reality contradicts predictions. Likewise, the "avoided cost" forecasts that were the essence of regulatory efforts to predict the price of generation in the 1980s and 1990s were almost always wrong, and by such large margins that they contributed substantially to the onset of competitive power procurement through electric restructuring in the 1990s.

Flexibility is necessary for a second and more important reason. It is especially problematic to forecast technological innovation. Most of the surprises in the energy sector, including environmental surprises, have come from technological innovations unforeseen even five years earlier. Examples include improvements in wind, solar, and energy-storage technologies, the rapid penetration of LED lighting and other energy efficient technologies, advanced electronic controls and other new techniques for grid management, and advances in technologies for producing and burning natural gas. In addition, many existing nuclear plants have substantially reduced costs and increased production due to pressure from electric restructuring and competing technologies. And the nuclear industry is counting on vast innovation in reactor design and construction to establish its own relevance.

In short, the design of any system of support for existing technologies must seek to encourage competition. The system must not lock in the market share of today's technologies for any longer than is necessary to keep the United States on track for achieving deep reductions in carbon emissions.

Overall ReEDS Model Assumptions

COST AND PERFORMANCE

Tables F-1 through F-4 show the cost and performance assumptions for electricity-generating technologies used in the ReEDS analysis.

We made several changes to NREL's capital-cost assumptions. The 2016.RE.TaxExt.P1 version of ReEDS uses the EIA's AEO 2015 cost assumptions for conventional plants; we based our revisions on the Energy Information Administration's (EIA) *Annual Energy Outlook* (AEO) 2018 (EIA 2018d) assumptions for capital costs, operating and maintenance (O&M) costs, and heat rates.

NREL provides a set of projections, which users can easily select, regarding cost and performance assumptions on renewable energy technologies. Our choices of these projections were consistent with the corresponding assumptions underlying the *Annual Technology Baseline 2017* report (NREL 2017). The main changes we made were in the following areas:

Coal. For new integrated gasification and combined cycle plants and for supercritical pulverized-coal plants, we used NREL's assumptions, which are based on the EIA's higher costs for a single-unit plant—600–650 megawatts (MW)—as opposed to dual-unit plants—1,200–1,300 MW. For plants with carbon capture and sequestration, we used the assumptions used by NREL and the EIA and included the tax credits from 45Q.

Natural gas. For new plants, we used NREL's assumptions, which are based on the average of the EIA's assumptions for conventional and advanced plants in 2018. For plants with carbon capture and sequestration, we used the assumptions used by NREL and the EIA and included the tax credits from 45Q.

Nuclear. We used the EIA's assumed costs for 2018 with no cost reductions from learning through 2050. This is a conservative assumption as recent projects in the United States (Vogtle and V.C. Summer) have significantly higher costs than EIA's assumptions and have experienced considerable cost overruns and delays. We also assumed that existing plants will receive 20-year license extensions, allowing them to operate for 60 years, and that they will then be retired because of safety and economic issues. To date, no existing plant has received an operating license extension beyond 60 years.

Onshore and offshore wind. We used NREL's cost and performance projections from its median cost-reduction case, as described in the 2017 *Annual Technology Baseline*. These cost and performance projections are based on NREL's estimate of median values from its review of literature.

Utility-scale solar photovoltaics (PV). We use NREL's 2017 *Annual Technology Baseline* cost and performance projections from its mid-cost case and included the effects of the solar tariff.

Distributed solar PV. ReEDS does not endogenously simulate the uptake of distributed PV systems (those installed on site by residential or commercial customers). Instead, users must select the appropriate projections for uptake of these systems as an exogenous input to the model based on projections

TABLE F-1. **Comparison of Overnight Capital Costs for Electric Generation Technologies**

Technology	Overnight Capital Costs (2017$/kW)				
	2010	2020	2030	2040	2050
Natural Gas, Combined Cycle	1,054	1,047	1,000	965	926
Natural Gas, Combined Cycle/Carbon Capture and Storage	N/A	2,146	1,864	1,570	1,335
Natural Gas, Combustion Turbine	895	895	851	820	785
Coal, Supercritical Pulverized Coal	3,186	3,699	3,570	3,478	3,359
Coal, Integrated Gasification and Combined Cycle	4,109	3,966	3,713	3,543	3,357
Coal, Pulverized Coal/Carbon Capture and Storage	7,109	5,627	4,958	4,358	3,807
Nuclear	5,946	5,946	5,946	5,946	5,946
Hydro*					
Biomass, Dedicated	4,466	3,873	3,656	3,511	3,339
Biomass, Cofired with Coal**	2,989	2,989	2,989	2,989	2,989
Solar, Utility-Scale PV	4,617	1,130	940	836	741
Solar, Residential PV	6,981	2,544	1,551	1,293	1,189
Solar, Commercial PV	3,488	1,877	1,149	1,045	993
Wind, Onshore (class 3)	1,920	1,488	1,404	1,415	1,377
Wind, Onshore (class 4)	1,920	1,500	1,344	1,336	1,290
Wind, Onshore (class 5)	1,488	1,323	1,404	1,311	1,262
Wind, Onshore (class 6)	1,779	1,469	1,290	1,268	1,214
Wind, Onshore (class 7)	1,635	1,448	1,267	1,243	1,189
Wind, Shallow Offshore	5,640	4,811	4,093	3,982	3,856
Wind, Deep Offshore	6,228	5,311	4,516	4,393	4,254
Landfill Gas	9,288	8,765	8,542	8,323	8,039

Notes: *Hydro capital costs are too detailed to show in this table; ReEDs uses supply curves with capital cost variation by potential resource capacity.
**The cost for biomass cofiring is per kW of biomass capacity.

SOURCE: UCS 2018.

from NREL's dGen model (NREL 2016b). For our reference case, we used NREL projections based on NREL's 2017 *Annual Technology Baseline* mid-cost case.

Concentrating solar power plants. We assumed that concentrating solar power plants will include six hours of storage and exhibit the capital and O&M cost projections of NREL's 2017 *Annual Technology Baseline* mid-cost case.

Biomass. We used the EIA's initial capital costs for new fluidized-bed combustion plants and for biomass cofiring with coal, but we did not include the EIA's projected cost reductions due to learning because we assumed that these were mature technologies. We also used a slightly different biomass supply curve from those of the EIA and NREL, based on a UCS analysis of data from the DOE's *Updated Billion Ton* study, which included additional sustainability criteria (ORNL 2011). We projected a potential biomass supply of 680 million tons per year by 2030 (UCS 2012). Further, we limited the coal capacity that can be retrofitted for cofiring biomass to 10 percent of a plant's capacity—not the 15 percent maximum used in NREL assumptions.

Geothermal and landfill gas. We did not make any changes to NREL's assumptions for these technologies.

Storage technologies. We assumed that utility-scale batteries are four-hour-duration, lithium-ion systems with cost assumptions based on recent studies (Lazard 2017; Cole et al. 2016).

Hydro. To reflect the long lead times for planning, permitting, and building large hydro dams, we restricted the construction of such facilities until after 2020. Based on the 2016 Hydropower Vision study, we increased the costs of non-powered dams to be twice those assumed by NREL (DOE 2016b). We did not make any other changes to NREL's assumptions for the hydro supply curves, which are site-specific.

ELECTRICITY SALES AND ENERGY EFFICIENCY PROJECTIONS

ReEDS does not endogenously model electricity sales or efficiency; instead, users provide assumptions of future use. As a default, electricity sales are taken from

TABLE F-2. **Operation and Maintenance (O&M) and Heat Rate Assumptions**

Technology	Fixed O&M ($2017/kW-yr)	Variable O&M ($2017/MWh)	Heat Rate (Btu/kWh)	
			2020	2050
Natural gas, combined cycle	10.6	2.8	6,624	6,275
Natural gas, combined cycle / carbon capture and storage	33.8	7.2	7,504	7,493
Natural gas, combustion turbine	12.3	7.2	9,756	9,075
Coal, supercritical pulverized coal	33.2	4.8	8,760	8,740
Coal, integrated gasification and combined cycle	54.1	7.6	7,867	7,450
Coal, pulverized coal / carbon capture and storage	70.0	4.7	9,105	9,316
Nuclear	101.3	2.3	10,479	10,460
Biomass	112.2	5.6	13,500	13,500
Solar PV-utility	13.4	0.0	n/a	n/a
Solar CSP-With Storage	68.3	0.0	n/a	n/a
Wind-Onshore	52.5	0.0	n/a	n/a
Wind-Shallow Offshore	136.5	0.0	n/a	n/a

Note: Fixed and variable O&M costs are for 2020 through 2050; costs for earlier years are higher.

SOURCE: NREL 2016A.

TABLE F-3. **Solar Capacity Factors**

Technology	Capacity Factor
Utility-Scale Solar PV	14-28%
Concentrating Solar Plant with Six-Hour Storage	8-38%

SOURCE: NREL 2017.

the EIA's AEO 2018 projections. ReEDS starts with the 2010 electricity sales for each state, then projects future electricity sales using the growth rate for the appropriate census region from the AEO 2018 reference case. We adjusted these projections to account for reductions in load growth resulting from currently enacted state energy efficiency resource standards (EERS) that are not included in the AEO 2018. Our adjustments follow the approach used by the Environmental Protection Agency in *Projected Impacts of State Energy Efficiency and Renewable Energy Policies* (EPA 2014).

STATE RENEWABLE PORTFOLIO STANDARD (RPS) PROGRAMS

ReEDS uses RPS data from a 2015 Bloomberg New Energy Finance (BNEF) RPS database. We adjusted ReEDS' representation of the state programs to account for recent legislation and demand forecasts. We based our adjustments on the Lawrence Berkeley National Laboratory's 2017 *RPS Annual Status Report* and industry reports and projections in NREL's *Annual Technology Baseline* (LBNL 2017; NREL 2017).

ACCOUNTING FOR RECENT OR PLANNED CHANGES TO GENERATING RESOURCE OR TRANSMISSION AVAILABILITY

We reviewed ReEDS assumptions for expected changes in power-plant capacity and transmission lines in the near term and compared that with our understanding, based on S&P Global data (S&P Global 2018) and industry reports and projections, of real-world conditions. Our updates to ReEDS included:

- Accounting for prescribed builds of newly constructed or under construction generating resources (including natural gas, nuclear, coal, wind, and utility-scale solar facilities) using a combination of S&P and industry association data published as of March 2018;
- Accounting for recent or recently announced coal-plant retirements through 2030 based on data published as of March 2018;
- Accounting for recent or recently announced nuclear-plant retirements based on data published as of April 2018;
- Accounting for transmission projects under construction or in an advanced stage of development using a combination of S&P and industry association data published as of April 2018; and
- Including California's requirement for storage (AB 2514).

CALCULATION OF THE MONETARY VALUE OF CARBON DIOXIDE (CO_2) REDUCTION BENEFITS

To determine the monetary value of CO_2 reductions, we used the US government's estimates of the "social cost of carbon"—an estimate of the damages, expressed in dollars, resulting from the addition of one metric ton of CO_2 to the atmosphere in a given year. We multiplied the tons of CO_2 reduced in our scenarios by the social cost of carbon to derive the CO_2-reduction benefits or the avoided damages.

We used the updated values for the social cost of carbon that were reported in the Environmental Protection Agency's (EPA) *Regulatory Impact Assessment for the Clean Power Plan Final Rule* (Table F-5) (EPA 2015).

CALCULATION OF THE MONETARY VALUE OF SULFUR DIOXIDE (SO_2) AND NITROGEN OXIDES (NO_X) REDUCTION BENEFITS

To value SO_2 and NO_x emissions reductions, we used estimates from the EPA *Regulatory Impact Assessment*

TABLE F-4. **Comparison of Wind Capacity Factors**

Technology	Capacity Factor				
	2014	2020	2030	2040	2050
Wind, Onshore Class 3	32.0%	34.5%	37.0%	38.3%	39.6%
Wind, Onshore Class 4	37.7%	40.7%	43.6%	45.1%	46.7%
Wind, Onshore Class 5	43.9%	46.5%	49.2%	50.8%	52.5%
Wind, Onshore Class 6	46.6%	49.0%	51.5%	53.2%	54.9%
Wind, Onshore Class 7	51.1%	53.7%	56.4%	58.2%	60.1%
Wind, Offshore Class 4	34.6%	35.3%	37.9%	38.3%	38.8%
Wind, Offshore Class 5	40.3%	41.2%	44.1%	44.7%	45.2%
Wind, Offshore Class 6	43.2%	44.2%	47.3%	47.9%	48.4%
Wind, Offshore Class 7	47.3%	48.4%	51.8%	52.4%	53.0%

SOURCE: NREL 2016A.

for the Clean Power Plan Final Rule of the dollar value of the health benefits per ton of SO_2 and NO_x reduced by different industrial sectors, including the electricity sector (EPA 2015).

In particular, for the 2020 emissions reductions generated in our models, we used the values in the EPA's Table 4-7. There, these values are expressed in 2011 dollars using a 7 percent discount rate, so we converted them to 2017 dollars to be consistent with other dollar values in our analysis. For 2025 and 2030, we used the values in Tables 4-8 and 4-9, again converted to 2017 dollars.

Policy assumptions. We compared a number of scenarios: a ReEDS reference case, three early retirement scenarios, a carbon-price scenario, and a low-carbon electricity standard scenario. For each scenario, we ran the ReEDS model for the contiguous United States, with a consistent set of assumptions across all states.

The ReEDS reference case includes:

- State and federal policies in place as of February 2018, and the assumption that no additional policies have been or will be implemented;
- The electricity demand and coal prices from the reference case of the AEO 2018;
- The natural gas price projection from EIA's AEO 2018 "high oil and gas resource and technology" side case to be consistent with the plant-level analysis;
- State energy-efficiency standards through December 2017, as calculated by UCS based on data from state utilities and from the Database of State Incentives for Renewables and Efficiency, using a methodology developed by the EPA for state analyses;
- State renewable energy standards, as established through July 2018 based on information calculated by Lawrence Berkeley National Laboratory or the National Renewable Energy Laboratory as part of ReEDS assumptions;
- The model's data for existing power plants updated to include recent and announced retirements and plants under construction and current state energy efficiency programs. This included the seven nuclear reactors at five plants

TABLE F-5. **Values for Social Cost of Carbon**

Year	2017$ per ton of CO_2
2018	$47
2020	$50
2025	$54
2030	$59

Note: Value assumes a 3 percent discount rate.

SOURCE: EPA 2015, TABLE 4-2.

that have firm plans to retire over the next eight years. We also included two reactors under construction at the Vogtle plant in Georgia.
- The model revisions described in the previous section.

The early retirement cases layer on the early retirement of plants that fail our screening test based on the results from the profitability analysis onto the ReEDS reference case. We prescribed retirement dates for existing nuclear power plants that we determined to be at risk based on the results of the plant-level analysis (see Table E-4 in Appendix E). The screening test focused on plants that showed up as unprofitable or marginal in the three five-year periods between 2018 and 2032.

The early retirement cases are:

- Early retirement case 1 represents merchant plants that fail the screening test in the profitability analysis reference case.
- Early retirement case 2 represents both merchant and regulated plants (Case 2) that fail the screening test in the reference case.
- Early retirement case 3 represents merchant plants that fail the screening test in a low gas price scenario.

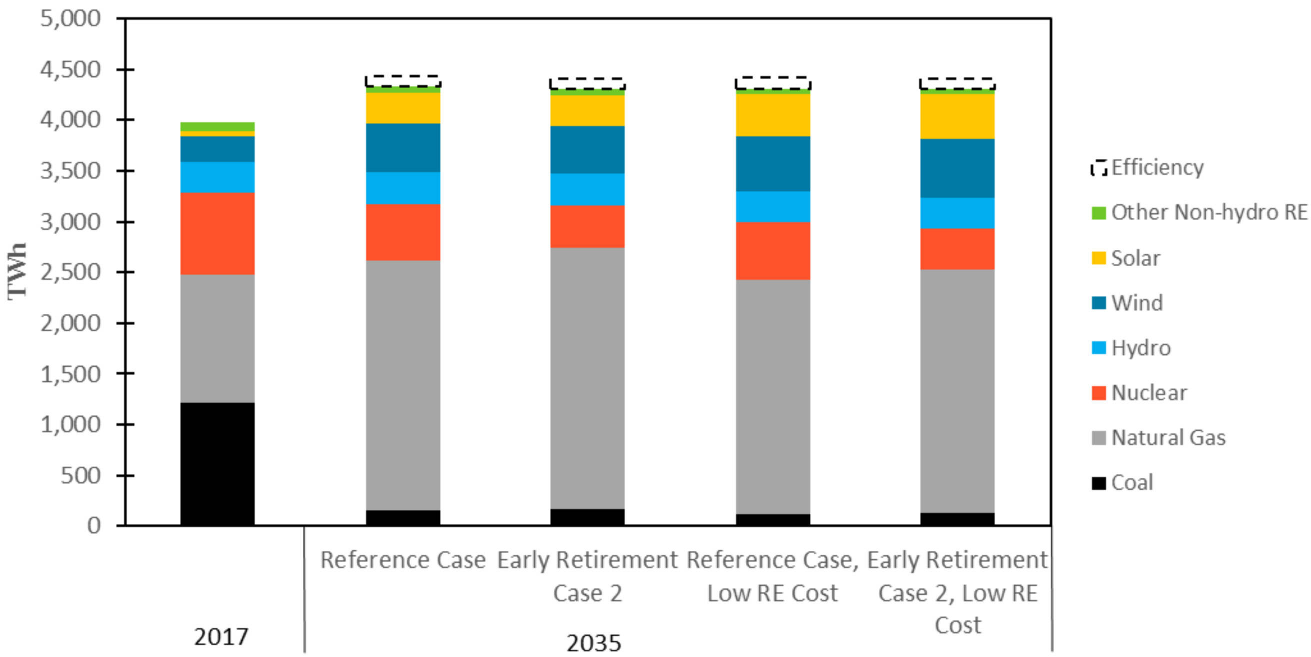
The national carbon-price policy case includes:

- A national carbon price of $25 per ton price on CO_2 in 2020, increasing 5 percent per year based on AEO 2018's scenario, layered over the reference case;
- A national energy efficiency standard that assumes that all states achieve at least a 1 percent per year reduction in electricity sales from 2022 to 2030 and that states with stronger energy efficiency standards continue to meet their respective targets (UCS 2016). This energy-efficiency policy is modeled as a reduction in electricity demand in ReEDS, with the costs of implementing the policy and net savings on consumer electricity bills estimated outside the model.

The national low-carbon electricity standard (LCES) case includes:

- A national LCES of 45 percent in 2020, increasing to 60 percent in 2030 and 80 percent by 2050 layered over the reference case. We estimated the share of generation in 2020 based on the results the ReEDS reference case and assumed LCES targets would ramp up at 1.5 percent per year through 2030 and 1 percent per year from 2031 to 2050. We assumed that several technologies would be eligible to meet the standard, including new and existing nuclear plants, renewable energy technologies (from hydro, wind, solar, biomass, and geothermal), and natural gas and coal plants equipped with carbon capture and storage (CCS), with capture rates of 90 percent or more. We assumed that nuclear and renewable energy facilities would get full credit toward the standard and CCS projects would receive partial credit based on their capture rate (e.g., a CCS project that captures 90 percent of CO_2 emissions would be credited at 90 percent of its generation).
- A national energy efficiency standard of at least 1 percent per year from 2022 to 2030, as in the carbon-price case.

FIGURE F-1. **US Electricity Mix, 2017 and 2035, Low Renewable Cost Sensitivity Analysis**



Sensitivity analysis

For this analysis, we also considered a number of sensi-tivity scenarios: a ReEDS reference case with low renewable technology costs and early retirement case 2 with low renewable technology costs.

The ReEDS reference case with low renewable technology costs includes renewable technologies cost projections from NREL's ATB 2017 Low Technology Cost Scenario, including the inputs for distributed PV, layered over the ReEDS reference case.

The early retirement case 2 with low renewable technology costs includes renewable technologies cost projections from NREL's ATB 2017 Low Technology Cost Scenario, including the inputs for distributed PV, layered over early retirement case 2.

The sensitivity analysis found that, while lower costs for renewable technologies lead to increased adoption (Figure F-1), early nuclear retirements are still replaced primarily with natural gas and coal (Figure F-2). Closing the at-risk plants early in the lower renewable cost scenarios results in a cumulative 13 percent increase in US power-sector carbon emissions by 2035 (0.6 billion metric tons) from burning more natural gas and coal (Figure F-3). Even with lower costs for renewable technologies, additional policies are needed for the United States to achieve deep cuts in carbon emissions.

FIGURE F-2. **Change in US Electricity Generation, Early Retirement Case 2 vs. Reference Case without Early Retirements, Low Renewable Cost Sensitivity**

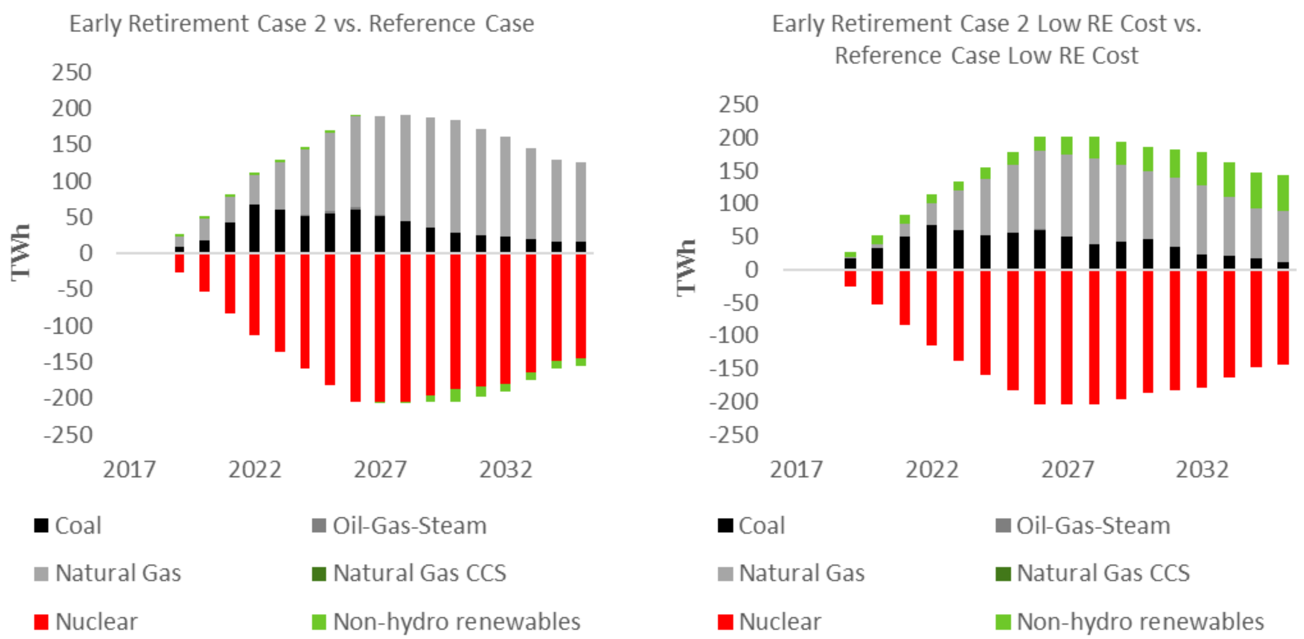


FIGURE F-3. **US Power Plant CO_2 Emissions, Sensitivity Analysis**