A Clean Energy Pathway for New Jersey

Prepared for New Jersey Conservation Foundation as part of ReThink Energy NJ
by the Institute for Energy and Environmental Research and PSE Healthy Energy

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Executive Summary

We have developed a clean energy pathway that will enable the state of New Jersey to halve its electric power sector carbon dioxide emissions by 2030, a key component of a broader effort required to meet the 2050 greenhouse gas emission targets under the Global Warming Response Act (GWRA). We describe a Clean Energy Scenario that relies on the combination of three elements to achieve affordable emission reductions: greater energy efficiency, continuing New Jersey's historic levels of solar growth, and a new focus on offshore wind. In this Scenario, in-state renewable energy provides 33% of total generation needs by 2030. The cost is estimated to be comparable to a business-as-usual approach. Additional considerations include partial electrification of transportation and fossil fuel heating and a contingency for early nuclear power plant retirements. This latter analysis suggests that near-term procurement of renewable electricity imports to offset premature nuclear retirements may be a prudent and cost-effective way to ensure that emission reductions are maintained. Health and equity concerns will require specific actions to realize pollution reduction and clean energy benefits for everyone, particularly people living in vulnerable and overburdened communities. The Clean Energy Scenario will set the state on a course to develop the clean, equitable and resilient electric power system needed to achieve deep decarbonization across all sectors by 2050.

Overview of findings

Achieving the GWRA's 80% greenhouse gas emission reduction target from all energy sectors by 2050 is contingent upon decarbonizing the electric power sector and converting transportation, heating, cooling, and other fuel-using systems to run on renewable electricity. We analyze the potential for reasonable deployment rates of in-state resources including solar, offshore wind, and efficiency to replace fossil fuel power generation and evaluate the generation costs associated with deploying these resources from 2018-2030. We find the clean energy pathway to be:

- **Essential:** Investment in energy efficiency and expansion of in-state solar and offshore wind resources to provide 33% of electricity will enable New Jersey to cut power sector emissions in half by 2030, an important and urgent intermediate step to ensure growth of low-carbon power for the electrification of transportation and heating required to achieve the state's 2050 GWRA goals.
- **Achievable:** The clean energy pathway developed here is a conservative projection of what can be achieved by 2030. The efficiency target of 2% per year is a rate that has already been attained in several states in the Northeast. Solar targets continue the historic growth already realized in New Jersey. The development of 3,250 megwatts (MW) of the state's plentiful offshore wind resources is feasible and could be expanded further as costs decline.

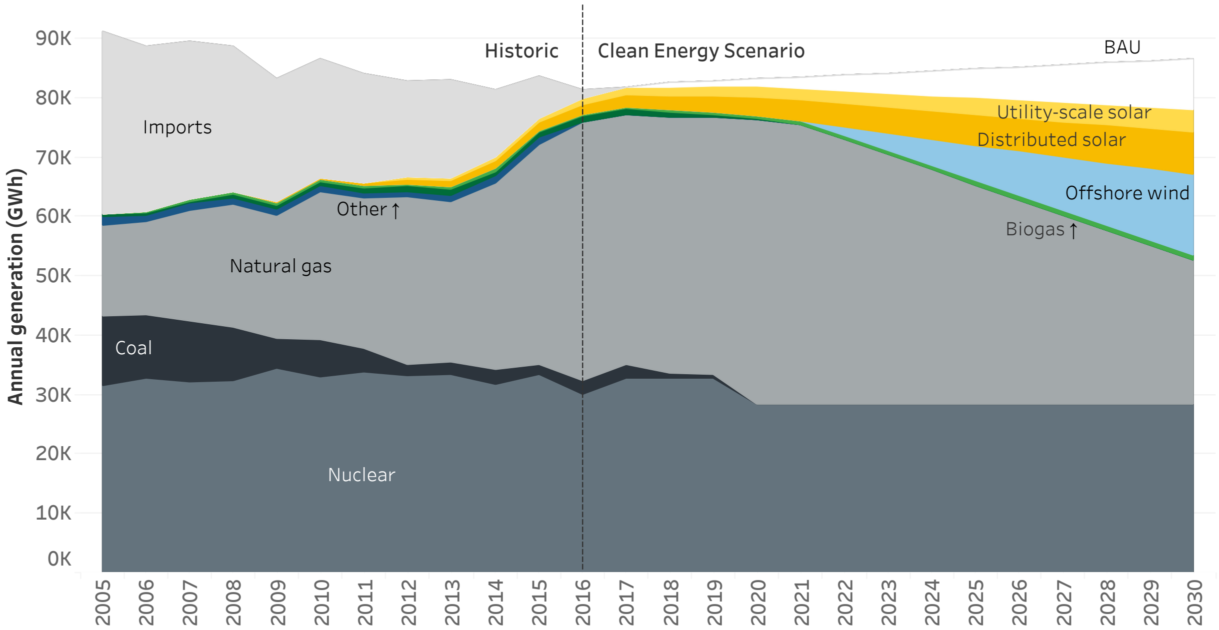

Figure E1: Electricity generation used to meet New Jersey's power sector needs, including the proposed Clean Energy Scenario to 2030. Expanded efficiency, offshore wind and solar resources displace coal and natural gas generation. Total generation in 2030 is lower than business-as-usual due to the growth of efficiency from 0.6% to 2%, even when accounting for initial electrification of vehicles and heating systems.

- **Affordable:** The proposed expansion of renewables is projected to moderately increase electricity generation costs, but overall costs of delivering electricity services to New Jersey consumers will be about the same due to efficiency savings.[1] Ongoing cost declines are expected to make renewables the most affordable energy generation resources after 2030. Additionally, wind and solar will provide a hedge against volatile or increasing natural gas prices. These cost projections do not include the significant health and environmental benefits of reducing harmful emissions.

We have developed a Clean Energy Scenario that incorporates these elements into an electricity system that can transition to deep decarbonization by the year 2050. New Jersey's historic nuclear and natural gas-dominated power generation mix and the proposed resources used to reduce emissions by 2030 are shown in **Figure E1**.

We also considered the Clean Energy Scenario cost impacts of two contingencies: 1) early nuclear power retirements, and 2) high natural gas prices. Important conclusions from these analyses are as follows:

- **Emissions can be reduced significantly, even if nuclear power retires early.** Given recent nuclear power plant retirements in Wisconsin, California, and elsewhere before their expiry dates, and plans for above-market payments to keep plants in New York and Illinois online, we considered the possibility that the Salem and Hope Creek Generating Stations would retire before 2030. If the retired nuclear plants are replaced by natural gas, power sector carbon emissions in 2030 would increase an estimated 5%

[1] The estimated difference in the year 2030 is that the cost of electricity in the Clean Energy Scenario will be about 1% more than business as usual. This is well within the uncertainty of the calculations and of the energy market. For instance, if the natural gas price rises faster than assumed, it would more than cancel out the cost increase (see below).

from 2015 levels even with the efficiency and renewable energy efforts outlined earlier, and spike significantly without such efforts. However, our analysis also suggests that policymakers can consider another option: building on the Clean Energy Scenario with about 500 MW of additional offshore wind and a significant expansion of low-cost renewable energy imports from PJM, the regional transmission operator (employing Virtual Power Purchase Agreements (VPPAs), for instance). This approach would allow New Jersey to meet the 50% emission reduction target from the electric sector by 2030 without any remaining nuclear plants at a cost comparable to the projected cost of above-market payments for nuclear, when analyzed from a generation cost standpoint. Additional reliability investment may be called for after required analysis by regulators. Ensuring grid reliability is the province of PJM.

- **The Clean Energy Scenario would cost less than business as usual if natural gas prices increase more than the reference scenario considered here.** If natural gas prices are on the high end of the U.S. Energy Information Administration's projections for 2030, then the proposed renewable energy expansion would cumulatively save about $2.4 billion by 2030,[2] illustrating that renewables provide a hedge against fossil fuel price uncertainty. Renewables will also provide fuel diversity and can mitigate price spikes from overreliance on a single fuel like natural gas.

Other important considerations and findings in the report include:

- **The Clean Energy Scenario sets the stage for electrification of transportation and heating.** We assume initial electrification of 5% of vehicle miles traveled in New Jersey by 2030, and 10% additional electrification of heating by replacing 80% of residential heating systems that currently use fuel oil and propane with highly efficient electric heat pumps. This electrification reduces both greenhouse gas and health-harming criteria pollutant emissions, and begins the pathway towards nearly complete electrification of these sectors by 2050. The values here are used to evaluate power sector impacts of electrification, not to explicitly set transportation or heating targets, which must also include efforts such as building weatherization and fuel economy improvements. Our calculations indicate that widespread electrification needed for deep decarbonization would roughly double the electricity generation needs of New Jersey by 2050 compared to 2030.

- **Planning is needed to ensure an equitable, healthy, and just transition.** We find that communities living near New Jersey's fossil fuel power plants have 50% more minority residents and 75% more low-income residents than the state average. Meanwhile, average rooftop solar deployment per household is half the state average in the zip codes with incomes in the lowest 20%. The proposed clean energy pathway is projected to reduce health-harming criteria pollutant emissions, including approximately 75% reduction in nitrogen oxide emissions and a near-total elimination of sulfur dioxide emissions from the power sector. However, the above data also suggest the need to assess equity when comparing emission reduction policy strategies. This includes ensuring that criteria pollutant emissions are reduced in New Jersey overall as well as in vulnerable communities in particular, and that solar and energy efficiency access increases for low-income communities.

- **The clean energy transition can help increase the resilience of the electric grid.** We included 1,600 megawatt-hours (MWh) of energy storage by 2030, allocating half to renewable microgrids that can increase resilience, including backup during

[2] Discounted at 3% to present value.

outages. Permitting and encouraging distributed solar systems to operate both with and independently from the grid can allow residents to access electricity even in the case of grid outages. Fuel diversity also increases resilience in the face of fuel shortages. While we did not include investments in additional smart grid upgrades in our cost calculations, the deployment of smart grid technologies can both increase demand flexibility to help incorporate renewables and allow for rapid outage detection.

- **Reduced natural gas use will lower upstream methane emissions along with carbon dioxide emissions.** Our analysis describes primary targets based on combustion-related power sector grid emissions, but methane, a greenhouse gas 86 times more potent than carbon dioxide over 20 years, can leak throughout the natural gas system. Exact leakage values are uncertain, but a 3.5% fugitive emission rate for methane, for example, would nearly double New Jersey's direct power sector greenhouse gas emissions. Because New Jersey's current carbon dioxide emissions from the power sector are primarily from natural gas, our 2030 targets can be expected to cut upstream methane emissions nearly in half along with combustion-related carbon dioxide emissions. The methane leakage issue reinforces the need to switch directly from other fossil fuels such as coal or petroleum directly to renewable electricity rather than resorting to natural gas as a transitional step.
- **The benefits of the Clean Energy Scenario are much greater than direct costs indicate.** As mentioned above, the Clean Energy Scenario will reduce emissions of carbon dioxide, methane, and health-harming co-pollutants, as well as provide storage and distributed generation to increase grid resilience. Additional benefits include the creation of local jobs, the opportunity for New Jersey to become an industry leader in offshore wind, reduction of health care costs occasioned by co-pollutants, and reduction of water use for power plant cooling.

Research approach and generation cost analysis

This analysis takes a New Jersey-centric approach to reducing power plant emissions. New Jersey comprises roughly 10% of the PJM grid, which provides significant balancing and grid reliability to the state. Because New Jersey participates in this larger PJM market, specific plant dispatch and operation will depend on PJM-wide decisions beyond New Jersey's borders, which we do not model here. However, the state-specific framework is useful for assessing New Jersey's potential contributions to climate-protection efforts. The emissions reduction scenarios described in the body of the report ensure that New Jersey's net generation matches load requirements until 2030, and assume renewable deployment in the state will displace in-state fossil generation. This displacement, however, cannot be realized with a renewable energy target alone because gas plants in the state may continue to export outside of the New Jersey grid. Additional policy and regulatory tools may therefore be required to ensure in-state emission reductions.

The scenarios described here are meant to provide an achievable approach to reducing emissions, but are by no means the only pathways available. We have fixed growth rates for solar, offshore wind, and efficiency at ambitious but realistic rates that have been achieved within New Jersey or other locations, or validated by industry sources when available. Higher growth rates may be achievable, but in the contingency of early nuclear power plant retirements, we have opted to rely primarily on out-of-state renewable energy imports to replace this lost generation rather than expand in-state deployment (other than offshore wind) faster than in our Clean Energy Scenario. This option is not without challenges, and may, for example, increase transmission and congestion charges in New Jersey. Changing inputs—including the rate of cost declines for renewables, PJM market decisions, natural gas prices, unexpected plant retirements, vehicle electrification rates and policies—may all affect the speed and pathway by which New Jersey reduces its greenhouse gas emissions.

In our carbon-cutting Clean Energy Scenario for 2030, we expand solar at the maximum historic annual growth rates seen in New Jersey, increase efficiency to 2% annual savings, and set a target of 3,250 MW for offshore wind. In **Figure** E2 we compare the cumulative costs of this scenario to the costs of a business-as-usual pathway based on PJM load forecasts, existing solar targets, current efficiency levels of 0.6%, and Energy Information Administration and Environmental Protection Agency cost projections. Renewable energy, energy efficiency and other technology costs that are used to calculate the scenario total costs are derived from the National Renewable Energy Lab, Lawrence Berkeley National Laboratory, the NJ Clean Energy Program, offshore wind studies, and consultation with industry. These technology costs are expected to be conservative, although we do assume that policy changes will result in lower-priced renewable energy incentives than New Jersey's current solar renewable energy credits (SRECs). This comparison of the total delivered costs of electricity primarily highlights differences in the electricity production costs, because assumed non-generation costs were similar in each case, with the exception of some avoided costs due to efficiency savings and the expansion of transmission and energy storage in the Clean Energy Scenario.

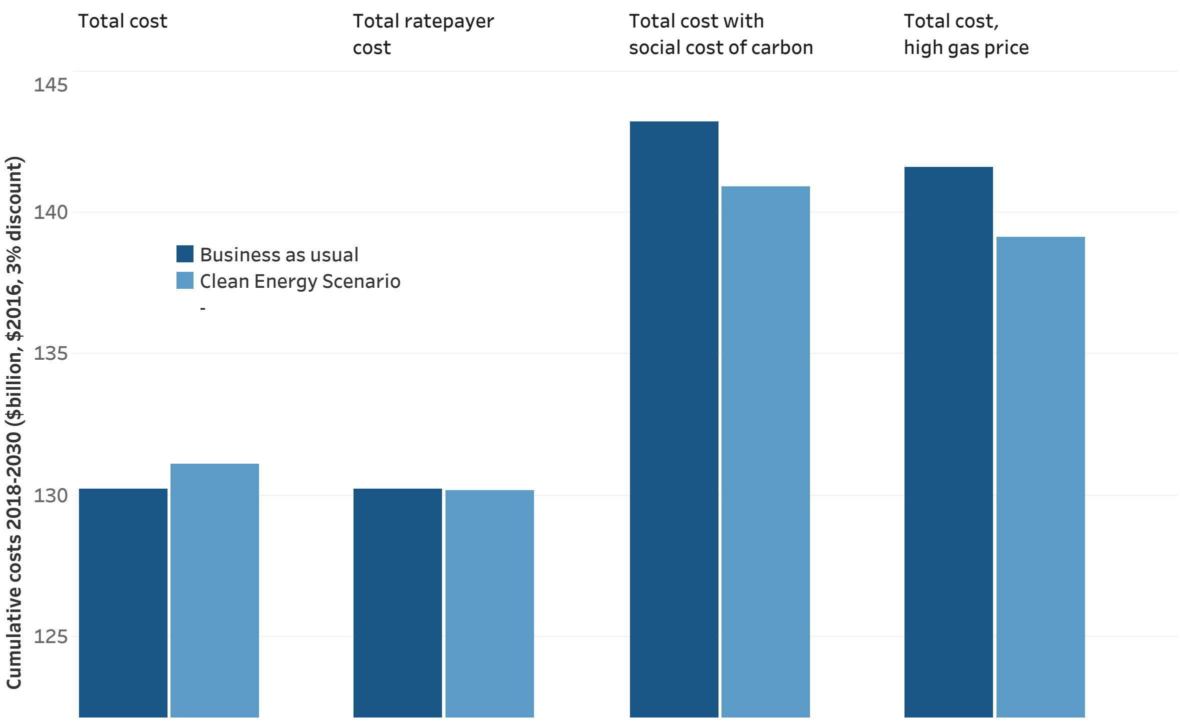

Figure E2: A comparison of the cumulative Clean Energy Scenario cost to the business-as-usual cost of electricity services from 2018-2030. Includes i) total costs (2016 dollars, 3% discount rate); ii) cumulative costs from the ratepayer perspective, excluding customer efficiency expenditures; iii) cumulative costs including the social cost of carbon; iv) cumulative costs in the case of high gas prices.

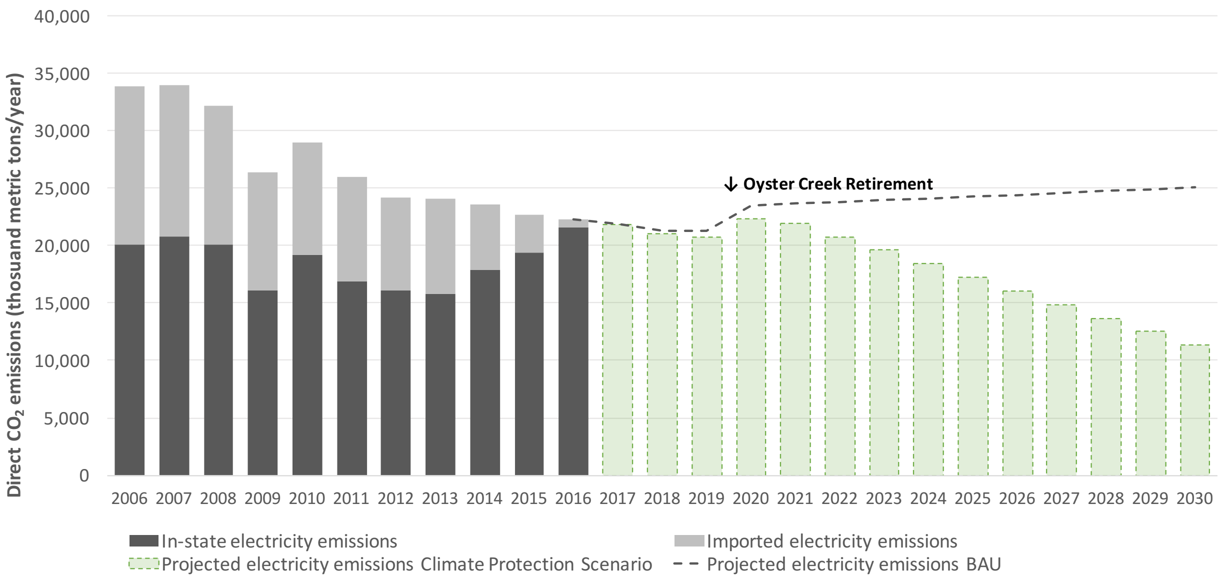

Figure E3: Historic and projected direct carbon dioxide emissions from in-state and imported electricity in New Jersey, comparing business-as-usual to the Clean Energy Scenario. Fugitive methane emissions (not shown) increase total emissions but are expected to fall in a similar proportion to direct carbon dioxide reductions.

With the caveat that future cost projections include significant uncertainties, our results suggest that New Jersey can cut electricity sector carbon emissions in half by 2030 without a significant cost penalty. The Clean Energy Scenario reduces cumulative power emissions from 2018 to 2030 by 85 million metric tons of carbon dioxide. The direct carbon dioxide emissions of the Clean Energy Scenario by year as compared to the business-as-usual scenario are given in **Figure E3**.

There are two principal reasons that the costs of the Clean Energy Scenario are comparable to business as usual, despite higher generation costs per megawatt-hour.

First, in the near term, greater efficiency reduces the need for electricity generation, including expensive peaking resources. For instance, we estimate that the need for peaking gas turbine generation would be 54% less than business as usual by 2030—a value in line with or conservative compared to PJM estimates. Peaking generation costs would be about $17 million lower in 2020, growing to almost $400 million lower by 2030 in the Clean Energy Scenario compared to business as usual (undiscounted). The overall avoided generation and related costs due to efficiency would grow over time, totaling more than $600 million in 2030.

The second reason for cost neutrality is fundamental to the current and projected economics of clean energy. Well before 2030, projections show that New Jersey utility-scale solar should be competitive with natural gas without subsidies; offshore wind costs are expected to decline rapidly. Utility-scale solar is already the cheapest source of electricity in some parts of the country, and the cost comparison comes out in favor of renewables in an ever-expanding set of regions when the social and environmental costs of carbon are considered. While New Jersey is unlikely to ever have the lowest cost solar in PJM due to its higher land values and land-use goals, costs within New Jersey are still expected to decline.

Table 1: Summary of costs and carbon reductions for business-as-usual and Clean Energy Scenarios. Values do not include electric vehicle (EV) and heating (HVAC) electrification unless otherwise indicated.

	Base case, no ZECs	Base case with ZECs	Early nuclear shutdown	Staggered nuclear shutdown	Business-as-usual
Cumulative generation, GWh	1,008,737	1,008,737	1,008,737	1,008,737	1,088,196
Cumulative generation with EV/HVAC, GWh	*1,037,473*	*1,037,473*	*1,037,473*	*1,037,473*	*1,088,196*
Cumulative CO_2 emissions, mil. mt	224	224	224	224	310
Cumulative cost 2018-2030, mil.$	$131,100	$136,300	$136,900	$135,300	$130,200
Cumulative cost increase relative to BAU, mil.$	$900	$6,100	$6,700	$5,100	NA
Cost increase per mt CO_2 reduction, $/mt	$11	$71	$78	$60	NA
Average cost increase per MWh, $/MWh	$1	$6	$7	$5	NA

In **Figure** E2 we have taken a total-cost-of-energy-services approach to comparing the Clean Energy Scenario with business as usual. This means that consumer costs, such as payments for owning distributed solar behind the meter and for purchasing more efficient appliances, are included in the total cost for the Clean Energy Scenario. However, it is relatively straightforward to estimate and separate the consumer payments for energy efficiency and estimate the ratepayer perspective on efficiency, all other things being equal.[3] This calculation is shown in **Figure** E2 (ii), illustrating that the average ratepayer cost in this case is actually slightly lower than business as usual. **Figure** E2 (i) implies slightly higher total costs for energy services; **Figure** E2 (ii) shows slightly lower average ratepayer costs when the consumer expenditures on efficient appliances are excluded to obtain a ratepayer perspective. However, it is not assured that everyone would benefit equally, in particular low-income households and renters which may lack access to efficiency upgrades without suitable policy efforts.

We also develop two contingency scenarios in which the nuclear reactors at the Salem and Hope Creek plants either retire at the end of 2021 or are phased out in stages between the end of 2021 and the end of 2025. In these contingency scenarios, we explored a policy option in which the lost generation is replaced with roughly 500 MW of offshore wind, with the rest being secured by wind and solar imports from across PJM. We have also included some costs for replacing lost tax revenues in communities where nuclear or fossil plants may close to prevent or at least significantly mitigate economic distress.

Importantly, total carbon dioxide emissions from 2018 to 2030 in the contingency scenarios are capped at the same level as in the base-case Clean Energy Scenario. By creating an artificial cap, we can ensure that any spikes in gas use after nuclear retirements are compensated for at other times.

For comparison, we also consider the option that nuclear power plants are subsidized with zero emission credits (ZECs) to continue operation past 2022, as is currently planned in

[3] In effect, this calculation assumes that all other costs except the consumer costs for efficiency are in the electricity bill. This "bill" represents the cost of energy services per month using a ratepayer perspective on efficiency. This calculation is meant to illustrate the impact of each scenario on average bills, but not to predict actual bills, which will depend on rate structure and other decisions beyond our scope.

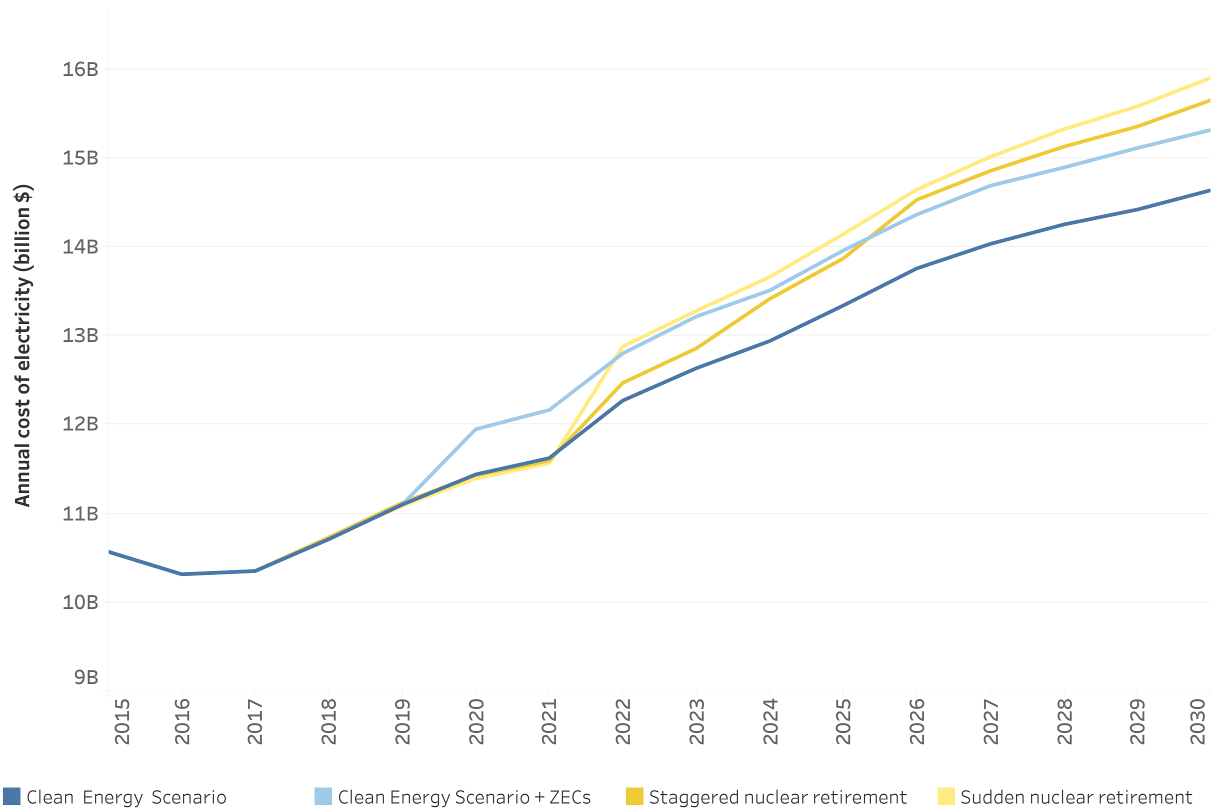

Figure E4: A comparison of four scenarios with the same constraints on carbon emissions: the Clean Energy Scenario with and without above-market payments to keep nuclear plants online (called "Zero Emission Credits," or ZECs) and early nuclear retirement with higher offshore wind and renewable imports. These costs include additional electrification of vehicles and heating systems, which are excluded from our business-as-usual scenario comparisons.

New York and Illinois. These costs are compared in **Figure E4**. If ZECs are priced at the same levels as proposed in New York State, then a ZEC subsidy offers no savings up to 2030 over retiring the nuclear power plants in New Jersey and importing renewable electricity from across PJM by utilizing VPPAs from the standpoint of electricity generation costs, although we do not analyze in-state reliability upgrades that may be needed in the case of retirements. Our analysis is indicative; further work will be needed to evaluate the risks and benefits of the two approaches (including financial risks), reliability needs, and costs in the post-2030 timeframe when the licenses of the nuclear plants are due to expire.

A summary of the costs of each scenario and emission reductions is presented in **Table 1**. The cost of reducing carbon emissions varies across these scenarios from $11 per metric ton in the base case of the Clean Energy Scenario to $78 per metric ton for sudden early nuclear retirement and $60 per metric ton in case of staggered nuclear retirement (at a 3% discount)[4]—all of which are close to or lower than the social cost of carbon, which is above $40 per metric ton, growing to $50 per ton in 2030 [1].

Our projections here are based on the best available data, but significant uncertainties remain, particularly regarding future costs of fuel and conventionally generated electricity. However, we do not expect the 33% renewable energy target to provide substantial reliability

[4]The cost in case of abrupt shutdown is higher because we assume that renewable energy would begin to be imported starting in 2019, even though shutdown is assumed at the end of 2021. Later acquisition of larger amounts of solar and wind would reduce these costs, while keeping cumulative emissions in 2018-2030 the same. Our assumption was made to indicate the potential for early action and its cost.

concerns, given that PJM recently modeled the impact of 30% renewables across PJM and found no significant reliability concerns [2], and New Jersey load accounts for only one tenth of PJM. However, in the case of nuclear retirements, PJM is required to conduct reliability analysis and could request that transmission upgrades be completed to ensure reliability prior to agreeing to such shutdowns.

Policy considerations

Our charge in this report was to illuminate policy options and their technical and economic implications, rather than to make specific policy recommendations. We have done so in certain key areas, mainly connected with an energy transition in which the role of efficiency and solar and wind energy is much greater than the present New Jersey trajectory. In this context, we have also addressed certain equity and community transition issues. Achieving emissions reductions in New Jersey will depend on a combination of policies designed to tilt market-based decisions away from fossil fuel generation. The emissions from individual plants will depend on market dispatch within PJM. Requiring high levels of in-state renewables may be one of the most direct ways to influence in-state fossil fuel generation levels, and energy efficiency investments can also impact demand for local generation. However, both market- and nonmarket-based policies should be considered to ensure real emissions reductions are achieved in state, particularly in communities that are most affected by health-harming co-pollutant emissions.

Efficiency: The expansion of efficiency from the present 0.6% per year to about 2% per year is at the core of ensuring the affordability of a Clean Energy Scenario to 2030. Efficiency program spending will need to increase to appropriate levels to ensure effective and successful results. Special policy measures will have to be adopted to guarantee that low- and moderate-income households, particularly renters, receive sufficient efficiency investments to lower their energy consumption and improve energy affordability.

Renewable energy targets: In our scenario, emission reductions of 50% assume a 2030 target of 33% in-state renewable energy. New Jersey's current renewable energy targets include 4.1% in-state solar generation by 2028 and 20.38% additional renewable energy credits for electricity generated somewhere within the PJM region. To ensure that in-state solar and offshore wind ramp up at the rates described here, several policy options are available, such as rebates for distributed solar and competitive capacity bidding for offshore wind—an approach that has led to steady cost declines elsewhere. A procurement process, such as the one newly adopted in Massachusetts, would enable New Jersey to use competitive bidding and Power Purchase Agreements (PPAs) to acquire between 3,250 and 3,800 MW of offshore wind energy by 2030.

Solar energy incentives: New Jersey's current solar incentives, the Solar Renewable Energy Credits (SRECs), have historically played a key role in catalyzing solar deployment but have not fallen in proportion to declining solar cost. Direct rebates per watt of installed capacity for distributed solar, such as that used in New York's "Megawatt Block" program, can help ensure that solar projects can obtain financing at lower cost based on a certain, though much smaller, incentive.

Planning for nuclear retirement contingencies: Without planning, an early retirement of Salem and Hope Creek nuclear plants is likely to result in a persistent rise in natural gas use and increased carbon emissions. A proactive strategy would substantially reduce the risk of increased emissions in case of such retirements. One approach is the acquisition of out-of-state renewable energy, such as through long-term VPPAs, beyond the in-state deployment rates described. Such procurement could begin as early as 2019, locking in low guaranteed prices for renewable energy generation past 2030 to help meet the demand for low-carbon electricity to electrify transportation and other sectors. Another option, adopted by New York's Public Service Commission in 2016, is to provide above-market payments for nuclear energy in the form of Zero Emission Credits (ZECs) to prevent premature shutdown. The costs of these approaches are broadly comparable up to 2030, as illustrated in Figure E3. However, it is important to note that investing in renewables in the near term rather than paying for ZECs will lower future replacement costs beyond 2030 and will help New Jersey maintain its carbon reduction goals whenever the nuclear plants do retire.

Impact on rates and bills: All other things (such as the impact of distributed solar installations and rate structure) being equal, the average ratepayer electricity bill is likely to decrease under a Clean Energy Scenario compared to the business-as-usual scenario. However, it is not assured that everyone would benefit equally. In particular, given that low-income renters have little leverage over efficiency investments, some households may see bill increases without specific measures to obviate this outcome, such as policies to ensure that a minimal level of efficiency improvements are implemented across the board. Currently, all New Jersey ratepayers pay to ensure that low-income households pay no more than 6% of income on energy bills. As a result, efficiency measures targeted at low-income households would also benefit non-low-income households by reducing these assistance expenses.

Equity and pollution reduction: We expect that overall air pollution and carbon emissions will decline as a result of increasing solar and offshore wind in tandem with efficiency increases. However, a reduction of pollution in the disproportionately impacted low-income communities is not a guaranteed outcome. Because New Jersey is part of the larger PJM grid, deployment of solar and wind may still allow fossil fuel plants to operate and export electricity to other parts of PJM. Specific policies may be needed to restrict emissions from individual plants, including in vulnerable communities. This can be accomplished in a variety of ways, including strategically deployed electricity storage and microgrids. We have included the costs of 1,600 MWh of battery storage to be used for peaking generation (800 MWh) and for microgrids (800 MWh); however, we have not done a siting analysis beyond a demographic analysis of communities near existing plants.

Community and worker protection: In addition to the potential early closure of Salem and Hope Creek nuclear plants, the energy transition may put some of New Jersey's fossil fuel plants at risk for closure. The negative impact of premature closures on communities and workers is a matter for the people of the state at large, well beyond any shareholder concerns. We have included $20 million per year in the early nuclear retirement scenarios to replace the various tax revenues that such retirements would entail; we have also included a provision of $40 million per year for communities that host fossil fuel plants that may close.

Preparing for 2050: Electrification of transportation on a large scale and conversion of fossil fuel heating to efficient electric systems will be essential for New Jersey to achieve its goal of 80% reduction in greenhouse gas emissions by 2050. This transition will roughly double today's electric load, but this electricity generation must be low-carbon to achieve deep decarbonization. Assuming that all nuclear generation has retired by 2050 and 90 to 100% of electricity would be provided by renewables, the deployment rate of renewables from 2030 to 2050 will have to be approximately triple the average annual deployment rate from 2020 to 2030 to meet growing demand. Renewables are expected to be the lowest-cost generation sources after 2030, but this scale of infrastructure expansion is not trivial. Pre-2030 contracts for out-of-state renewables can ease the required post-2030 growth. New Jersey can also lay the foundation for this transition by providing incentives, for example for conversion of fossil fuel space and water heating and vehicle electrification; electrification beyond the levels assumed here would similarly reduce the speed of infrastructure development required later. The transition to deep decarbonization using solar and wind as principal energy sources will require profound changes in other arenas as well, including the creation of a smart grid that would accommodate a refined demand-response system and millions of distributed generation sources, a new business model for utilities, and new approaches to rates.

Additional research needs: To help realize a clean energy transition by 2030, additional research would be useful to support planning, including: 1) identification of optimal land for solar deployment, with a focus on marginalized lands and brownfields; 2) analysis of reliability and renewable capacity attribution under nuclear retirement scenarios; 3) strategies to reduce peak demand; 4) projections of impact on energy market prices; 5) employment impacts; 6) amount and locations of deployment of storage and microgrids for resilience; 7) grid modernization strategies that enhance reliability and flexibility; (8) comparison of the risks of renewable energy imports using VPPAs with those of making above-market payments to keep nuclear plants operating both in the pre-2030 and post-2030 period.

In summary, we find that a 50% reduction in power sector emissions is necessary, achievable, and affordable with the deployment of 33% in-state renewables by 2030. With careful planning this transition can provide additional resilience, health, equity, economic, and environmental benefits. Our calculations indicate that the cost will be comparable to a business-as-usual approach even without including the benefits of pollutant emission reductions, health improvements, and the hedging value of fuel-free solar and wind energy against natural gas price volatility. Further, it appears advisable for New Jersey to prepare now for nuclear plant retirements through initiating VPPAs for renewable imports and through more vigorous development of offshore wind. These efforts will set the state on a path to achieve deep decarbonization by 2050.

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1. Introduction

1.1 Greenhouse gas emission goals

The New Jersey Global Warming Response Act requires the state to reduce greenhouse gas (GHG) emissions by 80% by 2050 relative to 2006 [3]. The Act does not specify intermediate targets. The principal aim of this report is to develop an approach to reducing electricity sector carbon emissions by 2030 along a pathway compatible with New Jersey's overall 2050 GHG emission reduction goal. The latter includes all energy-related emissions as well as emissions from other sectors, like agriculture.

Several states that have adopted goals of 80 or 90% reduction in GHG emissions by 2050 have also adopted intermediate targets. For instance, Maryland has a goal of 90% GHG emission reductions by 2050 relative to 2006; it also has an intermediate mandate to reduce statewide GHG emissions by 40% by 2030 [4]. As another example, Minnesota aims to reduce its greenhouse gas emissions by 80% relative to 2005 by 2050; it also has a target of 30% reduction by 2025 [5]. Similarly, California and New York have both set targets of 40% GHG reductions below 1990 levels [6, 7].

If New Jersey is to achieve its 2050 target for emission reductions, an intermediate target would help set policy and measure progress to check if the state is on track. A 40% reduction in statewide GHG emissions by 2030 compared to 2006 appears reasonable and compatible with the milestones set by other states.

Deep emission reductions in the electricity sector are less difficult than in other sectors, at least until the year 2030, and will enable GHG reductions in other sectors. Therefore, a reasonable pathway to deep decarbonization will likely rely on reducing carbon emissions in the power sector as quickly as possible, and using this decarbonized power to then reduce emissions from other sectors. For instance, even with the rapid introduction of electric vehicles, most transportation in 2030 will still be powered by petroleum; ultimately, the decarbonization of transportation will require electrifying vehicles and powering them with renewable electricity, in conjunction with efforts like public transit expansion. Aircraft will likely be powered by petroleum well beyond 2030. Converting space heating from direct fossil fuel use to electricity and making heating renewable-grid ready will also take time but similarly relies on decarbonizing the power sector.

In view of these factors, an overall 40% reduction in GHG emissions in the energy sector by 2030 implies a significantly higher reduction in electricity sector emissions. We therefore consider a goal of 50% reduction in electricity sector emissions by 2030 to be a reasonable target relative to the year 2015.[1] In 2015, direct carbon dioxide (CO_2) emissions due to electricity generation within the state were 19.4 million metric tons [8]. The total power

[1] This target is equivalent to a 63% GHG emission reduction from the power sector as compared to 2006.

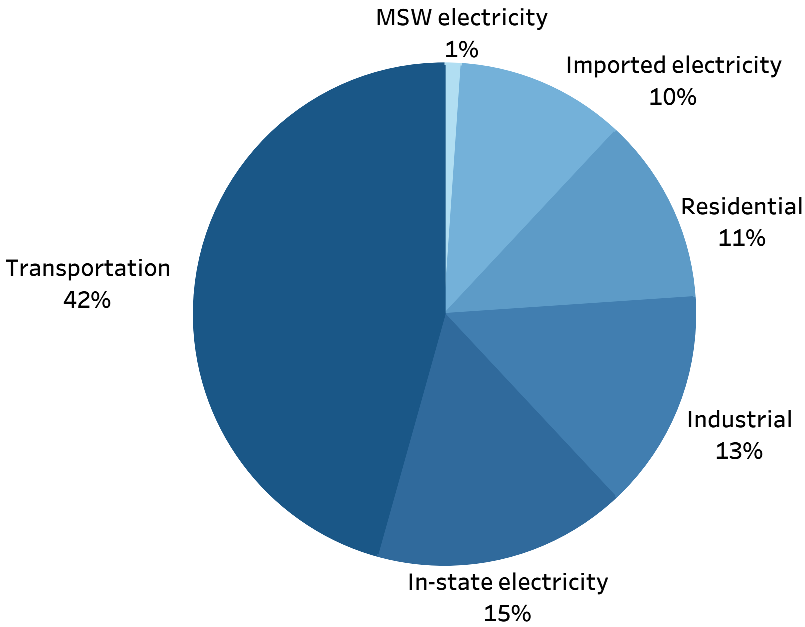


Figure 1.1: New Jersey Greenhouse Gas Inventory energy-related greenhouse gas emissions, 2006 [10].

sector CO_2 emissions, including net imports of about 7.1 million megawatt-hours (MWh) of electricity [8], were an estimated 22.7 million metric tons [9]. A 50% emissions reduction target therefore implies halving the CO_2 emissions from the power sector to 11.35 million metric tons by 2030. We discuss trends in New Jersey's electricity sector generation and emissions in more detail in **Chapter 2**.

1.2 2006 baseline and 2050 emission targets

New Jersey's total GHG emissions in 2006 amounted to about 134.5 million metric tons according to the state's Greenhouse Gas Inventory, of which 121.2 million metric tons, or over 90%, were energy-related [10]. **Figure 1.1** shows the sectoral distribution of New Jersey's energy-related greenhouse gas emissions from the baseline year of 2006, as reported in the state inventory. Direct fuel use in transportation—almost all petroleum—was the single most important contributing factor, accounting for 42% of the energy related emissions. The electricity sector was next with 25% of the energy-related emissions (including electricity imports). For comparison, the U.S. Energy Information Administration (EIA) reports 2006 in-state energy related emissions closer to 123 million metric tons [11], which we estimate totaling closer to 139 million metric tons when including electricity imports. The EIA estimates transportation-related emissions to be 34% higher than the New Jersey inventory, which is the primary contributor to the discrepancy in emissions totals between the two.

In broad terms, we can assess the compatibility of our two 2030 targets—40% overall emissions reduction as compared to 2006, and 50% reduction in power sector emissions as compared to 2015—with the overarching GWRA target of 80% emissions reductions by 2050 as compared to 2006. We use the EIA emissions data for this rough assessment due to the availability of more complete datasets through the year 2015 and compatibility with the data sources used in the rest of this report.

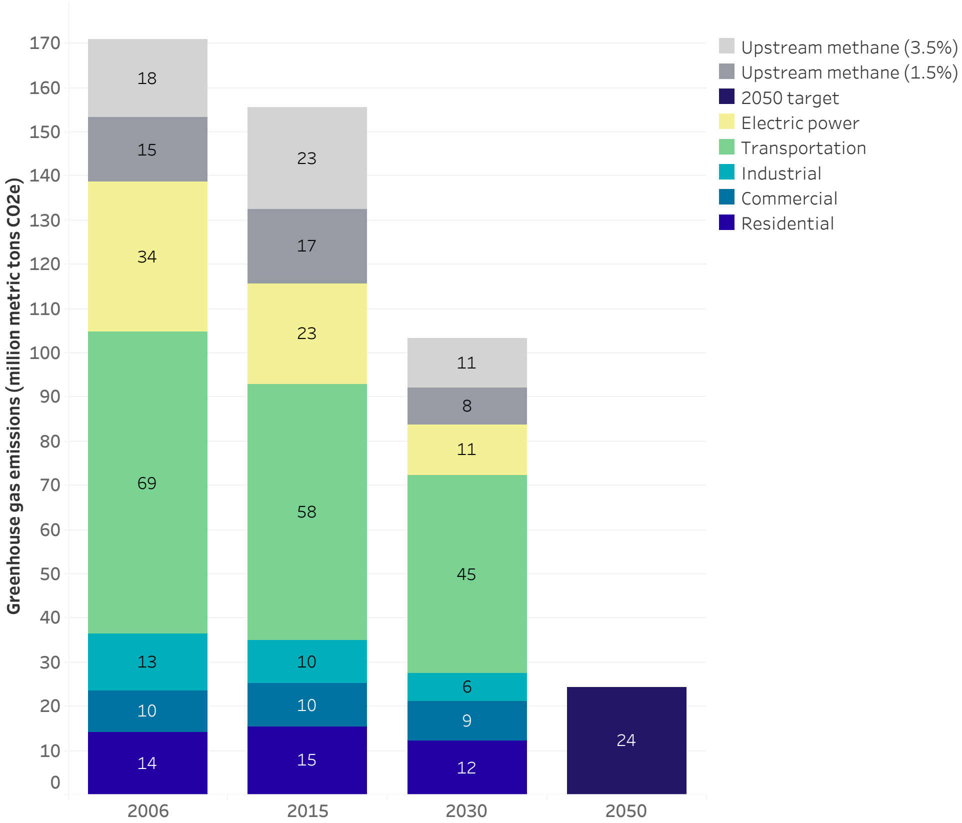


Figure 1.2: Historic and target energy-related sectoral greenhouse gas emissions. Targets reflect 40% CO_2 emission reductions by 2030 and 80% CO_2 emission reductions by 2050 as compared to 2006. Additional greenhouse gas impacts from fugitive methane emissions reflect 1.5% and 3.5% upstream leakage rates on an end-use basis.

In **Figure** 1.2 we show the direct historic CO_2 emissions reported by the EIA for the years 2006 and 2015, as well hypothetical cross-sector emissions that would allow the state to meet the 40% target. These sectoral emissions are meant to be purely illustrative: numerous scenarios could achieve these targets, and deeper decarbonization in one sector would allow for higher emissions in other sectors. We show total emission cuts required to achieve 80% reductions in energy sector emissions in 2050, but do not specify sectoral emissions. For the year 2030, we use an illustrative scenario with the following measures as compared to 2015:

1. 50% power sector emissions reductions, as outlined in this study;
2. 20% residential emission reductions, including 80% electrification of fuel oil and propane heating systems as outlined in this study and an additional 10% reduction from efficiency;
3. 10% commercial emission reductions through efficiency efforts;
4. 33% industrial emission reductions in line with historic trends;
5. 22% transportation emission reductions, including 5% electrification as outlined in this study combined with fuel economy savings from efficient and hybrid vehicles.

In addition to the direct CO_2 emissions reported by the EIA, fugitive methane emissions from across the natural gas lifecycle—and to a lesser extent from coal production—can greatly increase the total greenhouse gas impacts of fossil fuel use, although exact rates of methane leakage are highly uncertain and subject to an ongoing debate. research. We discuss methane emissions in detail in **Chapter 6**, but for the purposes of illustration we show the greenhouse gas impact of both 1.5% and 3.5% methane leakage from natural gas on an end-use basis, reflecting 1) EPA estimates [12] and 2) within the middle range of estimates reported in Brandt *et al.* [13]. To illustrate the carbon equivalence of methane, we use a 20-year global warming potential for methane of 86 CO_2e [14]. We include a rough estimate of methane emissions associated with electricity imports [9], but these values do not greatly affect the totals shown. Inclusion of fugitive methane emissions at a 3.5% leakage rate increases the 2006 greenhouse gas baseline by 23% and increases 2015 emissions by 35% due to recent increases in natural gas use. However, the targets outlined for 2030 still reduce total greenhouse gas emissions by 40% by 2030 due to reductions in natural gas use.

Together, these results suggest that a 50% reduction power sector emissions compared to 2015 is compatible with cross-sector efforts to cut overall emissions by 40% by 2030 as compared to 2006 on a pathway to 80% emission reductions in 2050. Furthermore, the reduction in natural gas use required for such a pathway will allow for significant reductions in the emissions of methane, a powerful greenhouse gas.

1.3 Scope of report

The focus of this analysis is to examine the evolution of the electricity sector under business-as-usual conditions and compare this scenario to the technical and cost implications of deep CO_2 emissions reductions (the "Clean Energy Scenario")—50% relative to 2015 by 2030 and 80% or more relative to 2006 by 2050. The analysis is supplemented with additional consideration of the potential early retirement of nuclear power plants, a provision for the initial electrification of transportation and heating, and an evaluation of some of the environmental and equity co-benefits of a clean energy transition.

There has been considerable uncertainty recently regarding continued operation of many existing nuclear power plants—specifically whether their owners will continue to operate them without payments above current market rules in deregulated areas such as the PJM grid, of which New Jersey is a part. This uncertainty has arisen in large part due to decisions made in New York and Illinois in 2016 to make above-market payments to nuclear power plants in response to their owners' warnings they might shut down. The issue is important economically; that importance is reinforced in a context of carbon reduction goals, since premature closure can cause spikes in carbon emissions if fossil fuel generation replaces the closed reactors.

Potential premature closure of nuclear power reactors has recently become an important economic and environmental issue for New Jersey as well. New Jersey has four operational nuclear reactors—Oyster Creek (one unit), Hope Creek (one unit) and Salem (two units). They supplied 45% of in-state electricity generation in New Jersey in 2015. Oyster Creek, the smallest reactor, is due to be permanently closed in 2019, but the other three units are licensed to operate well into the 2030s and 2040s.[2]

[2] The licenses of the two Salem reactors expire in 2036 and 2040 and the Hope Creek license expires in 2046 [15].

In this report, we explore options for New Jersey to meet the same carbon constraints as the Clean Energy Scenario by 2030 with and without in-state nuclear power generation. Other than continued operation without above-market payments, we also examine the economic implications of (i) acquisition of added renewable imports from the PJM region as part of contingency planning or (ii) above-market payments similar to New York's Zero Emission Credits (ZECs).[3]

Electrification of transportation is considered the most suitable route for longer term reduction in CO_2 emissions, complementing fuel efficiency improvements in the short- and medium term. It is likely that most electrification will occur in the post-2030 period but laying the infrastructural foundation for electric vehicles (public and private) in the pre-2030 period is important to long term emission reductions. In this report, we make a provision for additions to renewable generation in the pre-2030 period that correspond to a 5% electrification of projected vehicle miles travelled in New Jersey in 2030. We recognize that electrification of road transportation is a fast-moving sector. The figure of 5% of vehicle miles is used for illustrative purposes only.

Another sector that must be largely converted to renewable energy by 2050 is space and water heating in residential and commercial buildings. At present, conversion of natural gas-heated buildings to efficient electric systems is not economical (at least not without internalization of the social and environmental costs of CO_2 and upstream methane emissions). Studies in other states such as Maryland and New York indicate that conversion of oil-heated systems to efficient electric ones is already economical.[4] We have made a provision in the Clean Energy Scenario for the conversion of 80% of New Jersey's oil and propane residential heating systems. Our goal here is not a precise projection of the electricity requirements for these conversions; rather it is to represent the kind of renewable generation increases that would be needed on an order of magnitude basis.

We make an approximate projection of electricity generation requirements in 2050, assuming near complete electrification of on-road transportation, some non-road transportation, and most fossil fuel-based space and water heating. We have not conducted a detailed economic or systems analysis of the energy sector in 2050. Our aim is to provide a sketch of the generation requirements in 2050 for more detailed studies and for policy discussions on the future of electric utilities and third-party providers that are now taking place all over the United States and the world.

Finally, we include additional considerations of environmental impacts and equity. We examined the environmental justice implications of the locations of New Jersey's power plants and the deployment of solar in low-income communities. We briefly discuss ways in which the benefits of reduced emissions can be extended with certainty to low-income and minority communities. We have also added costs to the early nuclear retirement scenarios to limit economic damage to the communities and workers where the nuclear plants are now located. Lastly, we analyze the criteria pollutant and upstream methane emission reductions associated with the Clean Energy Scenario.

[3] New York's formula for calculating the value of a Zero Emission Credit includes an adjustment for the price of a permit to emit a ton of CO_2 under the Regional Greenhouse Gas Initiative (RGGI) that limits emissions from designated fossil fuel plants in participating states. New Jersey participated in RGGI in the past, but is not participating at the time of the preparation of this report. Our calculations assume that the RGGI permit value would be factored in to reduce the value of a ZEC (and hence the payments to be made). If this does not happen, the payments would be significantly greater. See **Chapter 4**.

[4] For Maryland see Makhijani and Mills 2015 [16]. For New York see Makhijani 2017 [17].

1.3.1 Energy projections

We develop the Clean Energy Scenario based on projections of electricity use, business-as-usual electricity generation portfolio, and various technology and efficiency costs. We have kept our estimates conservative when possible but precluded the inclusion of additional costs that do not reflect recent technology trends, particularly for photovoltaic and offshore wind technology. We have primarily relied on the National Renewable Energy Laboratory's (NREL) very detailed technology cost forecasts from August 2017 [18]. In the case of offshore wind, the NREL forecasts were complemented by an analysis prepared by the University of Delaware [19]. Our cost comparisons between business-as-usual and the Clean Energy Scenario are focused primarily on differences in electricity production costs, but do not reflect any change in costs resulting from PJM market impacts, such as changing capacity market costs. We have made some additional provisions for transmission investments and energy storage where needed.

Perhaps the most important uncertainty in our cost analysis arises from natural gas price projections. Following standard practice for business-as-usual projections, we have used the U.S. Energy Information Administration's 2017 Annual Energy Outlook (AEO) mid-Atlantic values for both natural gas prices and overall business-as-usual electricity costs [20]. Given that natural gas prices have been low for some time and remain so in the AEO projections, we have also examined a higher natural gas price scenario prepared by the EIA. In all cases, we have adjusted the starting year prices to correspond to New Jersey electricity prices.

We develop our business-as-usual electricity demand based on projections from the regional transmission operator, PJM [21]. For the Clean Energy Scenario, we have included a gradual increase of efficiency savings to 2% per year, an ambitious target that has nevertheless been achieved in numerous other states. This efficiency ramp up is important to the economics of a renewable energy transition as we will see in **Chapter 4**.

1.3.2 New Jersey-specific focus

New Jersey is part of the PJM grid, which in turn is part of the much larger Eastern Interconnect. The latter extends from the Atlantic Coast to the western edge of the Great Plains, excluding Texas. A detailed realistic simulation would examine New Jersey's electric future as part of the PJM grid. However, this would be a complex, costly and time-consuming exercise that is not justified by the limited goals of this work—to examine and compare the costs and requirements of a business-as-usual scenario with a clean energy pathway to the year 2030 that would lay the foundation for deep GHG emission reductions in New Jersey by 2050.

For our purposes, it is sufficient to examine such a clean energy pathway as if New Jersey were operating a grid of its own. This approach sacrifices the modeling of the import and export of electricity that is a normal part of grid operation. This omission affects our cost estimates—for example, we do not examine trading of electricity that would normally help minimize costs, and we do not analyze other PJM market impacts of our scenarios. Our purpose, instead, is to isolate the impact of different electricity resources on total costs. Furthermore, we assume that in-state renewable generation will reduce in-state fossil generation, which might not occur in actual market operation without explicit emission constraints because fossil generators could continue to generate in the presence of in-state renewable growth and simply export that electricity to other states. PJM decisions also influence additional market operations and prices which we do not attempt to model here. We do, however, assume that balancing across PJM will continue as normal and therefore in-state electricity generation does not have to precisely match in-state demand, as is true currently.

We do rely on broader PJM resources when examining the possibility of early retirement of the Salem and Hope Creek nuclear plants. The most straightforward approach to contingency planning for replacing this generation would be to acquire onshore wind and utility-scale solar that is now in the PJM queues but is not committed for sale. These wind and solar purchases would complement in-state development of solar and offshore wind under the Clean Energy Scenario (which assumes continued nuclear operation without above-market payments).[5]

1.3.3 Limitations

There are a few other limitations of our work in addition to the ones noted above:

1. We have not carried the analysis forward up to and past the license expiry dates of the Salem and Hope Creek nuclear reactors. These dates are rather far off, making cost projections uncertain. The main result of this omission is that we omit costs associated with replacing this nuclear generation in the years just prior to license expiry. The near-term costs of acquiring additional renewable imports in the case of a nuclear retirement contingency would offset the need to replace nuclear generation when these plants retire in the longer term. Hence, from a long-term point of view, the early nuclear retirement scenarios appear to be higher cost than they would be in reality.[6]

2. Apart from the nuclear shutdown contingency scenarios, we have not considered normal electricity trade across the New Jersey border. This means that our CO_2 reductions are a net annual estimate. It is possible that there will be a corresponding reduction of fossil fuel (natural gas) generation as a result. But it is also possible that New Jersey continues to generate fossil fuel electricity in order to export it. We briefly consider this issue from an environmental justice point of view and outline approaches that may avoid such an outcome.

3. Apart from a brief review of transmission considerations in relation to potential premature shutdown of the Salem and Hope Creek plants, we have not considered transmission issues. We have of course taken transmission (and other) costs into account.

[5] These wind and solar resources would likely be acquired by "Virtual Power Purchase Agreements" (VPPAs). The electrons are fed from the renewable facilities to the PJM grid, but not directly to New Jersey. Our aim here is not to sort out the various financial and risk issues associated with VPPAs but rather to compare the cost with that of making above-market payments for keeping nuclear power plants in operation. See **Chapter 4**.

[6] Early retirement of nuclear reactors has been the norm. In fact, all reactors that have permanently shut down have done so before their licenses (including any extensions) had expired. Licenses are issued for 40 years of operation; when extended, they are extended for a further 20 years. For a list of shut down reactors as well as the dates of commissioning and shutdown, see NRC Information Digest 2016-2017, Appendix C [15].

2. New Jersey energy use and greenhouse gas emissions

2.1 Greenhouse gas emission trends

New Jersey's greenhouse gas emission footprint is dominated by transportation, which accounts for nearly half of the state's emissions, followed second by power generation at about 20% and finally by emissions from the residential, industrial, commercial, and other sectors [10]. The state estimates that in 2012 these emissions had fallen by nearly 18% from the baseline year of 2006. New Jersey has set a greenhouse emission reduction target of 80% by 2050, as compared to 2006.[1] The state has an intermediary target of reducing emissions to the 1990 level by 2020 [3], but reports that it has already achieved this target [22].

Although the transportation sector is the primary source of greenhouse gas emissions in New Jersey, the reduction of greenhouse gas emissions from the power sector can enable emission reductions in all other sectors. One of the primary strategies for reducing greenhouse gases from transportation, home and water heating, and other sources is to electrify these sectors and power them with renewables. For example, the greenhouse gas emissions from cars can be reduced by converting them to more efficient electric vehicles that are charged with renewable energy resources like wind or solar power. Therefore, New Jersey needs to reduce the greenhouse gas footprint of its electric sector both to reduce emissions from electricity generation itself, and to set the groundwork for reducing emissions from other sectors.

The historic direct greenhouse gas emissions from electricity generation in the state of New Jersey as well as from electricity imported into New Jersey are shown in **Figure 2.1**, as well as estimates of the lifecycle greenhouse gas emissions inclusive of fugitive methane emissions. In-state generation emissions are reported by EIA [11], and out-of-state emissions are estimated by applying the average PJM system-wide greenhouse gas emission rate [9] to the magnitude of electricity imports reported by EIA [8].[2] We note that these values do not exactly match the numbers reported in New Jersey's Greenhouse Gas Inventory [10], but we use the EIA numbers for consistency with the rest of this report. The direct emission values are only those associated with combustion of fossil fuels. For the lifecycle estimates, we include methane associated with both coal and gas. Small amounts of fugitive methane are associated with coal production [23]. More importantly, methane can leak out throughout the entire natural gas lifecycle, including production, processing, transmission and distribution, which we discuss in detail in **Chapter 6**. The exact methane leakage rates are unknown, and likely change by year with production practices. The EPA estimates methane leakage at approximately 1.5% [12], whereas a growing body of scientific literature has found significantly higher leakage rates [13, 24, 25]. In **Figure 2.1**, we show

[1] Note that the emissions reported in the state GHG inventory do not include full upstream methane emissions.

[2] Emission rates could not be determined before 2012, so 2012 rates were applied to the 2006-11 imports and should be considered very approximate.

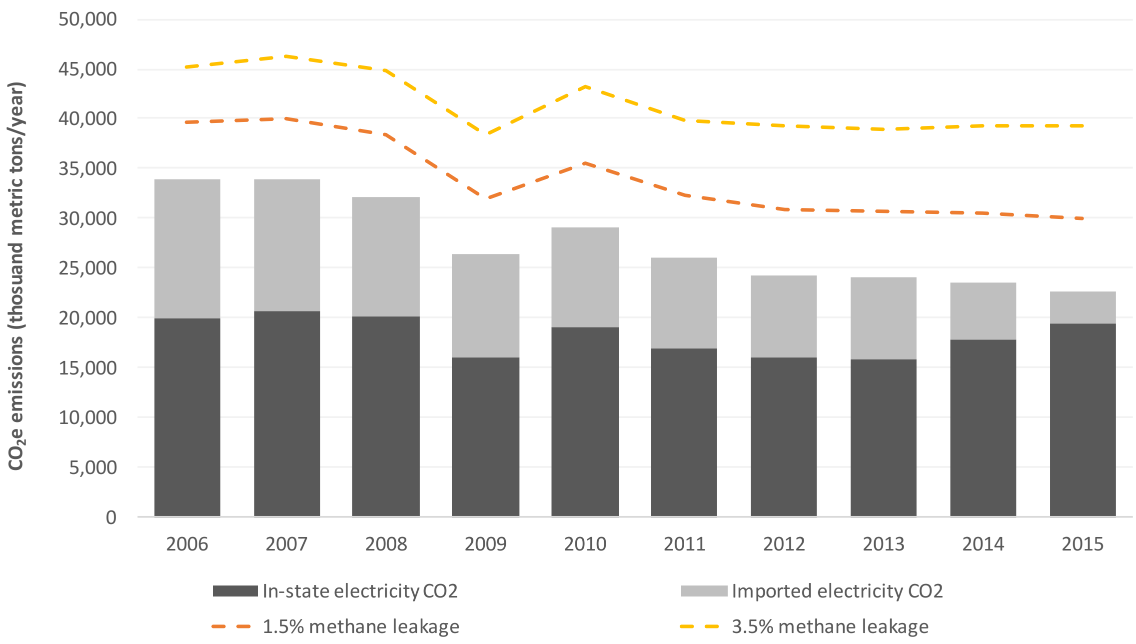


Figure 2.1: Historic annual greenhouse gas emissions from electricity consumed in New Jersey. Estimated combustion-related CO_2 emissions from both in-state generation and electricity imported from out-of-state, as well as lifecycle greenhouse gas emission estimates inclusive of fugitive methane emissions from natural gas at 1.5% and 3.5% leakage rates. (Data sources: [8, 9, 11].)

the greenhouse gas emissions inclusive of methane leakage at the EPA-estimated rate of 1.5% as well as a higher rate of 3.5%. This latter value is estimated to be in the middle range end of likely fugitive emission levels on an end-use basis from a review study by Brandt *et al.* (2014) [13], which aggregated results from numerous papers. We use methane's 20-year global warming potential of 86 CO_2e. Both the direct and upstream methane emissions associated with PJM imports are highly uncertain due to unknowns regarding which marginal resources across PJM (e.g. coal, gas, hydropower) were actually dispatched to meet New Jersey demand.

These emission trends show that total direct electric sector CO_2 emissions, including imports, fell by roughly a third between 2006 and 2015, but in-state emissions only fell by roughly 2% during that time and actually increased steadily between 2013 and 2015. While final emission numbers for 2016 have not yet been released by EIA, the 18% increase of in-state natural gas generation from 2015 to 2016 suggests that in-state CO_2 emissions in 2016 were likely 10% higher than in 2006 [26]. Fugitive methane leakage from throughout the natural gas lifecycle undermines some of the reported power sector emission reductions even at EPA-estimated emission rates, and more so at the higher rates found in much of the scientific literature.

2.2 New Jersey's current electric power sector

New Jersey's current power sector is heavily dominated by natural gas and nuclear generation. **Figure 2.2** shows historic monthly in-state electricity generation in New Jersey, along with the state's approximate total generation requirements, which includes both demand and estimated transmission and distribution losses [26]. These data reflect an increase in

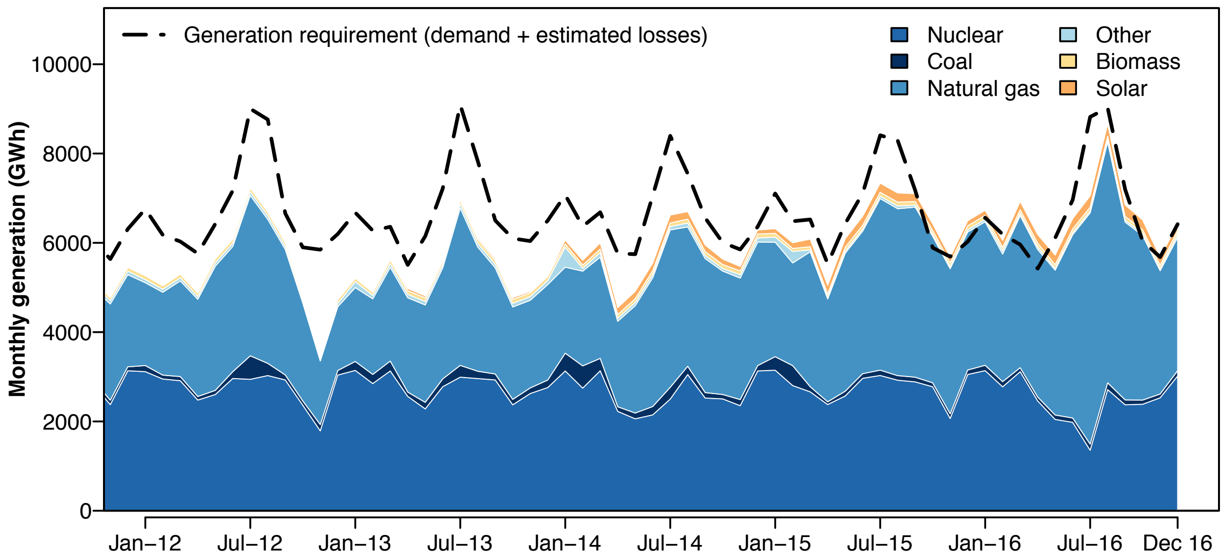


Figure 2.2: Historic monthly in-state electric generation in New Jersey, 2012-2016 [26]. Note: rooftop solar generation is only included as part of solar generation beginning in 2014. Generation requirement includes retail sales of electricity as well as estimated transmission and distribution losses. The difference between the generation requirement and in-state generation reflects net monthly imports and exports.

in-state natural gas generation and decrease in imports over the past few years. Coal generation has been low in recent years. The state also generates some electricity from biomass and biogas (including landfill gas and municipal solid waste), has small contributions from wind and hydropower, and has growing solar capacity. About 60% of 2016 solar generation came from residential and commercial rooftop installations and 40% from utility-scale projects [27].

The state's installed power generation capacity,[3] given in **Table 2.1**, includes 4,100 MW of nuclear power, 8,300 MW of natural gas combined cycle (NGCC) plants, 2,300 MW of simple cycle gas plants, 790 MW of coal generation, 690 MW oil/gas steam (mostly older and close to retirement, often burning both fuels), 70 MW of landfill gas, 8 MW of wind, 12 MW of hydro, and 2,000 MW of solar, approximately three quarters of which is behind-the-meter [27, 28]. As of 2016, the state also had roughly 3,100 MW of combined heat and power, running on a mix of fuel sources including gas [29].[4]

PJM projects that in coming years New Jersey's peak summer demand will increase only slightly from today's 19,000 MW (excluding behind-the-meter resources like rooftop solar and some combined heat and power systems). As of June 2017, PJM estimates that grid-connected capacity across New Jersey's four main utilities is 16,550 MW, meaning that the state currently relies on out-of-state resources to meet peak demand, albeit less than in recent years [30].[5] Moving forward, plant retirements would imply the need for new capacity or additional PJM imports to meet peak. Total imports have declined in recent years, and

[3]Capacity refers to the maximum power output of a generator, measured in watts (W), kilowatts (thousands of watts—kW), megawatts (millions of watts—MW) or gigawatts (billions of watts—GW). The amount of energy supplied by a power plant is calculated by multiplying the power output by the amount of hours the plant is running, and therefore is reported in watt-hours (Wh), kilowatt-hours (kWh), megawatt-hours (MWh) or gigawatt-hours (GWh). Electricity bills typically report household usage in kWh.

[4]Because many of these systems are behind-the-meter, data on these resources is limited.

[5]The values in **Table 2.1** sum to more than 16,550 MW due to the inclusion of behind-the-meter resources, recent capacity changes, and slight variations in reported capacity values between the EIA and PJM.

Table 2.1: New Jersey in-state generation by fuel type and installed capacity by plant type, 2016.

Fuel type	Generation (GWh)	Plant type	Installed capacity (MW)
Nuclear	29,885	Nuclear	4,100
Coal	1,759	Coal	790
Biomass/biogas	967	Landfill gas[a]	70
Wind	22	Wind	8
Distributed solar	1,708	Residential and commercial solar	1,530
Utility-scale solar	1,038	Utility-scale solar	480
Natural gas	43,646	Natural gas combined cycle	8,300
		Simple cycle peaker	2,300
		Combined heat and power (CHP)[b]	3,100
Oil and pet coke	166	Oil/gas steam[c]	690

[a]Municipal solid waste combustion capacity unknown but may be reflected in biomass numbers.
[b]Some generation from CHP plants may be behind-the-meter and not reflected in natural gas generation numbers.
[c]Also burns natural gas.

net in-state generation is close to the state's demand requirement. The approach which we focus on here is to ramp up efficiency and renewable generation to replace the demand for natural gas. Even if New Jersey generates the same amount of electricity in-state as it consumes, however, it will continue to rely on resources from a much larger area to help reach its summer peak demand. New Jersey is part of the much larger PJM Interconnection. PJM operates the grid across the Mid-Atlantic region, stretching west to Ohio and south to Virginia, and electricity generation is balanced across this entire territory.

A number of plants in New Jersey's fleet of generators are expected to retire or repower in the coming years: the 619 MW Oyster Creek Nuclear Generating Station retires in 2019, 306 MW of coal is expected to be repowered in 2019, and additional steam plant capacity may retire as well. The majority of New Jersey's natural gas plants were built in the last thirty years, as shown in **Figure 2.3**. Two thirds of the state's natural gas combined cycle capacity will be less than 35 years old in 2030, and 92% will be less than 40 years at that time, suggesting that much of the state's natural gas capacity could still run in 2030 if needed even though a few plants would be nearing retirement. An additional 2,260 GW of natural gas combined cycle plants are planned in New Jersey, including the conversion of an aging coal plant and two gas steam plants to natural gas combined cycle plants.

2.3 New Jersey's existing renewable energy targets

New Jersey has a number of existing clean energy targets and provisions, including renewable energy targets and a range of tax credits, incentives, standards, and rebates to encourage

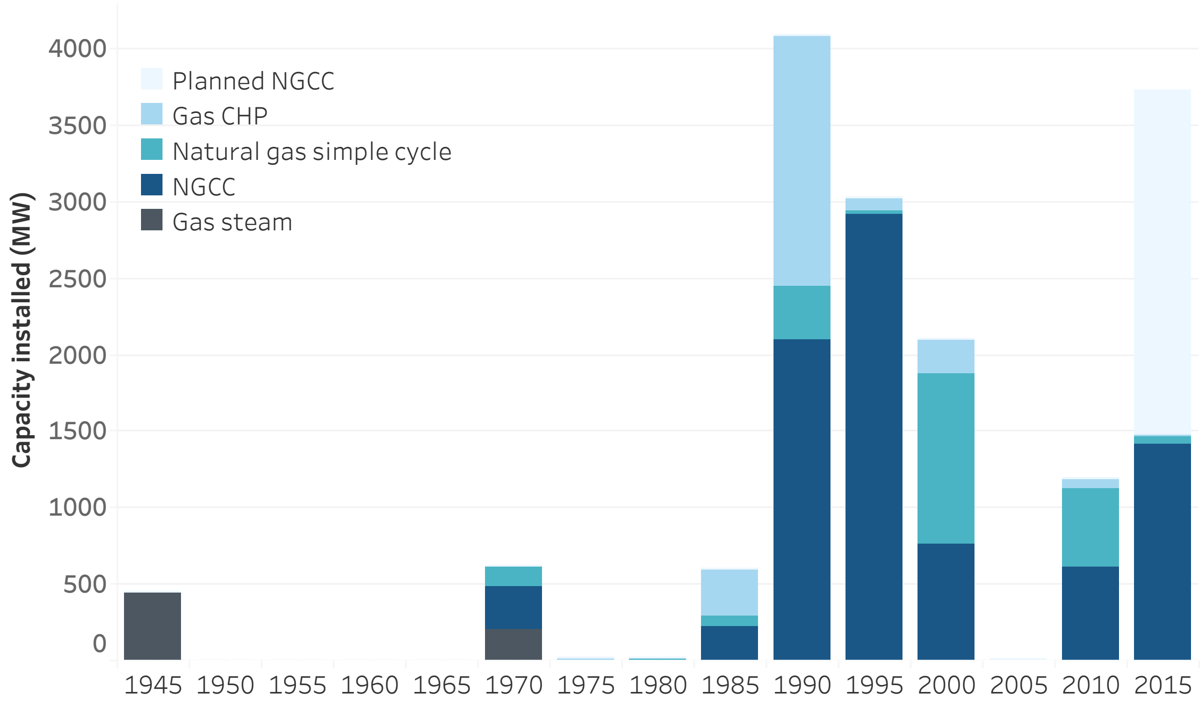


Figure 2.3: New Jersey's natural gas plants, by type and vintage [28, 29].

energy efficiency for buildings and appliances. The state's Renewables Portfolio Standard (RPS) requires that 20.38% of electricity sales come from renewable resources by 2020-2021, and an additional 4.1% of electricity sales be generated by in-state solar power by 2027-2028. The state has a separate target of 1,100 GW of offshore wind, with no target date [31].

The solar carve-out is meant to specifically encourage solar development within the state of New Jersey; the Renewable Portfolio Standard is intended to encourage the least cost development of renewables anywhere across the PJM Interconnection. The Renewables Portfolio Standard splits renewables into Class I (solar, wind, wave/tidal, geothermal, landfill gas, anaerobic digestion, small hydro, and some additional fuel cell and biomass), and Class II (municipal solid waste combustion, large hydro) [30]. New Jersey utilities purchase the Renewable Energy Certificates (RECs) associated with this generation, although in general they are not buying the electricity generated itself. In the 2015-2016 energy reporting year, the RECs used to meet New Jersey's RPS came from 983 GWh of landfill gas (from nine states, primarily New Jersey, Pennsylvania and Virginia), 5,426 GWh of wind (from seven states, primarily Illinois and Indiana), 1,686 GWh of municipal solid waste combustion (New Jersey and Pennsylvania), 2,037 GWh of New Jersey solar, and small amounts of other gas and hydro [32]. Altogether, only 31% of the renewables used to meet New Jersey's RPS were generated within the state itself, and 30% of those in-state renewables came from burning municipal solid waste, which is arguably not renewable.

Within this study, we shift the target goals for renewables to be primarily in-state; renewable imports are added only for contingency scenarios reflecting early nuclear power retirement. The in-state carve-out for solar is increased and a new carve-out for offshore wind is proposed. This target shift has a number of potential benefits for New Jersey, including energy security and job creation. By purchasing in-state renewable generation via PPAs, New Jersey would also acquire renewable energy credits that are tied to actual in-state renewable electricity generation. Currently New Jersey purchases "unbundled" RECs—that is it purchases the certificates that represent renewable energy generation without typically purchasing the electricity itself.

Furthermore, by displacing in-state fossil generation, New Jersey can also reduce in-state emissions of criteria pollutants. Later in this study when we do examine renewable imports, we suggest acquiring them through power purchase agreements (PPAs), probably in the form of Virtual PPAs (VPPAs). VPPAs can be designed to require the construction of new renewables, which will inherently guarantee that the renewables being added for New Jersey are *additional*—that is, that they would not have been built otherwise. We also shift the targets to exclude municipal solid waste, and only include biomass sources that consist of landfill gas or biogas produced from anaerobic digestion.

2.4 New Jersey's existing energy efficiency targets and potential

New Jersey's energy efficiency efforts are administered primarily through the New Jersey Clean Energy Program (NJCEP)—the state umbrella entity for renewable energy and energy efficiency. NJCEP is managed by the Office of Clean Energy within the New Jersey Public Utilities Board and offers financial incentives and services for residential, commercial and municipal clients. The program is funded through the societal benefits charge (SBC) collected by the investor-owned utilities. In recent years, however, portions of the SBC have been repeatedly reallocated to the general fund to close state budget gaps, thus reducing the funding available for energy efficiency [33].

While the state has made efforts to promote energy efficiency measures through NJCEP and has successfully implemented efficiency programs for some of its state facilities, it has also lagged behind other states in the region in overall rates of efficiency implementation. New Jersey ranked 24th on the 2016 ACEEE energy efficiency state scorecard behind Wisconsin and ahead of Tennessee, with an average efficiency savings of about 0.6% per year [34, 35]. In comparison, other states in the region such as Rhode Island, Massachusetts, Vermont, Maine and Maryland have achieved significantly higher annual savings rates of 2.9, 2.7, 2.0, 1.5 and 1.0% respectively. In addition, these states have all adopted aggressive efficiency targets of at least 2% per year. New Jersey currently has no official annual energy savings target and has set one efficiency goal of 20% savings by 2020 relative to the predicted energy consumption in 2020, a goal established in its Energy Master Plan back in 2008 [36]. This target, however, is only advisory and carries no consequences if the goals are not met.

A number of reports have evaluated the performance of NJCEP and analyzed the energy efficiency resource potential in the state. One study, conducted by EnerNOC in 2012, prepared a detailed market assessment and energy efficiency potential analysis to estimate the possible statewide impacts of energy efficiency resources in the period from 2013 to 2016. [37] The study employed a bottom-up approach to identify various efficiency measures and estimate their energy savings potential. **Figure 2.4** shows EnerNOC's baseline electricity sales forecast for the 2013-2016 period as well as the estimated range of achievable savings potential and the estimated energy savings economic potential. We have also added the actual electricity sales in New Jersey for that period for comparison. The achievable savings lower bound of about 0.8% reflects expected energy savings in the presence of significant barriers to customer participation and limited program budgets, while the upper achievable bound of about 1.5% denotes efficiency savings under ideal program implementation and

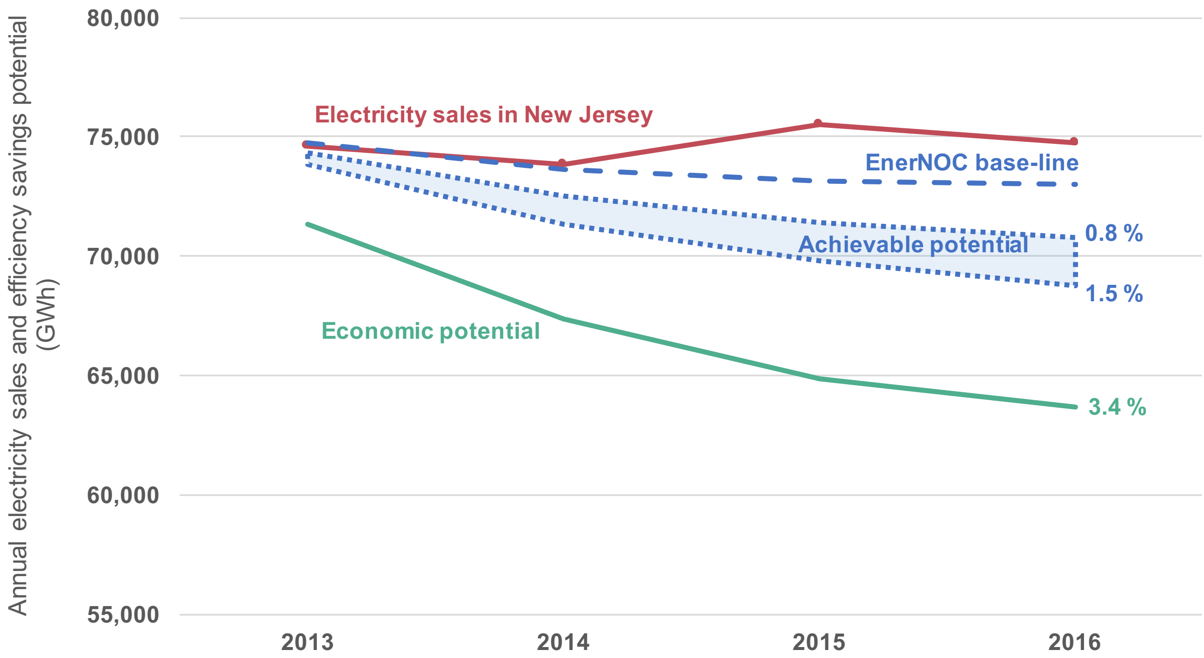


Figure 2.4: Electricity sales in New Jersey for 2013-2016 compared to baseline projections from the 2012 EnerNOC study [37]; a range for the achievable efficiency potential (blue shaded area); and an estimate for the energy savings economic potential (green line). The achievable and economic potential values are incremental to the already existing annual energy savings in New Jersey, which are incorporated in the baseline projections.

informed customer preferences. The economic potential of roughly 3.4% represents the adoption of all cost-effective energy efficiency measures as measured by the total resource cost (TRC) test. We note that all of these values are incremental to the already existing 0.6% annual energy savings in New Jersey, which are included in EnerNOC's baseline forecast along with other assumptions about economic activity, electricity prices, appliance and building standards, weather data and so on.

It is evident from **Figure 2.4** that New Jersey has considerably underperformed compared to the achievable path outlined in the EnerNOC report. The actual electricity sales in New Jersey were slightly higher than even the baseline estimates in the report. The EnerNOC projections were accurate for 2013 and 2014 but diverged on a more optimistic path from the actual electricity load in 2015 and 2016. While some of this discrepancy could be attributed to inaccurate economic growth assumptions and weather-related effects such as increased weather-adjusted summer peak demand in 2015-2016 compared to 2013-2014 [38], it is apparent that New Jersey is far from reaching the estimated achievable efficiency potential in the state. This suggests that significant expansion in the program funding may be required in order to sustain greater penetration of energy efficient technologies in the near future.

Assessing the full energy efficiency potential in New Jersey is a considerable undertaking—a detailed efficiency resource potential analysis is beyond the scope of this report. Evidence from nearby states, however, strongly suggests that New Jersey can, and should, aim for much higher levels of cost-effective energy efficiency savings. We believe that an annual efficiency target of 1.4% above the business-as-usual rate of 0.6% is both reasonable and feasible based on historic rates maintained by other states in the region. A rate of 1.4% also falls within the range defined as achievable in the 2012 EnerNOC report in **Figure 2.4** and is close to their projected high achievable rate of 1.5% above current savings.

2.5 Renewable energy resource potential

While in-state wind and solar energy contributed less than 4% to the state's total in-state generation in 2016, New Jersey has significant renewable energy resource potential, particularly for solar and offshore wind generation. We evaluated the technical potential for renewables in New Jersey based on preliminary assessments from the National Renewable Energy Laboratory (NREL), as well as additional published analyses [39, 40, 41]. We updated the estimates from these studies to reflect technological improvements, including an increase in solar panel efficiency to 20% to reflect the most efficient panels sold on the market today and an offshore wind capacity factor of 47.5%, reflecting NREL's projections for the mid-2020s [18].

Using these technological updates, the technical potentials for offshore wind (415,000 GWh/yr) [42],[6] and rural utility-scale solar (651,500 GWh/year), far exceed our projected generation requirement of approximately 77,800 GWh/year in 2030. Additionally, NREL estimates 65,640 GWh/year of "urban utility-scale" solar (after adjustment to 20% efficiency), but limits these sites to those larger than 4.5 acres, suggesting there may be significantly more potential space on smaller urban plots to support community solar or other ground-mounted systems.

The offshore wind and solar values reported here will likely be even higher in 2030 as solar panel efficiencies increase and offshore wind turbines grow in capacity. 20% efficient solar panels are at the high end of currently available commercial panels. We can expect the efficiency of commercially available solar panels to increase somewhat over time; the technical potential of solar energy would increase proportionally.[7] Land area requirements for a given amount of energy would also decline. Given the large technical potentials reported here, we consider these resources to be constrained by regulatory, economic and deployment factors, such as limitations on siting solar panels on agricultural lands, as opposed to being limited by technically available area.

Rooftop solar technical potential is constrained by the available area of rooftops that have limited shading and relatively flat pitch, and so we checked to ensure our targets did not push up against the technically feasible capacity. We adjusted the rooftop solar estimates from Gagnon *et al.* by increasing panel efficiency to 20% as we did for the utility-scale estimates [40], and assumed a capacity factor of 14.7% based on estimates from NREL's solar estimation tool PVWatts [43]. Using these adjustments, we estimate the rooftop solar potential to be around 38,000 GWh/yr. The adjusted estimate from Kurdgelashvili *et al.* reflecting 20% efficiency yields 31,000 GWh/year [41], although we note that these estimates differ regarding the proportion of rooftop capacity available on residential as compared to commercial buildings.

[6] Assumes an offshore wind capacity factor of 47.5%.

[7] In all cases, we assume that solar generation, which is direct current (DC), would be converted to alternating current (AC). This entails losses but it is needed to make solar generation compatible with grid electricity. However, a large number of uses of electricity—computers, televisions, cell phones—are powered by DC electricity which requires reconversion of AC to DC. If technical arrangements are made to use part of solar electricity as DC, there would be considerable electricity savings; in other words, the capacity of solar generation required for a given level of activity would decrease. This is a complex topic that we are not covering in this report.

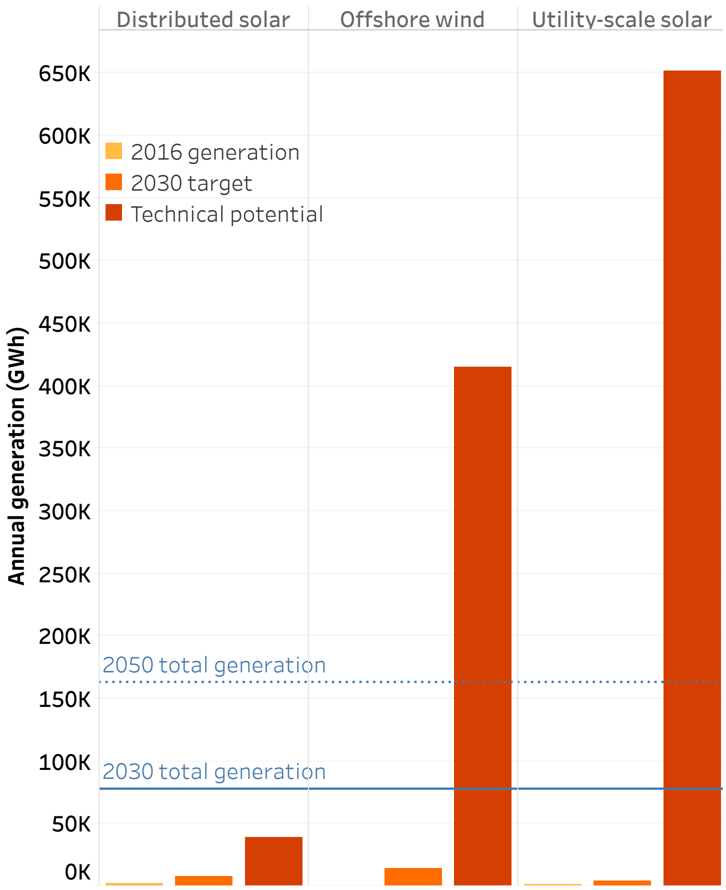


Figure 2.5: Technical resource potential for rooftop solar, offshore wind, and rural utility-scale solar. Urban utility-scale solar not shown. Distributed solar generation in 2016 reflects behind-the-meter rooftop and ground-mount systems, while the technical potential includes only rooftop area. The distributed solar potential is therefore higher when considering the potential for behind-the-meter ground-mount systems.

These values suggest that New Jersey has significant potential to reduce power sector emissions by developing rooftop solar, offshore wind, and efficiency resources. We note that onshore wind potential in New Jersey is limited, and so we exclude in-state onshore wind from our resource portfolio. In **Figure 2.5** we show the existing generation, proposed 2030 generation, and total technical potential generation from solar and offshore wind, as compared to the total projected electricity generation required by 2030. The existing distributed solar in New Jersey includes both rooftop solar and ground-mount systems, while the distributed solar potential shown reflects only rooftop potential. Therefore, we expect the total technical potential for behind-the-meter distributed solar systems to be even larger than reported here when such ground-mount systems are included.

While there is substantial technical potential for urban and rural utility-scale solar, the development of utility-scale solar will depend on land-use constraints. Urban utility-scale solar is available on smaller plots, but the current and potential use of this land must be determined by local planning commissions. One potential option includes the development of brownfields, such as landfills, to deploy solar panels. New Jersey has already begun to install some landfill solar systems and the potential is probably even higher, as explained in **Section 3.4.1**. A full analysis of the available land for solar deployment is beyond the scope of this report but recommended for further research. Due to the large technical potential for offshore wind and solar, we instead base our target deployments on the potential growth rate of these technologies, as described below, rather than technical limitations.

Biomass and municipal solid waste energy resources qualify as renewables in some state targets, but we use only a limited set of biomass resources in this study due to concerns about environmental impacts. As noted earlier, New Jersey currently considers municipal solid waste to be a Class II renewable resource, but we exclude this source due to concerns about criteria and hazardous air pollutant emissions. Similarly, we exclude direct burning of biomass sources like wood due to concerns about both criteria pollutant emissions and the difficulty of ensuring that these resources are sustainably harvested. We include landfill gas generation, which is already present in New Jersey, and gas from anaerobic digestion of food waste and yard waste. Rutgers estimates the technical potential for landfill gas generation at 960 GWh/year, and the generation potential of anaerobic digestion of food and yard waste at 310 GWh/year [44].

Our choices are perhaps best illuminated by the definition of the term "renewable energy" in the fifth assessment (most recent) of the Intergovernmental Panel on Climate Change (IPCC):

> **Renewable energy (RE):** Any form of energy from solar, geophysical, or biological sources that is replenished by natural processes at a rate that equals or exceeds its rate of use [45].

There are some key phrases in this definition that can guide choices. For instance, trash is not created by "natural processes." Indeed, it is recognized that by definition nature creates no trash. In light of this, municipal solid waste incineration does not fit the definition of "renewable energy." Another key phrase is "at a rate that equals or exceeds its rate of use." This phrase greatly restricts many kinds of biomass use; furthermore, the verification of the "renewability" of biomass is very difficult under these standards, even before the issue of change in soil carbon content is taken into account.[8]

A note on the phrase "clean energy" is also in order. This description is claimed by proponents of a variety of energy sources, including some that emit CO_2. We use the term in this report to mean that clean energy must be renewable (by the definition above) and also include other aspects of sustainability such as zero or minimal emissions of co-pollutants and minimal upstream and decommissioning impacts from developing these energy resources.

[8]For further discussion of the implications of the IPCC definition for biomass use, as well as related issues, see [46].

3. Business-as-usual & clean energy pathways

3.1 Overview of methods

In this section, we estimate projections for business as usual and develop a Clean Energy Scenario, which offers one potential pathway to cut direct power sector emissions by 50% by 2030 as compared to 2015 levels. This target is equivalent to a 63% emission reduction from 2006 levels, including emissions attributable to in-state generation as well as those attributable to electricity imports.

Figure 3.1 shows the historic in-state generation trends in New Jersey for its four primary sources of electricity generation—nuclear, natural gas, renewables, and coal/other—as well as projected future generation by fuel source for the business-as-usual and the Clean Energy Scenarios. In the past few years, natural gas has surged past nuclear power as the leading source of electricity generation in the state, displacing coal and other fossil fuels as well as imports. In our business-as-usual scenario, we assume that any growth in demand beyond the state's existing renewables requirement is met by natural gas, which grows to about 61% of the electricity supply by 2030. As a result, the emissions reduction goals of the Clean Energy Scenario need to be achieved by cutting the projected 2030 electricity generation from natural gas by about 54% and replacing it with renewable energy resources and efficiency.

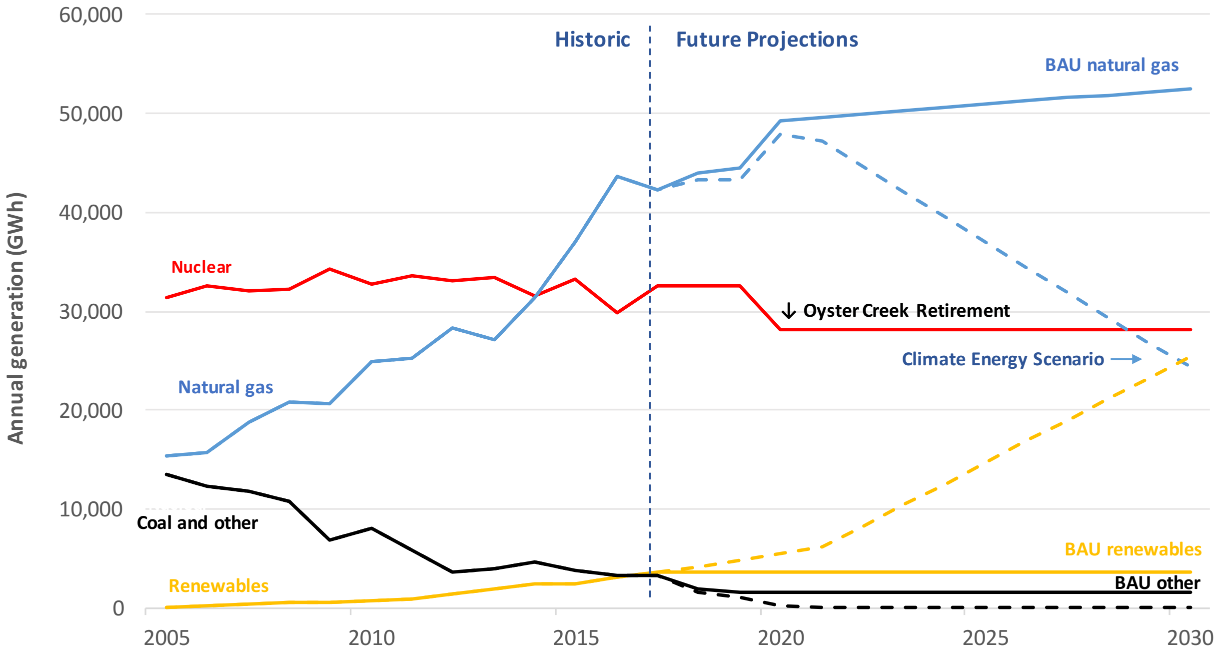


Figure 3.1: Historic and projected in-state electricity generation from the four primary sources of electricity in New Jersey—nuclear, natural gas, renewables, and coal/other. Solid lines indicate business-as-usual; dotted lines indicate projected generation in the Clean Energy Scenario.

We also consider two contingency scenarios in which the state's two remaining nuclear power plants (Salem and Hope Creek) retire early—first, the sudden retirement of these nuclear power plants by 2022, and second, a staggered nuclear power retirement scenario where the state's nuclear capacity declines to zero by 2026. In the Clean Energy Scenario, we focus on the development of in-state renewable energy and efficiency resources to displace fossil fuels and achieve greenhouse gas reductions. In the nuclear retirement contingency scenarios we also rely on the import of renewable energy resources from across PJM to help ensure that this generation is replaced with low-carbon alternatives rather than fossil fuels. The scenarios presented here are not the only pathways to achieve the target emission reductions, but instead serve to demonstrate an achievable approach to reducing greenhouse gas emissions from New Jersey's power sector.

We present four different scenarios altogether, including a business-as-usual scenario, along with our Clean Energy Scenario and the two nuclear contingency scenarios. The Clean Energy and contingency scenarios all achieve 50% greenhouse emission reductions by 2030 compared to the 2015 baseline power sector emissions, including both in-state generation and imports. In the contingency scenarios, we also cap cumulative CO_2 emissions from 2018-2030 to match the Clean Energy Scenario. This cumulative cap ensures that if the retirement of a nuclear power plant triggers a sudden increase in the use of natural gas, the subsequent spike in CO_2 emissions is compensated by an increase in carbon-free generation at other points in the analysis period (2018 to 2030). All three scenarios therefore reduce the same amount of cumulative carbon emissions in addition to reaching the same 2030 target.

To develop our scenarios, we first develop a business-as-usual baseline, which incorporates forecasts from both PJM [21] and the EIA Annual Energy Outlook [20]. Next, we calculate the potential to reduce electric demand with efficiency savings. We also add in demand growth from the electrification of vehicles and fuel oil heating systems, both of which are necessary to achieve deep decarbonization across all sectors by 2050. Having calculated the projected electric demand out to 2030, we analyze the potential for renewable energy growth to reduce power sector emissions.

The efficiency in the Clean Energy Scenario is ramped up from 0.6% (business as usual) to 2% over five years starting in 2018 and kept at that rate thereafter to 2030. We then analyze both the total technical potential for renewable energy and the historic deployment of these technologies. We cap natural gas use such that we achieve our 2030 emission targets, and then determine an achievable mix of renewables that will allow us to meet our total 2030 demand, based on both historically proven growth rates and technical potential. The costs for these scenarios are analyzed in **Chapter 4**.

3.2 Business-as-usual scenario

To develop a business-as-usual electricity demand scenario for 2030, we rely primarily on PJM's load forecasts to determine load growth rates, and incorporate energy and cost estimates from the EIA's Annual Energy Outlook [21, 20]. We first isolate the four major New Jersey utilities from PJM's 2016 Load Forecast report and sum the projected electricity demand across these utilities [21]. This load forecast reflects both demand-side efficiency savings of roughly 0.6% per year, in line with historic efficiency savings in New Jersey [35, 34], and distributed solar deployment. We add the distributed solar estimates to the

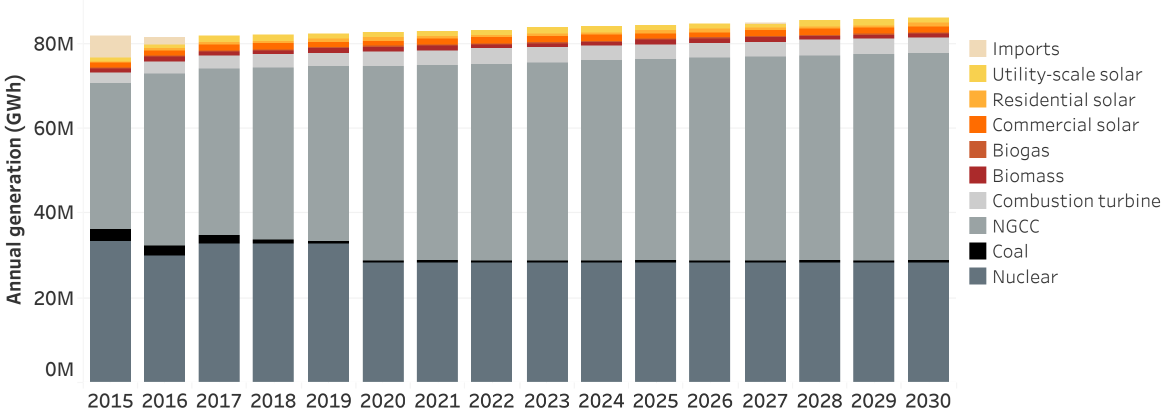


Figure 3.2: The business-as-usual electricity generation mix, reflecting the retirement of Oyster Creek at the end of 2019, 0.6% demand-side efficiency, solar generation at levels required to meet the state's solar carve-out, and expanding natural gas to meet the remaining load.

load forecast, yielding the total electricity demand requirements. The expected load growth from both combined demand and solar growth averages 0.4% per year. We apply this load growth rate to the historic electricity demand as reported by EIA [26],[1] yielding our business-as-usual demand curve (shown later in **Figure 3.6**).

The electricity mix used in our business-as-usual scenario for 2030 is similar today, but with some modifications to reflect proposed plant retirements and existing solar targets. The electricity generation mix, shown in **Figure 3.2**, reflects the proposed retirement of Oyster Creek nuclear generating station and some aging coal generation. Solar generation is assumed to reach the state's target of 4.1% of sales by 2028, and biomass and biogas generation is held constant at 2016 levels. The remaining demand is met with natural gas, increasing from about 54% of the total requirements in 2016 to about 61% in 2030.

3.3 Clean Energy Scenario load projections

The Clean Energy Scenario modifies business-as-usual demand with the incorporation of additional demand-side efficiency and the electrification of some vehicles and heating and cooling. While distributed solar will also reduce the demand that must be met by the utility power supply, we incorporate this generation source afterwards. We first set an efficiency target of 2% demand-side savings per year, which has been achieved in states like California and Rhode Island. Assuming an existing efficiency level of 0.6% per year, this implies an additional 1.4% annual reduction in demand. Next, we assume the electrification of 80% of the residential heating systems in New Jersey which rely on liquefied petroleum, propane or fuel oil, covering roughly 10% of homes. This conversion is a first step towards the electrification of all heating systems in New Jersey, although additional emission reductions from weatherization and other measures will be needed in this sector to meet an overall 40% emission reduction target. We similarly assume the electrification of 5% of all electric vehicle miles travelled in 2030, required as a first step in the electrification of the transportation

[1] We note that the load reported by PJM across these utilities and the 2016 load reported by the EIA do not match, but the rest of our analysis is based on EIA data so we apply the growth rates from PJM to the historic data.

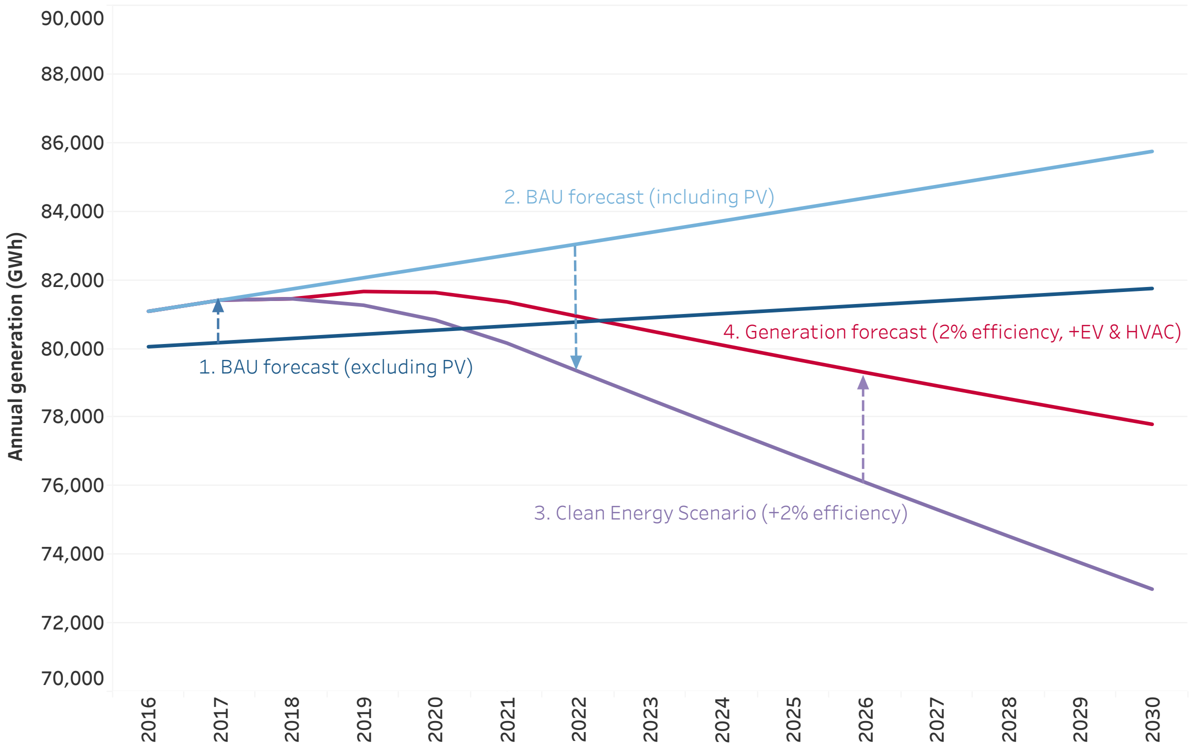


Figure 3.3: Electricity generation requirements for (i) business-as-usual scenario, excluding and including distributed solar (blue); (ii) Clean Energy Scenario, reflecting 2% annual demand-side efficiency savings (purple) (iii) Clean Energy Scenario including additional electrification of 10% of residential heating demand and 5% of electric vehicle miles travelled by 2030 (red). See **Table 3.1**.

sector to achieve emission reductions, also assuming this sector will see emission reductions from the adoption of hybrids and other fuel-efficient vehicles.[2]

Throughout this report we will typically compare business-as-usual costs to the electricity costs excluding this electrification for the sake of a fair comparison of costs to meet the same set of demands, but include this demand to ensure that renewables growth is sufficient to meet this additional demand. In **Figure 3.3**, we show the business-as-usual demand with and without rooftop solar generation, along with the Clean Energy Scenario demand reflecting 2% demand-side efficiency savings with and without the electrification of vehicles and heating and cooling. We note that the 5% vehicle electrification value for 2030 is used primarily to ensure our power sector calculations will accommodate vehicle electrification, but that specific state policies that encourage electric vehicle adoption could lead to higher electric vehicle penetration and correspondingly higher electric demand in 2030.

We have not done a detailed assessment of the requirements of a fully renewable electricity sector in New Jersey for the year 2050, but we present a preliminary analysis of the electricity requirements in **Figure 3.4**. We provide order of magnitude estimates of the electricity requirements for 100% electrification of transportation by 2050. We use electricity consumption data for presently available electric passenger vehicles to estimate electricity requirements for that segment. For other types of vehicles, we have used the ratios of petroleum fuel requirements per mile to that of passenger vehicles to make an order of magnitude estimate of the electricity requirements for 100% electrification. A partial electrification of non-road transport is also included. A very preliminary estimate of electric

[2] We increase electricity requirements by 20% to account for non-road transportation conversions.

Table 3.1: Generation and electrification requirements, efficiency savings, and CO_2, 2015 and 2030.

Generation requirements		2015	Clean Energy Scenario 2030	Notes
Electric generation requirement	GWh	81,572	77,787	PJM projects 1% growth if excluding demand reduction from efficiency and rooftop solar; 2% annual efficiency target yields 1% decline per year. Includes EV and HVAC conversions.
CO_2 emissions reduction from 2015 levels	%	0%	50%	50% reductions in 2030 power sector relative to 2015 consistent with 40% overall reductions by 2030 and 80% overall by 2050.
Annual demand-side efficiency savings	%	0.6%	2.0%	Assume 2% target continues to 2050.
Transportation electrification [47]	% GWh	0.7 2,420%	5.7%	100% electric vehicles miles travelled in 2050 and some non-road transport electrification would require 52,000 GWh, including T&D losses.
HVAC electrification	% GWh	12.0% 2,386	21.8%	90% electrification in 2050 would require 24,000 GWh, including T&D losses.

vehicles transportation electricity requirements is 52 million MWh for 2050. We assume a modest but steady improvement of electric vehicle efficiency beyond the year 2030.

CO_2 emissions from fossil fuel-reliant space and water heating in New Jersey are the same order of magnitude as emissions from the electricity sector. Converting fossil fuel space and water heating systems to efficient electric systems and putting the electricity sector on a zero emissions path by 2050 would eliminate emissions from this sector. Advanced air source heat pumps and geothermal heat pumps provide efficient solutions that promise to perform well in New Jersey. These technologies draw heat from the environment (air or the ground) and "pump" it up to the required temperature for heating in the winter. In the summer, they can function as air-conditioners, taking heat from the inside and transferring it to the outside. Geothermal heat pumps are more expensive but also more efficient. These conversions would create substantial new demand for electricity which is included in our assessment of renewable energy requirements. To do these calculations we obtained data for heating fuels used in New Jersey housing as well as household fuel use (natural gas and fuel oil) from the 2009 household fuel energy use survey [48, 49]. We use parameters for advanced heat pumps to estimate the electricity requirements for the retrofitting.[3] We assume the fuel oil and propane retrofits would be given priority before 2030 since these are likely to be economical on a life-cycle basis even at present.

[3] Coefficient of performance in the winter = 3 for cold climate heat pumps, which are advanced air-to-air heat pumps, and = 4 for geothermal heat pumps. See [16] for details of how similar calculations were done for Maryland as part of a four-year investigation of a transition to renewable energy.

About 12% of New Jersey households already use electricity for heating. We have not analyzed the efficiency of this usage. Typically, a mix of ordinary air-to-air heat pumps and resistance heating is used, suggesting that electricity use for heating could be significantly reduced for the resistance heating users by promoting geothermal heat pumps, cold climate air-source heat pumps, or comparable emerging technologies. High-end heat pump technology has the added benefit of lowering air-conditioning summer peaks. We assume these and other efficiency are ramped up from the current 0.6% such that annual demand-side efficiency savings reach 2% by 2022. The economics of retrofitting natural gas heating systems are more complex. We assume these systems will be 90% electrified in 2050. A preliminary estimate of electricity requirements by 2050 for retrofitting fossil fuel space heat and water heating systems with efficient electric ones is 24 million MWh by 2050.[4]

Several elements that play small or moderate roles in 2030 will become very important by 2050. Energy storage requirements would be much larger, and similarly losses resulting from charging and discharging of batteries would increase in magnitude. Additional non-fossil fuel peaking resources will also be required. Technological options include demand response and load shifting, batteries or other energy storage devices, or light-duty fuel cells run on hydrogen produced by electrolysis of water using solar and wind energy. This battery charging or electrolysis would be conducted when electricity prices are close to zero—that is when surplus electricity after meeting all demand is still available. Even after using much or most of the surplus electricity for hydrogen production or battery storage, there would still likely be some hours of the year when all demands would be met and surplus wind and solar would still be available. In such circumstances, wind and solar generation would be curtailed or sold at low or even zero price to other parts of the PJM grid. We have increased total electricity requirements by 20% to account for battery storage and hydrogen production losses, and curtailment.[5] A comparison of the 2015, 2030 and 2050 electricity generation requirements is shown in **Figure** 3.4.

3.4 2030 electricity generation portfolio

We develop 2030 targets for electricity generation in New Jersey based on the existing generation portfolio, the technical potential for each resource, historic deployment rates for these technologies, and an overarching greenhouse gas emission reduction goal of 50% from 2015 levels. Within these constraints, New Jersey's best choice for achieving an energy system primarily based on renewables would be to pursue very vigorous offshore wind development as well as rooftop and ground-mounted solar. The latter category may include urban and some rural utility-scale solar to the extent practical. In the case of early nuclear power plant retirements, the residual load can be met with imports of renewable energy, including utility-scale solar and onshore wind from across PJM with sufficient additional transmission capacity. We develop our resource mix as follows:

[4]This is based on a detailed evaluation of a similar conversion for Maryland, with adjustment for population and numbers of households being converted [16].

[5]The 20% figure is a rounded value based on a detailed hour-by-hour analysis done by IEER as part of the Renewable Maryland Project. See Chapter VII, Section 4 [46]

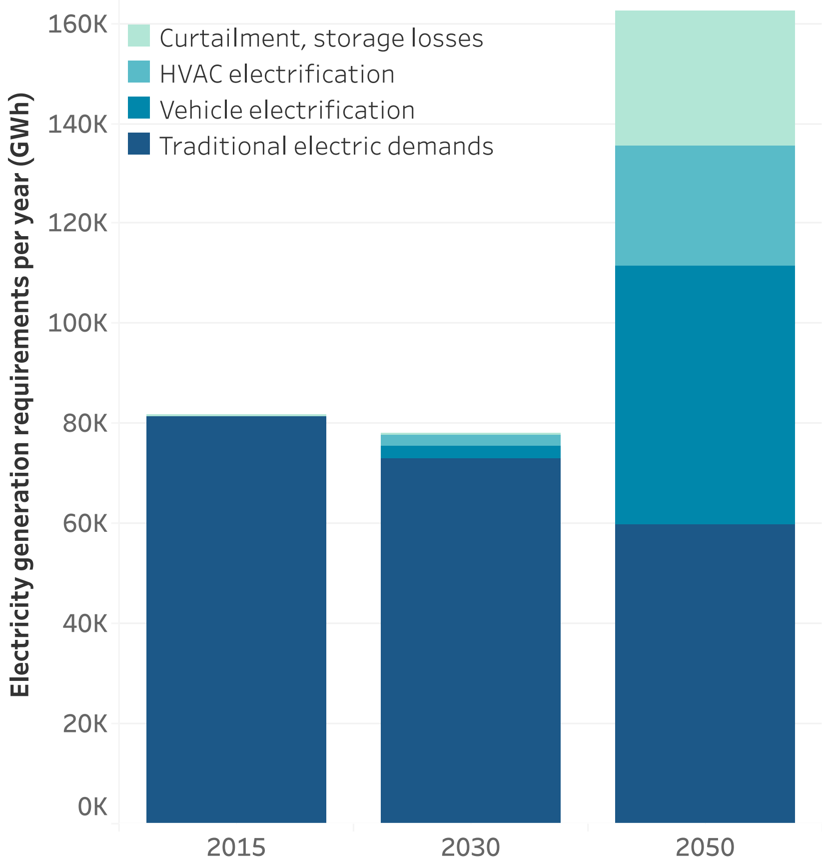


Figure 3.4: Electricity requirements in 2015, 2030 and 2050 show the demand requirements to meet traditional electric loads, as well as additional generation requirements to provide electricity for transportation and HVAC systems. An additional factor in 2050 reflects over-generation needed to accommodate both potential renewable energy curtailment and energy storage losses.

3.4.1 Solar

The use of New Jersey's solar resource is constrained by land-use policy goals as well as achievable annual solar deployment rates. To minimize land-use impacts, we assumed the majority of solar generation in New Jersey in the coming years would come from distributed solar installations, reflecting historic trends. Distributed solar includes both rooftop solar as well as ground-mounted installations at commercial and industrial sites. To project distributed solar installations in 2030, we identified the maximum historical annual capacity growth of distributed solar in New Jersey (summing commercial and residential), and assumed this growth rate (309 MW_{dc}/year[6]) would continue every year to 2030.[7] This rate is sufficiently aggressive to reach a significant contribution of solar by 2030 but is also a rate that has been historically proven to be achievable.

Under these assumptions, rooftop solar installations in 2030 would reach approximately 19% of the technical potential for rooftop solar in New Jersey as estimated by NREL (2016), after

[6] All solar capacity in this report is in terms of MW_{dc}, unless otherwise specified. Electricity output is in terms of MWh_{ac} or GWh_{ac}.

[7] There are other approaches we could take as well, such as using the average of the annual capacity added each year over the last five years. Under more aggressive targets, the capacity added per year could increase beyond the maximum historical level, assuming that deployment may increase as costs fall. The primary constraint is that total distributed generation remain a fraction of the maximum technical rooftop potential of about 31,000 MW, although even this constraint is flexible considering ground-mount systems.

scaling for 20% efficient panels. This value is roughly equal to 8% of the total rooftop space.[8] In practice, a lower fraction of this capacity would likely be used considering the inclusion of ground-mount distributed solar systems. By 2030 the total distributed capacity deployed at this growth rate is 5,853 MW. We replicated this approach for utility-scale solar growth. The total generation from utility-scale solar is projected to be slightly more than one half of that from rooftop solar; we add utility scale solar at the maximum historic growth rate of 138 MW/year. At this deployment rate, New Jersey would deploy 2,417 MW_{dc} of utility-scale solar by 2030, covering roughly 10,000 acres at 4.5 acres/MW_{dc}.[9]

Historically, approximately 2/3 of New Jersey's distributed solar capacity has been installed at non-residential sites, and 1/3 at residential sites, but in the last two years (2015 and 2016), residential capacity additions have surpassed commercial capacity additions. Moving forward, we assume that rooftop solar capacity will be split evenly between commercial and residential for the Clean Energy Scenario. The ratio makes some difference to the total cost of electricity, since commercial rooftop solar is more economical than residential rooftop solar. We consider this assumption to be somewhat conservative, because a larger proportion of commercial installations would lower our total cost estimates.

While the technical potential for utility-scale solar deployment is large, the available area for solar is limited by constraints on agricultural land and environmental considerations. A full analysis of the New Jersey land area available for utility-scale solar is beyond the scope of this report. However, we note that the land-use impacts of solar development can be minimized by focusing on siting solar on already-degraded lands such as brownfields or landfills. As an example, we explore the potential to site solar on New Jersey's brownfields and landfills in **Box 3.4.1**.

In **Figure 3.5** we show the projected growth of solar power in New Jersey if the state maintains its historic maximum deployment of utility-scale and distributed commercial and residential installations every year until 2030. In **Table 3.2** we summarize these data on projected 2030 deployment and technical potential for New Jersey's solar resources.

[8] Based on rooftop area estimates from [41].

[9] Ong *et al.* report the ratio of the AC capacity rating to the DC capacity rating at 0.85 [50]. Expressed in terms of MW_{ac}, our estimate implies an area of 5.3 acres per MW_{ac}. We assume the systems will generally be smaller than 20 MW_{ac}. The direct area required per unit of installed capacity varies a great deal, depending on topography and panel efficiency. In addition, total area varies even more, due to factors such as setback requirements. Ong. *et al.* cite various studies that report average direct land use requirements per MW_{ac} between 3.8 and 5.5 acres per MW_{ac} for fixed tilt systems and 5.1 to 6.3 acres per MW_{ac} for single axis tracking systems (p. 7). The direct area requirements for fixed tilt systems show a clear downward trend with panel efficiency but no similar trend is evident for single-axis systems. The reasons for the large variations are not well understood [50]. The area estimate provided here should therefore be considered very approximate. New Jersey specific data for utility-scale solar land requirements are needed to provide a better estimate.

3.4.1: Siting solar on brownfields and landfills

Brownfields are degraded sites that are promising for solar deployment because they offer an opportunity to utilize areas that may be unsuitable for other needs and repurpose them for environmental benefit. There are numerous sites designated as brownfields throughout New Jersey, with more than 11,000 potential sites included in the EPA's RE-Powering database [51], which was designed to help decision-makers screen for degraded sites usable for renewable energy deployment. While many of these listings are duplicates, and numerous others are sites with existing buildings or structures, some may be utilizable for solar. As a case study, we looked at the landfill subset of these brownfield sites. Landfills in New Jersey are already home to tens of megawatts of solar power. To analyze the rest, we first isolated landfills from the RE-Powering database and crosschecked the land area for these sites with the New Jersey Landfill database [52]. Next, we looked up each site on Google Maps [53] to determine if the area was built up, covered in trees, already had solar, or open, and estimated approximately 6,000 open acres. If solar were deployed on 25% of this open landfill area, more than 300 MW of panels could be deployed at 4.5 MW_{dc}/acre. Some of these sites might need remediation before building, but the remediation will provide additional environmental benefits. This landfill area is just an example of the kind of location where land use impacts of solar would be minimized.

We have used capacity factors specific to New Jersey: 14.7% for residential solar, 15.3% for commercial solar, and 18% for utility-scale solar. We assume utility-scale solar will be single-axis tracking systems, and all others will be fixed tilt. Capacity factors do vary modestly within New Jersey; however, this is a refinement that would not significantly affect our overall cost estimates. In addition, the expansion of solar installations in the Clean Energy Scenario means that the geographical distribution of solar in New Jersey will likely change. That distribution is difficult to estimate and is beyond the scope of the present effort.

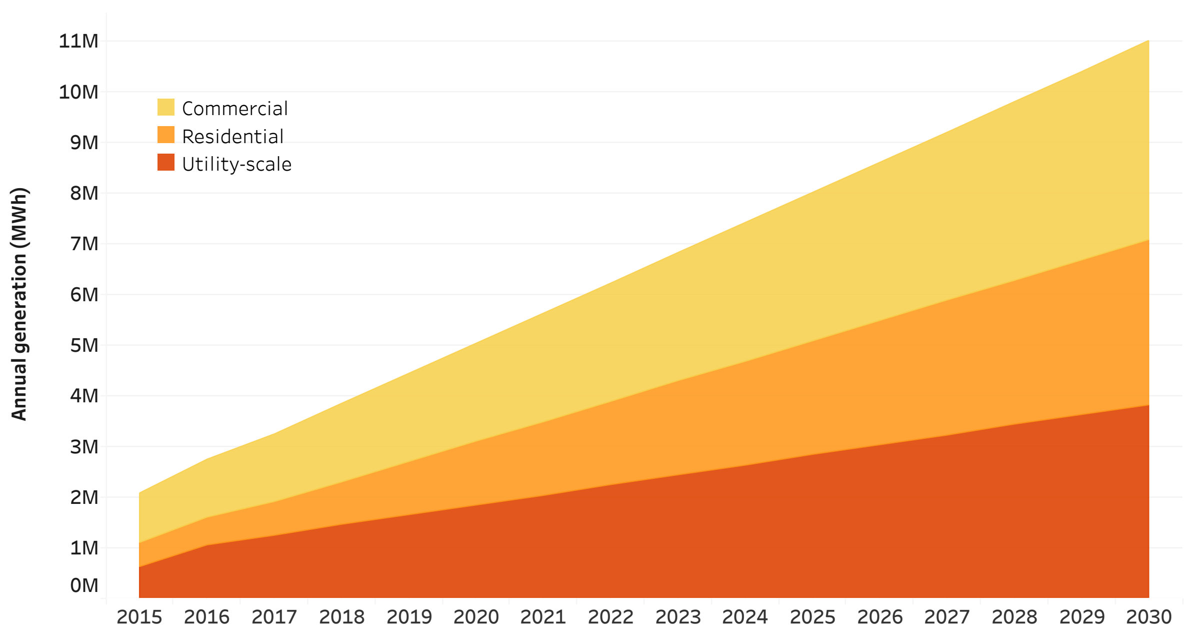


Figure 3.5: Growth of solar power in New Jersey 2015-2030 under the Clean Energy Scenario.

Table 3.2: Potential for solar growth in New Jersey.

Solar resource			2015	2030 target	Technical potential and notes
Distributed solar Includes any generation "behind the meter"	Residential rooftop	MW	337	2,654	About 31GW, 38,000 GWh of rooftop potential at 20% efficiency. 2030 target would use 19% of this potential if all distributed solar were installed on rooftops, but some will likely be ground mounted. Ground mounted potential likely large, but magnitude unknown. Community solar projects, notably, are often ground mounted. Additional space available on canopies and in open plots near buildings. In 2016, NJ had 491 MW residential and 1,034 MW commercial capacity.
	Commercial rooftop	MW	961	3,197	
	Commercial groundmount	MW	–	–	
	Total behind the meter	GWh	1,435	7,178	
Utility-scale solar Includes any generation that is grid-connected	Traditional utility scale	MW	351	2,417	651,500 GWh potential (only need 0.6% for 2030 target), but most area unsuitable due to land use constraints; significant urban area also available. Roughly 6,000 acres of unbuilt, unforested landfill area identified from EPA RE-Power and NJ landfill database. Brownfields and degraded lands should be prioritized; currently there are roughly 45 MW of PSEG landfill and brownfield solar installations.
		GWh	628	3,809	

3.4.2 Offshore wind

New Jersey's abundant offshore wind potential—almost 350 million MWh per year—far surpasses the total electric demand for the state of New Jersey. In consultation with the offshore wind industry, we assume that the state deploys between 3,250 MW and 3,800 of offshore wind by 2030. We use the higher value in our contingency scenarios where the nuclear power plants retire early and must be replaced by low-greenhouse gas resources. At an 8Dx8D grid density, this scale of offshore wind deployment would reach just over half of the potential capacity estimated by NREL [54] within the Bureau of Ocean Energy Management's initial New Jersey offshore wind leasing area [55]. This leasing area has wind speeds over 8m/s, shallow depths, sufficient distance from shore, and minimized ecological impact. Due to the time needed to develop the nascent U.S. offshore wind industry, however, we do not assume any of these turbines come online until the year 2022. New Jersey has the potential to develop significantly more offshore wind capacity, and is expected to continue to expand its offshore wind after 2030 as the technology matures.

3.4.3 Biomass, landfill gas, biogas and anaerobic digestion

As noted previously, New Jersey currently relies on both burning municipal solid waste and landfill gas to meet some of its renewable energy requirements. Municipal solid waste combustion, as well as the combustion of wood products and other biomass, releases health-harming co-pollutants. Furthermore, municipal solid waste does not meet the definition of "renewable" set forth by the IPCC, as discussed in **Section 2.5**, and the sustainability of other forms of biomass is often hard to prove. As a result, we assume municipal solid waste and other solid biomass burning is phased out in New Jersey. By 2030, we expand electricity generation from landfill gas and anaerobic digestion of food and yard waste to 70% of their estimated potential of about 960 GWh/year and 310 GWh/year [44], respectively.[10]

3.4.4 Fossil fuels

We assume all coal and oil generation is phased out by 2020. Coal generation in New Jersey has plummeted in recent years. Petroleum liquids, which are typically used for peaking generation, have also fallen dramatically and continue to decline nationwide. To meet our emission reduction target, we cap natural gas use such that direct combustion at natural gas plants in 2030 emits 50% of the state's 2015 power sector emissions, including from in-state generation and imports. We assume that the ratio of generation from natural gas combined cycle plants compared to natural gas simple cycle combustion turbines remains constant from 2015 to 2030. In PJM's grid modeling study of renewable energy integration, the scenario with high offshore wind and 30% renewables (most similar to our New Jersey analysis) found combustion turbine use would fall by 70% compared to business-as-usual while combined cycle use would only fall 50% [2]. As a result, we expect that our analysis is likely conservative because it may overestimate combustion turbine use, contributing to higher cost and emission estimates in 2030.

We also assume that the emission factors from these plants remain constant at 0.46 metric tons CO_2 per MWh and 0.54 CO_2 metric tons per MWh, respectively.[11] In practice, more efficient and newer plants will likely run at higher frequency than less efficient, older plants in 2030, and therefore these emission factors are expected to be an upper limit on emissions from natural gas generation in 2030. Net emissions, as a result, would be lower than 50% of 2015 values if the 2030 emission factors are lower due to higher use of more efficient plants.

Due to incomplete data about the operation of New Jersey's combined heat and power plants, and the difficulty of determining what fraction of natural gas is used for electricity or for heat, we use a simplified 2030 scenario where only NGCC and combustion turbines are used to estimate emissions and costs from natural gas-fired electricity in 2030.

3.4.5 Nuclear power

New Jersey is scheduled to lose 15% of its nuclear power generating capacity when the Oyster Creek Generating Station retires in 2019. In our Clean Energy Scenario, we assume

[10] Using landfill gas in fuel cells is more expensive but cleaner than using it in internal combustion engines to generate electricity, because combustion creates air pollutants like nitrogen oxides. There are chemicals in landfill gas other than methane and CO_2. Their disposition is beyond the scope of this report.

[11] Values derived from EPA Air Markets Program Data tool [56].

that the three remaining nuclear reactors—Hope Creek (one unit) and Salem (two units)—remain online through 2030. As noted in the introductory chapter, the reactor at Hope Creek has a license to operate until 2046; Salem Unit 1 has a license to operate to 2036 and Salem Unit 2 to 2040. As mentioned earlier, we also consider two contingency scenarios, wherein these power plants retire earlier than scheduled and their emissions must be offset with renewable energy imports. These scenarios are described in detail in **Section 3.5.2**.

3.4.6 Renewable electricity imports

In our Clean Energy Scenario, we focus on the development of in-state renewables to meet the 2030 carbon emission goals. However, in the contingency case where New Jersey's Hope Creek and Salem nuclear generating stations retire earlier than expected, New Jersey may need to rely on out-of-state renewables to maintain its emission reductions. Historically, New Jersey has purchased Renewable Energy Credits (RECs) to meet its renewable energy targets. Here, we suggest using long-term contracts instead, such as power purchase agreements (PPAs) or virtual PPAs, to develop wind and solar power across PJM. While this electricity generation would not necessarily feed directly into the New Jersey grid, the PPA can be structured to require the build of new renewables, and New Jersey could import electricity from PJM to make up the nuclear deficit. The actual generation displaced by these renewables will depend on the location and time of generation—for example, a solar farm in Virginia might displace different emissions than a wind farm in Ohio—but given that most of PJM has higher-emitting electricity generators than New Jersey, on average, it is likely that much or most of these renewables would displace coal in addition to natural gas.[12]

In order to determine the potential speed with which renewable PPAs could be added to the PJM grid, we first analyze the existing queue of generating stations that have requested interconnections to the PJM grid as of mid-2017. Some of the proposed renewable energy projects will likely be used to meet renewable energy targets in other states. The subset of solar projects currently in the queue in states with low or no solar targets is over 14,000 MW, mainly in Indiana, Kentucky, North Carolina, Ohio, and Virginia; the subset of wind projects in states with low or no renewable requirements is about 6,000 MW in states such as Indiana, Virginia and West Virginia [57]. While the majority of the projects requesting interconnection are never built, this queue capacity suggests there is significant developer appetite to add renewable energy; the proposed PPA structure could help increase the build rate by guaranteeing a customer for these projects. We expect wind power imports to be maximized first, given the higher current build rates and lower costs than solar. In consultation with the wind industry, we set an upper limit on annual wind energy capacity additions at 1,000 MW per year. We assumed a capacity factor of 40%, in line with NREL estimates for the PJM region for the mid-2020s [18], about the same as the average capacity factor of new wind projects in the Midwestern grid (MISO) but above the low end of new projects in the Interior in 2015 (35%) [58]. We added additional solar power as needed (up to about 700 MW per year at 21% capacity factor) to ensure that the state meets the stated emission targets. Imports begin in 2019 or 2020 as needed, beginning before any nuclear power plants are expected to retire in order to compensate for the anticipated loss of low-carbon generation. These additions come to about 5,500 MW of onshore wind and 3,500 MW of solar in 2030.

[12]See **Box 4.3.1** for a discussion of Virtual PPAs.

It is important to contextualize the suggested scale of renewable project development within PJM compared to current deployment. In June 2017, PJM reported only 8,800 MW of grid connected solar and wind.Collectively, renewable portfolio standards across PJM states require that Tier I renewables meet 6.3% of the 2017 PJM load and an estimated 12.6% of the 2028 load [30], where Tier I renewables include landfill gas, wind, solar and run-of-river hydropower. As a result, the proposed magnitude of renewable imports holds the potential to catalyze renewable energy growth across PJM.

3.4.7 Transmission

In our Clean Energy Scenario, we do not assume any new transmission except that needed to connect offshore wind projects to the coast. In the nuclear contingency scenarios with renewable energy imports, we estimate required transmission additions from the PJM renewable integration study [2]. In the PJM study scenario with high offshore wind (similar to our study) and 14% renewables across PJM (in line with current targets), $2.6 billion is required to build transmission for 20 GW of wind to bring electricity from inland to the coasts. We therefore add roughly $130 million of transmission for every GW of imported wind electricity, although we note that if renewables remain low across PJM this additional transmission may be unnecessary, and that if PJM sets very aggressive renewable targets then more transmission infrastructure will likely be needed.

3.4.8 Energy storage

As New Jersey generates higher levels of in-state renewable energy, strategies will be needed to balance the grid. Currently, the penetration of variable renewable generation in the PJM region is still very low. It is difficult to estimate the amount of electricity storage that will be needed in New Jersey as renewable energy increases, given uncertainties regarding the fraction of renewables in the rest of PJM. To be conservative, we have used California's storage targets as a benchmark, given that (i) that state's renewable generation consists mainly of solar and wind, and (ii) the size of the Western Electricity Coordinating Council interconnect is about the same as the size of PJM. California has a high renewable energy target of 33% by 2020.[13] Its storage target for that year is 1,325 MW. At 261 million MWh, California's electricity sales are over three times that of New Jersey [26]; this means that a 33% renewable energy portfolio would necessitate more renewable energy than New Jersey's entire electricity usage. Our Clean Energy Scenario results in an implicit 33% RPS in New Jersey by 2030. Assuming an average of four hours of discharge time for California's storage target (i.e. 5,300 MWh of storage), California's storage target would scale to 400 MW/1600 MWh of storage for New Jersey in 2030.

We assume that the use cases in New Jersey will vary somewhat from California. Specifically, we allocate energy storage to two use categories: 1) peaker plant replacements, and 2) microgrids for additional resilience benefits. We use Lazard's energy storage use case definitions for our cost estimates, namely 2 MW (2 MWh) systems for microgrids and 100 MW (400 MWh) systems for peaker replacements [59]. Maintaining the 1,600 MWh target outlined above, we include storage for two peaker plant replacements totaling 200 MW (800 MWh) and 400 microgrids totaling 800 MW (800 MWh), for a total capacity of 1,000 MW.

[13] California currently meets some of its RPS with geothermal and biomass resources, but the state does not include distributed solar as part of its RPS, meaning that the total proportion of variable wind and solar resources in 2030 will likely still be close to 33%.

New Jersey is a small (∼10%) part of the PJM grid in terms of electricity load.[14] The Clean Energy Scenario implicitly assumes that other states in the PJM region would also adopt ambitious renewable energy targets for the year 2030; if no other states aggressively pursued renewables then most balancing could occur without relying on storage, and, in principle, PJM could integrate up to 30% variable renewables without requiring additional energy storage [2]. This storage balancing requirement also ignores the interconnections of PJM with the Midwestern grid (MISO), the New York grid (NYISO), and the New England grid (ISO-NE). We have not explicitly included demand response because it does not involve any generation elements. An extensive demand response capability would also reduce capacity and storage requirements.

However, we have included significant energy storage for the following additional reasons:

1. **Resilience:** distributed solar and battery storage (along with smart inverters) can provide grid resilience in the face of storms, grid outages, and a changing climate.

2. **Peaker replacement:** Energy storage costs, notably for batteries, are falling as deployment increases. Storage therefore has the potential to reduce the use of expensive and polluting peaker plants. Careful regional planning could further help reduce pollutant emissions from these plants near vulnerable and overburdened communities.

3. **Grid modernization:** Storage can help increase grid flexibility as the state modernizes its grid to integrate renewables beyond 2030; as such, the inclusion of storage provides a more realistic comparison to business-as-usual, which does not include any storage.

3.5 2030 Clean Energy Scenarios

3.5.1 Clean Energy Scenario: base case

The base-case Clean Energy Scenario relies on an expansion of in-state solar, offshore wind, and efficiency resources to reduce power sector emissions by 2030. **Figure 3.6** shows both the historic electricity mix in New Jersey and the portfolio used to reduce electricity sector emissions by 50% by 2030 from 2015 levels. Efficiency savings reduce demand by about 14.9% from business as usual. Solar power, offshore wind, and a small contribution from biogas and landfill gas fully displace coal, oil, and municipal solid waste, and contribute to a reduction in natural gas use of nearly 45% from 2016 levels (34% from 2015 levels), while precluding the need for net electricity imports. The generation targets are summarized in **Table 3.3**.

This Clean Energy Scenario reflects a renewable energy target of 33% of generation, including 14.1% from solar power, 17.4% from offshore wind, and the remainder from biogas. **Figure 3.7** compares in-state generation from the Clean Energy Scenario to the state's existing Renewables Portfolio Standard (RPS) of 22%, including the state's solar carve-out of 4.1% of sales [31]. The state RPS stops growing in 2021, with the exception of the solar carve-out, which continues to increase slowly until 2028. The majority of renewables cur-

[14]New Jersey's electricity sales of 75.5 million MWh in 2015 were just under 10% of the PJM annual electricity load (776 million MWh) for that year—for PJM data see Table 1-1 [60].

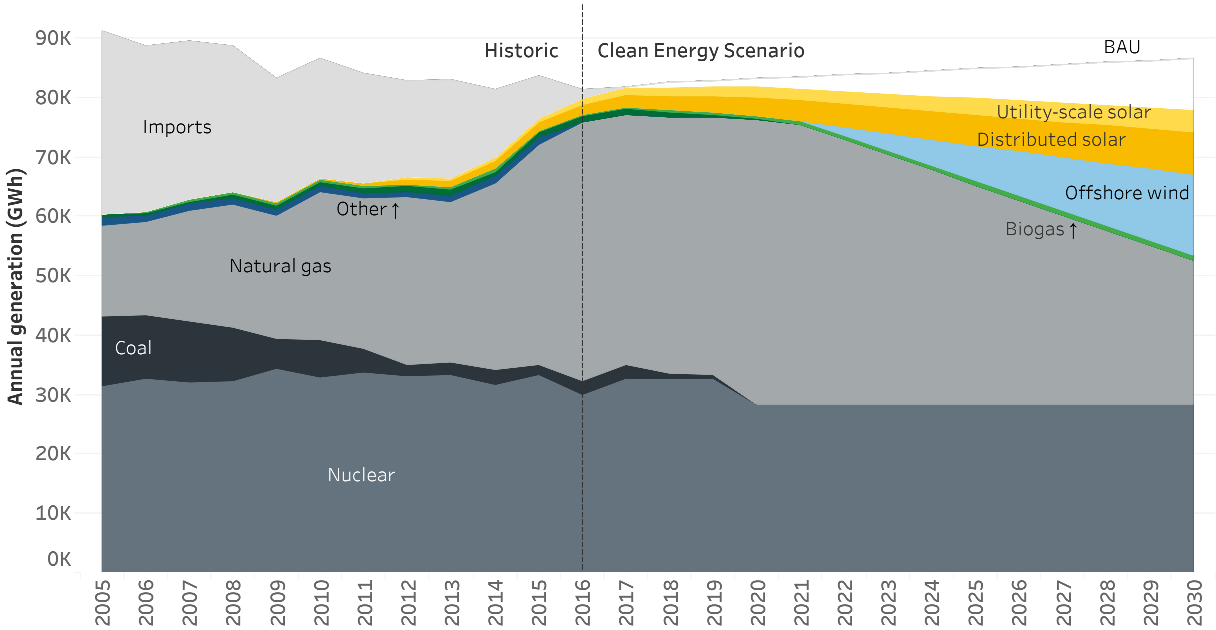


Figure 3.6: Clean Energy Scenario electricity generation portfolio in New Jersey, 2005-2030. This scenario reduces direct power sector CO_2 emissions by 50% compared to 2015 levels.

rently used to meet the state's RPS target are not generated in the state of New Jersey. Moreover, they represent only unbundled Renewable Energy Credits (RECs) and not actual renewable energy. Our Clean Energy Scenario would expand actual in-state renewable generation, so that this generation surpasses the existing target by 2027. The RECs would be acquired with the generation, reducing the expenditures now made to acquire RECs unbundled from the energy itself to meet the existing RPS. Note that in 2016 solar generation had already reached the solar target for 2020.[15]

The greenhouse gas emissions from New Jersey electricity use under the Clean Energy Scenario are compared to business as usual in **Figure 3.8**. The additional greenhouse gas implications of fugitive methane at leakage rates of 1.5% and 3.5% are provided using a 20-year global warming potential of 86 [14]. Methane leakage is discussed in detail in **Section 6.3**. Under the Clean Energy Scenario, direct greenhouse gas emission reductions are achieved in large part through a decrease in natural gas combustion, the reduction of which is also expected to reduce upstream methane emissions as shown here.

[15] Solar renewable energy credits (SRECs) can be banked for future dates, so this result does not mean all of this generation was used to meet the carve-out in 2016.

Table 3.3: Summary of Clean Energy Scenario, 2015 and 2030.

		2015	2030	Notes
Electric generation requirement	GWh	81,570	77,800	
PJM Imports	%	7%	0%	
Distributed solar	GWh	1,435	7,180	1,700 GWh in 2016
	MW	1,300	5,850	Growth rate: MW/year; 50% residential/50% commercial
Utility-scale solar	GWh	630	3,810	1,000 GWh in 2016
	MW	350	2,420	Growth rate: 126 MW/year
Offshore wind	GWh	0	13,520	
	MW	0	3,250	Technical potential ∼100,000 MW
Onshore wind	GWh	22	22	
	MW	7.6	7.6	
Biomass (municipal solid waste)	GWh	850	0	2015 estimate is from MSW burning in GATS. EIA estimates 946 GWh from “biomass.”
Biogas and landfill gas	GWh	310	889	Assume all growth is from biodigester and landfill gas
Natural gas	GWh	36,980	24,300	
Coal	GWh	1,760	0	Two plants closed in 2017.
Nuclear power	GWh	33,260	28,230	Oyster Creek retires in 2019; Hope Creek and Salem online in 2030
	MW	4,090	3,470	
Energy storage (exc.pumped hydro)	GWh	1.6		GWh here refers to energy capacity, not net supply
	MW	5	1000	2015 storage capacity is an estimate
Implicit RPS		12.2% RPS + 2.45% solar	33% RPS	The Clean Energy scenario increases 2030 renewables 11% beyond the current 2028 target and shifts all renewable generation in-state; currently only about 30% of RPS is generated in-state.

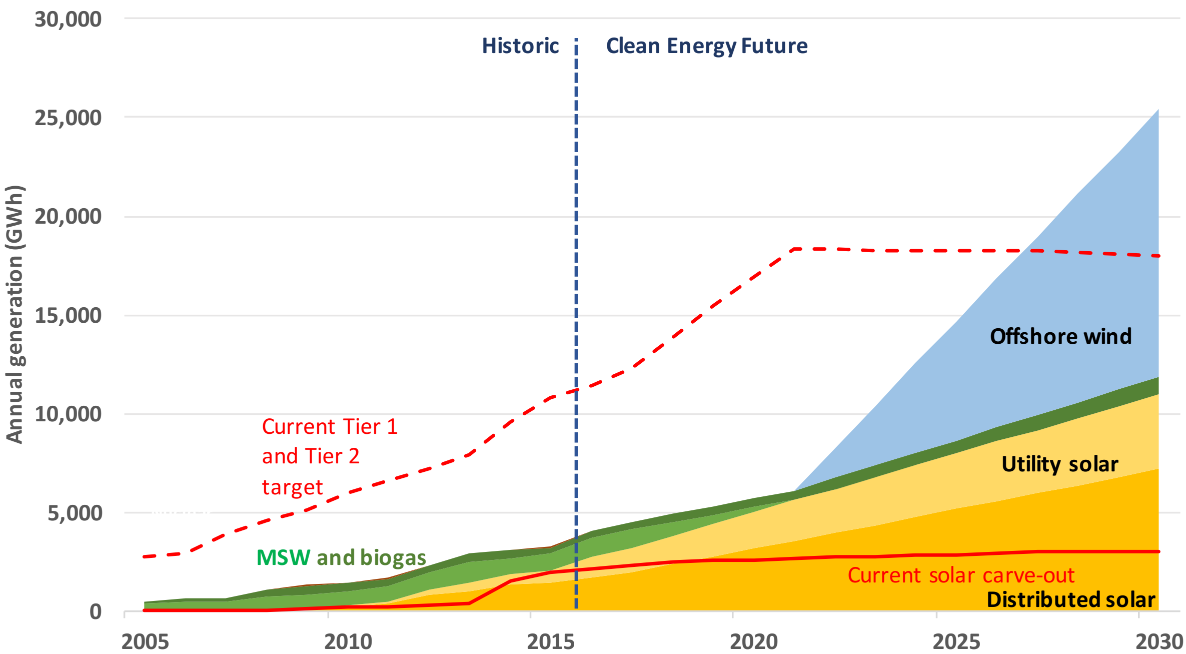


Figure 3.7: Renewable generation in New Jersey, as compared to the state's existing Renewables Portfolio Standard (reflecting in- and out-of-state RECs) and solar carve-out.[a]

[a]We note that we are defining our renewables targets as a percent of generation whereas the current RPS sets targets as a percent of sales, which does not reflect transmission and distribution losses.

3.5.2 Clean Energy Scenario: nuclear shutdown contingencies

We develop two contingency scenarios to assess the impact of early retirement of nuclear power plants. We are not advocating such early retirement here. In any case, a decision to retire a nuclear power plant is made by the corporation that owns it (for instance on financial grounds) or by federal agencies, notably the Nuclear Regulatory Commission. We include these contingency scenarios because events in 2016 in both New York State and Illinois have resulted in situations where companies considered early closures of some reactors. In both states, the corporations have been promised considerable sums of money in excess of market prices to keep the nuclear plants open.[16] In both cases, there was no contingency planning to deal with the situation from the point of view of power planning, carbon emissions, or the economic problems that workers and communities might face in the event of premature closure. The entire suite of issues involved is complex and beyond the scope of this report. By planning for the contingency that nuclear generation would become uneconomic at an earlier year than their license expiry date, additional investments in renewable energy and energy efficiency can be planned. Thus, we consider two scenarios that achieve emission targets by 2030, even with the loss of New Jersey's nuclear capacity. These scenarios should be considered for heuristic purposes to explore strategies to achieve carbon reductions in the case of nuclear power retirement; as such they are illustrative rather than definitive.

A large variety of scenarios could be constructed to illustrate the contingency of early nuclear plant retirement with the constraint of a fixed CO_2 reduction target in the year 2030. All

[16]While the states have allotted additional monies above market prices, the cases are still contested in various ways, for instance at the level of the Federal Energy Regulatory Commission.

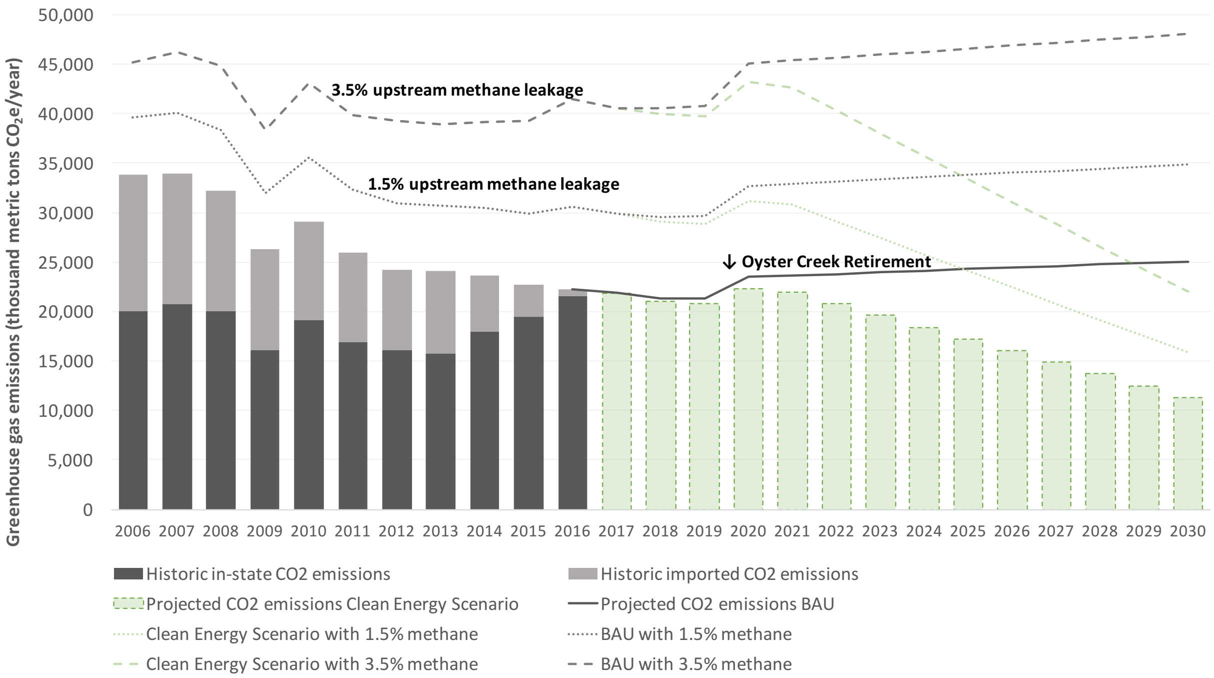


Figure 3.8: Historic and projected greenhouse gas emissions under the business-as-usual (BAU) and Clean Energy Scenarios. In addition to direct CO_2 emissions, the greenhouse impacts of fugitive methane leakage at 1.5% and 3.5% are illustrated with the dotted and dashed lines, respectively.

commercial nuclear power reactors that have closed permanently in the United States so far have shut down before the expiry of their licenses (including any license extensions).

After Oyster Creek retires at the end of 2019, New Jersey will have three operating nuclear units, including two at Salem Generating Station and one at Hope Creek. In the sudden nuclear shutdown scenario, we assume an extreme case wherein all three units shut down by the end of 2021. In the staggered nuclear shutdown case, we assume that one unit retires at the end of 2021, one at the end of 2023, and the last at the end of 2025.

The specific dates assumed can be varied; the selected ones are not intended as predictions and later closure is possible. The analysis simply provides a basis for assessing sensitivity. Nuclear power plants bid their capacity into PJM three years in advance. Hence, the likelihood of closure increases in case a plant does not clear the capacity auction. We also do not fully explore the reliability impacts of early retirement of all of the nuclear power plants. Our intent, instead, is to determine the feasibility of meeting carbon emission reduction targets under such a scenario.

As described earlier, we require the nuclear contingency scenarios to both meet the same emission reductions target as for the Clean Energy Scenario and we further constrain total carbon emissions from 2018 to 2030 to the same total as under the base case. This second constraint ensures that any spike in emissions from natural gas use after nuclear retirements is offset by additional renewable energy generation elsewhere in the time frame considered, and as such makes the scenarios and benefits of each scenario directly comparable to one another.

To replace the lost generation in the nuclear contingency scenarios, we evaluate one of many possible options. We first assume that the state's offshore wind target expands from 3,250

Table 3.4: Comparison of scenario electricity generation mixes in 2030.

Generation type[a]	BAU (GWh)	Clean Energy Scenario (GWh)	Nuclear retirement scenarios (GWh)
Solar	3,250	10,990	10,990
Offshore wind	0	13,520	15,780
Onshore wind (in-state)	22	22	22
Biogas and biomass	1,280	889	889
Nuclear	28,230	28,230	0
Natural gas	52,560	24,300	24,300
PJM renewable imports	0	0	25,780
Total	85,730	77,800	77,800
Effective RPS	4%	33%	69%
Fraction of 2015 CO_2	113%	50%	50%

[a]Note: 250 GWh of pumped hydro (a negative number) is not shown

MW to about 3,800 MW. The remaining generation is met with renewable energy imports, including an annual addition of up to 1,000 MW of wind energy imported from PJM and the remainder met with solar. In the sudden nuclear retirement scenario, imports are required to start by 2019 to ensure that total emissions remain under the cumulative cap, while in the staggered scenario renewable imports start in 2020. These would not be actual imports of the electricity; much more likely the electricity would be acquired by Virtual Power Purchase Agreements, as discussed in **Box 4.3.1**. The annual energy generation mix for these two scenarios compared to the Clean Energy Scneario is given in **Figure 3.9**. In all cases, nuclear shutdowns trigger a spike in emissions from natural gas use the following year, to be offset by greater renewables in later years. The renewable imports in 2030 are equal to 33% of generation for both contingency scenarios, although the cumulative imports and rate of renewable PPA growth is higher for the rapid shutdown scenario, as would be expected. While New Jersey has greatly reduced its electricity imports in recent years, we note that the state imported this magnitude of electricity as recently as ten years ago [8, 61]. We assume that the renewable energy imports help displace natural gas generation in our calculations, although we note that the renewables may be connected to a distant component of PJM's grid and some average grid mix of electricity will enter New Jersey directly. The generation mixes are summarized in **Table 3.4**.

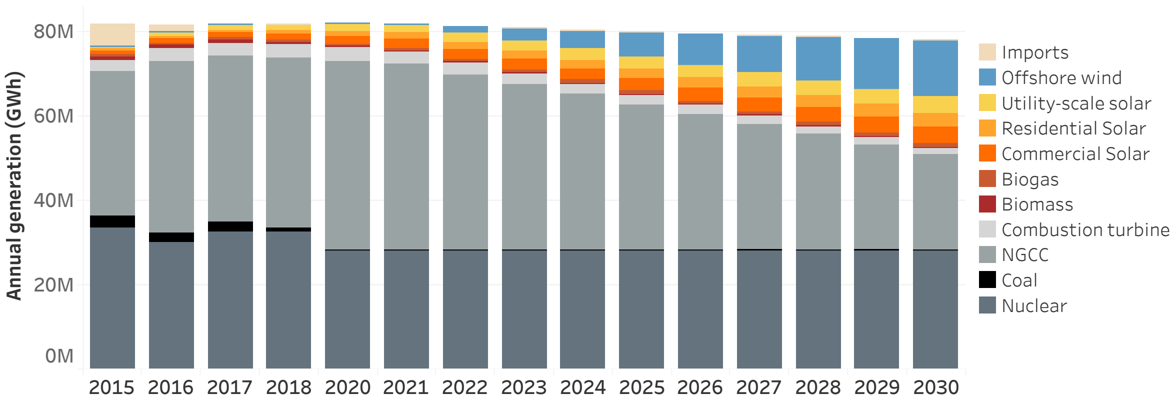
We note that the scenarios here are not the only options to replace this capacity: additional demand-side efficiency savings beyond 2% per year or more rapid expansion of in-state solar and 2% per year, New Jersey would require 69% renewable energy by 2030 including both in-state generation and imports via VPPAs in order to ensure 50% reduction in emissions. If the nuclear power plants are retired and replaced by natural gas, all other aspects of these scenarios being equal, then emissions would increase 11% above 2015 levels even with the rapid expansion of in-state solar and offshore wind described.

3.5.3 Setting the stage for 2050

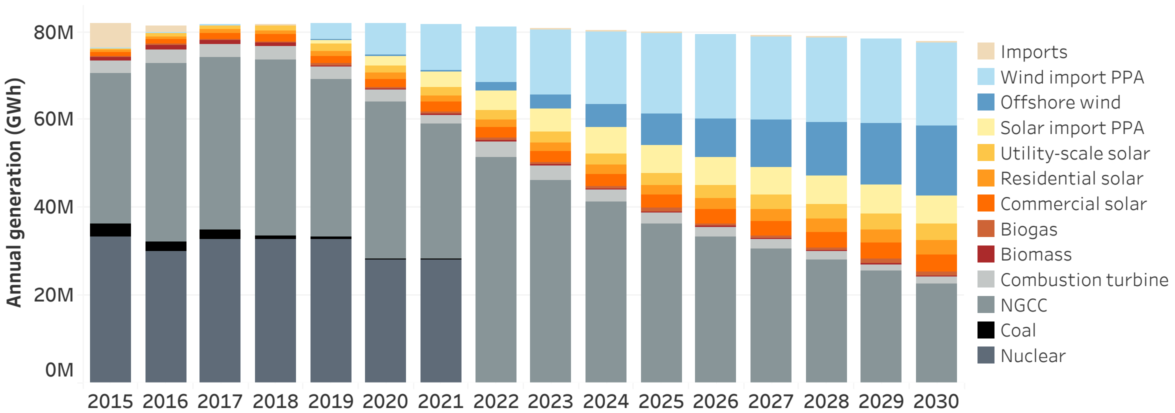
The scenarios described here are meant to enable deep decarbonization by 2050. The transition between 2030 and 2050 will require re-thinking of energy-using sectors as an integrated system. The commonly agreed-on steps to achieve deep decarbonization include reducing demand through efficiency, decarbonizing the electric grid by powering it with renewables, and then electrifying all of the other sectors—transportation, industry, residential and commercial—such that all direct fuel use is replaced with renewable electricity [62]. In some cases, such as for transportation and heating, this electrification will also increase energy efficiency.

We estimate that this electrification will roughly double electric demand from today's levels, as described earlier. The power sector itself will likely have to decarbonize more than other sectors, in order to accommodate difficult-to-decarbonize fuel users like certain industrial applications or heavy-duty transportation. Assuming all nuclear retires by 2050, this result implies that renewable energy generation will have to increase six-fold from 2030 to 2050—meaning renewables deployment after 2030 will have to average three times the annual growth in capacity that we average from 2018-2030. The post-2030 transition will be easier than pre-2030 from the standpoint that the major renewable energy resources that are not at grid parity today—notably offshore wind—will likely have reached parity by or before that time, making renewables increasingly the most affordable choice to provide electricity. However, faster ramp-up of renewables pre-2030, such as through PPAs for renewable energy imports, will reduce the speed with which renewables must be deployed later. Similarly, expansion of vehicle and home heating electrification before 2030 will reduce the rate of home and vehicle conversions required later. The trade-off here illustrates that a more rapid transition in the coming years, including accelerated renewable deployment and widespread electrification, may be more expensive in the near term but reduce the pace of infrastructure deployment required later.

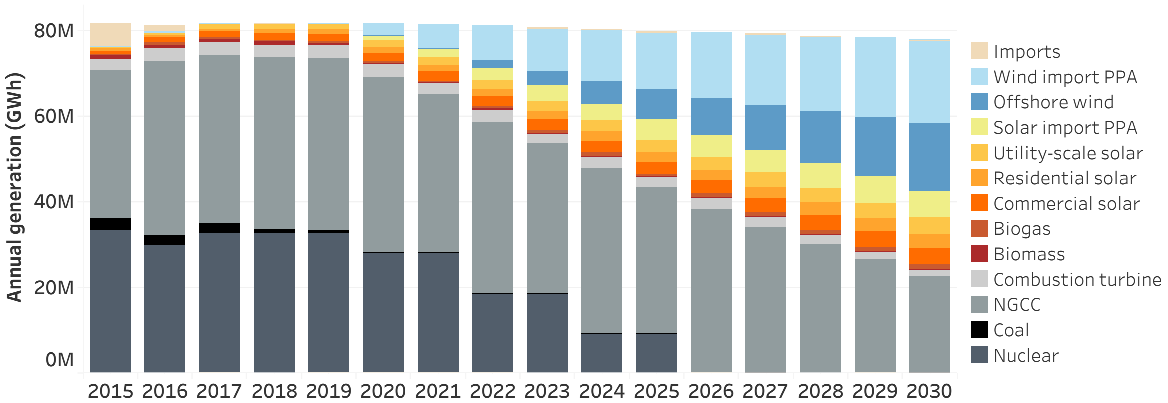
The 2030-2050 transition will involve additional major challenges, notably in the institutional and regulatory arenas, but also in the technological fields. While our energy sectors are currently designed such that supply matches need (e.g. electricity generation matches load, or cars are refueled on demand), the integration of high penetrations of variables renewables and electrification across sectors will require that the load be flexible in addition to the supply. Resources like batteries or hydropower can be dispatched to meet electric demand as usual, but other resources—like electric vehicle charging—may be shifted around to when supply is most plentiful, such as in the middle of a sunny day when solar generation peaks. A smart grid (including two-way communication between consumers and producers) will be essential. Demand response will play a central role. A new infrastructure for electric vehicle transportation will be needed. Regulatory agencies, utilities, and others are beginning to grapple with these tasks. The challenges of accomplishing these changes equitably and in a manner that protects communities and workers with fossil fuel infrastructure will likely grow. We have only covered only a few aspects in this study that will be among the important considerations for laying the foundation for meeting those challenges.



a. Clean Energy Scenario base case.



b. Rapid nuclear shutdown case.



c. Staggered nuclear shutdown case.

Figure 3.9: Annual electricity generation mix in the Clean Energy Scenario and nuclear shutdown cases. Imports are non-renewable unless otherwise indicated.

4. Cost analysis

In this chapter, we develop a detailed and somewhat conservative approach to estimating the costs of the Clean Energy Scenario compared to business as usual. Our cost analysis is focused primarily on the generation component of delivered electricity costs and the avoided costs due to energy efficiency. At lower renewable energy penetration levels, the cost of generation is the primary electricity cost element affected when solar and wind displace fossil fuels, including any fuel costs associated with conventional generation as well as the operations and maintenance costs of various generation technologies. Of course, other cost elements are also affected, including transmission and distribution costs. For instance, major development of offshore wind involves significant new transmission infrastructure costs to bring the electricity to shore, which we explicitly add in our calculations. In the other direction, distributed solar systems reduce transmission and distribution costs, notably in the summer, when the avoided transmission and distribution losses are much larger than the 5 or 6% annual average losses. We have also estimated these cost reductions in our analysis. However, our analysis does not examine the market impacts of renewable energy integration, such as changes in capacity market prices or changes in energy prices due to merit order effects.[1] Following the PJM Renewable Integration study [2], which finds that up to 30% renewables across PJM do not require significant grid upgrades, we assume minimal incremental renewable integration costs beyond the transmission and distribution considerations mentioned above and some additional energy storage. We leave the market analysis impacts of renewables integration to a future study, ideally as part of a PJM-wide analysis.

Another critical component of our cost estimates is the avoided cost due to accelerated efficiency. Apart from the obvious generation costs, these also include avoided transmission and distribution losses, ancillary services, avoided capacity costs, and others. We explicitly estimate these savings in our calculations and include a cost for efficiency implementation that is split into program and customer cost in order to obtain a ratepayer perspective on the total cost of the Clean Energy and business-as-usual scenarios. In sum, our analysis focuses primarily on the impact of different technology generation costs on delivered electricity costs, but actual costs and bills may also vary due to market and rate structure decisions.

Any cost projections over a dozen years involve significant uncertainties. The most important uncertainties for the next decade or so for New Jersey are:

1. **Natural gas prices:** natural gas plants supplied more than half of in-state electricity generation in 2016 [26], and fluctuating gas prices in New Jersey varied by a factor of two in 2016 alone [63].

[1] The merit order effect describes the impact of renewable energy on the wholesale market clearing price. Because renewables have nearly zero operational costs, they can bid into the market at very low prices, forcing out resources with higher operational costs and leading to lower wholesale prices.

2. **Premature nuclear retirements:** early retirements of the Hope Creek and Salem nuclear plants would affect the costs associated with either making contingency provisions (such as renewable energy purchases in anticipation of early closure) or above-market payments to nuclear plant owners to keep them open.

There are additional uncertainties such as the evolution of the cost of solar and offshore wind technologies. However, the evolution of cost trends in these technologies are relatively well established; in the case of offshore wind the cost trends are established mostly from the European experience, where the first offshore wind turbines went on line off the shore of Denmark in 1991 [64]. Whenever possible we have relied on actual industry cost data as compiled by the Lawrence Berkeley National Laboratory and the National Renewable Energy Laboratory, as well as direct conversations with members of the solar and wind industries.

4.1 Cost calculation methods

There are several cost components[2] in a typical electricity bill:[3]

1. **Generation (energy):** The cost to generate electricity, proportional to the amount of energy (kWh) used;
2. **Capacity and ancillary services:** A capacity charge paid to generators and other resources,which bid at auctions to keep capacity available for grid reliability purposes, and compensation to ensure power quality;
3. **Renewable energy:** Charges related to renewable energy, notably compensation for the Renewable Energy Certificates (RECs) and Solar Renewable Energy Certificates (SRECs) that electricity supply companies must acquire to meet New Jersey's Renewables Portfolio Standard;
4. **Transmission:** The cost of transmitting electricity at high voltage from centralized power plants to the point of delivery to the distribution utility—this element of the cost includes the cost of the transmission system and its maintenance and operation as well as the electricity that is lost in the process of transmission;
5. **Distribution:** The (regulated) price charged by utilities for converting high voltage-electricity tolower voltages and distributing that electricity to residential, commercial and industrial customers—including the cost of building and maintaining the distribution system, and the losses incurred in delivery to consumers;
6. **Taxes and fees:** All other taxes and charges on the electricity;
7. **Connection charge:** A connection charge that is fixed to bring the electricity lines to the consumer and measure the amount of electricity used.
8. **Miscellaneous:** Additional charges reflect transition charges left over from electricity deregulation, risk and profit, and other factors.

[2] As an example, see: [65, 66]

[3] We use the term "cost" here to refer to the cost seen by the consumer. Thus, the "generation cost" is cost of generation that the consumer would pay. This is the price that the distribution utility (also often called the "load serving entity" because it supplies the final users of electricity) would pay to the seller of power. The generation cost usually does not appear by itself as a line item in a bill, because there are other compensation elements that distribution utilities pay to merchant companies when they purchase the electricity (with the grid operator as the intermediary).

There are more detailed elements within each of these categories. For instance, generation, transmission, and distribution charges for large users generally have a demand charge (corresponding to maximum power demanded at any time within a month), and a charge for the amount of energy used.[4] Electricity prices can (and often are) also set according to the time of use, since it costs more to supply power during hours (or seasons) of peak use.

Since the focus of this effort is on generation, we parse the generation cost from all other costs. We assumed that the majority of other costs associated with delivering electricity would remain the same in the business-as-usual and Clean Energy Scenarios, except when specific circumstances, such as offshore wind transmission costs, justify an adjustment. The generation costs are then added to all other costs to get a total cost.This approach allows us to compare the impact of electricity generation choices on the cost of electricity in the Clean Energy Scenario and the business-as-usual scenario. We can also infer the average cost of reducing a metric ton of CO_2.We estimate undiscounted costs, costs discounted at 3% and costs discounted at 6%, all in 2016 dollars—that is, factoring out any inflation in general prices that may occur in the economy. We use the Gross Domestic Product deflator to convert costs in dollars of any other year to 2016 dollars.[67]

We use EIA projections for the overall cost of the business-as-usual scenario and levelized cost estimates for the various generation components in the Clean Energy Scenarios and business as usual. The final electricity prices paid by consumers in various categories (residential, commercial and industrial) are compiled by state and year by the Energy Information Administration (EIA) of the U.S. Department of Energy [26]. The EIA also compiles data on generation by energy source, electricity sales, emissions, and net interstate electricity trade. However, since the EIA is focused on sales of electricity, its data is limited for solar energy that is "behind-the-meter"—which consists mainly of generation by distributed small and medium solar installations and some other small generation sources. We have therefore dealt with distributed solar as a separate generation category in order to be able to properly account for all the generation that helps meet electric loads. This kind of accounting becomes more important as the proportion of behind-the-meter electricity generation increases significantly, as it does in the Clean Energy Scenario.

An explanation about our use of levelized costs is in order. The primary aim of our cost analysis is to compare a business-as-usual cost projection out to the year 2030 with a scenario where efficiency and renewables replace some of the business-as-usual fossil fuel generation. Levelized cost provides a discounted value of all cost elements combined into a single cost per megawatt-hour. All elements—capital cost, fuel costs, operations and maintenance costs—are included and estimated over the expected life of the project. The capital cost element includes consideration of the different components of financing (typically debt and equity), depreciation (based on prevailing laws), and taxes. Construction costs generally include the profit of the construction contractors. We consider solar incentives in **Section 7.1.3**.

Technologies with high upfront capital cost, like solar or offshore wind, would face financing uncertainties in the absence of policies that guarantee a return on investment, such as a mandate to purchase power at a predetermined price (as with a feed-in tariff) or some other means. Since the context of our cost estimation is the public policy needed to arrive at a goal for CO_2 emission reductions, we presume suitable policies, like purchased power agreements for renewables, and efficiency targets with funding for incentives, to achieve the

[4]This would be like charging for the maximum horsepower of a vehicle's engine used at any time during a trip (demand charge) and for the fuel (energy charge). The two charges are generally rolled into a single number as a charge per unit of energy use for residential customers.

needed climate goal. Thus, financing uncertainty is not a major issue for the purposes of this analysis.

The uncertainty of fuel costs is a large concern, especially in light of the historical volatility of natural gas prices. Natural gas prices have been low for some time, and the EIA projects that they will continue to be so [20]. The relative economics of renewables compared to natural gas shift if gas prices rise. We have taken this into account by doing a sensitivity analysis utilizing a higher natural gas price case than in the Clean Energy Scenario. Such an analysis would allow for the derivation of the hedge value of sources that have no fuel costs (wind, solar, efficiency) provided we can assign a probability to natural gas prices being above the reference price case. We have not attempted such an exercise here; we only show the cost in case of high natural gas prices and compare it to the case of reference gas prices.

Another concern is that, under some circumstances, levelized costs for variable sources like solar are not directly comparable to levelized costs of dispatchable sources, such as natural gas combined cycle power plants. This is not a significant issue in our study up to the year 2030 because the level of variable generation up to that time can be accommodated in the PJM grid [2, 68]. Furthermore, improved weather prediction capability allows prediction of solar and wind for the next day with increasing reliability. These predictions have allowed grid operators to assign a capacity value to wind and solar based on experience with variable sources in a particular region. Capacity is primarily a concern at times of high demand. We have assigned capacity values to wind and solar according to the values designated by PJM to meet peak load hours on summer afternoons [69], although the PJM Renewables Integration Study finds that higher capacity values for solar capacity in the PJM region may be warranted [2]. In our Clean Energy Scenario we do not explicitly project any retirements (beyond announced nuclear and coal retirements), and we add renewable energy and storage capacity, meaning that we do not necessarily predict any capacity constraints. PJM would determine if any uneconomical plants proposing retirement are needed for capacity reasons, but determining the capacity costs in such a case is beyond our scope.

We also note that regulatory decisions are often made based on levelized costs. For instance, the Maryland Public Service Commission's assignment of REC values to two offshore wind projects it authorized in May 2017 was based on levelized cost assessments.[5]

Fossil fuel generation has numerous externalities, including carbon emissions, air pollution and attendant cardiovascular and respiratory health impacts, high water use of thermal generation, and continued environmental damage from mining and drilling activities. We discuss most of these externalities qualitatively and quantitatively without assigning any cost values. However, in the case of carbon dioxide we calculate the cost of reducing carbon emissions, and compare these costs to the social cost of carbon [1] for emissions in the business-as-usual and Clean Energy Scenarios.

A final note about what these costs are and are not is in order. The totals represent costs incurred by all parties to arrive at the result of the Clean Energy Scenario. For example, we include the costs incurred by consumers to purchase more efficient appliances and also the rebates they receive from utilities for the same purpose. As another example, we include the costs of distributed solar installations belonging to private parties, even when the entire cost is paid by the owners. As a result, the cost comparison is the cost of providing the same energy services in the Clean Energy Scenario as in the business-as-usual scenario.

[5] Commission found "...that it is appropriate to levy a gross levelized OREC price of $131.93 (2012$) on both Applicants, subject to a 1.0% price escalator" [70].

By the same token, the total costs estimated here cannot represent the perspective of any sub-group of customers, businesses, utilities, or generation companies because by their nature they include all of them. In particular, the total of all costs includes bills paid by ratepayers but they also include other elements, such as costs of solar installations and efficiency not incurred by ratepayers. We can (and do) use total costs to heuristically examine the effect of any particular element on bills; specifically, we do so to examine the impact of uneven implementation of efficiency on rates and bills. This analysis is useful for policy decision-making, but it should not be mistaken for actual rates and bills. A full analysis of rates and bills is beyond the scope of the present effort. It would require a policy analysis of the evolution of rate structures, including how distributed resources are priced and compensated for electricity drawn from or contributed to the grid.

4.2 Business-as-usual costs

An estimate of business-as-usual costs is needed for two reasons:

1. The business-as-usual costs over time provide a baseline to which the costs of various climate protection approaches to CO_2 emission reductions must be compared.

2. We use business-as-usual costs to estimate non-generation costs for our Clean Energy Scenarios. These non-generation costs include transmission and distribution costs (as seen by consumers in their bills), taxes, connection charges, and various other charges outline above, including the costs of Renewable Energy Credits (RECs) and Solar Renewable Energy Credits (SRECs). We estimate these costs, which are about two-thirds of the total, by subtracting the generation costs per MWh from the total costs in the business-as-usual scenario.

As mentioned above, some adjustment is needed to the non-generation costs category derived from the business-as-usual case, such as reduced transmission and distribution losses corresponding to increased efficiency and increased distributed solar relative to business-as-usual. Our business-as-usual solar projection is based on New Jersey's current law—4.1% of sales by the year 2027 (and remaining at that percentage thereafter) [31]. We also include energy storage costs and additional transmission costs for offshore wind to bring the energy to shore.

The main element in the comparison is the relative cost of business-as-usual generation on the one hand and the combination of solar, offshore wind and efficiency on the other. A critical point to note, which we will revisit when we compare rates and bills, is that the generation requirement in the Clean Energy Scenario is significantly lower because of higher efforts to increase efficiency relative to the business as usual, even when accounting for growth in electric vehicles and heating systems. The costs associated with the increased efficiency are of course factored in.

As mentioned above, the most common and accepted business-as-usual scenario is provided by the EIA. We have used the Reference Scenario in the 2017 Annual Energy Outlook (AEO) published by the EIA [20]. AEO 2017 contains a Mid-Atlantic cost projection, which we have adjusted to correspond to New Jersey's specific costs based on historic cost data [26, 63]. Specifically, there are cost elements in New Jersey that are not present in or much less important in other neighboring states. New Jersey's SRECs are a significant part

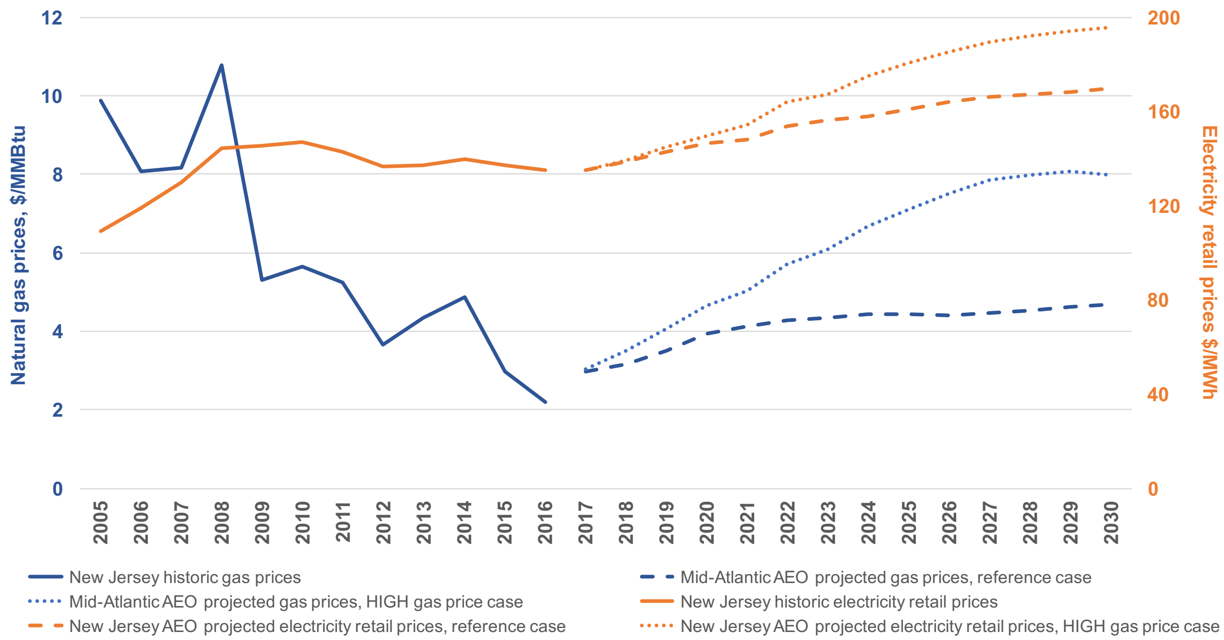


Figure 4.1: Historic electricity and natural gas prices in New Jersey and the Mid-Atlantic, and forecasted electricity prices in EIA AEO [20, 26, 63].

of the difference. New Jersey is also in an area of high transmission congestion, which results in higher capacity charges for its ratepayers.[6] Historic and projected natural gas prices and electricity prices from the EIA are shown in **Figure 4.1**, including both projected reference values and high gas price values used later in our sensitivity analysis.

4.3 Energy resource costs

The three energy resources that distinguish the Clean Energy Scenario from business-as-usual are the expanded use of efficiency and solar energy and an ambitious offshore wind program. The early nuclear reactor retirement scenarios feature additional imports of on-shore wind from the Midwest and imports of utility-scale solar from PJM region states with low or no solar energy carve outs.

4.3.1 Efficiency

Efficiency cost is generally expressed as a levelized cost per megawatt-hour of electricity saved. This levelized cost represents the present value of energy savings over the lifetime of the efficiency measure (such as the expected lifetime of the light bulb or a heat pump water heater). The typical efficiency measure requires an upfront investment in a more efficient device, with the savings being recouped over time.

[6] PJM holds capacity auctions. Companies that can guarantee the availability of capacity up to three years in advance bid into the auction with the price they would have to be paid to provide assurance of the availability of that capacity in the specified time period. The highest price required for the last megawatt of required capacity is paid to all successful bidders. Bids with higher prices than that are rejected. Capacity can be either generation or reduction of demand [71].

We estimate total efficiency costs, in constant 2016 dollars, to start at $40 per MWh in 2018 and grow to $60 per MWh by 2030. This growth in costs is included because early measures would capture the lower cost "low hanging fruit," like the replacement of incandescent and older compact fluorescent light bulbs by LEDs, or hot water heater wraps to reduce heat losses. As the easier measures come close to saturation, the costs would be expected to increase, requiring more expensive efforts such as the replacement of older air-conditioners with highly efficient ones, or replacement of ordinary (resistance-heated) electric water heaters with heat pump water heaters. Note that these are total costs, including the costs of rebates and incentives provided by utilities, program administration costs (both of which appear in electricity bills and are part of the rate structure), as well as the added costs that consumers pay to purchase appliances that have been designated as having sufficiently high efficiency to qualify for rebates.[7]

We estimate the cost of an initial intensive energy efficiency effort ($40 per MWh) using a variety of sources. Maryland has had an intensive efficiency program for a number of years which requires savings of 1.5% per year per capita; its total program costs (including both ratepayer and consumer elements) have averaged between $35 and $45 per MWh [73]. In recent years New Jersey's efficiency costs have been similar or even slightly lower [35].

It is important to note that we express efficiency costs in terms of dollars per unit (MWh) of energy saved in each year. This is essential to get an estimate of total costs of providing all the energy services in each year of the period under study. Efficiency is normally achieved through a higher upfront investment in the more efficient air conditioner or water heater or light bulb. The benefits of this investment are realized over the lifetime of the equipment. For instance, an LED bulb would typically last much longer than an incandescent one; similar for a heat pump water heater compared to a regular (resistance) electric water heater. That greater investment is amortized over time. The annualized cost and annual energy saved give the cost per MWh of any particular efficiency measure. The cost we use the cost averaged over all efficiency measures needed in any year to achieve a 2% savings relative to no efficiency program.

The American Council for an Energy Efficient Economy (ACEEE) compiled the costs of efficiency programs in many states in 2014 [74]. For seven of them, it broke down total costs into a ratepayer segment ("program cost") and a customer cost. **Table 4.1** shows those details for six of these states (omitting Hawaii):

The unweighted average of total efficiency costs is about $50 per MWh. The cost in Rhode Island, which has had the most intensive program among these states, would be more indicative of the costs of an ambitious New Jersey program after many years of implementation. These data give us an indication of a reasonable end point for efficiency costs in the year 2030—namely, $60 per MWh.

There are two perspectives on efficiency cost in terms of estimating the overall cost of this resource: the full cost and the program cost. In the Clean Energy Scenario we include the full cost of the efficiency investments that are needed to reduce electricity load (and hence the need for generation). Adding the full cost of incremental efficiency above business-as-usual to the Clean Energy Scenario therefore gives us the basis for comparing the two.

[7] There are federal and, in many cases, state efficiency standards for appliances. These standards set the minimum efficiency requirements that all appliances must meet. Typically, rebates are provided for appliances that significantly exceed the minimums. A common minimum benchmark for the more efficient rating is the "Energy Star" label, under a federal government program run by the Environmental Protection Agency. See [72].

Table 4.1: Program and total costs of efficiency per megawatt-hour [74].

	Program costs	Total costs	Ratio
Illinois	$16	$41	39%
Iowa	$19	$49	39%
New York	$20	$73	27%
Pennsylvania	$18	$43	42%
Rhode Island	$45	$56	80%
Wisconsin	$19	$41	46%

However, a part of the cost of efficiency is borne by the consumers who invest in more efficient appliances, building retrofits, etc. These same consumers also get economic benefits in terms of lower bills, greater comfort, and often better-performing equipment. These benefits are not reflected in the comparison. Neither are the costs borne by consumers reflected in electricity rates.

From a ratepayer perspective, the efficiency costs that matter are the "program costs." These are the costs incurred by utilities (and/or third parties) to administer efficiency programs, and the cost of the rebates and incentives to induce consumers to purchase more efficient equipment and to retrofit homes and commercial buildings to reduce heating and air-conditioning requirements. These program costs are shown separately in **Table 4.1** above. The average fraction of program costs to total costs in the six states in the table is 46%. We will use this fraction in our estimates for New Jersey.

Program costs appear in the bills of consumers. Since ratepayers pay only for these "program costs," a ratepayer perspective on the cost of the Clean Energy Scenario would include only the program costs for comparison with the business-as-usual scenario. Of course, ratepayers who invest in efficiency will benefit; those who do not will see the program cost portion of efficiency cost but not the benefits of reduced bills. We will take up this question when we discuss rates and bills.

4.3.2 Solar

We have relied primarily on the NREL technology cost forecasts to estimate the levelized cost of solar. NREL analyzes the state of the technology in some detail, and projects costs out to the year 2050 [18].

The NREL forecasts provide a range of levelized costs based on low, medium, and high capital cost projections; they also take into account locational differences in solar capacity factors since insolation varies significantly across the United States.**Table 4.2** shows the financial parameters that NREL used in its technology forecast for utility-scale solar. The parameters for commercial solar were the same. Residential solar, with faster construction times, had a construction finance factor (essentially interest during construction) of 1 instead of 1.013.

Table 4.2: NREL financial assumptions for utility-scale, commercial solar levelized cost calculations [18].

Financial assumptions	
Inflation rate	2.5%
Economic lifetime (years)	20
Interest rate—nominal	4.4%
Calculated interest rate—real	1.9%
Interest during construction—nominal	4.4%
Rate of return on equity—nominal	9.5%
Calculated rate of return on equity—real	6.8%
Debt fraction	60.0%
Tax rate (federal and state)	40.0%
WACC—nominal	5.4%
WACC—real	2.8%
Depreciation period	5
Construction finance factor	1.013
Present value of depreciation	0.866
Project finance factor	1.089
Capital recovery factor (CRF)—nominal	8.3%
Capital recovery factor (CRF)—real	6.6%

We adjusted the NREL levelized cost numbers for solar in three ways:

1. We interpolated NREL data to correspond to New Jersey-specific capacity factors, estimated using the NREL estimator called PVWatts [43].

2. NREL levelized costs did not factor in the federal investment tax credit (ITC). We factored that in, and discounted its value by one year, assuming the credit is recovered in the year after commissioning. The ITC is set at 30% until 2019, 26% in 2020, 22% in 2021 and zero thereafter for residential projects and 10% for other projects.[8]

3. We adjusted costs to 2016 dollars (from 2014 dollars in the NREL spreadsheet) using the Gross Domestic Product deflator (101.4%) [67].

The NREL estimates correspond to the generation portion of the solar cost. In order to get total cost, we have added all costs other than generation (as describe above) for utility-scale solar. For behind-the-meter systems, we have added these costs and then adjusted for the expected reduction in transmission and distribution costs that solar produces for distributed systems. Since the business-as-usual scenario also has distributed solar (as

[8]For a summary of the solar investment tax credit, see [75] . Projects begun before the end of 2021 and completed by 2023 would be eligible. We have assumed for simplicity that the tax credit will expire for all residential projects completed in 2021 and go to 10% for all commercial and utility-scale projects commissioned in 2022 and after. This would overestimate costs somewhat for the years 2022 and 2023. For the level of commercial and utility-scale ITC in the year 2022 and after, see [76].

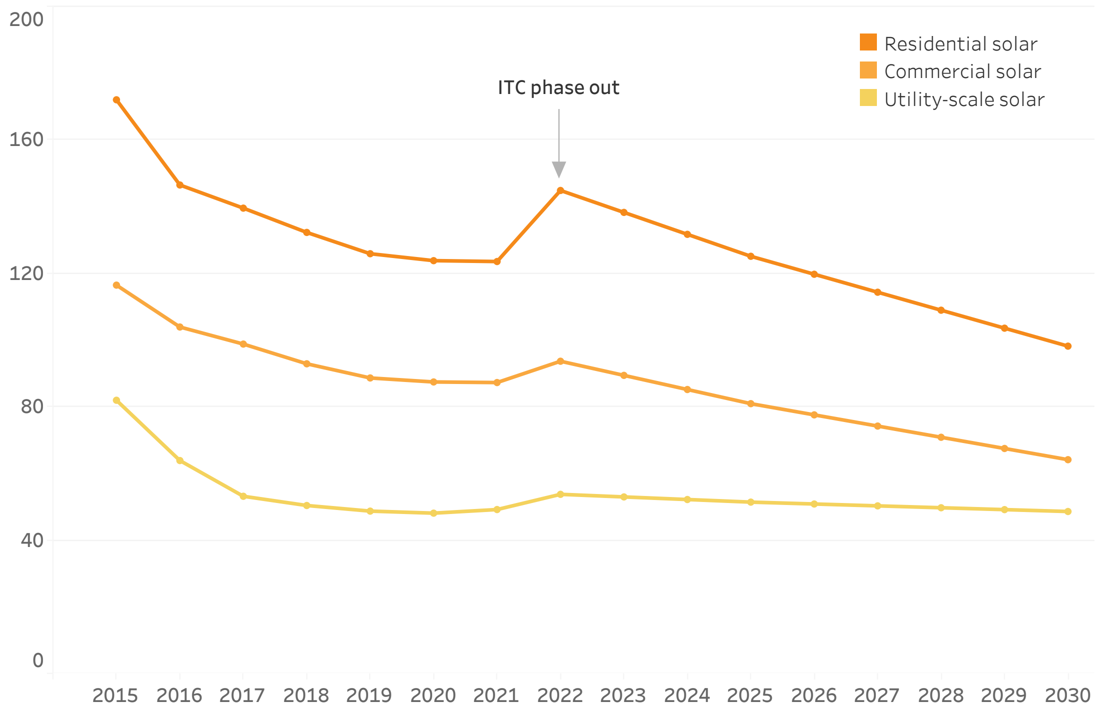


Figure 4.2: Levelized cost of energy from utility-scale, commercial and residential solar. The investment tax credit is phased out for residential solar in 2022 while the commercial and utility scale credit drops to 10%.

part of the present RPS), we have only adjusted the Clean Energy Scenario costs for the increment in distributed solar above the RPS mandate. This reduction in transmission and distribution costs is estimated at about \$15 per MWh in 2018, growing to \$19 per MWh by 2030.[9] The levelized cost of solar from residential, commercial and utility-scale systems is given in **Figure 4.2**.

4.3.3 Offshore wind

When estimating costs for offshore wind, two cost trends are important. The first is the cost decline that occurs as an industry scales up. Costs decline rapidly due to competition, efficiencies and the development of a network of skilled labor and suppliers. Currently, there is only one offshore wind installation in the United States—off the coast of Rhode Island—with five turbines and a total capacity of just 30 MW [78]. For comparison, by the end of 2016 ten countries across Europe had collectively installed 12,000 MW [79], with more than 90% off the coasts of Western and Northern Europe. The second trend is due to technical improvements that yield higher capacity factors and greater efficiency of installation. In Europe, costs continue to decline. The winning bid by DONG Energy for the Dutch "Borssele 1&2" wind farms was only 72.70 euros per MWh (\$85.53/MWh), far lower than the price of 100 euros per MWh previously projected by DONG itself for 2020 [80].[10]

[9] Estimates of the value of transmission and distribution capital savings vary widely, and are dependent on local grid characteristics. We select a middle value from the studies reviewed by RMI. Additional benefits, such as reduced line losses for distributed solar, are reflected elsewhere in our analysis. Regulatory design can help incentivize solar deployment at locations with the greatest grid benefits, reducing both distribution infrastructure and local capacity needs, whereas lack of planning will reduce these savings. The specific values used do not significantly affect our results [77].

[10] Dollar value calculated using the exchange rate of 1 euro = \$1.1765 as per the NY Times, August 16, 2017 [81].

Costs can be expected to decline further. To achieve comparable costs in the US, an industry of significant scale will likely have to be established along the eastern seaboard.

We have used the most recent assessments that take into account the dramatic cost declines in Europe in 2015 and 2016 and examine their implications for the United States. We rely mostly on an NREL analysis which was published in September 2016 and evaluates the projected levelized costs of offshore wind generation from 2015 to 2027 [82]. The study estimates the levelized costs and transmission to shore by modeling the cost impacts of numerous locational and market variables.To get total costs, we add all non-generation costs, as has already been described.We have also reviewed the trends in a 2016 University of Delaware study that analyzed the cost of the proposed development of offshore wind on a significant scale in Massachusetts [19]. The turbine to shore transmission portion was estimated at about 25% of the total in each case. For simplicity, we assume that offshore wind grows steadily, with the first tranche of 360 MW coming online in 2022 and growing to 3,250 MW in 2030.

4.3.4 Landfill gas and biomass

Landfill gas and biomass are a small portion of the Clean Energy Scenario (less than 1% of total generation in 2030). For biomass, we used the levelized cost estimate made by the Wall Street firm Lazard at the end of 2016 [83]. We assumed this same cost for landfill gas. Our result is not sensitive to these assumptions.

4.3.5 Nuclear, ZECs, and contingency renewable imports

Nuclear generation and operating costs are derived from the EPA's Integrated Planning Model runs used for the Clean Power Plan's Regulatory Impact Analysis [84]. These Model runs output operational cost estimates for existing nuclear power generation in the EPA-EMAAC region for 2018, 2020, 2025, and 2030, and we adjusted results to 2016$ and extrapolated values for the intermediary years.

As discussed in **Chapter 3**, two of our scenarios are designed around contingencies to address the contingency of premature nuclear power plant retirement. An additional scenario, which incorporates above-market payments similar to New York State, does not require a separate technical scenario, but does require a cost estimate of the above-market payments for the purposes of comparison. We have used New York's proposed values, which are based on the social cost of carbon, to estimate the per MWh payments that may be made ("Zero Emission Credits" or "ZECs", in New York's terminology).[11] These values start at $17/MWh in 2018 and gradually increase to $32/MWh in 2030.

One way to replace nuclear generation with zero emission generation is to import some combination of wind energy from the Midwest and utility-scale solar from states in the

[11] The New York PSC Order calculates the value of a ZEC as follows: ZEC price (i.e., the payment to be made per MWH of nuclear generation) = [the social cost of carbon] – [a baseline cost of an allowance under the Regional Greenhouse Gas Initiative (RGGI)] – [a zonal strike price that the nuclear plant can be expected to recover by sale of the electricity into the upstate New York market]. The price of a ZEC is adjusted downward if the recovered price for electricity sales is higher than the strike price. In assuming the New York values of ZECs estimated by the New York PSC we are implicitly assuming that a factor corresponding to a RGGI allowance would also be used in New Jersey, with by New Jersey joining RGGI or by agreement with the nuclear plant owners. The New York PSC's formula can be found in Appendix E of its August 1, 2016 Order [85].

PJM region where plants are in the PJM queue but do not yet have offtakers for the power. These solar plants are largely in states that do not have in-state mandates for solar energy or have very low targets. The imports would likely be in the form of Virtual Power Purchase Agreements. Under these New Jersey would commit to buy the electricity at a certain price, but the electricity itself would be delivered into the PJM grid. New Jersey would get its requirements from the PJM grid. This is a net carbon reduction approach. Like ZECs, VPPAs have their own advantages and risks. See **Box 4.3.1**.

At the time of the preparation of this report (August 2017), the typical utility-scale solar projects in the PJM queue located in states with low mandates are much larger than projects in New Jersey, ranging from 50 MW to 200 MW or more. Our assumption is that going forward, utility-scale solar will primarily be single axis tilt. Accordingly, we have used NREL's low-cost forecast for this technology, starting at $1.05 per watt in 2018 and declining to $0.67 per watt in 2030.[12] The levelized costs (in 2016 dollars) corresponding to these capital costs are $45 per MWh in 2018 and $37 per MWh in 2030. The corresponding cost assumptions we made for New Jersey are $1.15 per watt in 2017 and $0.92 per watt in 2030.

Wind imports from the Midwest are another option for replacing nuclear generation under contingency planning. We used the medium NREL technology cost forecast for onshore wind at 41% capacity factor [18], adjusted for the existing production tax credit (which will gradually decline to zero by 2020) to estimate the cost of importing wind. We assume that the mix of imports will be 75% wind and 25% solar. The actual mix would, of course, depend on the bids provided. Our result for total costs is insensitive to the fraction of solar or wind that would be imported.

We are exploring the option of imports with Virtual PPAs with a limited goal: to compare imports of renewables at low cost with New York ZEC-type above-market payments to keep afloat nuclear power plants that might otherwise close in operation. We note that virtual PPAs are complex instruments, often used by large corporations to purchase renewable energy for a variety of reasons, including lower costs and green energy attributes. The ZEC also has its risks. (See **Box 4.3.1** on Virtual PPAs and ZECs.) The analysis in this report indicates a comparable cost in the period before 2030; extending the period beyond 2030 may well change that conclusion significantly, since it is likely that nuclear generation will have to be replaced by other zero carbon options in any case.

Of course, Salem and Hope Creek may continue to operate without above market payments. This is our base case for the Clean Energy Scenario. New Jersey may also elect to make above-market payments to prevent premature shutdown of these plants, instead of acquiring solar and wind energy to replace them. In all these cases, the carbon emissions constraint is maintained—that is the cumulative CO_2 emissions between 2018 and 2030 are maintained to about the same level. This constraint makes the scenarios comparable.

[12] Single axis tracking systems were estimated to cost $0.05 to $0.20 more than fixed tilt systems [86]. We note that the costs of the fixed tilt systems declined to less than $1 per watt in 2017, three years ahead of the official date for achieving that target [87].

4.3.1: Virtual Power Purchase Agreements and Zero Emission Credits

Virtual Power Purchase Agreements (VPPAs, also called "synthetic PPAs") come in a variety of forms. In this report, we assume that VPPAs would be of the "contract for differences" variety where New Jersey imports wind and utility-scale solar from other states not bordering it but within PJM. A VPPA would commit New Jersey to paying the fixed PPA price (the "strike price") to the developer of solar or wind energy, who would sell into the PJM grid. When the PJM market price is above the strike price, the developer would pay New Jersey (effectively its ratepayers) the difference and vice versa. There is evidently some risk involved.

We have assumed that the PPAs will be mainly onshore wind imports (75%); the cost of the PPAs assumed is well above $40 per MWh (in 2016 dollars) as compared to 2016 PPA prices in the $20 to $40 range, with Midwestern prices being closer to $20 [88]. If the strike prices are in the $20 to $40 range, the cost would be lower than assumed in our calculations. In 2016, the average PPA price was in the middle of the average market price of electricity in the Midwestern region [88]. Further, we have built in a hedge against price-related risk. New Jersey would acquire the RECs associated with the energy.

There are also risks associated with Zero-Emission-Credit type of above-market payments to keep nuclear plants operating. For instance, the ZEC value, as determined in the New York formula, depends on the price of a RGGI allowance, under which combined emissions of CO_2 in participating states are capped. The price of an allowance has varied over the years from under $2 to over $7 per short ton of CO_2 [89]. A $5 difference would translate into about $2 per MWh for New Jersey (which was not part of RGGI when this report was prepared)—representing an uncertainty of over $50 million per year. Further, paying above-market subsidies does not guarantee that the nuclear plants would stay on line for the duration. For instance, operators may demand higher payments in case of increasing costs due to new federal safety requirements or to replace aging equipment. Requirements related to nuclear plant safety are preempted by the federal government.

In sum, our approach puts renewable energy imports with above-market Zero Emission Credits on a reasonably comparable footing. This suffices for the purpose of comparing options with the same cumulative carbon emissions reduction. A detailed evaluation would require addressing the comparative risks and other considerations, such as reliability and transmission issues. We note in this context that the amount of solar and wind energy involved is considerably less than the combined amounts in the solar and wind PJM queues—and that only up to the year 2021. Our comparison involves large, but gradual acquisitions staring in the year 2019 or 2020 and continuing up to 2030.

Sources: [88, 89, 90, 91, 92]

4.3.6 Natural gas

Like nuclear, natural gas plant non-fuel operating costs (NGCC and simple cycle) were derived from the EPA's IPM model runs for the Clean Power Plan in the PJM-EMAAC region [84]. We assume that the proportion of NGCC generation to the proportion of more expensive simple cycle generation remains the same as 2015, as calculated from EPA data [56]. These proportions could change, as discussed later.[13] We calculate the fuel cost component using the projected gas price for electric power from the AEO 2017 Reference Case for the Mid-Atlantic region (see **Figure 4.1**) [20], and assume the average heat rate improves by roughly 10% between 2015 and 2030 for NGCC plants, reflecting an expected higher utilization rate of the more efficient plants in 2030. Our sensitivity analysis uses the natural gas price from the "Low oil and gas resource technology" scenario, which is 70% higher in 2030.

For peaking gas turbines, we use a 7% capacity factor and the 2017 NREL operating and maintenance costs [18]. Since these are existing but relatively new plants (see **Section 2.2**), we assumed that capital costs per MWh would be 75% of the cost for a new plant. For existing NGCC plants, which are older, we used 25% of the capital cost for a new plant.

4.3.7 Storage

For purposes of illustration and cost estimation, we divided the target for battery storage into two equal components—one for displacing peaking generation and the other for use in microgrids, which can be a critical element in increasing resiliency. The operating characteristics and costs are different in each category. We use the most recent evaluation of costs by the Wall Street firm Lazard [59]. Lazard's assumptions about size and operating characteristics of the battery storage are as follows:

1. **Peaking generation replacement battery:** two storage installations, 100 MW (400 MWh) each, with one full discharge per day.

2. **Microgrid batteries:** 2 MW (2MWh) size, which means that there would be 400 such microgrids in New Jersey by 2030. Each battery would have one full equivalent discharge per day.

Lazard provides costs for a variety of battery technologies. We use the costs for lithium-ion batteries, an advanced and established technology whose costs are declining rapidly. We use Lazard's low cost estimate for the year 2018 and we assume that costs would decline by a factor of two by 2030. Lazard does not project costs that far; its average estimate of the reduction of capital cost of lithium ion batteries is 38% by 2022 relative to 2016. These estimates may be conservative: recent analysis based on learning curves suggests battery costs may fall by nearly 40% by 2020 compared to 2016 [93]. While the use cases here would imply two 100 MW storage peaker replacements by 2030, these values are simply illustrative to estimate costs; actual deployment may vary based on local need. In California, for example, Southern California Edison procured 250 MW of energy storage in 2014 including one 100 MW installation to replace peaker generation similar to the use case here, 135 MW of distributed storage to reduce commercial building demand charges, and some additional thermal ice storage [94]. We have not integrated these batteries into the load modeling.

[13] We exclude small amount of gas steam generation and expect these plants will retire soon.

They are included in order to illustrate the kinds of costs for storage that could be expected under the Clean Energy Scenario.

4.4 Scenario cost analysis

We estimate electricity generation costs for our scenarios using the approach for each element described above. The two primary cases are the business-as-usual scenario and the Clean Energy Scenario. The generation requirements in these two scenarios are different because the latter has more efficiency (and corresponding costs and savings) built into it. In addition, electric conversions of transportation (5% of vehicle miles[14]) and of 80% of residential space and water heating that now uses oil or propane will increase electricity requirements, decrease fossil fuel use, reduce fuel expenditures, and reduce CO_2 emissions. This electrification is not part of the business-as-usual scenario. We have included neither the costs of conversion (investment in EV charging infrastructure and efficient heat pumps) nor their benefits. Our goal at this stage is to indicate an order of magnitude of additional generation needed in order to lay the foundation for deep, economy-wide reductions in CO_2 emissions throughout the energy system.

We also examine costs in three other scenarios in which the cumulative 2018-2030 CO_2 emissions are maintained at the level of the Clean Energy Scenario:

1. Early nuclear reactor retirement (at the end of 2021);
2. Staggered nuclear reactor retirement (one unit each at the end of 2021, 2023, 2025);
3. No reactor retirement, but with payments (ZECs) to the reactor owners to keep the reactors on line. The generation mix in this case is the same as in the Clean Energy Scenario, but the costs are different because payments corresponding to ZECs have been added.

We compare the total costs of these three cases for generation levels that do include transportation and heating conversions. This framework is the most suitable approach when comparing early nuclear retirements or above-market payments for nuclear energy with the Clean Energy Scenario.

4.4.1 Production cost analysis

Figure 4.3 shows how the production costs per MWh of the various technologies evolve over time. These are costs for generation only, except in the case of offshore wind, where the transmission cost of bringing offshore wind to shore is included. The most expensive resources for most years are simple cycle natural gas turbines (NGCT), which are typically used infrequently to meet peak demand requirements.

[14] 5% of all vehicle miles likely implies a higher fraction of light duty vehicle electrification, which is proceeding more rapidly than truck electrification. Furthermore, this value implies a much higher fraction of sales of electric vehicles by 2030. Transportation emissions can also be reduced with an increase in hybrid vehicles, increased walking and biking, smart city planning, and public transit, but those approaches are not discussed here because they do not increase electric load or would do so only marginally. Our purpose is not to develop a clean transportation pathway but to broadly estimate the impact such a pathway might have on the power sector by 2030.

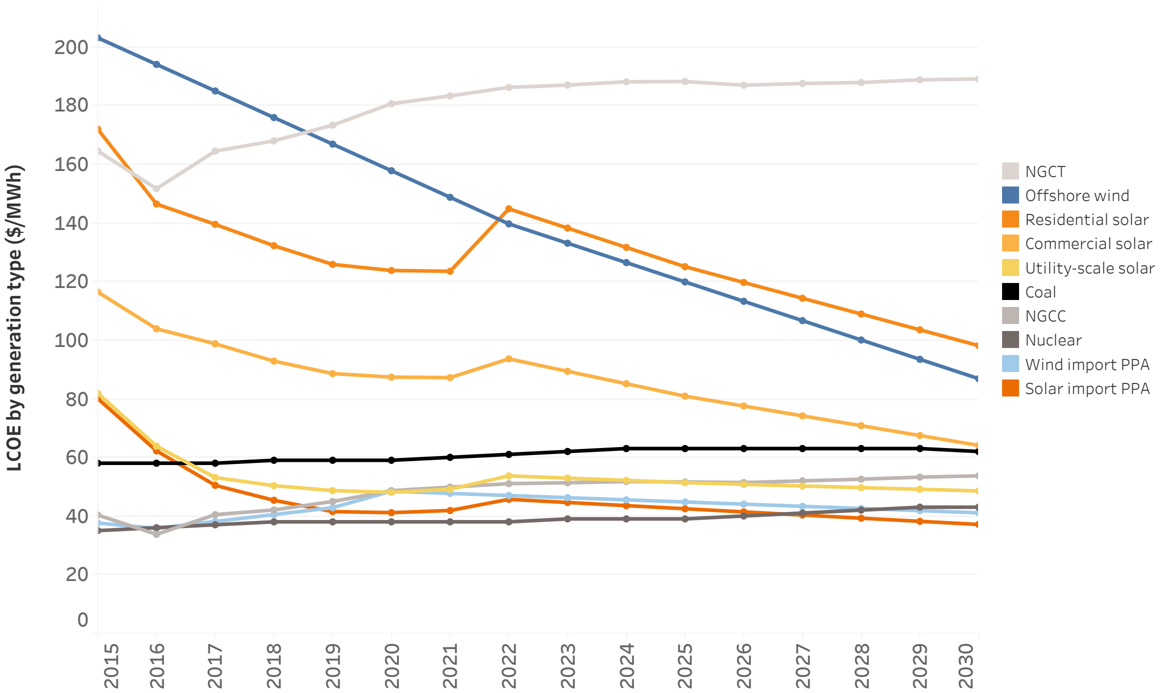


Figure 4.3: Evolution of generation costs per MWh of the various technologies used in this study. NGCT are natural gas combustion turbines primarily used to meet peak loads.

The generation costs in each year are applied to the corresponding output for that source to get the total cost of electricity generation. Note that the per-MWh costs of generation for new construction are paired with the incremental generation in that year. Those costs are carried through to the year 2030 (and would be carried through beyond that to the expected life of the plant).

Figure 4.4 shows the cost of generation breakdown in the Clean Energy Scenario including ZEC payments.

4.4.2 Total Clean Energy Scenario costs

To calculate the total costs of meeting New Jersey's electricity demand, we now add all the non-generation costs to the generation costs shown above. As noted earlier, these bundled costs include transmission and distribution, Solar Renewable Energy Credits, other Renewable Energy Credits, state and local taxes, charges for efficiency programs, connection charges, etc. **Figure** 4.5 shows the total costs of the business-as-usual scenario compared to the Clean Energy Scenario. The costs shown by the solid lines are directly comparable. The dashed line includes the added generation and associated delivery costs for electric vehicles and for conversion of 80% of oil and propane space and water heating systems.

We estimate that the total costs of electricity in the Clean Energy Scenario would be a little more than total business-as-usual costs (about 0.5% more in 2030) when excluding electricity used for EV and HVAC electrification. The difference is marginal and is well within the uncertainties of our analysis, notably uncertainty about future natural gas prices.

The main reason for the comparable costs of the Clean Energy Scenario to business as

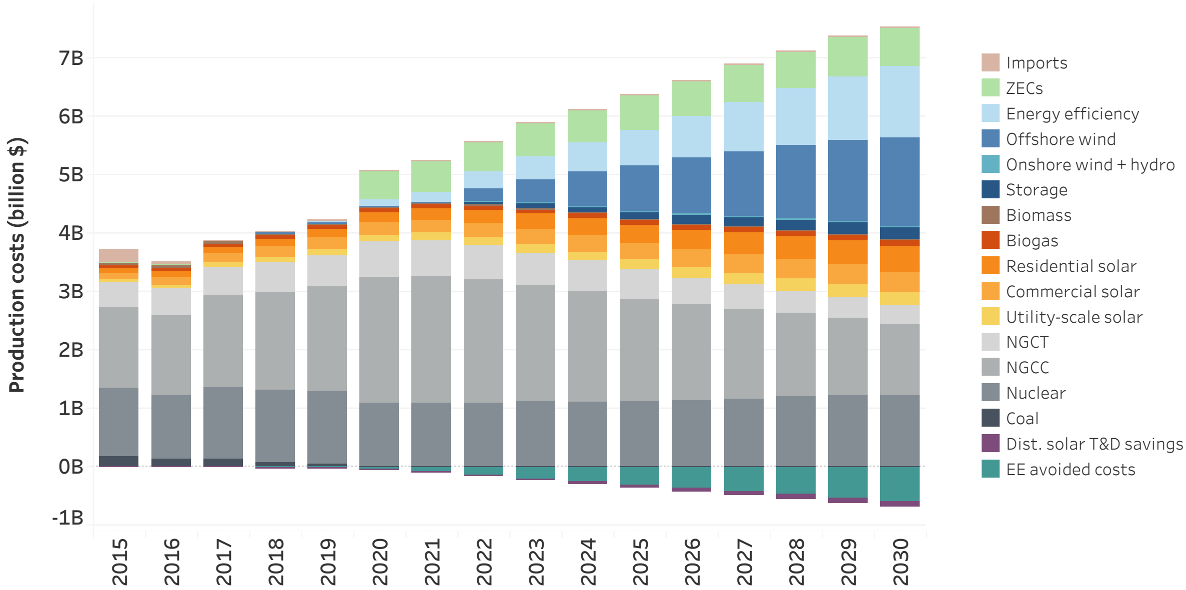


Figure 4.4: Electricity generation costs in the Clean Energy Scenario. The above market payment for nuclear power "Zero Emission Credits" is shown to illustrate the effect in case New Jersey chooses that option.

usual, despite its higher generation costs (see **Figure** 4.7 below), is the much lower cost of efficiency and the reduction of peaking gas plant use. Efficiency provides energy services at much lower cost than the corresponding energy supply in business as usual. Meanwhile, the most expensive electricity supply is peaking gas turbine generation. There is considerably more peaking generation in business as usual than in the Clean Energy Scenario leading to peaker costs of almost $400 million more than in the Clean Energy Scenario.

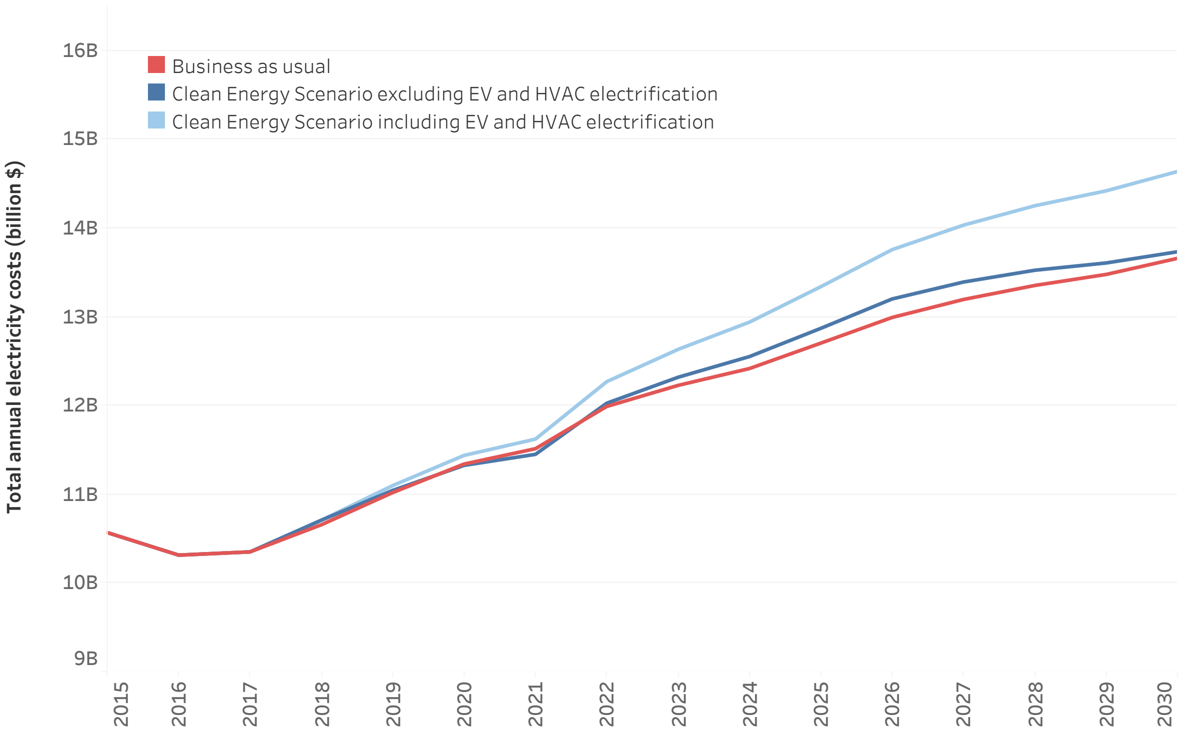


Figure 4.5: Total annual costs of electricity in the business-as-usual and Clean Energy Scenarios, including the additional costs of electricity for initial EV and HVAC electrification.

Another way of interpreting this result is that the cost of reducing CO_2 emissions is low—considerably lower than the social cost of carbon; it may be zero or negative in case natural gas prices increase faster than in the AEO Reference case. The additional benefits of overall pollution reduction and reduced water use are essentially free co-benefits. We note here, for later elaboration in this report, that net air pollution reduction does not necessarily imply local air pollution reduction, which may or may not occur based on individual plant operational changes. As noted previously, our model is an aggregate one, for New Jersey as a whole, for one entire year at a time. We model neither local areas nor specific seasons, notably the summer when pollution from generation due to gas turbine and diesel generation use are expected to be higher. New Jersey's net CO_2 emissions could go down even as it exports natural gas-generated electricity above its own demand requirements for the Clean Energy Scenario. We return to this topic in the **Section 6.2** where we also conduct an environmental justice analysis of power plant location.

Figure 4.5 also shows the total costs of the Clean Energy Scenario including the electricity generation needed for EVs and HVAC conversions. This cost is not comparable to the business-as-usual scenario, which does not include the corresponding generation provisions nor the respective costs for vehicle and heating fuel. Nonetheless, it is of interest to show the full electricity generation costs with this additional electrification. The cost of the Clean Energy Scenario with EV and HVAC conversions is about $1 billion more than business as usual in the year 2030, of which about $900 million are due to electricity attributable to the conversions. However, the estimated avoided cost of transportation and heating fuels in 2030 would be on the order of $1.3 billion.[15] The overall cost calculation is more complex, since the cost of capital investment in EV transportation infrastructure and HVAC equipment needs to be taken into account and translated into annual costs. Further, there would be about 20 million metric tons (net) of cumulative avoided CO_2 emissions in the 2020-2030 period due to these conversions. At $50 per metric ton social cost of carbon, the cumulative avoided emissions alone would be worth roughly $1 billion (rounded to one significant figure).

4.4.3 Early nuclear retirement

We do not take a position on nuclear power retirements in this report; we only recognize that early retirement is a possibility. Accordingly, we develop contingency scenarios that would ensure carbon emission reductions are maintained even in the case of such retirements. All of these scenarios have a common set of carbon constraints—the 2030 emissions would be 50% less than the 2015 level, and cumulative carbon emissions between 2018 and 2030 are capped at the same total. One approach to address the potential for early nuclear retirement is to procure replacement zero carbon resources, as described in **Section 3.4.6**. Given our assumption that the Clean Energy Scenario represents the maximum reasonable rate of in-state renewable deployment, replacement zero carbon resources will likely necessitate the import of onshore wind from the Midwest portion of PJM and/or import of utility-scale solar from the PJM region.

[15] The avoided heating fuel is about 34 trillion Btu. Mid-Atlantic residential heating oil and propane prices, in round numbers, are projected to be roughly $24 per million Btu (AEO 2017 Reference Case) [20], giving an avoided heating fuel cost of about $800 million in 2030 (rounded). Avoided transportation expenses would be roughly $500 million. This assumes a fleet average of 26 miles per gallon for light duty vehicles, corresponding improvements in other transportation, and vehicular petroleum averaging $25 per million Btu in 2030, all in 2016 dollars.

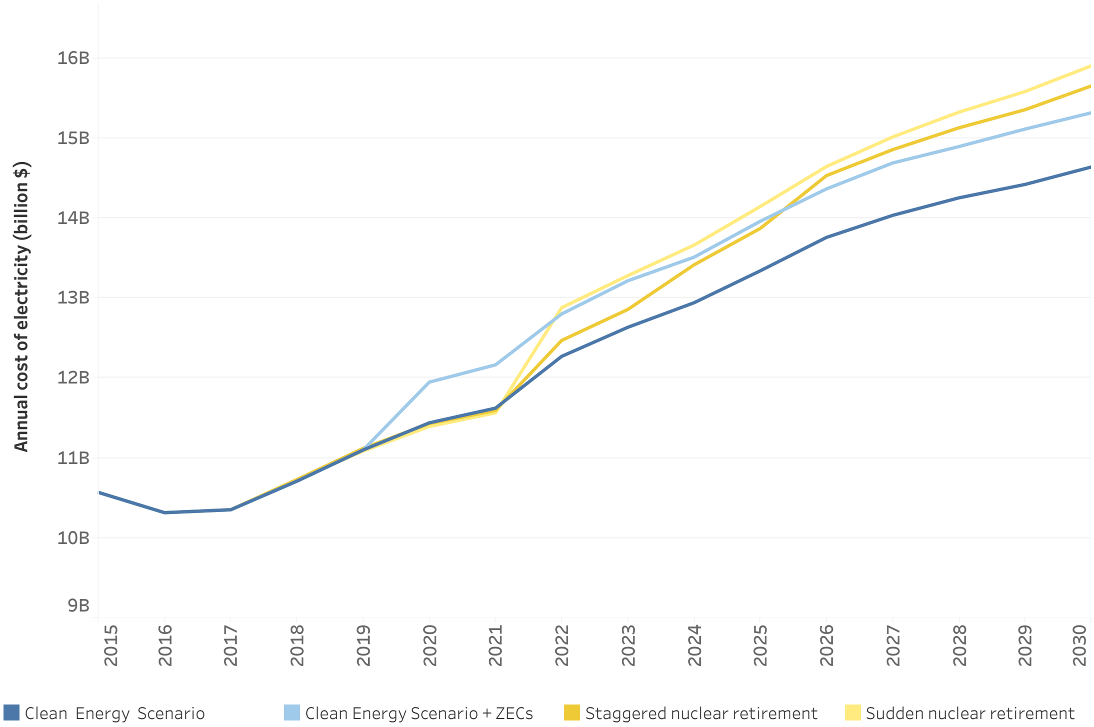


Figure 4.6: Comparison of the costs of early nuclear retirement scenarios to the Clean Energy Scenario with and without above-market payment (ZECs) for nuclear energy.

One contingency scenario is in case of a sudden simultaneous retirement of Hope Creek and Salem at the end of 2021. To prepare for such a contingency, the first set of imports would begin in 2019. In the second contingency scenario with staggered reactor retirements, each reactor would close two years after the previous one, with the first one closing at the end of 2021; imports of renewables would begin in 2020. We compare these renewable import cases with the option of above-market ZEC payments.

Figure 4.6 shows the total cost results for these contingency scenarios. We have compared the total costs of sudden and staggered nuclear retirement to the Clean Energy Scenario costs with and without ZECs. All have the same cumulative carbon emissions. There are financial risks that would accompany both imports of renewables via Virtual PPAs and committing to ZEC payments, as discussed in **Box 4.3.1**. The graph shows costs on a comparable basis.

It is clear that the most economical scenario is the continued operation of the nuclear plants without above-market payments. Such above-market payments raise the cost by over $600 million per year, if the payments are similar to New York's payments based on the social cost of carbon. The cumulative costs between 2019 and 2030 for making such payments would be comparable to importing wind and solar energy to replace nuclear generation and increasing offshore wind by about 600 MW.

We also note again that the cost comparison between ZECs and imports discussed here focuses only on generation costs. Given the large fraction of electricity supplied by nuclear power in New Jersey, the potential retirement of these plants would require significant reliability analysis, which may yield the need for additional investments to meet local capacity needs. We discuss these capacity needs briefly in **Section** 5.2 but a full reliability and cost analysis is beyond our scope here.

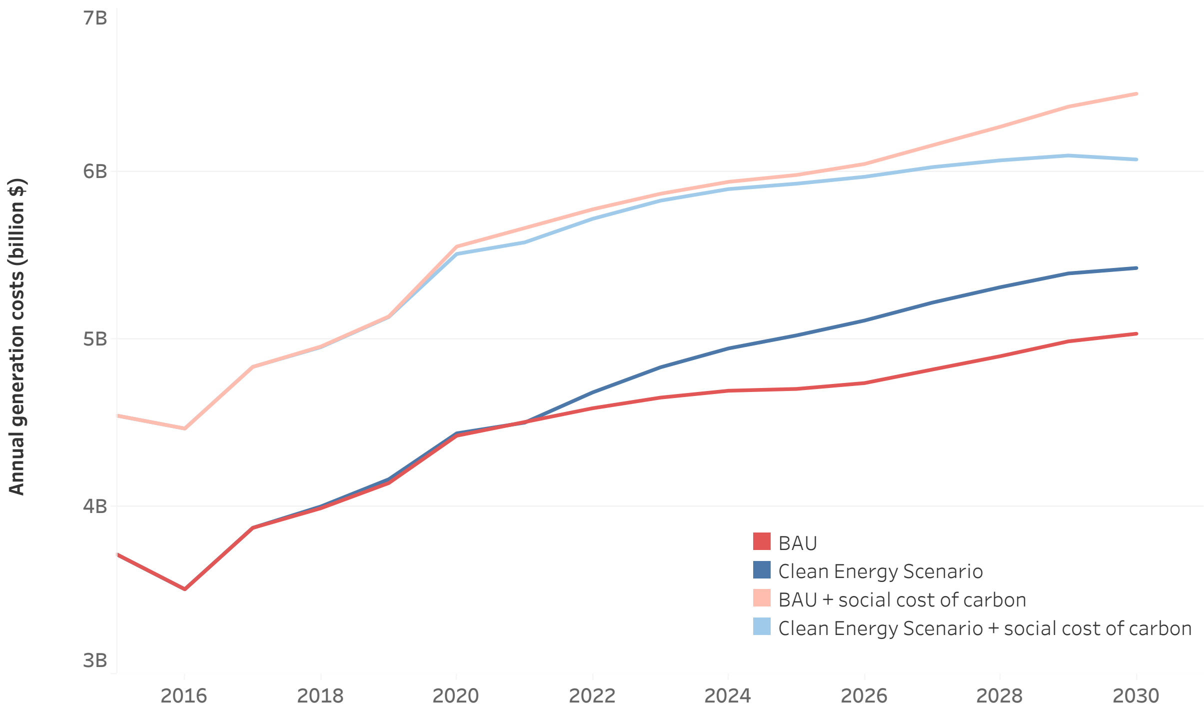


Figure 4.7: Electricity generation costs with and without the social cost of carbon added.

This view extends only to the year 2030. The licenses of the three reactors are due to expire in 2036 (Salem 1), 2040 (Salem 2), and 2046 (Hope Creek). Extending the time horizon of a scenario with ZEC payments up to retirement and considering replacement resources in the 2030s and 2040s would be a useful exercise.

4.4.4 Comparison of scenarios

When generation costs alone are considered, the Clean Energy Scenario has higher costs than the business-as-usual scenario. This result is shown in **Figure** 4.7, and is another way of showing that efficiency is key to reducing the total costs of energy services. **Figure** 4.7 also shows both scenarios with the social cost of carbon added. When this externality is accounted for, the Clean Energy Scenario is lower cost than the business-as-usual scenario on the basis of generation costs alone. A comparison of all scenarios is given in **Table** 4.3.

4.4.5 Energy services costs and energy bills

We have so far explored the total cost of energy services in the Clean Energy Scenario (with and without early nuclear retirement) and compared results to the total cost of business as usual. As noted earlier, the total costs include all expenditures and investments, including those that are made by individuals and businesses that do not show up in electricity rates, and those that are included in rates.

Table 4.3: Summary of costs and carbon reductions for business-as-usual and Clean Energy Scenarios. Values do not include EV and HVAC electrification unless otherwise indicated.

		Base case, no ZECs	Base case with ZECs	Early nuclear shutdown	Staggered nuclear shutdown	Business-as-usual
Cumulative generation, GWh		1,008,737	1,008,737	1,008,737	1,008,737	1,088,196
Cumulative generation with EV/HVAC, GWh		*1,037,473*	*1,037,473*	*1,037,473*	*1,037,473*	*1,088,196*
Cumulative CO_2 emissions, mil. mt		224	224	224	224	310
Cumulative CO_2 emissions with EV/HVAC, mil. mt		*230*	*230*	*230*	*230*	*310*
Cumulative cost 2018-2030, million $	Undiscounted	$161,700	$168,300	$169,400	$167,300	$160,500
	3% discount	$131,100	$136,300	$136,900	$135,300	$130,200
	6% discount	$108,200	$112,400	$112,600	$111,300	$107,500
Cumulative cost increase relative to BAU, million $	Undiscounted	$1,200	$7,800	$8,900	$6,800	NA
	3% discount	$900	$6,100	$6,700	$5,100	NA
	6% discount	$700	$4,900	$5,100	$3,800	NA
Cost increase per metric ton CO_2 reduction, $/mt	Undiscounted	$14	$91	$104	$79	NA
	3% discount	$11	$71	$78	$60	NA
	6% discount	$8	$57	$60	$44	NA
Average cost increase per MWh generated, $/MWh	Undiscounted	$1	$8	$9	$7	NA
	3% discount	$1	$6	$7	$5	NA
	6% discount	$1	$5	$5	$4	NA

Exploring the impact on electricity rates and bills and comparing business as usual with deep emission reduction scenarios is complicated by four major factors:

1. **Smart grid impacts:** The transition to a renewable energy system, with high penetration of solar and wind, is likely to be accompanied by a transition to a smart grid, a different business model for utilities, and different rate structures. This will fundamentally impact electricity bills, which could be very different from the bills under today's rate structures, even if electricity consumption remained the same.

2. **Distributed solar impacts:** The Clean Energy Scenario has far more distributed solar than the business-as-usual scenario. Behind-the-meter solar energy produces complex costs and benefits for ratepayers who do not have behind-the-meter solar. We have only addressed one issue related to distributed solar installations—that of reduced transmission and distribution costs compared to centralized generation. We do not consider issues such as compensation structure for distributed solar owners, emerging grid features such as widespread demand response, distributed storage, and provision of ancillary grid services like voltage regulation and frequency regulation. The issue of the impacts of distributed solar on electricity rates and bills is intimately connected with the previous point regarding smart grid impacts.

3. **Electrification of transportation and heating:** We have included the electricity requirements for electrifying 5% of vehicle miles and converting 10% of residential fossil fuel space and water heating to efficient electric systems. This makes the energy services that electricity provides in the Clean Energy Scenario significantly greater than in the business-as-usual scenario. The consumers who have made the conversions will see higher electricity bills than otherwise but lower total fossil fuel expenditures. There will also be some private and public investment (including ratepayer investment) in the transportation and heating system transitions. In addition, there are co-benefits such as reduced CO_2 emissions, reduced air pollution, and better health. We have included the additional electricity required but not addressed the other factors in ways that would make a comparison of expenditures possible, which would require a study of the entire energy sector rather than the electricity sector alone.

4. **Efficiency investment impacts:** As noted in **Section 4.3.1** of this chapter, efficiency investment consists of two major components: (i) the ratepayer investment, which includes incentives, administration, measurement, and verification, and (ii) the private investment, which is the increase in customer expenditure above any incentives required to procure more efficient devices and systems. We have made estimates of the total efficiency investments as well as the partition of those investments into ratepayer and private investment components.

Of the four factors above, the first two are well beyond the scope of this study and have not been addressed here. We have taken the third factor into account very approximately, by comparing total energy expenditures without and with HVAC and EV conversions to the business-as-usual scenario. All other things being equal (see items 1 and 2 above) we can examine the impact of the added electricity and corresponding reduced fossil fuel consumption on energy expenses.

As for the fourth factor, it is possible to examine the impact of efficiency on the cost of energy services as a whole. By separating out the ratepayer funded part of efficiency, it is also possible to examine the impact of efficiency on electricity bills, all other things being equal. So far as rates are concerned, we are comparing the rate impacts of efficiency rather than estimating actual rates. We extract the efficiency impact isolated from all other factors, like smart grid, demand response, varying rate structures, and behind-the-meter solar installations. The calculations below are a heuristic exercise that yields important insights about (i) the role efficiency in reducing the cost of energy services, and (ii) the differential impacts between those who do implement efficiency measures and those who do not. The comparison with the business-as-usual scenario is made excluding the extra electricity costs due to EVs and HVAC conversions.

Two other assumptions are important in this heuristic exercise. First, we assume that the fraction of total electricity used in the residential sector (excluding EV and HVAC conversions) will remain the same as in 2015. Second, we assume that the ratio of residential rates to average rates will also remain constant at the 2015 value of 1.151. With these caveats and assumptions, we can examine the impact of a renewables plus efficiency on rates and bills. **Figure 4.8** shows residential rates in the Clean Energy and business-as-usual scenarios. **Figure 4.8** reflects the reality that the cost of generation in the Clean Energy Scenario increases substantially over time compared to business as usual, although more slowly past about 2026, as can also be seen in **Figure 4.5**.

Figure 4.9 shows the corresponding average residential bills. The impact of efficiency is obvious. Despite the higher rates, the bills are lower in the Clean Energy Scenario. The savings grow over time as the use of electricity becomes more efficient relative to the business-as-usual scenario.

A comparison of **Figure 4.9**, which shows the ratepayer perspective, and **Figure 4.5**, which shows the total cost of energy services perspective is instructive. The total cost of

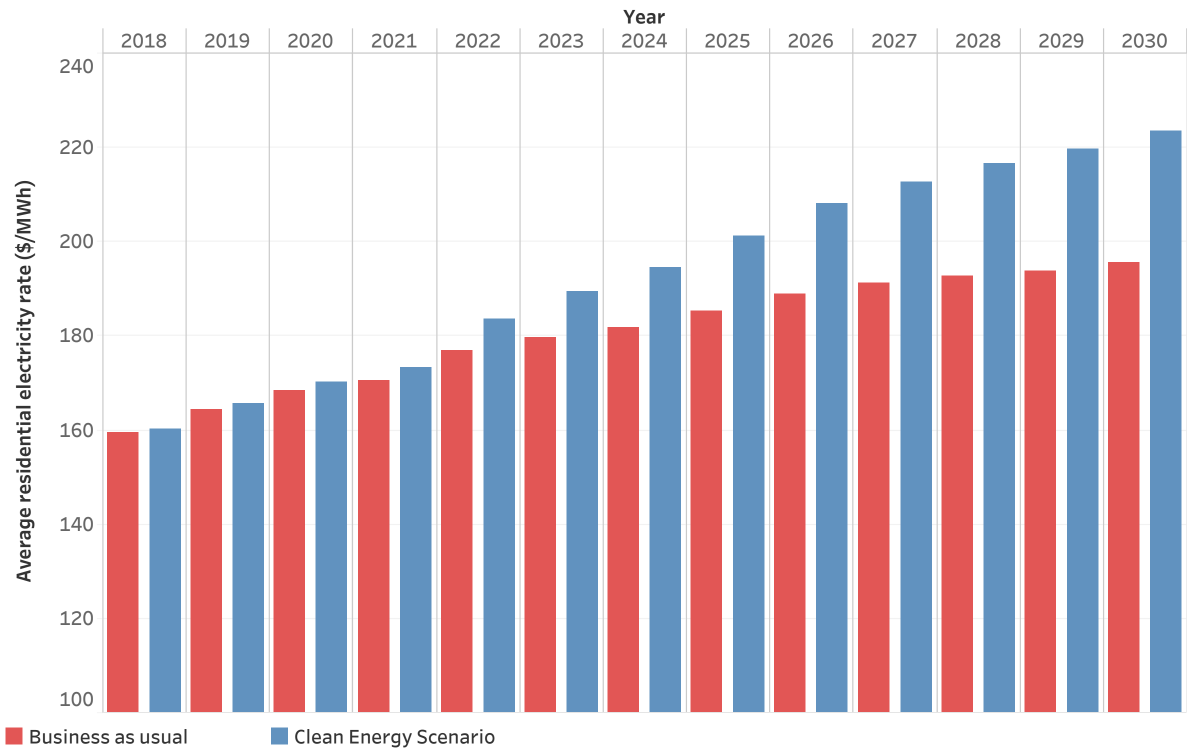


Figure 4.8: Average residential electricity "rates" in $/MWh in the business-as-usual and Clean Energy Scenarios.

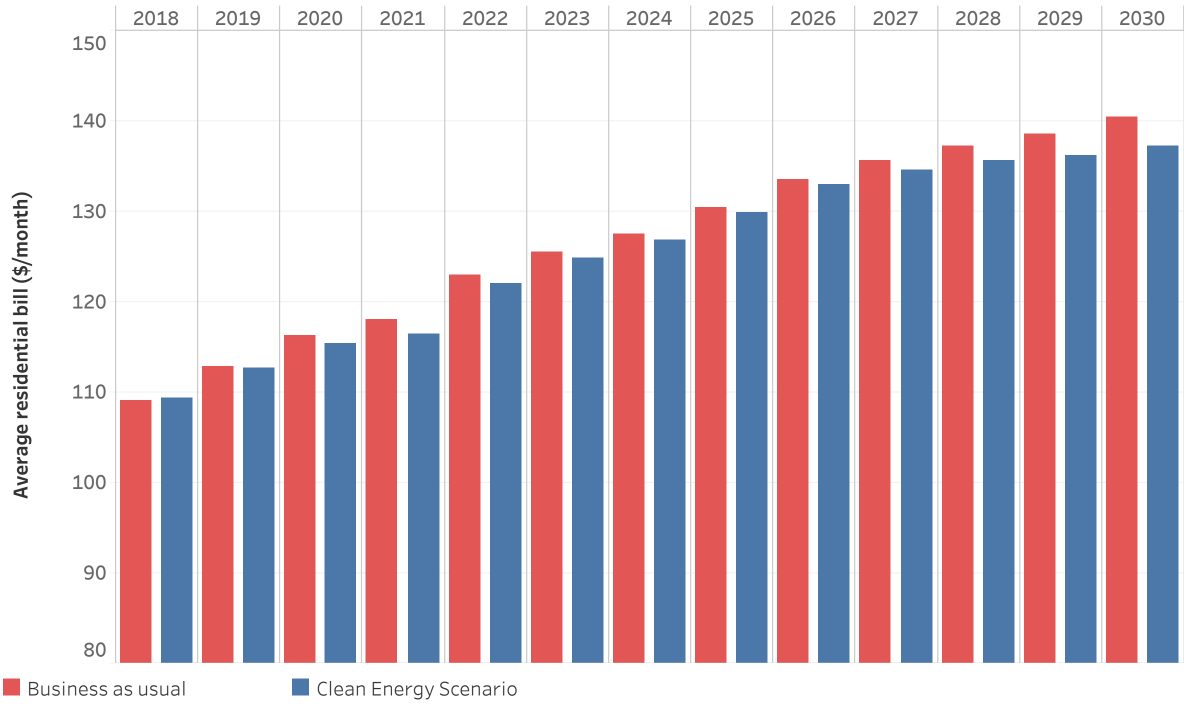


Figure 4.9: Business-as-usual and Clean Energy Scenario monthly residential bill impacts.

energy services in the Clean Energy Scenario is slightly higher (by about $74 million in 2030) than the business-as-usual scenario. The efficiency portion of this total cost includes both the ratepayer contribution to efficiency (utility incentives, administration, etc.) and the consumer cost for efficiency improvements (not seen by the utility). The latter cost is significant—about $400 million in 2030. When it is excluded to obtain the ratepayer perspective, the cost of the Clean Energy Scenario is lower than the business-as-usual scenario, which translates into lower bills. We stress again that the calculations in this section aim only to isolate the effect of efficiency on rates and bills with "all other things being equal."

Figure 4.10 shows the residential bill savings per month and how they change over time. Note that initial savings grow rapidly as the impact of efficiency is felt. The savings subsequently decline as the initial offshore wind tranches go online. As offshore wind and solar costs come down and more efficiency is achieved, bill savings increase after 2026.

The above bills represent the average impact over all consumers. Seen another way, they represent a hypothetical situation in which all consumers have made similar investments in energy efficiency. This is unlikely, particularly in the absence of special efforts to ensure that rental properties and low-income households make investments comparable to the typical level in the Clean Energy Scenario. There is therefore an important issue of equity associated with the implementation of efficiency measures.

We illustrate the issue of impact of differential efficiency implementation with a heuristic example. We assume for the sake of illustration that half the households make the same intensive investments and achieve double the average efficiency gains, while the other half make none. In this case, the efficient half will see much greater reductions in bills, while the inefficient half will have bills higher than the business-as-usual scenario. **Figure 4.11** shows the results. The calculation in **Figure 4.11** is for illustrative purposes; it serves only to underline show the importance of efficiency explicitly and starkly.

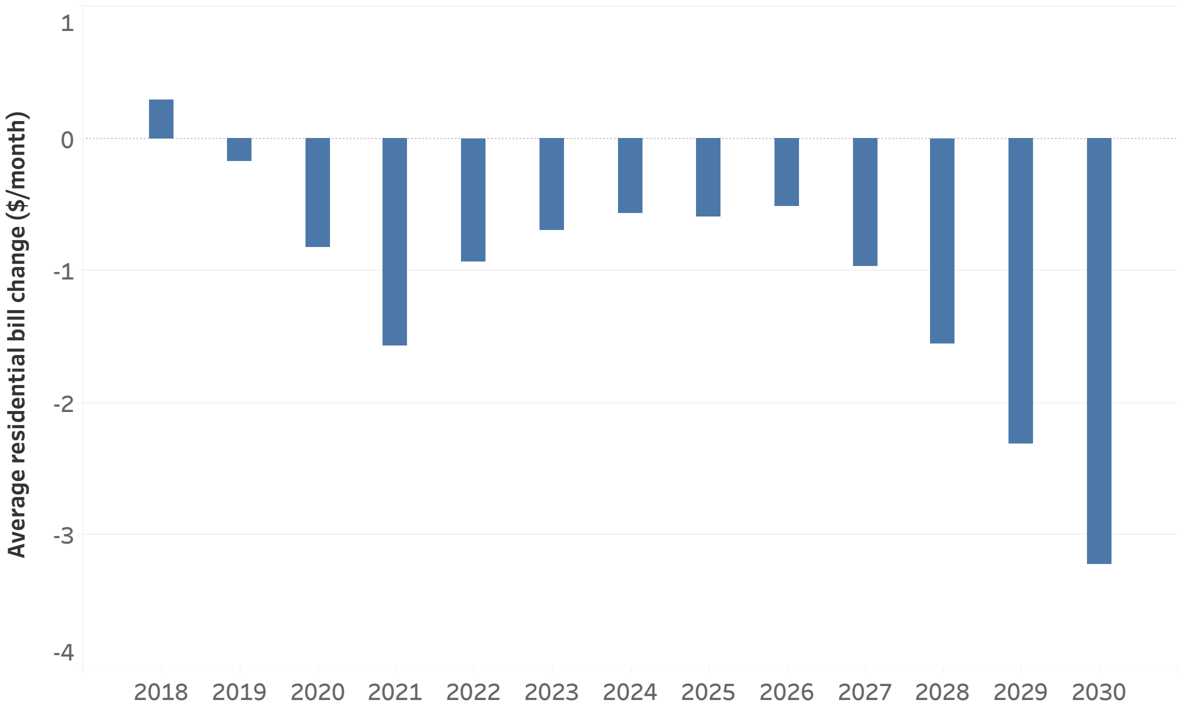


Figure 4.10: Monthly bill savings in the Clean Energy Scenario compared to the business-as-usual scenario.

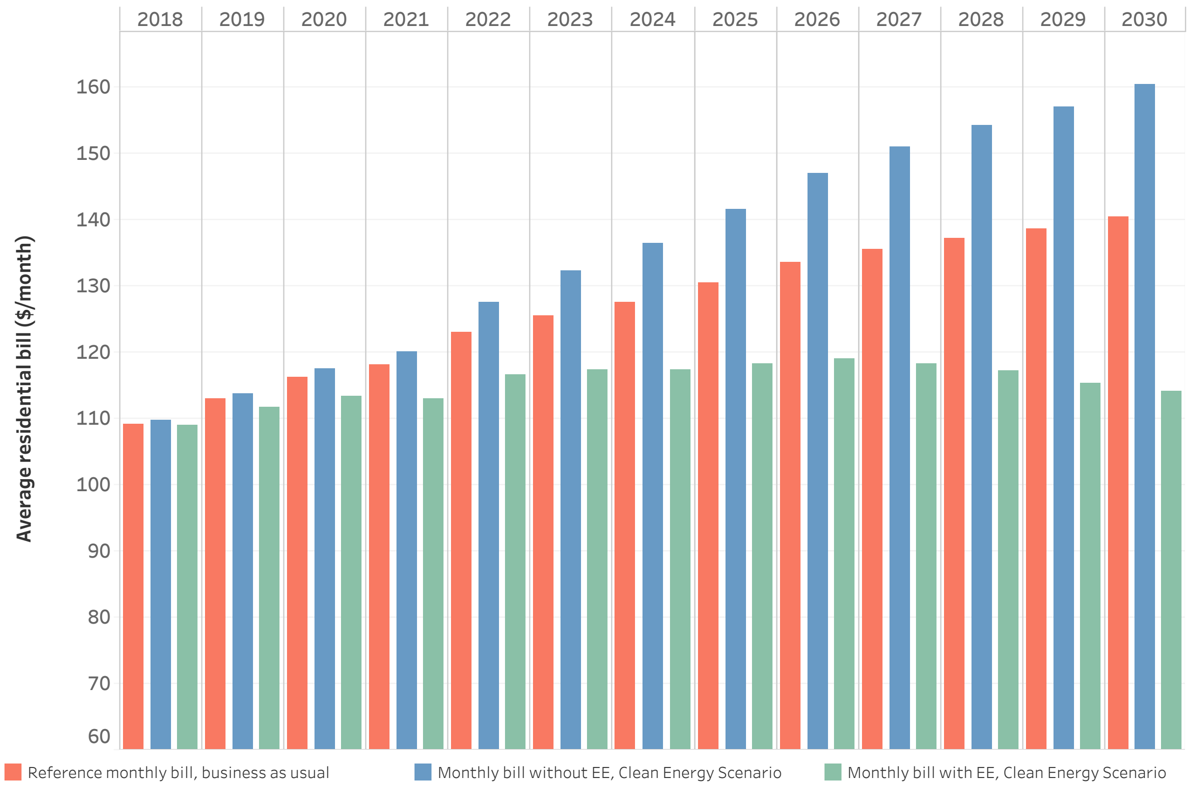


Figure 4.11: "Bills" of households with and without efficiency in the Clean Energy Scenario compared to business-as-usual monthly residential bills. Illustration reflects impact of efficiency on bills but is not meant to predict actual bills.

It is also important to note that the effect on most low-income households of unevenness in efficiency implementation will likely not be as serious in New Jersey as it would be in most other states. New Jersey's Percentage of Income Payment Plan (PIPP) limits electricity plus natural gas bills of low income households to 6% of gross income [95]. Thus, those low-income households, especially renters, who do not have significant access to efficiency, will in most cases have higher bills and higher assistance. The net result in many or most cases will be that their post-assistance bills will not go up; rather the amount of assistance needed would rise. However, assistance is limited to a maximum $1,800 per year, so that some low-income customers, especially those with large families, poorly weatherized homes, and/or electric resistance heat, who are also at the lower end of the income spectrum, may see net bill increases. This serves to stress the importance of at least a modest level of efficiency efforts in all households, and especially those at the lowest income levels. For instance, a set of minimal targets might be that (i) all households are retrofitted with LED bulbs throughout and (ii) all electric water heaters and associated hot water pipes are wrapped with insulation. These efforts would also help reduce low-income energy assistance costs currently paid for by higher-income customers.

4.5 Sensitivity analysis: high gas prices

The price of natural gas is one of the most important uncertainties in electricity sector cost projections. The AEO 2017 Reference Scenario has a rather low growth of natural gas prices based on recent experience with rapid growth of shale gas production by hydraulic fracturing. However, continued low prices are far from assured, even though these prices form the basis of the business-as-usual scenario we have modeled here. The EIA also models a "Low oil and gas resource and technology" case where natural gas prices rise faster [20]. We have used this scenario to check the sensitivity of the business-as-usual scenario cost results to natural gas prices. As a reminder, we are using natural gas prices for the electricity sector only.

In the high natural gas price scenario, delivered natural gas prices for combined cycle plants rise from about $3 per million Btu in 2017 to about $8 in 2030, instead of $4.70 or so in the Reference business-as-usual case, as shown in **Figure 4.1**. **Figure 4.12** shows total costs of electricity in the business-as-usual and Clean Energy Scenarios when both rely on high natural gas prices.

It is easy to see that natural gas prices are the most important uncertainty in the business-as-usual scenario. Business-as-usual costs at the high gas price would be about $1.4 billion greater in 2030 than in the business-as-usual AEO Reference Case gas price (discounted at 3%). The cost comparison with the Clean Energy Scenario is reversed. Total costs of energy services in the Clean Energy Scenario would be about $2.4 billion lower cumulatively than the business-as-usual high gas scenario (discounted at 3%). Although the price of natural gas is higher in both cases, the much lower natural gas generation in the Clean Energy Scenario makes it less vulnerable to natural gas price volatility or increase.

This sensitivity analysis shows an increasing difference in costs between the business-as-usual and Clean Energy Scenarios. The cumulative difference of $2.4 billion is a proxy for the hedge value of zero fuel cost solar and wind energy combined with efficiency. It should be noted that these are very approximate values. The actual cost difference depends on a number of factors, including the mix of solar and wind, how much gas turbine generation is displaced

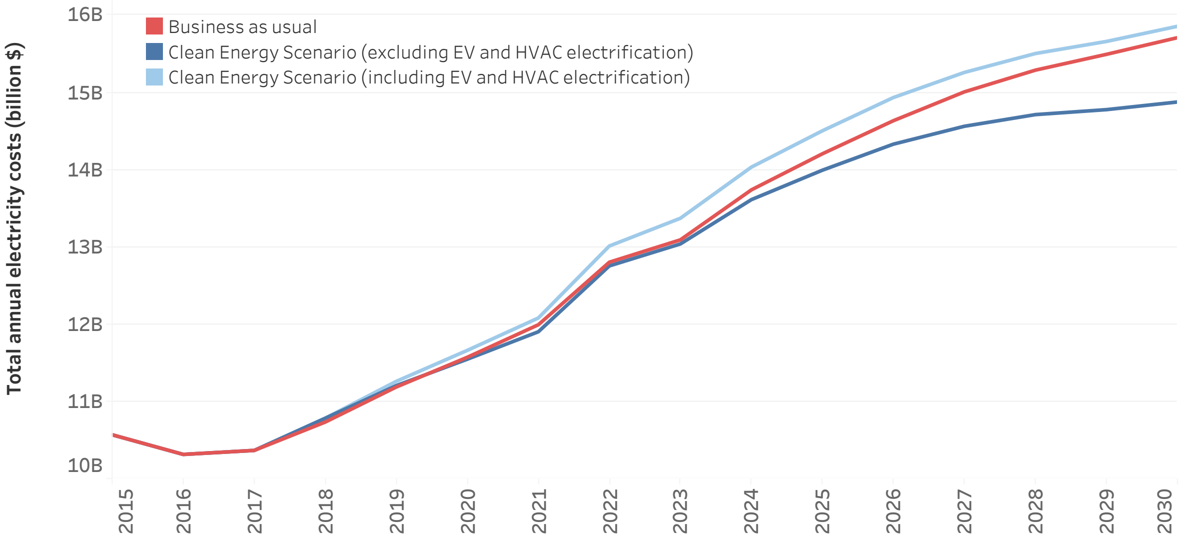


Figure 4.12: Comparison of Clean Energy Scenario and business-as-usual costs with high gas prices.

relative to combined cycle generation, and the level of total solar and wind penetration. According to an NREL analysis, beyond about 30% variable resource penetration, issues relating to storage, curtailment, demand response, etc. become important [96]. Finally, we have not estimated an actual hedge value, which requires an estimation of the actual probability of the higher natural gas prices.

The results of these analyses are summarized in **Figure 4.13**, reflecting the total scenario cost from 2018-2030, total cost from a ratepayer perspective, and the impact of social cost of carbon and high gas prices on these totals.

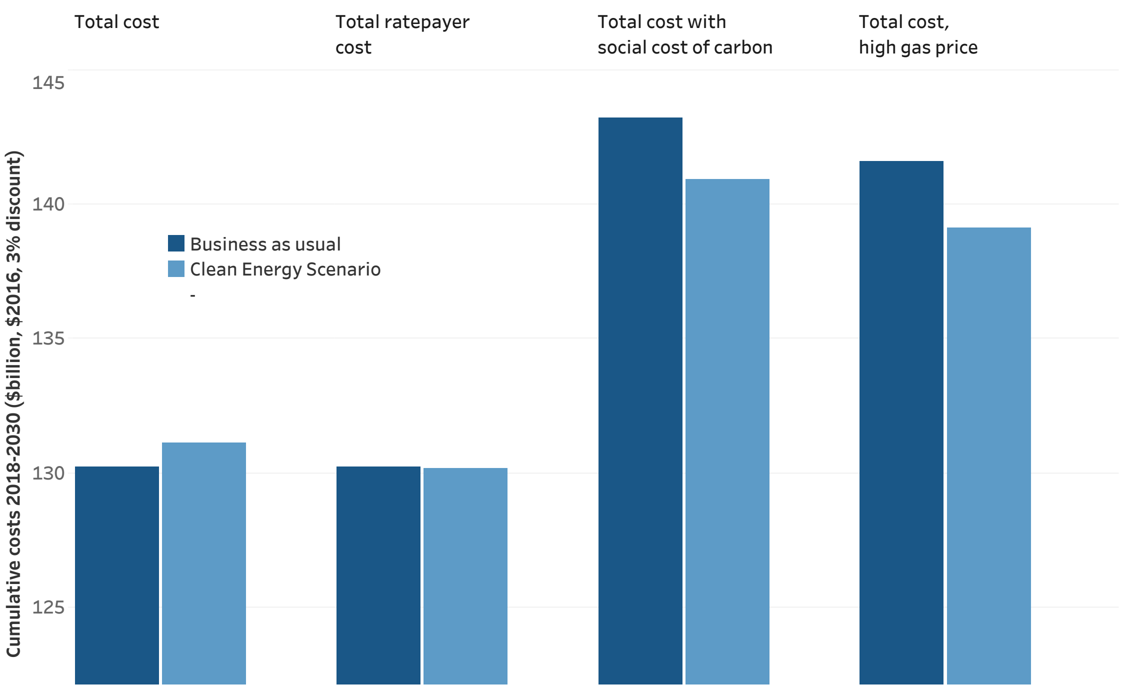


Figure 4.13: Comparison of the total costs from 2018-2030 (3% discount) of the business-as-usual scenario to the Clean Energy Scenario, i) inclusive of all costs, ii) as seen by the ratepayer (i.e. excluding customer efficiency investments), iii) including the social cost of carbon, and iv) in the case of high gas prices.

5. Grid considerations

5.1 Renewable generation variability

The Clean Energy Scenarios developed here rely on a much higher fraction of variable renewable resources than used to meet New Jersey's historic energy demand. Wind and solar resources are variable on numerous different time scales: a passing cloud can reduce solar output in seconds; solar and wind both tend to peak at different times of day, with solar generating electricity during the day and wind often strong at night; and seasonal variations occur as wind and solar resources vary throughout the year with changes in sunlight and weather. The electric grid is relatively flexible, and already has to accommodate large daily and seasonal fluctuations in demand as well as periodic losses of large fossil generators, such as during July 2016 when one of New Jersey's nuclear generators was largely offline for maintenance. Looking at other studies as well as real-world examples, we find that the level of renewables proposed here is not likely to result in significant concerns due to variability.

We do not do any hourly modeling here, which we believe is best conducted as a regional modeling exercise due to the practice of balancing the grid over a much broader region than New Jersey. Instead, we look to other regional studies and examples to determine if the renewables introduced here are likely to increase reliability concerns for the grid. Most importantly, PJM commissioned a study from GE to assess the impact of the integration of up to 30% variable renewables across the PJM region [2]. This study found that PJM "would not have any significant reliability issues operating with up to 30% of its energy [...] provided by wind and solar generation." New Jersey does not have to balance its grid on its own, and instead grid balancing takes place across this broader PJM interconnect. Similarly, NREL modeled the integration of up to 30% wind and solar across the entire Eastern Interconnect at five minute intervals, and found that the grid could manage this level of variable renewable generation without additional storage, demand response, or other grid balancing technologies [68]. However, balancing does become easier with greater inter-regional coordination.

In comparison with these regional studies, the Clean Energy Scenario relies on 33% renewables, about 32% of which are wind and solar and 1% is landfill gas and anaerobic digestion. In reality, New Jersey's energy use is only about one tenth of PJM's total demand, meaning 32% solar and wind in New Jersey affects only about 3% of PJM's total electricity generation. Such a target should have a small PJM-wide impact. Regardless, the studies mentioned above suggests that even if the rest of PJM follows suit in setting aggressive renewable energy targets for 2030, the grid can accommodate these higher levels of renewables. In our nuclear contingency scenarios, which rely on imports from across PJM, the fraction of renewable energy used to meet New Jersey demand increases to roughly 69%, meaning these renewables would account for about 7% of PJM's total generation—still very low in terms of overall PJM impact. Current Tier I renewables requirements for PJM (wind, solar, run-of-river hydro and landfill gas) reach only 12.8% of generation in 2028, inclusive of

New Jersey's current targets [30], suggesting significant renewables expansion beyond these targets should still not cause reliability concerns.

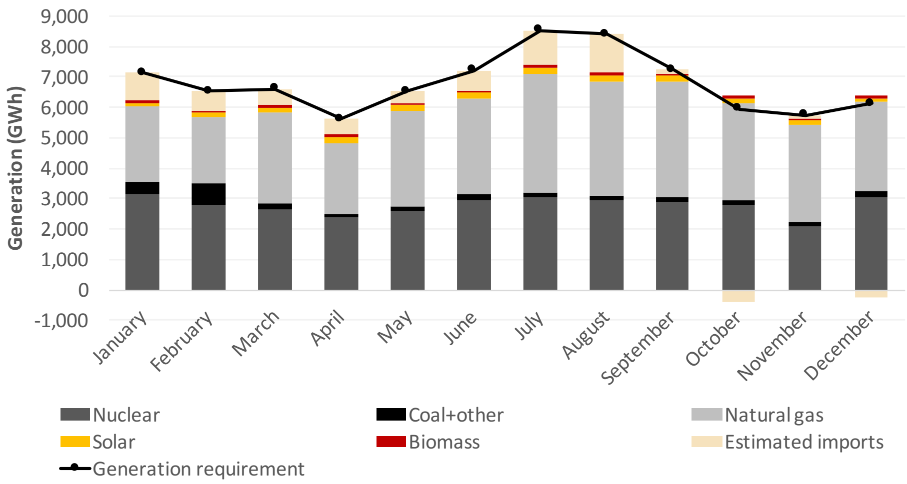
As noted earlier, we do introduce some considerations to help accommodate renewable energy integration. We incorporate additional transmission in the case of renewable energy imports at levels suggested by the PJM hourly integration study, which should not only allow this generation to meet load centers on the coast but also improve load balancing across PJM. We set energy storage targets for New Jersey in proportion to California's 2020 targets at the same penetration of renewables, under the assumption that the grid flexibility provided by this storage should be sufficient to integrate New Jersey's renewables. In practice, New Jersey may be able to balance any variability across PJM without energy storage, but storage can 1) allow for increased grid resilience, 2) help reduce peak demand, and 3) help increase grid flexibility to ease the incorporation of higher penetrations of renewable resources after 2030.

While the above studies demonstrate the ability of renewables to meet grid needs on an hourly basis, we do take a deeper look at the seasonal variability of the renewables used in our Clean Energy Scenario. We did not model the impact of efficiency on seasonal demand, but efficiency could play a role in reducing summer loads. Instead, we assumed that the seasonal load shape in 2030 is similar to 2020, for illustration purposes [1]. In **Figure 5.1.1** we show how the resources proposed would match up to seasonal demand on a monthly basis, where **Figure 5.1.1a** shows 2015 generation and **Figure 5.1.1b** shows estimated 2030 generation. We assume nuclear power reactors refuel in April or October in the years when they are refueled. Monthly solar generation is calculated using PV Watts [43]. Monthly average wind speeds are reported from AWS Scientific data for wind speeds at 29m [97], and scaled to a 90 meter hub height using an assumed power factor of 0.11. Monthly generation is calculated using offshore wind roughness assumptions input into the Danish Wind Calculator [98]. After adding solar and a small fraction of biogas, the remainder is met with natural gas. In 2015, the maximum monthly natural gas generation was roughly 80% higher than the minimum natural gas generation. In 2030, the seasonal variation in natural gas use varies by a factor of four, although this variation could be reduced with increased summer efficiency efforts. In total, peak monthly natural gas use in 2030 is still lower than in 2015 or 2016. These figures illustrate that wind and solar couple relatively well from a seasonal basis, with higher wind in the winter and higher solar in the summer, but that natural gas or efficiency will be needed to help meet summer and winter peaks.

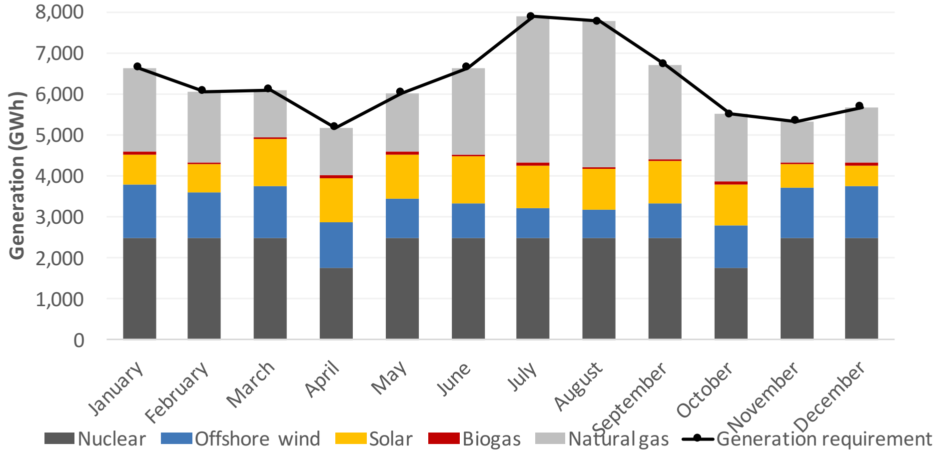
5.2 Peak demand and capacity needs

Our analysis has been focused primarily on meeting New Jersey's energy needs with a low-carbon generation portfolio, and so far we have not done a full capacity analysis. Our base-case Clean Energy Scenario adds significant levels of generation, but does not predict retirements beyond limited coal and aging oil and gas steam generators and the planned Oyster Creek retirement. If the natural gas plants stay online, simply operating at a lower capacity factor, then we do not expect to have a shortage of capacity. If some retire due to economic pressure, then capacity requirements to meet reliability needs would have to be determined on a case-by-case basis. Below, we briefly discuss a few factors related to capacity as well as strategies to ensure capacity requirements are met moving forward.

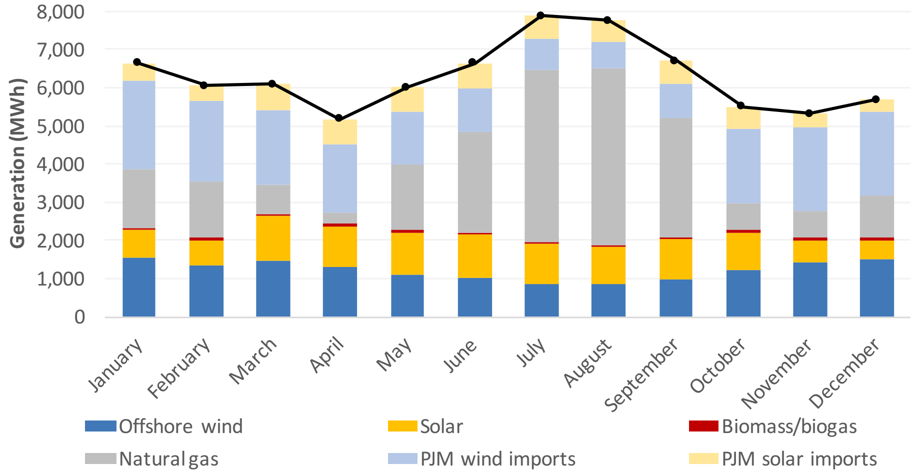
[1] This assumption is purely for illustration purposes. The load shape is likely to change due to adoption of electric vehicles, heating electrification, growth in air conditioning, and other factors.



a. Historic 2015 electricity mix.



b. Estimated monthly 2030 electricity mix.



c. Estimated monthly 2030 electricity mix, no nuclear.

Figure 5.1.1: Monthly electricity mix showing seasonal variability. Imports estimated. Negative values imply net exports. 2030 estimate does not reflect future changes to monthly load shape.

Across PJM, capacity is currently not heavily constrained. NERC requires a reserve capacity margin of 16.6%, but current reserve margins are at 28.4% [99]. As a result, it is likely that capacity services historically provided by retired natural gas plants could be easily met with resources across PJM. Furthermore, as of 2007 New Jersey imported 30% of its electricity, and only recently has reduced its imports [8]. While some of the transmission used for historic imports may be utilized for other purpose now, there is likely some additional capacity for imports if needed. As noted earlier, PJM considers New Jersey's available grid capacity to be 16.6 GW [30]—well below the state's 19 GW peak load [21]—meaning the state already relies on the larger PJM grid to meet peak demand. The assumption that New Jersey may have sufficient capacity even in the case of retirements was validated in the summer of July 2016, when the 2.3 GW Salem Generating Station was unexpectedly removed from service for most of the month. Retail sales of electricity that month were the highest they had been in three years, but nuclear power generation was lower than any month since 2004. The loss of nuclear generation was met with a combination of natural gas generation and imports. Price impacts appear to have been minimal. Average day-ahead prices in New Jersey were \$58.6/MWh in July 2016 as compared to \$56.7/MWh in July 2015, well within the usual variation in the system and also in line with the higher demand in July 2016 compare to July 2015 [100].[2] The real-time prices similarly show no significant difference between July 2015 and July 2016.

While the above discussion suggests there may be a surplus of capacity on the grid, the renewable energy and efficiency resources added in the Clean Energy Scenario are also expected to provide some capacity benefits. PJM assigns solar a capacity benefit of 38% of installed capacity and onshore wind a capacity benefit of 13% of capacity. As such, our added in-state solar generation would have a capacity value of 2.2 GW. At 13%, our offshore wind would have a capacity value of only about 420 MW. However, offshore wind generates electricity more reliably than onshore wind, and the Atlantic's offshore wind resource is shown to coincide quite well with demand across the East Coast [101], suggesting that PJM may choose to assign offshore wind a higher capacity benefit than onshore wind. With a capacity benefit of 25% of installed capacity, offshore wind in the Clean Energy Scenario would provide 810 MW of capacity to the PJM market. We also note that the capacity values used in the PJM market may be an underestimate of the true value of these resources: the PJM renewable integration study finds a capacity value of 55-58% for distributed PV, 63% for centralized PV, 21% for offshore wind and 17% for onshore wind in its high offshore wind scenario with 30% total renewables. At lower levels of PJM-wide renewables, offshore wind is given a capacity value of 27% [2]. At these higher valuations, the capacity value of added solar and offshore wind in the Clean Energy Scenario is 4,200 MW.

Beyond generation additions, the Clean Energy Scenario includes energy storage and efficiency measures that can also help reduce peak demand. We have added 1,600 MWh (1,000 MW) of storage (with 200 MW of capacity for peaking replacement and 800 MW for 400 microgrids) in the Clean Energy Scenario. To calculate the capacity value of efficiency, we use values from efficiency programs in New England, which average a reduction in peak demand of 0.137 MW/GWh saved [102]. If our targets for New Jersey achieve the same peak demand reduction, this would yield a demand reduction of about 1.6 GW, or 1.4 GW when accounting for projected PJM demand growth.[3] We did not analyze demand response,

[2] Average day-ahead prices in 2015 were \$50.5/MWh, and June 2016 were \$41.5/MWh, showing much greater inter-annual variability than in July 2015 and 2016 [100].

[3] While we assume increased electricity demands from heating and vehicle electrification in the Clean Energy Scenario, the heating load is expected to increase in winter, while peak demand occurs in summer, and electric vehicle charging can be timed such that the bulk of charging avoids time of peak demand. We therefore do not expect the electrified loads we have included in 2030 to greatly affect peak demand.

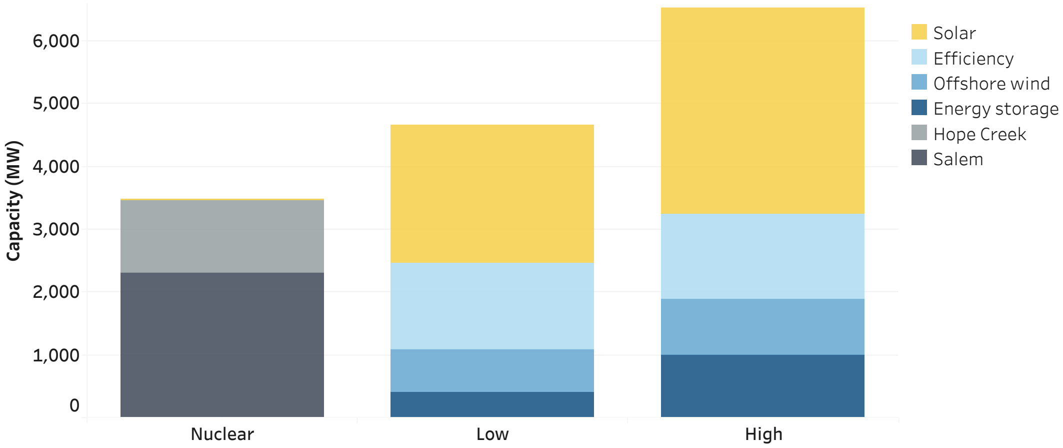


Figure 5.2.2: Nuclear and clean energy capacity comparison. Hope Creek and Salem Nuclear Generating Station capacity compared to the clean capacity value of renewables, storage and efficiency in the Clean Energy Scenario in 2030 (low and high estimates).

but significant additional potential demand reduction would be available through demand response programs. Assuming a low capacity value for storage of 400 MW, due to the limited discharge times of the microgrid storage systems, and a high capacity value of 1,000 MW, the cumulative added capacity values of our clean energy resources are estimated at 4,660 MW (low) and 6,530 (high).

We do not necessarily predict significant natural gas retirements before 2030. Two thirds of the state's NGCC capacity will be less than 35 years in 2030, and over 90% will be less than 40 years, meaning most plants will not be forced into retirement due to age, although some may be approaching it. The majority of the state's gas simple cycle capacity was built after the year 2000. Additional retirements could occur in the case of loss of economic competitiveness, but we do not analyze such market-driven dynamics here.

The capacity additions described would provide significant flexibility if some power plants retire. Even if both Salem and Hope Creek shut down, the lost capacity (3.5 GW) is 1.2 GW below the low estimate of our clean capacity additions and 3.0 GW below our high estimate as of 2030, which is illustrated in **Figure 5.2.2**. The pace of capacity additions is roughly on par with the pace of nuclear capacity loss in the staggered nuclear retirement contingency. In the case of sudden nuclear shutdown, capacity may be sufficient if the loss of Salem Nuclear Generating Station in July 2016 does indeed indicate that 2.3 GW of load can be easily met with imports. However, additional reliability analysis will be required to ensure that sufficient capacity and reserve margins are available in the case of sudden nuclear shutdown, particularly in the case of near-term retirements of remaining coal and fossil steam capacity on the New Jersey grid. We have not the capacity represented by solar and onshore wind imports since most or all of that may be by Virtual PPAs.

This section is not meant to imply that a capacity and reliability analysis is not needed in the case of retirements, but simply to suggest that we do not expect significant capacity concerns in the Clean Energy Scenario and that even in the case of nuclear retirements the addition of clean energy resources within the state has the potential to meet capacity needs. Additional analysis would be needed to assess market impacts on natural gas plant retirements, as well as local capacity constraints and reliability needs, and such an assessment could further help inform the deployment of distributed resources to help meet these local grid requirements.

5.3 Market impacts

While we do not model the market impacts of the Clean Energy Scenario, we discuss a few potential impacts here. Increased wind and solar generation, which have minimal operating costs, may drive wholesale costs down due to the merit order effect. Because wind and solar have low variable operating costs and zero fuel cost, they enter the market at a low marginal price, pushing more expensive generation further down the dispatch order and making it less likely to clear the market. This impact can result in lower wholesale energy costs. However, renewables typically have a lower capacity value than traditional generation. Capacity prices across PJM and in New Jersey have increased in recent years [60] and a renewable-heavy resource could have a further impact on these capacity prices. Additionally, if renewables lead to increased cycling of power plants, this effect could contribute to both a change in operational costs and increased co-pollutant emissions. Changes to the market design may be required to accommodate and reflect changing resource portfolios and grid needs.

A detailed consideration of the structure of the grid of the future and the associated technical, regulatory (including rate structure), and investment issues associated with it are beyond the scope of this report. For instance, we do not consider the role of demand response, or infrastructure investments that will be needed for electrifying transportation. As another example, we do not consider the smart grid investments that will be needed to accommodate a diverse mix of demand response components that could make high variable resource penetration more efficient and economical. Current regulatory proceedings in New York and California are attempting to determine methods to value distributed resources and incorporate this valuation into market operation and incentives. The results of these studies and regulatory efforts may be valuable reference points for New Jersey.

5.4 Energy storage, resilience, and equity

As described, we have included 200 MW of energy storage to replace peaker plants and 800 MW for microgrid installations. This mix of storage, at the levels specified, could make a substantial impact on both equity and resilience. We have noted that a net reduction of 50% in CO_2 reductions by 2030 on a statewide basis does not guarantee a reduction of local air pollution. For instance, New Jersey could become an exporter of fossil fuel generation without affecting net annual emissions attributable to electricity use in the state. However, strategic deployment of energy storage can be coupled with policies to reduce generation or phase out specific fossil fuel plants in communities disproportionately impacted by air pollution [103].

Deployment of microgrids is already considered an important part of increasing resilience, perhaps more so in New Jersey, with its devastating experience of Hurricane Sandy, than in most other states. Four hundred microgrids in 2030 would mean one microgrid on average for approximately every 24,000 New Jersey residents. These microgrids could be deployed strategically at the junction of environmental justice and climate change adaptation. The new point here is that renewable energy development can help enhance efforts to increase resilience, invest in adaptation, and redress environmental injustice. Specifically, existing microgrids and peaking generation are typically dependent on natural gas use. The scale of storage deployments we have included in the Clean Energy Scenario can redirect resilience and adaptation efforts to instead rely on distributed storage and solar generation.

6. Health, equity and environment

6.1 Health-harming co-pollutant emissions

In addition to the greenhouse gas emissions associated with the power sector in New Jersey, burning fossil fuels releases criteria pollutants that have significant negative health impacts. These pollutants include nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulate matter, among other hazardous and toxic air pollutants. While high concentrations can be harmful directly, NO_x and SO_2 also contribute to the formation of secondary particulate matter and ozone, with impacts up to hundreds of miles away from the emission source. Associated health impacts can include respiratory and cardiovascular health impacts, including asthma attacks, heart attacks and premature death [104, 105, 106, 107]. The magnitude of these impacts depends on regional air quality conditions, population density, and other environmental factors. A co-benefit of reducing carbon dioxide emissions from the power sector includes the reduction in emissions of these health-harming criteria pollutants.

Under the Air Markets Program, the EPA requires plants larger than 50 MW to report hourly CO_2, NO_x and SO_2 emissions using continuous emissions monitoring systems (CEMS). In **Figure 6.1**, we show total CO_2, NO_x and SO_2 2015 emissions by power plant type for those reporting emissions, and in **Figure 6.2** we show the rate of these emissions per MWh of generation. NGCC, gas simple cycle, and coal emissions are reported by EPA [56]; municipal solid waste data is estimated by the EIA [108], but should be considered significantly more uncertain due to the absence of CEMS reporting for these plants. However, we

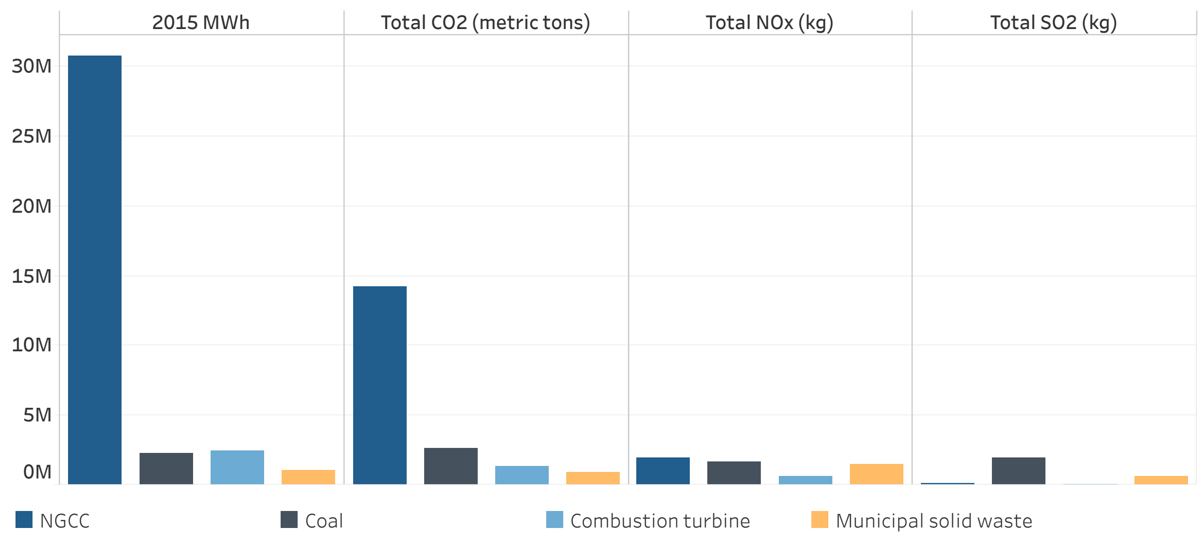


Figure 6.1: Carbon-emitting generation and emissions from New Jersey power plants by plant type, 2015. Oil, gas steam, landfill gas, and CHP plants, and any plant under 50 MW in capacity, are not included in totals. All data retrieved from EPA Air Markets Program [56] except for municipal solid waste (MSW), which is estimated by the EIA [108].

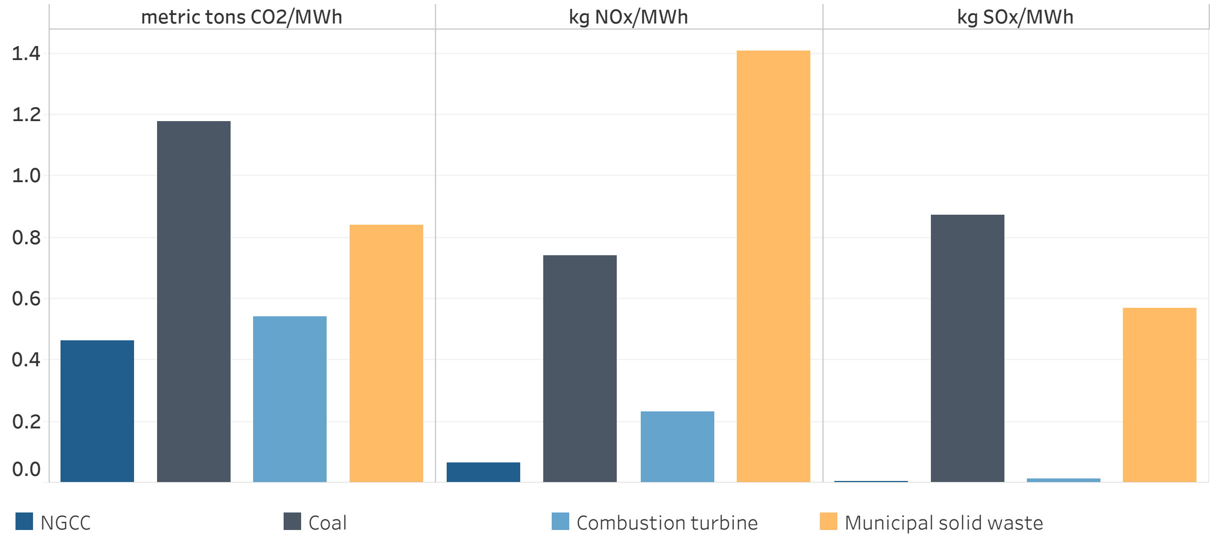


Figure 6.2: Rate of emissions per MWh of generation from NGCC, coal, gas simple cycle and municipal solid waste plants in New Jersey in 2015.

note that the emission factors for municipal solid waste are in line with estimates published elsewhere [109].

We omit low levels of emissions from petroleum liquids and petroleum coke, in part because of limited data for these fuels; gas steam plants, which are a small contributor to overall emissions; combined heat and power, for which we have minimal data; and landfill gas, for which we also do not have complete data. However, landfill gas emission factors can be relatively high, and it may be valuable to determine the relative emissions impacts of utilizing landfill gas for energy as compared to other methods of disposal.

These data show the high relative criteria pollutant emissions contributions of coal and municipal solid waste combustion, even though these sources provide a small fraction of New Jersey's total electricity. For example, coal plants supplied only 2.4% of all in-state generation in 2015, but a disproportionate share of criteria pollutants, including roughly 30% of NO_x and nearly all SO_2 reported. The municipal solid waste emission estimates also illustrate another reason to reconsider using this resource as a component of clean energy planning. Note that some coal plants also used petroleum fuels in 2015, and while we excluded the oil-burning units when possible, the coal emissions may still reflect multiple fuels used at coal plants.

In the Clean Energy Scenario, the criteria pollutant emissions shown here are expected to fall even more than carbon dioxide due to the elimination of coal and municipal solid waste fuels—and in fact, recent coal retirements have likely already reduced emissions from 2015 levels. The average emissions rate of natural gas plants may be affected by plant retirements, which would likely leave more efficient and lower polluting plants on the grid, as well as the relative ratio of operation of NGCC to simple cycle plants, which we have assumed to be constant in our Clean Energy Scenario. Assuming, however, that the rate of emissions from gas generation remains the same as in 2015 (and this rate is similar for the smaller plants for which we do not have data), we calculate that the Clean Energy Scenario in 2030 will reduce in-state NO_x emissions from natural gas, coal and municipal solid waste combustion for electricity generation by roughly 75% and nearly eliminate power sector SO_2 emissions in the state. The reduction of electricity imports from across PJM would also reduce criteria pollutant emissions in other states across the region.

Given that simple cycle gas plants have nearly four times the rate of NO_x emissions per MWh of generation as compared to NGCC plants, if the use of these plants is higher than assumed in our report, then the NO_x reductions will not be as great. Such a possibility may occur if these plants are needed to increase the flexibility of the grid at high penetrations of renewables, particularly in cases with low energy storage and poor grid integration across a large geographic area. Additionally, when natural gas power plants are turned on and off frequently, emissions may go up because plant emission rates are higher during start-up and ramping. Dispatch algorithms that minimize start-up and ramping, perhaps through employment of energy storage and demand response, can help reduce these emission impacts. It is also possible to reduce the use of simple cycle plants by focusing efficiency measures on peak electricity use periods, notably hot summer afternoons and evenings.

Our estimates of pollutant reductions do not include the emission benefits of electrification of HVAC and vehicles, which would further reduce health-harming criteria pollutant emissions in homes and on the road. Between 2030 and 2050, an additional benefit of electrification of these sectors will be the significant reduction or near-total elimination of criteria pollutants from these sectors.

6.2 Environmental justice and equity

Power plants tend to be disproportionately located in or near low-income and minority communities, many of which are burdened with numerous additional sources of pollution [103, 110, 111]. While the health impacts of power plant emissions extend over broad regions, up to hundreds of miles from the stack, studies show that living near power plants is associated with negative health outcomes like increased hospital visits, low birthweight births, and other health impacts [112, 113]. Certain populations, such as children and the elderly, may be particularly vulnerable to additional sources of pollution. Similarly, plants are often located in communities with low economic status and a cumulative burden of numerous environmental and socioeconomic factors, which has been found to make these populations particularly vulnerable to additional environmental stressors.

To identify any potential equity concerns in power plant location, we first investigate the locational distribution of New Jersey's existing large power plants with respect to the demographics of nearby communities—namely, we include plants regulated under the EPA's Clean Power Plan, including NGCC, coal, and fossil steam plants, as well as those recently retired. We analyzed demographic indicators for populations living within three miles of these power plants using data reported by the EPA in their environmental justice analysis for the Clean Power Plan [110]. While health impacts stretch far beyond this radius and are dependent on factors like wind direction, and some concerns may apply exclusively to populations living nearer to plants, this approach provides a screen to determine if there are patterns of inequality associated with where these plants are located. We consider both the fraction of low-income populations living near plants, defined by the EPA as the percentage of the population living at or below double the federal poverty limit, and the fraction minority population, defined by the EPA as the fraction of non-White people (as reported in census data).

In **Figure 6.3**, we plot the population number living within a 3-mile radius of each plant. Each axis represents the percentile minority or low-income population living within that radius, as compared to the rest of New Jersey; any score over 50 suggests that the population has a larger fraction of minority or low-income inhabitants than the median census tract in the state. As the figure illustrates, all but one of these plants are located in communities with lower incomes than the median (measured by the percent of households living below double the federal poverty line), and the majority are located in communities with a larger fraction of minority inhabitants than the median. If we sum all of the populations living near these power plants, we find that 59% are minority, as compared to a state average of 41%, and 35% are low-income, as compared to a state average of 21%. In **Figure 6.4**, we visualize these data along with a few additional demographic indicators, including linguistic isolation, less than a high school education, and populations under five and over 64. These data indicate some additional trends. For example, the communities living near power plants tend to be more linguistically isolated than others and have lower educational attainment. Both are factors that hamper community engagement. Enhancing and facilitating engagement is a critical component of strategies to achieve a clean energy transition. We also find that the recently retired plants (primarily coal) are located in communities with particularly high minority and low-income populations nearby, suggesting a positive trend but also an ongoing need to ensure that any remaining waste or contamination at these plants is properly mitigated.

Overall, these data could suggest that power plants were constructed in low-income and minority communities, or they could indicate that these communities tend to be more likely to move into a neighborhood near a power plant. Either way, a reduction in fossil fuel dependence under the Clean Energy Scenario has the potential to reduce these inequities in

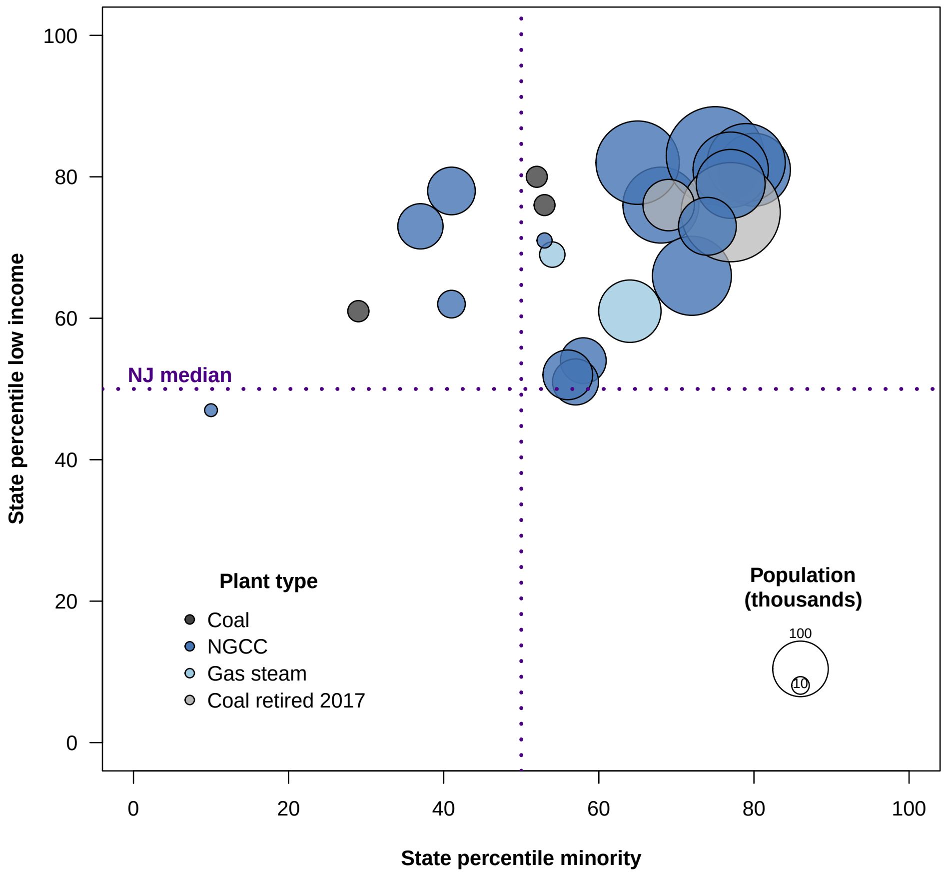


Figure 6.3: Demographics of populations living near large fossil fuel power plants in New Jersey. Bubble size represents population size living within three miles of each plant, and axes indicate the state percentile for low-income and minority inhabitants, as compared to the rest of New Jersey.

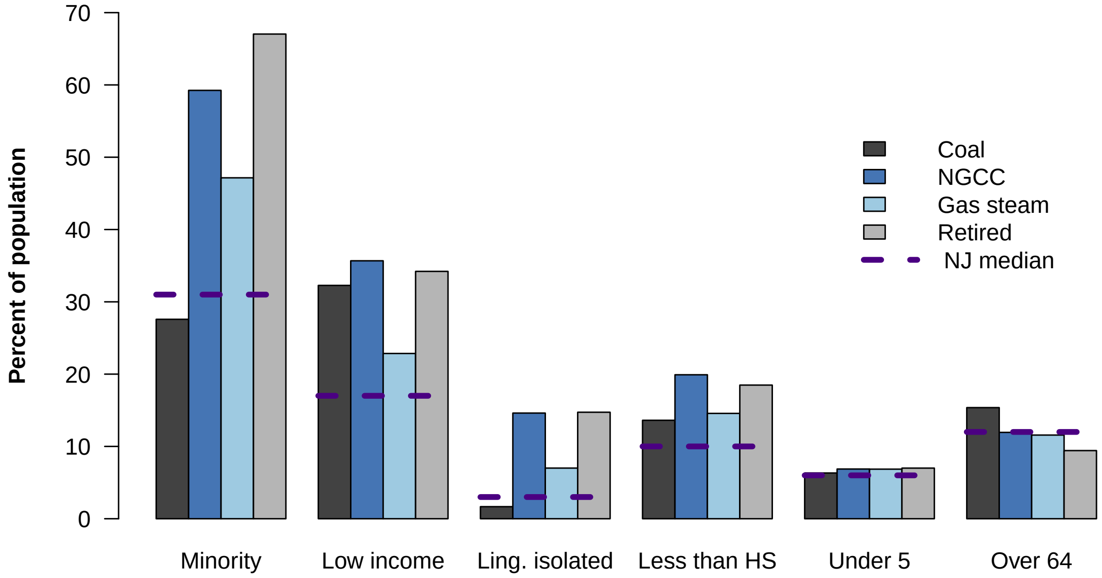


Figure 6.4: Demographic indicators for the total population in New Jersey living within three miles of each class of power plant.

power plant location. Specifically, policies could explicitly factor in environmental justice concerns when making decisions that affect which plants will operate and how much, as the proportion of wind and solar in the energy mix increases. Such an approach could include the modeling of plant operation under policy frameworks such as cap-and-trade, renewable portfolio standards, and other approaches, to determine the potential equity impacts. A full analysis would include additional air modeling of pollutant formation from these plants to determine which communities specifically may be affected. The disproportionate distribution of power plants in low income and minority communities highlights the need to both engage with these communities and consider equity when developing power sector policy.

Environmental justice and equity concerns from the power sector include not only impacts from existing fossil fuel infrastructure but also whether benefits from clean technologies like rooftop solar power are reaching otherwise disadvantaged populations. Siting a solar panel on a rooftop will not necessarily reduce local power plant emissions, although a coordinated effort to deploy solar, storage and other resources can be used to mitigate such emissions particularly in transmission-constrained locations. Moreover, ensuring access to clean resources such as efficiency and solar for low-income and other disadvantaged populations can help reduce electric bills and provide price stability, as well as empower these populations to have control over their energy resources.

To assess access to rooftop solar, we analyze the deployment of residential solar panels in relation to zip code income levels. This approach is imperfect, given that we do not have information about the income levels of individual households that adopt solar within each zip code and variations in income levels within zip codes. However, we can use this approach as a screen to determine whether rooftop solar access may have a relationship to neighborhood income levels. Solar installation data is reported on a zip code basis by the New Jersey Clean Energy Program, through June 2016 [27]. Median zip code income level is derived from the U.S. Census [114], and reported for zip code tabulation areas. In **Figure 6.5**, we divide zip codes into income quintiles based on median income, and report the average solar capacity per household located in these zip codes.

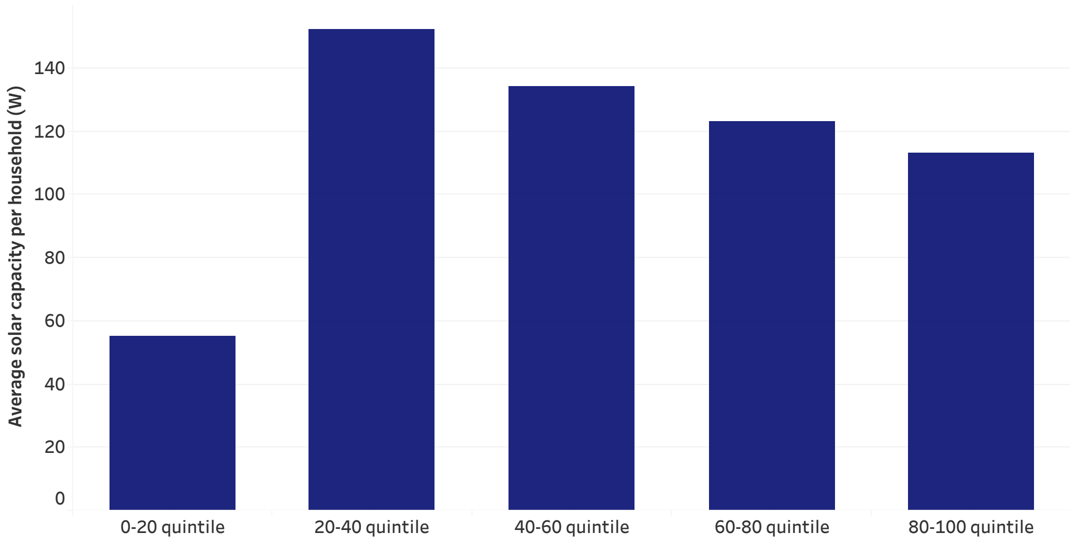


Figure 6.5: Average solar capacity per household, broken down into quintiles based on median income level of the zip code in which each household is located. Lowest income = 0-20 quintile.

The pattern looks similar for both total number of installations per quintile and per capita, rather than per household. The lowest-income quintile shows the lowest solar adoption rates, at roughly one solar installation for every 140 households, whereas the second-lowest quintile shows the highest solar adoption rates at one solar installation for every 53 households. Barriers to solar access in low-income households may include lack of access to capital, low rates of home ownership, inadequate opportunities for renters to access solar, and other challenges. The highest income quintile also shows lower solar adoption rates than the middle-income range, suggesting that additional barriers beyond income levels may be inhibiting solar growth. Opportunities to increase solar in low-income communities include community solar, remote net metering, single-family and multi-family affordable solar housing programs, property-assessed clean energy (PACE) financing, benefit-sharing between renters and landlords, and education, among other approaches. Opportunities to increase solar adoption in richer communities are less well studied.

To look at potential regional variations, which could impact solar adoption, we map residential solar capacity by zip code in **Figure 6.6**. Solar adoption per capita is much higher in the south of the state, which has a slightly better solar potential than the north, but is also much less populated. The map suggests that the cities and suburbs around New York are lagging at solar adoption. It may be worth exploring whether population density, rental rates, or other factors may be at play in these regions in order to increase solar adoption rates.

6.3 Methane

The emission targets outlined in this report have been based on direct combustion-related CO_2 emissions from burning fossil fuels, as reported by the EIA [11]and EPA [56]. However, the greenhouse gas emissions associated with the full lifecycle of energy production and use are higher than these direct emissions alone. Additional emissions may be associated with

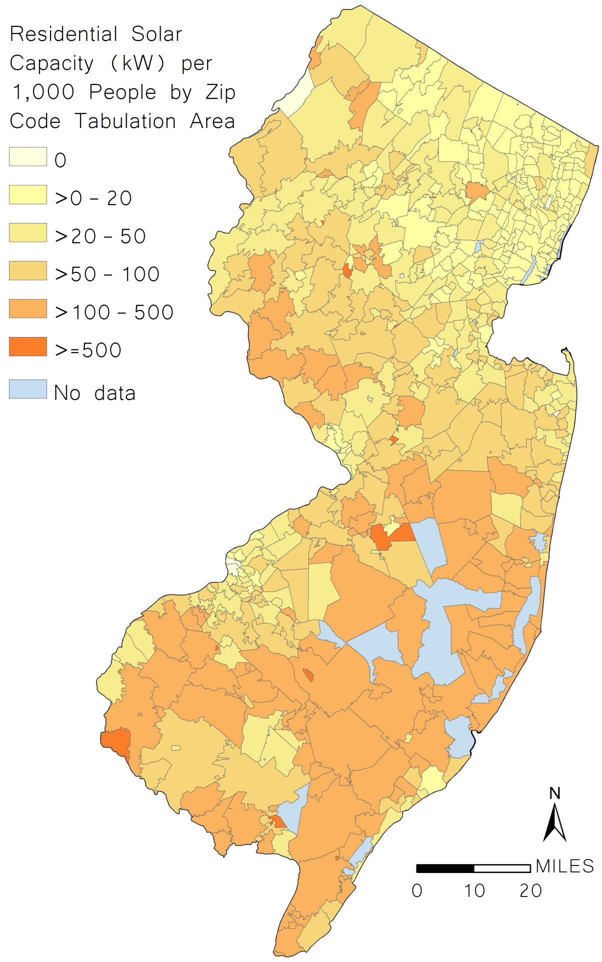


Figure 6.6: Distributed solar capacity per capita, New Jersey.

the production, processing, transmission and distribution of fossil fuels, as well as the construction and later decommissioning of both fossil fuel and renewable energy infrastructure [13, 24, 25, 115, 116]. While a full analysis of the lifecycle impacts of energy use is beyond our scope, we do analyze the impact of upstream methane emissions on our results.

Methane is a powerful greenhouse gas with a global warming potential (GWP) 36 times as powerful as CO_2 over 100 years and 86 times as powerful as CO_2 over 20 years. Methane is also the main component of natural gas [14]. Methane can leak out during the entire natural gas production cycle, from the wellhead through compression, transmission and distribution. As a result, the lifecycle greenhouse gas emissions of using natural gas for electricity generation may be much higher than the direct emissions reported above. Lower levels of emissions may also be associated with coal mining [23].

The actual rate of methane emissions across the natural gas life cycle is still highly uncertain, and may vary by means of production, from gas field to gas field, and even leak at different rates from individual components such as valves and pipes. The rate is also likely to have changed and continue to change based on the mixture of both conventional and unconventional gas production across the United States and the impact of new regulations meant to mitigate some methane emissions.[1]

[1]The EPA has recently passed regulations to minimize methane emissions from oil and gas production, but the enforcement of such regulations has faced challenges under the current Administration and may be somewhat difficult to enforce due to limitations in our understanding of underlying emission rates.

The EPA Greenhouse Gas Inventory estimates upstream methane leakage rates at very roughly 1.5% of production (slightly higher as a percent of end-use), although we note these estimates have fluctuated with each year's inventory [12]. The EPA produces a bottom-up leakage rate based on estimated emission factors from individual components and processes across the natural gas system. However, many field studies which measure atmospheric concentration of methane above individual production fields have resulted in much higher leakage estimates, including 8.9% over Utah's Uintah Basin [25]; 9.1-10.1% over the oil-producing Eagle Ford and Bakken Fields [115]; 4.1% in Colorado [116]; and other varying estimates in numerous other studies. Many of these studies exhibit very wide uncertainty ranges. Brandt et al. (2014) synthesized numerous studies across many fields and processes and estimated an upper limit of more than 5% leakage on an end-use basis [13].

Here, we do not attempt to estimate the nationwide methane emission rate. Instead, we look at the impact of a range of methane leakage rates on emission reductions. This comparison is meant to be illustrative and not to preclude the possibility that methane leakage rates are at some value higher or lower than examined here. Instead, we assess the impact of 1.5%, 3.5% and 5.5% upstream methane leakage rates on our emission targets. We calculate the CO_2-equivalent (CO_2e) value of this methane using a 20-year global warming potential of 86. We choose the 20-year value rather than the 100-year value due to concerns about rapid near-term warming, particularly for a coastal state such as New Jersey which is particularly vulnerable to sea level change and weather extremes. We assume the leakage rate stays constant through the years in each case, although these values may change over time as noted. Furthermore, we only compare 2015 emissions to 2030 due to even higher unknowns associated with leakage rates in 2006. We also increase coal emissions by roughly 7% CO_2e to reflect the median estimated increase in emissions from coalbed methane in a meta-analysis of 53 studies [23], after correcting this value to reflect a methane GWP of 86.

To calculate the $CO_2$2e value of methane emissions at each leakage rate, we assume that natural gas plants operate at the reported 2015 national average heat rate of 7,898 Btu/kWh, use a higher heating value for methane of 1010 Btu/cf and assume that the methane fraction of natural gas is 95%. In **6.7** we show the impact of upstream methane leakage rates of 1.5%, 3.5%, and 5.5% of natural gas end use on the 2015 and 2030 Clean Energy Scenario and business-as-usual CO_2e emissions, inclusive of coalbed methane emissions in all leakage scenarios and using a GWP of 86. At 1.5% leakage, Clean Energy Scenario methane emissions in 2030 are 48% lower than 2015 due to reductions in gas use—but total emissions are nearly 50% higher than without any fugitive methane emissions. As leakage rates increase, the 2030 Clean Energy Scenario emission fraction compared to 2015 decreases somewhat more, while the lifecycle greenhouse gas emissions increase. The fact that New Jersey relies heavily on natural gas today means that the emission reductions target as a fraction of 2015 emissions is not greatly changed when considering different methane leakage rates. More importantly, the total greenhouse gas emissions increase significantly when considering fugitive methane leaks. If natural gas continues to expand in New Jersey, as assumed in the business-as-usual scenario or in the case of nuclear power plant retirements without contingency planning, lifecycle greenhouse gas impacts will grow accordingly.

The high impact of even relatively low methane leakage rates on total greenhouse gas emissions emphasizes the need to continue to shift away from natural gas. While the leakage rates are uncertain—and indeed may even be outside the range of values shown here—the significant impact of high leakage rates on emission totals highlights the great risk of relying on natural gas to achieve climate benefits. This figure further illustrates the need to convert systems currently dependent on coal or oil, including transportation and home heating, di-

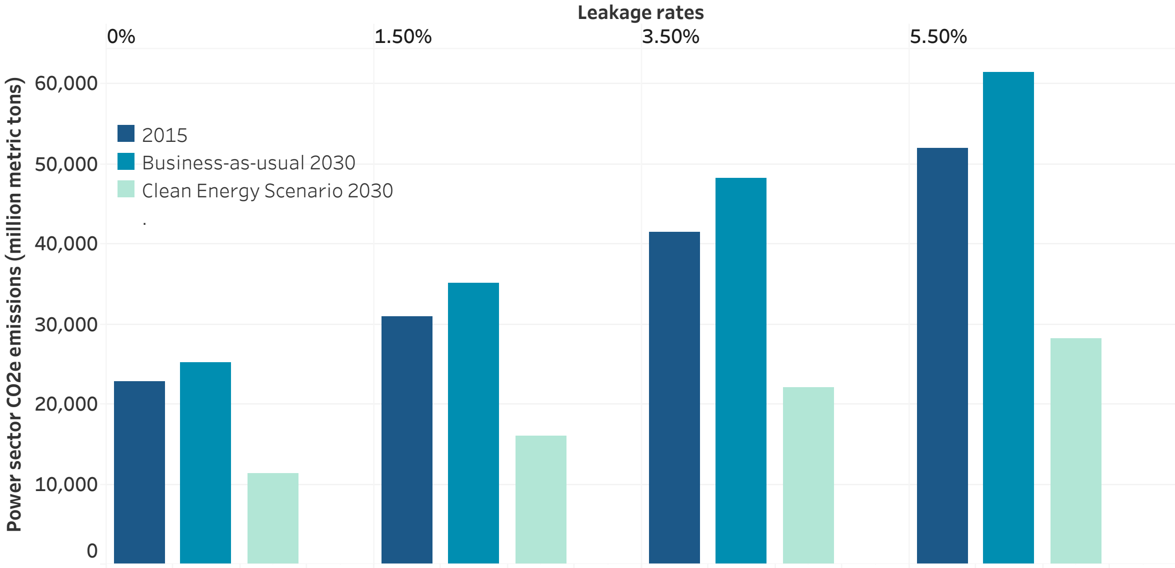


Figure 6.7: Impact of 1.5%, 3.5% and 5.5% upstream methane leakage rates on New Jersey's power sector emissions in 2015 and 2030 using a GWP of 86 for methane and incorporating coalbed methane emissions for coal use in 2015.

rectly to renewable-powered electric systems rather than switching these systems to running off of natural gas as a transitional fuel.

7. Policy discussion

Our mandate in this study was to consider technical and economic components of a clean energy pathway for New Jersey and lay out options in a way that would make their policy implications clear. Below, we elaborate on some of these options, which are either implicit or explicit in the technical and economic analysis in this report. We also discuss opportunities for future research.

7.1 Areas of policy consideration

7.1.1 Efficiency

Our analysis has shown that rapidly ramping up efficiency from the present estimated 0.6% per year to 2% per year is critical to achieving an economic outcome in which the cost of carbon emission reductions remains low. The approximate cost parity between business-as-usual and the Clean Energy Scenario can be achieved even though the latter relies on some higher-cost generation sources. We have chosen these resources in part for their external benefits:

1. Investment in higher-cost offshore wind can help develop the economy, create local jobs, and make New Jersey a national leader in the industry;
2. A larger proportion of more expensive distributed solar than in other states, as compared to imported or in-state utility-scale solar, provides opportunities for increased equity, environmental justice and grid resilience along with reduced land-use impacts.

The result of these energy resource choices, however, is that generation alone in the Clean Energy Scenario is more expensive than in the business-as-usual scenario. Efficiency investments ensure that the total costs of energy services in these scenarios are about the same—within the limits of uncertainty of the analysis here. Not only does efficiency reduce the need for generation, it also avoids a number of other costs associated with delivering those electrons to the final consumers, including components of transmission and distribution, as well as some other charges that are levied on consumers on the basis of electricity consumed. These combined avoided costs are central to the positive economic result.

The magnitude of efficiency savings and the speed with which New Jersey achieves these savings is a policy choice that New Jersey must make. We chose a target of 2% per year reduction in load because it has precedent in other states, the costs are modest, and the benefits large. For instance, in 2017 Maryland adopted a target of 2% efficiency gains per year legislatively, with the specific programs to be designed by the Public Service Commission as part of its normal business—that is, in collaboration with utilities and with input from the public, government agencies, ratepayer representatives, etc. Maryland's program would ramp up to 2% by increasing by 0.2% per year [117]. Rhode Island has an even more ambitious program: 2012–2014 targets of 1.7% per year and a ramp up to 2.5–2.6% per year for the 2015–2017 period [118].

We considered a range of targets for efficiency from 1.5 to 2.5% per year (relative to no efficiency program) to be the achievable range in which our analysis yields a low estimated cost of overall carbon reductions. We chose 2%, which is in the middle of that range. New Jersey's current savings of just 0.6% per year is significantly below the more ambitious states and could probably be ramped up quickly. We chose a ramp up from 0.6% in 2017 to 2% in 2022. Indeed, given the relatively modest resources that have been devoted to efficiency compared to the potential benefits, a more ambitious choice such as 2.5% per year might be considered. Specifically, it may be valuable to consider such an increased efficiency target as one component of a clean energy resource portfolio that could help prepare for premature shutdown of the Salem or Hope Creek nuclear plants without impacting cumulative carbon emissions. This increased target would be a complement to the option of importing of wind and utility-scale solar and increasing in-state offshore wind, which we have already discussed. Furthermore, additional efficiency efforts targeted specifically at reducing peak demand can help bring down capacity requirements and associated costs.

The distributional aspects of efficiency are also critical. As we have seen, households that do not implement efficiency may see rising electricity bills since the generation costs per MWh in the Clean Energy Scenario are estimated to be higher than business as usual. This disparity in bills could be a particular risk for very low-income households who rent their homes, have high bills, and little control over efficiency investments. Thus, a focus on verifiable achievement of efficiency in low-income households is an important consideration for equity.

New Jersey's ratepayers in general would also benefit from improvement of efficiency in low-income households. New Jersey's energy assistance program limits the electricity and gas bills of low-income households to 6% of income (with a cap on assistance of $1,800 per year), meaning that when the bills of those receiving assistance are reduced, non-low-income ratepayers also benefit because the amount of assistance needed declines. By the same token, a lack of vigorous efficiency implementation in low-income households could result in increases in assistance requirements, which would also impact the bills of non-low-income households.

7.1.2 Utility-scale and distributed solar

While New Jersey's technical solar potential is high, particularly in rural areas, we have relied more heavily on distributed solar growth in the Clean Energy Scenario with only modest growth of utility-scale installations. We have implicitly assumed that most of the rural areas which could technically be used for utility-scale solar will not be significantly developed. The total amount of New Jersey solar utilized is a small fraction of New Jersey's technical potential for utility-scale solar and roughly 19% of available rooftop capacity [40, 41], although this latter category will be smaller when accounting for ground-mounted distributed systems. Co-benefits of this distributed solar emphasis include opportunities for greater resilience, energy equity, and environmental justice, as well as reduced land-use impacts from utility-scale installations. The development of solar on brownfields, landfills, and urban impacted areas can also help minimize land-use impacts. As a trade-off, the ap-

Table 7.1: Cost evolution of New Jersey's RPS for Class I and II RECs and SRECs. The alternative compliance payment (ACP) is the amount to be paid for a REC if a utility does not acquire the required solar credits on the market, effectively putting a cap on REC prices [120].

	2011	2012	2013	2014	2015	2016
Class I RPS requirement	5.49%	6.32%	7.14%	7.98%	8.81%	9.65%
Dollar value of Class I RECs + ACPs ($million)	$10.6	$20.1	$37.7	$41.7	$83.5	$108.5
Class II RPS requirement	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Dollar value of Class II RECs + ACPs ($million)	$2.4	$2.6	$5.2	$5.5	$8.4	$9.8
Solar RPS requirement	MWh (SREC) specification			2.05%	2.45%	2.75%
SREC obligation (GWh)	306	442	596	1,569	1,847	2,040
Dollar value of SRECs + ACPs ($million)	$185	$126	$107	$276	$356	$460
Total REC and SREC payments ($million)	$198	$149	$150	$323	$448	$579
Percent of incentive payments for SRECs	93.4%	84.7%	71.4%	85.4%	79.5%	79.6%

proach used here implies a slightly higher generation cost than expanding rural utility-scale development elsewhere in PJM.

However, as demonstrated by the low adoption rates of solar in low-income communities shown in **Figure 6.5**, the equity benefits of distributed solar are not guaranteed without careful planning to overcome barriers to access to solar. Realizing the benefits and opportunities of distributed solar and distributed storage will of course require close collaboration between communities, the Board of Public Utilities, the distribution utilities in New Jersey, the Rate Counsel, and others. For instance, the targeted siting of solar installations on a significant scale, along with distributed storage, could be used to reduce gas turbine generation, eliminate diesel generator use, and provide increased resilience in vulnerable communities. Such technical and policy considerations, while beyond the scope of this report, could be principal elements of the detailed design of a clean energy pathway, should New Jersey decide to implement it.

7.1.3 Financing renewables: RECs, SRECs, rebates and PPAs

To date, New Jersey has primarily relied on Solar Renewable Energy Credits (SRECs) given to in-state solar installations to drive solar development. The relatively high prices of SRECs have been very instrumental in the rapid growth of solar electricity generation in the state, which had the fourth-highest total solar generation of any state in 2016 [26]. The other side of that coin has been that the cost of SRECs is now so high that it is a not insignificant part of the overall cost of electricity in New Jersey, and the incentive per MWh is higher than in most other states if they have an incentive at all [119].

The cost evolution of New Jersey's Renewable Portfolio Standard for RECs (Class I and II) and SRECs is shows in **Table 7.1** [120].

The SREC payments comprise the large majority of expenses for New Jersey's RPS implementation; in 2016, the cost amounted to about $6 per MWh of total electricity sales.

On the other hand, New Jersey's SRECs have actually promoted development of renewable energy within the state. The other REC purchases are expenditures for purchases of RECs that are disconnected ("unbundled") from the renewable energy generation itself. In the 2015–2016 reporting year, only 15% of non-solar RECs represented generation in-state, and three-fourths of that in-state generation came from burning municipal solid waste [32].

In light of these considerations, we have assumed that New Jersey will acquire offshore wind energy through a competitive procurement process similar to a Purchase Power Agreement. It would acquire the RECs associated with the offshore wind generation as part of the procurement. We have also assumed that imports of onshore wind and utility-scale solar in the nuclear contingency cases would be made by Purchase Power Agreements, probably Virtual PPAs, which would come bundled with their own RECs—a potentially significant financial advantage.

So far as solar energy is concerned, reliance on SRECs for the proposed scale of solar development in 2018 and beyond would involve costs considerably above those we have modeled if SREC prices remain above $200 per MWh as seen in recent years [119]. The maximum compliance payments for SRECs remain at or above $250/MWh until 2027; they would fall to $239 in 2028 [31].[1]

Given recent solar energy cost declines and existing net-metering policy for behind-the-meter systems and the current federal tax incentive of 30% for all systems, additional large solar incentives no longer appear to be needed. Large utility-scale systems (∼100 MW) have declined in cost to less than $1 per watt in some places.[2] The federal incentive will decline slowly to 22% in 2021; it expires at the end of that year, although it would be available for projects started by then. For commercial and utility-scale projects, a 10% tax credit will remain indefinitely, as per the current law. In addition, these two sectors receive a significant benefit from accelerated depreciation.[3]

At current costs, there does not appear to be a need for additional rebates and incentives for utility-scale solar. Continued net metering for behind-the-meter systems in combination with the federal tax incentive would, in principle, provide sufficient economic justification for distributed solar.[4] But New Jersey may want to ensure specific amounts of distributed solar are added to achieve its renewable energy, resilience and equity goals. The incentives for that can be structured in various ways.

[1] We assume that RECs and SRECs up to 2017 would be grandfathered in—that assumption is part of our cost estimation process of separating generation costs from all other costs in the business-as-usual scenario. The projection for all other costs contains, among other things, the costs of complying with New Jersey's RPS. This includes the costs of the RECs and SRECs detailed above. The business-as-usual projection includes these costs as well. Our approach to cost estimation therefore essentially grandfathers in the business-as-usual RPS compliance costs. As mentioned briefly, the acquisition of solar and wind by PPA in the Clean Energy Scenario may present opportunities to reduce those costs. We have not factored that into our estimates for the Clean Energy Scenario.

[2] A caveat is in order at the time of writing. The cost of solar panels could rise significantly if the federal government imposes tariffs on imported panels pursuant to a trade complaint before the International Trade Commission [121].

[3] Depreciation allows a business to recover the cost of its investment in equipment and property over time. Accelerated depreciation allows faster recovery than the normal expected life of the equipment. Depreciation is a business cost and is deducted from taxable income. Accelerated depreciation therefore allows early cost recovery through lower tax liability in the years immediately after the equipment is purchased. In tax terminology, accelerated depreciation is formally known as "Modified Accelerated Cost Recovery System." See [122].

[4] This assumes that distributed solar costs decline as estimated in the medium cost case in the 2017 NREL Technology Cost Baseline [18]; these cost declines offset the reductions in the federal tax incentive (down to zero in the case of residential systems by the end of 2021).

For example, New Jersey could adopt the model of a direct rebate on a $/watt basis. A version of this approach is working well in New York State. It is called the "Megawatt Block" incentive [123]. It has high rebates for initial applicants, with the amounts declining for subsequent blocks of solar. The rebates are established for three categories: "Residential," "Small Commercial," and "Commercial and Industrial." These rebates also vary by region, since electricity prices across New York State vary much more than is typical for most states. For instance, the first 14 MW block of residential solar in the New York City area (Served by Con Edison) has a rebate of $1 per watt; the seventh block, which is partially subscribed as of this writing, is much larger at 45 MW but has a rebate of $0.40/watt. The eighth and ninth blocks are 70 MW and 120 MW, with rebates of $0.30/watt and $0.20/watt respectively. The rebates for commercial and industrial systems are much smaller. Once the blocks of capacity for which rebates are available are accounted for, no more rebates would be available, under the present program design.

A similar program has been proposed for New Jersey by the Mid-Atlantic Solar Energy Industries Association (MSEIA) [124]. There is, however, one significant difference between the New York program and the MSEIA proposal. The New York program aims to [123]:

> "...eliminate cash incentives in a reasonable timeframe, and allow for the elimination of those incentives sooner in regions where market conditions can support it, based on market penetration, demand, and payback."

The MSEIA paper proposes to start the rebates at an average of $0.537/watt, 50% higher than New York's established program. The rebates would decline gradually but still be rather high at about $0.30 per watt in 2030 [124]. MSEIA estimates the present value of its rebate program at $1.11 billion compared to a cost of between $6.01 billion and $7.65 billion for an SREC program.[5]

A rebate program along the lines of the New York Megawatt Block design is clearly more economical than continuing SRECs for new residential and commercial construction. We estimated the cost of a rebate programs beginning at $0.537 per watt (average for residential and commercial) in 2018, declining by $0.015 and $0.02 per watt in 2019 and 2020 respectively and then going smoothly to zero by 2030. The results are shown in **Figure 7.1**.

The initial cost of the rebates shown in **Figure 7.1** would be $166 million in the first year, declining gradually to zero in 2030.

Another advantage of a direct rebate is that the purchaser and vendor have certainty about the price. Marketable SRECs can cause continued large expenses not justified by market conditions within a few years (or less) after the installation; on the other hand, a collapse of prices, as has occurred in Maryland, can be very disruptive.

Feed-in tariffs are another option that provide market certainty and are therefore likely to be accompanied by lower financing costs (other things being equal).

In sum, SRECs have been successful in making New Jersey a leader in solar capacity. However, the decline in prices of solar and the scale of solar energy deployment required in the Clean Energy Scenario would create a significant impact on the cost of CO_2 emission reductions. Alternative policies would reduce costs, while providing financial certainty. Policies

[5] The $0.537 starting value is an average rebate; in practice, rebates for each consuming sector would be established. Rebates per watt are higher for smaller systems.

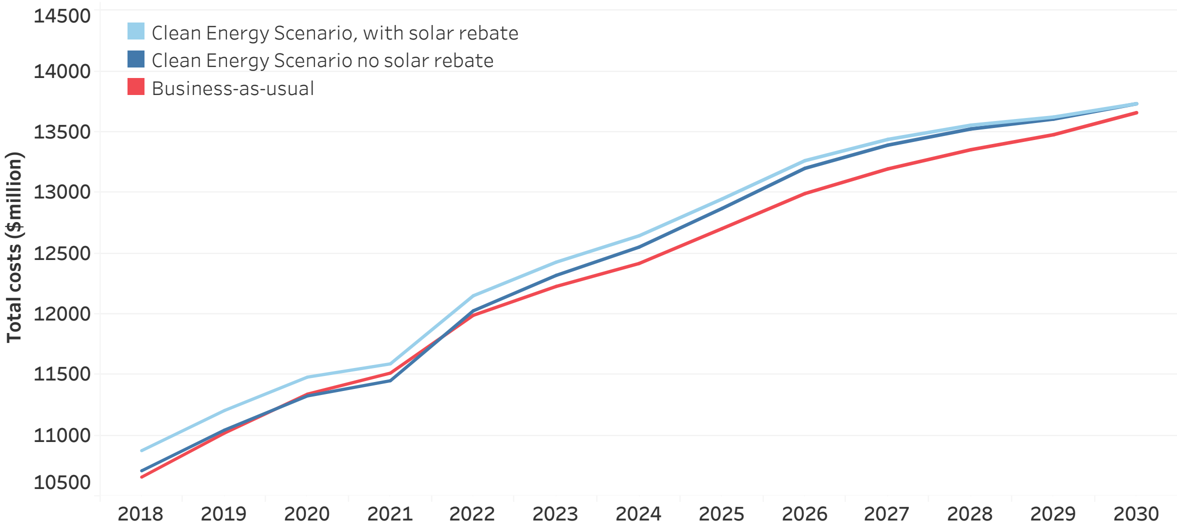


Figure 7.1: Total costs of the Clean Energy Scenario with and without solar rebates, in undiscounted 2016 dollars.

that are flexible enough to be adjusted annually may be especially suited to conditions in which solar technology (and battery technology) costs are changing rapidly. More flexibility would also be useful as New Jersey makes investments in grid modernization, since incentives for solar could be coupled with other goals and technologies as conditions evolve without carry-over of liabilities from past installations.

7.1.4 Fossil generation: stranded assets, emissions, environmental justice

Rapid increases in solar and wind capacity would mean a reduction in sales of fossil fuel energy in the PJM grid. The zero fuel-cost of solar and wind resources could also create conditions in which the value of conventional resources, which have fuel costs and often higher operations and maintenance expenses, would fall.

The decline in the value of merchant generating assets is not a concern for ratepayers. These assets were spun off from vertically integrated utilities when the various states in the PJM region deregulated generation, but kept distribution within the regulated arena. A decline in capacity due to uneconomical generating plants would only occur in a manner that is compatible with reliability, which is the responsibility of the Regional Transmission Operator, PJM. In other words, PJM ensures that enough capacity is available; it has the regulatory instruments to be able to increase payments to ensure that sufficient generating capacity is available to meet demand at all time of the year. In addition, like all grid operators, PJM requires sufficient reserve capacity above the expected peak demand to ensure reliability. As of 2017, the reserve capacity in PJM (28.4%) far exceeds the federal required reserve capacity (16.6%) [99]. However, with significant retirements, capacity prices could increase.

A central concern regarding which power plants will operate and which ones will not relates to environmental justice. Fossil fuel plants are disproportionately located in minority and low-income communities, as we have seen in **Chapter 6**. If these plants continue to operate while others shut down, the impact will become even more skewed. Specific policies will be needed to ensure that fossil fuel emissions are reduced in low-income and minority communities to redress historical imbalances.

A second concern is that the closure of fossil fuel plants could cause significant economic dislocation in the communities where they are located. The impact on workers and communities of an early shutdown of the Hope Creek and/or Salem nuclear plants is also a concern. Fees and taxes that power plants pay are used for essential services like fire departments and schools and amenities like parks. In addition, when the plants are in small communities, unemployment can create disruption on an even more significant scale.

Preventing harm to workers and communities before it occurs to the extent possible is an important arena for energy policy, given the magnitude of the energy transition. A detailed evaluation of this issue is beyond the scope of the present report. But it is important to note in the context of comparing business as usual with the Clean Energy Scenario that the marginal costs of protecting workers and communities in the transition to a climate-safe energy system should be included in the cost of the latter scenario. We have included costs as follows:

1. $20 million per year to replace property, sales and income taxes paid by the plants and the employees to the local and state governments.[6] This amount was added only to the early nuclear retirement scenarios.
2. $40 million per year for communities hosting fossil fuel plants that would shut down, for all scenarios other than business as usual.[7]

These are annual revenues that would need to be generated to support these communities in the event of plant closure. They are rough numbers meant to indicate that (i) a provision for protection of communities and workers must be made in the transition and (ii) it should be included in the cost of the transition.

7.1.5 Carbon regulations: RGGI and CO_2 taxes

We have not addressed the issues of New Jersey re-joining the Regional Greenhouse Gas Initiative or the issue of a CO_2 tax in this report. It is worthwhile to mention these in the context of the energy transition, since one or both of them could be a source of revenue for the energy transition and in particular for supporting communities and workers negatively affected by the transition. The Labor Network for Sustainability and the Institute for Energy and Environmental Research proposed a modest carbon tax as one way to raise significant revenues for supporting communities and workers and also supporting low-income households during the energy transition [126].[8] New Jersey's Societal Benefits Charge could also be used to meet some of the transition costs.

[6] Estimated from Nuclear Energy Institute 2006 as follows: According to this study of the impact of the two nuclear plants (which are located close to one another in Lower Alloways Creek Township) one paid $1.2 million in local property taxes and another $7.1 million in state and local taxes in 2004. The total tax payments including income taxes paid by employees were $25.9 million, which amounts to about $32.4 million in 2016 dollars. A significant number of employees would be expected to remain; the proportion would depend on the schedule for decommissioning activities. We have used $20 million (2016 dollars) as an approximate initial estimate to replace all state and local taxes plus some state income taxes [125].

[7] New Jersey's fossil fuel capacity was about double that of the Salem and Hope Creek nuclear plants combined. Using the same per megawatt estimation process compared to nuclear, the annual taxes would be $65 million. Assuming half the capacity is affected (based on 50% CO_2 emission reductions), we get an estimate of $32.5 million, which we have rounded up to $40 million per year. However, we do not necessarily expect this level of retirement, in part because some plants may stay online to meet capacity needs.

[8] INote that the carbon tax proposed is quite small (relative to many other proposals)—about $20 per metric tons of CO_2. The proposal suggested creating jobs preemptively in communities that are likely to be affected so that the need for support would decline over time, along with the tax.

We also note here that our calculations about the price of a ZEC, based on the New York State approach, includes a deduction of the price of a RGGI allowance from that price. Thus, if New Jersey does not rejoin RGGI, some proxy for the price of a RGGI allowance would have to be factored into the calculation of the ZEC price. If it is not, the price of a ZEC, and thus the total payments would be higher than estimated in this report, all other things being equal.

7.1.6 Integration with PJM

We have modelled New Jersey as an electrical unit in itself for the purposes of this study. New Jersey is part of the PJM grid, so in practice the routine purchase and sale of electricity from and to the rest of the PJM grid (and beyond in the Eastern Interconnect) will affect the economics. As noted, they will also affect the distribution of benefits and costs.

On the one hand, purchase and sale of electricity into the wider market would likely make the overall cost lower than estimated here.However, there could also be negative repercussions, especially if New Jersey continues to generate fossil fuel electricity above its requirements and becomes an exporter of electricity (unlike its historical record of being a net importer). Specific complementary policies to promote environmental justice will be needed. We have not examined the cost implications of such policies in this report.

Furthermore, the level of renewable energy penetration within the rest of PJM may affect costs and scenario outcomes. Higher levels of renewables across this region may require larger transmission or energy storage investments than if New Jersey's neighbors lag in renewable energy adoption.

PJM markets will affect Virtual PPA transactions, since the developer of the renewable energy would sell into the grid at market prices. PJM prices also affect the viability of continued nuclear plant operation; therefore the PJM market could also affect the amount of above-market payments that nuclear plant operators may request to continue operation.

7.1.7 The path to 2050

The year 2030, with a 40% emission reduction target, is only a convenient way station in preparing the state for deep decarbonization in the following two decades. Our decision to include EVs and fossil fuel heating conversions in the year 2030 was made with that objective. We do not detail the cross-sector efficiency and fuel economy efforts that will nevertheless be necessary to achieve 40% greenhouse gas emission reductions from 2006 levels in 2030.We also have not covered the complementary transitions to a smart grid or the transformation of the transportation infrastructure that will be needed. All of these efforts will require additional study and planning in the near term in order to ensure a sufficiently rapid transition.

We have sketched out the generation requirements for an energy sector that would reduce emissions by 90% or more by 2050. One feature of note, of course, is that generation requirements will roughly double by 2050 despite efficiency improvements. The new load will come mainly from electric transportation and conversion of heating from fossil fuels to efficient electric systems. A coordinated strategy for a transition would mean a much bigger electricity sector as those conversions proceed, requiring even more rapid deployment of renewables post-2030. By the same token, the demand for fossil fuels and associated infrastructure will decline. The need to support communities and workers in that transition will correspondingly increase. It will be important to test the policies and programs to meet those needs in the coming decade when they are still small relative to the transition in the 2030-2050 period.

7.1.8 Price volatility

Our analysis, like many others, indicates a very substantial hedging value (in financial terms) of increasing the proportion of electricity supplied by sources that have no fuel costs and low or no variable operation costs. We calculated the total cost in a high natural gas price scenario, but not the actual hedging value, which requires accurate estimates of the probability of higher prices. We note here that a potential avenue for raising resources for the energy transition might be to estimate that hedging value and explore how that it could be monetized.

7.1.9 Nuclear ZECs

If early nuclear retirements are proposed, New Jersey may choose to support these plants with ZECs or alternatively import wind and solar energy to replace the nuclear generation and maintain greenhouse gas emission reductions.[9] We have used the New York State Public Service Commission formula for calculating the price of ZECs. New Jersey would of course have its own evaluation of the appropriate formula and the various factors in it. They include the proper PJM price above which the ZEC price would be reduced, the specific social cost of carbon to be used (since it varies according to the discount rate used, among other things [1]), and the proxy for a RGGI allowance in case New Jersey does not rejoin RGGI. There are risks associated with ZECs; there would also be risks specific to the formula adopted. As noted, there are risks with Virtual PPAs as well. Thus a comparison of the risks will involve policy decisions regarding ZECs, in addition to research.

The choice to pursue ZECs or imports should be considered in the context of post-2030 costs as well, in particular with regard to the costs needed to replace nuclear generation at some future retirement date. Specifically, it may prove beneficial in that context to invest now in renewable energy build-out in lieu of making above-market payments for nuclear; such investments would limit the need for similar investments post-2030 and create early additional carbon emission reduction benefits.

7.2 Recommendations for future study

Our research here has highlighted the need for additional future studies on various topics to help ensure a rapid, equitable, and healthy transition. Some of these research needs are as follows.

[9] There is also the possibility of significantly increasing in-state renewable energy. Other than an increase of about 500 MW offshore wind, we have not examined this option, for reasons explained in **Chapter 3**.

Solar land use. While New Jersey technically has sufficient area to deploy significant amounts of ground-mounted solar, it is not clear where the best locations may be based on land use constraints and environmental impacts. The state, as well as individual counties or municipalities, may help accelerate solar adoption by identifying acceptable locations for solar deployment. These plots may be rural or urban and may allow for a range of solar installation sizes. A first step may be the identification of additional brownfields or other degraded lands in addition to landfills that do not have a higher level of use, where solar deployment may have the lowest level of impact, and where brownfield remediation may have some environmental health co-benefits. The analysis of additional sites should reflect sensitive environmental areas for flora and fauna, agricultural considerations, and other land use demands. Finally, the analysis of urban plots can be done in consideration of where solar siting could perhaps be used to provide community solar for populations that might not otherwise have access, such as low-income, renter, or dense urban communities.

Reliability needs under nuclear retirement contingency. Our analysis addressed the renewable energy growth that would be needed to achieve emission targets in the case of large nuclear power retirement, but we did not model whether these plants are needed locally for reliability reasons. Additional study would allow for the determination of how much local capacity is needed, and can guide the deployment of clean technologies like distributed solar and storage to help meet these local reliability needs if possible. There may be additional reliability concerns even in the case where nuclear power plants stay online if natural gas plants retire, which would merit analysis on a case-by-case basis.

Comparative risk assessment related to nuclear retirement. The two approaches that we have outlined to keeping the 50% carbon emission reduction goal in the case of nuclear plant owners' demand for above-market payments have their own financial risks. The price of the VPPAs and that of ZECs needs policy direction in the specific New Jersey context as well as further research. The issues would need to include both the period before 2030 and the period after it, when the licenses of the Salem and Hope Creek reactors are due to expire. New Jersey may also want to expand this list of options to include efficiency above the 2% per year considered in this report, for instance.

Energy efficiency market assessment and resource potential. Assessing the efficiency resource potential in New Jersey as well as analyzing in detail the various energy end-use savings options and total resource benefit/cost ratio is a prerequisite to an aggressive ramp up of annual efficiency savings from 0.6 to 2%. There is a need to review and update the 2012 EnerNOC Market Potential Assessment in order to: (i) estimate the availability of new technologies and update the study's end-use energy cost estimates; (ii) establish energy savings objectives and benchmarks for the New Jersey efficiency program administrator as well as develop a recommended level of funding and paths for procuring it; and (iii) include a detailed market potential study with a cost-benefit analysis of the various efficiency options as well as a thorough investigation of the barriers to implementing efficiency in the state.

Environmental justice. Our initial screen of power plant locations found that New Jersey's fossil-fired power plants are overwhelmingly located in urban low-income and minority communities. As such, there will likely be additional need to assess the impact of various policies that might affect power plant operation in these communities. For instance, cap-and-trade implementation should not increase burdens on any communities. These analyses can be coupled with air quality modeling, both in-state and of plants outside the state in the case of any multi-state carbon mitigation strategies such as rejoining RGGI. Constraining the operation of certain plants should be studied as one of the possible options, within the reliability constraints of PJM. The provisions we have made for battery peaking plants could also be examined for reducing pollution in disproportionately impacted communities.

Marginal emission impacts. We calculated our emission reductions using an average emission reduction approach—we simply assumed that after coal and oil-fired plants retire, natural gas plants would continue to operate with the same average emission rate as before. However, the integration of new resources may actually affect which plants and types of plants operate, and therefore could displace plants with higher or lower levels of emissions of both CO2 and health-harming co-pollutants. Hourly modeling would help identify which hours have the highest marginal emission impacts, and therefore which technologies (e.g. solar facing south or west) or which dispatch approaches (e.g. for demand response or energy storage) will have the greatest emission benefit. The marginal grid emissions are likely to change significantly by 2030, which would require continuous refinement of these marginal emission calculations.

Peak demand reduction. We provided some initial discussion of peak demand, including the benefits of efficiency, storage and solar towards reducing peak electric demand. However, a detailed analysis of the potential peak demand reduction across the state, including specifically from storage, efficiency, and demand response, would allow the state to craft policies that would bring grid stability and cost savings even in cases without significant renewable energy penetration.

Grid modernization and resilience. Our analysis here includes microgrid energy storage and significant distributed solar which can both play roles in increasing grid resilience. However, much additional research is required to help New Jersey transition its grid to a more resilient power supply. Such analysis would require both analyzing how grid modernization, including smart grid technology, can help reduce outage time, as well as how to encourage energy storage and microgrid growth so that these technologies both help integrate growing renewables and also provide backup at schools, hospitals and other critical facilities. Finally, it may merit analysis to determine how policies such as permitting and encouraging rooftop solar systems to island—that is, to operate even if the grid goes down—would minimize the impact of widespread outages after extreme weather events.

Market impacts. We analyzed the impact of energy production costs on total power sector costs, but did not analyze the specific market impacts of a changing energy portfolio. Increased supply of renewables may actually decrease wholesale generation costs because renewables typically bid into the market at the lowest rate and may drive higher cost generation sources out of the market. However, capacity market costs could potentially increase. These cost impacts also depend on the rest of PJM, the structure of the capacity markets, and considerations such as the capacity value assigned to renewables (e.g. offshore wind). Additional analysis could help determine both market impacts of increased renewables and guide strategy to reduce costs while ensuring reliability.

Employment impacts and job training. We included some additional costs to reflect the need to retrain workers who may have worked in the fossil or nuclear power sector. However, a full analysis would be required to determine the employment impacts of this transition, in terms of both jobs lost and jobs gained in the renewable energy industry, the quality of those jobs, the location of those jobs, and additional transitional support needed to help ensure a just transition.

7.3 Conclusions regarding policy considerations

Our main charge in this report was to do an analysis of the technical approach to 50% carbon reductions and the related costs. We also examined certain equity issues and questions relating to possible early nuclear plant requirements. We have not recommended specific policies; rather our analysis shows that achievement of carbon reduction goals equitably and affordably will require policies in the following areas:

- Ramping up efficiency from the present 0.6% per year to 2% per year in a way that is adequately resourced;
- Ensuring that efficiency improvements are broadly made across all income levels;
- Setting targets for offshore wind and deciding on methods of procurement that will result in declining costs;
- Considering the issue of economical methods to ensure procurement of sufficient solar energy, and specifically sufficient distributed solar so as to meet goals relating to renewable energy targets, equity, environmental justice and resilience;
- Setting out a range of approaches to deal with the possibility of early nuclear plant retirement so that New Jersey's goals regarding carbon emission reductions and affordability can be maintained both in the period up to 2030 and in the period beyond that.

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