2024 NJ Energy Master Plan

Integrated Energy Plan Technical Appendix

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Introduction

New Jersey's 2024 Energy Master Plan (EMP) serves as a long-term strategic roadmap for meeting the state's climate and clean energy goals—including an 80% reduction in economy-wide greenhouse gas (GHG) emissions by 2050, as mandated by the Global Warming Response Act (GWRA), and the target of 100% clean electricity sales by 2035, as established in Executive Order No. 315. This edition of the EMP builds on the 2019 EMP, incorporating the latest advancements in technology, policy, and programming to create a cost-effective, sustainable energy future. The 2024 EMP includes an accounting of progress made on the State's carbon reduction strategies, a summary of stakeholder feedback collected throughout the EMP process, and an updated Integrated Energy Plan (IEP) based on economy-wide energy system modeling of New Jersey's pathways for meeting near and long-term climate and energy goals.

The development of the EMP spanned from early 2024 through late 2025. To support this effort, the New Jersey Board of Public Utilities (BPU) and the Office of Climate Action and the Green Economy (OCAGE) engaged a consulting team comprised of Energy and Environmental Economics (E3), ILLUME Advising, and BW Research. E3 conducted quantitative modeling that informed the IEP, and the following sections are appendices providing additional detail and methodology on the IEP modeling.

Pathways Modeling

Section 1: Model Overview

Pathways is an economy-wide energy and GHG emissions accounting model. E3 created the Pathways model to help policymakers, businesses, and other stakeholders analyze paths to achieving deep decarbonization of the economy. Pathways is not an optimization or general equilibrium model, but instead allows for comparison of user-defined scenarios of future energy demand and emissions to explore the implications of potential climate and energy policies. Variables that impact final energy demand in the model (e.g., customer adoption of electric vehicles, amount of space heating demanded per household), are specified by the user. The Pathways model accounts for annual energy demands and GHG emissions from the following final energy demand and non-energy and/or non-combustion sources:

- Energy Demand Sectors
    - Residential
    - Commercial
    - Industrial
    - Transportation
- Non-Energy, Non-Combustion Sectors

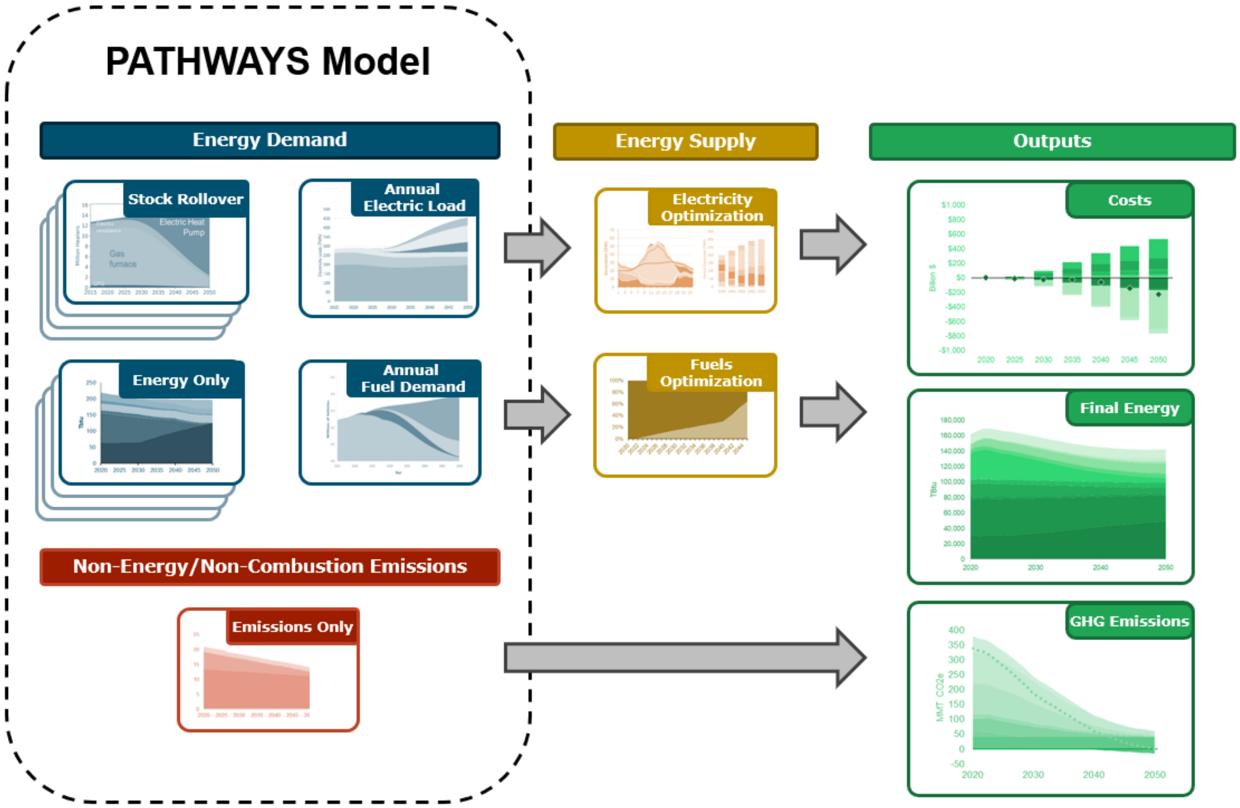
- Agriculture
- Coal Mining
- Natural Gas & Oil Systems
- Industrial Processes & Product Use (IPPU)
- Waste
- Land-use, Land-use Change, & Forestry (LULUCF)

The sources from these sectors are categorized into one of three subsector types:

1. **Stock Rollover –** Subsectors where Pathways accounts for the stock rollover of energy-consuming devices in the economy. Here, final energy demands and direct emissions are calculated based on demand for energy services (e.g., vehicle miles travelled, delivered heat), the fuel type of devices, and the efficiency of devices.
2. **Energy Only –** Subsectors where Pathways accounts for annual energy demands and direct emissions, but does not model stock rollover of devices due to a lack of high-quality, comprehensive data on device stocks, service demands, and efficiencies (e.g., industrial process heat).
3. **Emissions Only –** Subsectors where emissions are generated from sources other than energy demand and/or fuel combustion, so only the annual direct emissions are tracked (e.g., landfill methane leakage).

The final energy demands from Pathways are typically passed to energy supply models like PLEXOS for electricity sector capacity expansion and the E3 fuels optimization module to determine the cost and emissions associated with meeting final energy demands under various resource and emissions constraints. *Figure 1* below shows the process flow for a typical economy-wide analysis using Pathways in conjunction with these other tools. Using energy supply models to optimize electricity sector costs and emissions rates and fuel prices and blend levels is not required to generate economy-wide outputs using Pathways, as users also have the option to input pre-determined emissions rates and prices for all fuels within Pathways itself.

Figure 1: Flow Chart of Pathways Model Used in Conjunction with Energy Supply Models



Section 2: Stock Rollover Subsectors

Overview

Pathways models 31 distinct stock rollover subsectors across the Residential, Commercial, and Transportation sectors. For each subsector, the total stock of devices and the share for each technology type is benchmarked in the base year using historical data. For future years, the total stock is determined using growth rates for various key indicators (e.g., population). *Table 1* below shows the default stock rollover subsectors in Pathways and the growth rates used to determine total device stocks in future years.

Table 1: Stock Rollover Subsectors in Pathways

Subsector	Growth Rate
Residential Central Air Conditioning	Households
Residential Clothes Drying	Households
Residential Clothes Washing	Households
Residential Cooking	Households
Residential Dishwashing	Households
Residential Freezing	Households
Residential Exterior Lighting	Households
Residential General Service Lighting	Households
Residential Linear Fluorescent Lighting	Households
Residential Reflector Lighting	Households
Residential Refrigeration	Households
Residential Room Air Conditioning	Households
Residential Single Family Space Heating	Households
Residential Multi Family Space Heating	Households
Residential Water Heating	Households
Commercial Air Conditioning	Commercial Square Footage
Commercial Cooking	Commercial Square Footage
Commercial General Service Lighting	Commercial Square Footage
Commercial HID Lighting	Commercial Square Footage
Commercial Linear Fluorescent Lighting	Commercial Square Footage
Commercial Refrigeration	Commercial Square Footage
Commercial Space Heating	Commercial Square Footage
Commercial Ventilation	Commercial Square Footage
Commercial Water Heating	Commercial Square Footage
Transportation Light Duty Cars	Population
Transportation Light Duty Trucks	Population
Transportation Light Medium Duty Trucks	Population
Transportation Medium Duty Trucks	Population
Transportation Heavy Duty Trucks (Short-haul)	Population
Transportation Heavy Duty Trucks (Long-haul)	Population
Transportation Buses	Population

The final energy demand from stock rollover subsectors is a function of the total number of devices, the service demands per device, the share of various technologies among the total number of devices, and the average efficiencies of these devices. Each year, the model retires devices based on survival profiles that determine the fraction of devices retired from year to year, and then sells new devices so that the total number of devices equals the amount calculated using the base year stocks and top down growth rates.

Users have the option of changing the market share for new device sales as a scenario input. Examples of user inputs are measures that lead to an increase in sales of more efficient devices with the same fuel type or measures that lead to an increase in sales of devices with a different fuel type (e.g., shifting sales of gasoline vehicles to battery electric vehicles). In addition, users can input service demand modifiers that change the underlying amount of energy services required, which in turn change the final energy demand (e.g., reducing vehicle miles travelled). One unique service demand modifier available for buildings is the deployment of more efficient building shells that reduce space heating and cooling needs. Unlike other service demand modifiers like behavioral conservation or VMT reductions, the model accounts for the capital costs of building shell measures that reduce service demands, although the user must specify the cost and percent reduction in heating and/or cooling demand associated with each efficient shell type. The section below walks through the calculations for stock rollover and energy demand.

Section 3: Calculations

Stock Rollover Calculations

Stock rollover calculations are performed for each stock rollover subsector. The goal of the stock rollover calculations is to calculate the 3-dimensional stock array, $Aijk$, which represents the number of devices that exist in year i of vintage j and device type k (e.g. for the light duty vehicles subsector in the year 2024, how many 2002 vintage gasoline internal combustion engine cars are on the road).

Key model inputs for the calculation of the stock array, $Aijk$, include:

- $A0jk$, the base year stock share
- ri, the total number of devices that exist in year i across the entire subsector
- $Sijk$, the survival profile matrix, which represents the percentage of devices that will survive from year i−1 to year i
- $Bijk$, the natural retirement sales share, which represents the fraction of natural retirements in year i of vintage j that will be replaced with device type k. The value is typically the same across all vintages for a given year i.
- $Dijk$, the early retirement sales share, which represents the fraction of early retirements in year i of vintage j that will be replaced with device type k. The value is typically the same across all vintages for a given year i.
- Xik, the early retirement stock fraction, which represents the fraction of devices of type k that will be retired early in year i. Note: the vintage is not specified. The calculations assume that the oldest devices will be retired first.

Key intermediate calculated quantities include:

- $Pijk$, the array of natural retirements occurring in year i of vintage j and device type k
- $Qijk$, the array of early retirements occurring in year i of vintage j and device type k
- $Yijk$, the array of sales occurring in year i of vintage j and device type k
- $Aijk$, the stock array in year i of vintage j and device type k after accounting for natural retirements, but **before** accounting for early retirements and sales

- $Aijk$, the stock array in year i of vintage j and device type k after accounting for both natural and early retirements but **before** accounting for sales

The stock rollover calculations occur iteratively from years (i= 1…n), assuming that stocks in year 0, $A0jk$, are known. The following steps are performed for each successive year:

Step 1: subtract natural retirements

The first step is calculating the number of devices that will naturally retire given the starting stocks and the survival profile. The number of natural retirements, $Pijk$, and the intermediate stock array, $Aijk$, are calculated as shown in Equations 2.1 and 2.2 below:

$$Pijk=A(i-1)jk*Sijk \qquad 0.1$$

$$Aijk= A(i-1)jk- Pijk \qquad 0.2$$

Step 2: subtract early retirements

The second step is calculating the number of early retirements. Devices are retired from oldest to youngest, until the specified early retirement fraction, Xik, is reached. The number of early retirements, $Qijk$, are thus calculated such that Equation 2.3 is satisfied:

$$jQijk=Xik*jAijk \qquad 0.3$$

Intermediate stock array, $Aijk$, represents the stock array **after** accounting for both natural and early retirements but **before** accounting for sales. $Aijk$ is calculated as shown in Equation 2.4:

$$Aijk=Aijk- Qijk \qquad 0.4$$

Step 3: add sales

After both natural and early retirements have been accounted for to produce the intermediate stock array, $Aijk$, the third and final step in the calculation of the final stock array, $Aijk$, is to add the anticipated sales. This is achieved by replacing natural and early retirements, as well as adding new devices to meet the total number of devices specified for the subsector, ri. The sales, $Yijk$, are calculated as shown in Equation 2.5:

$$Yijk = Pijk * Bijk + Qijk * Dijk + ri - jkAijk * Bijk \qquad 0.5$$

Where:

- $Pijk$ is the array of natural retirements occurring in year i of vintage j and device type k,
- $Bijk$ is the natural retirement sales share, which represents the fraction of natural retirements in year i of vintage j that will be replaced with device type k,
- $Qijk$ is the array of early retirements occurring in year i of vintage j and device type k,
- $Dijk$ is the early retirement sales share, which represents the fraction of early retirements in year i of vintage j that will be replaced with device type k, and
- ri is the total number of devices that exist in year i across the entire subsector.

The final stock array, $Aijk$, is calculated by adding the sales, $Yijk$, to $Aijk$ (the intermediate stock array coming out of the previous step), as shown in Equation 2.6:

$$Aijk = Aijk + Yijk \qquad 0.6$$

Energy Demand Calculations for Stock Rollover Subsectors

Once the stock rollover has been calculated, energy demands are calculated for each year i, device type k, and fuel type f. Key inputs for the energy demand calculations include:

- $Aijk$, the final stock array defining the number of devices that exist in year i of vintage j and device type k. This is the main output of the stock rollover calculations.
- $Xijkf$, the fuel share of service demand for fuel type f for devices in year i of vintage j and device type k. This represents the percentage of service demand that is served by a particular fuel type.
- $Fijkf$, the efficiency of devices in year i of vintage j and device type k and fuel type f (in units of (MMBtu out)/(MMBtu in)).
- dik, the service demand in year i for device type k (in units of MMBtu/year)

The resulting energy demand, $Eikfs$, represents the energy demand year i for device type k and fuel type f. $Eikfs$ is calculated as shown in Equation 2.7:

$$Eikfs = dik * jXijkf * (Aijk \div Fijkf) \qquad 0.7$$

The final energy demands are aggregated over all devices in the subsector to yield $Eifs$, the total final energy demand for each year i and fuel type f as shown in Equation 2.8:

$$Eifs = kEikfs \qquad 0.8$$

Emissions resulting from these energy demands are dependent on the energy supply and are described in Section 7: Energy Supply.

Costs for Stock Rollover Subsectors

Three types of costs are calculated for devices within a stock rollover subsector:

1. **Device costs:** capital costs to purchase new devices. Overnight capital costs are calculated by multiplying annual device sales by the capital cost for each device. Annual levelized costs are calculated from the overnight costs assuming a financing rate and financing lifetime specified for each subsector.
2. **Operation and maintenance (O&M) costs:** annual costs associated with O&M for a specified device type. O&M costs are calculated by multiplying the total number of devices operating in a given year by the annual O&M cost for each individual device type.
3. **Fuel costs:** annual costs associated with fuel consumption for each device. Fuel costs are calculated by multiplying the energy demand for each device by the fuel price per MMBtu for the fuel it consumes.

Section 4: Data Sources

Table *2* lists the default data sources for key inputs to the stock rollover subsectors.

Table 2: Stock Rollover Default Data Sources

Subsector	Stocks	Service Demands	Device Efficiency	Device Costs
Residential Central Air Conditioning	NREL ResStock[1]	NREL ResStock	NREL ResStock	Wilson et al., 2024[2]
Residential Clothes Drying	NREL ResStock	NREL ResStock	EIA NEMS	EIA NEMS
Residential Clothes Washing	NREL ResStock	NREL ResStock	EIA NEMS	EIA NEMS
Residential Cooking	NREL ResStock	NREL ResStock	EIA NEMS	EIA NEMS
Residential Dishwashing	NREL ResStock	NREL ResStock	EIA NEMS	EIA NEMS
Residential Freezing	NREL ResStock	NREL ResStock	EIA NEMS	EIA NEMS
Residential Exterior Lighting	DOE 2020[3]	EIA NEMS[4]	EIA NEMS	EIA NEMS

[1] National Renewable Energy Laboratory. (2024). ResStock Dataset 2024.2; https://resstock.nrel.gov/datasets
[2] Wilson et al. (2024). *Heat pumps for all? Distributions of the costs and benefits of residential air-source heat pumps in the United States*; https://www.nrel.gov/docs/fy24osti/84775.pdf
[3] U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy. (2020). *Adoption of Light-Emitting Diodes in Common Lighting Applications*; https://www.energy.gov/sites/default/files/2020/09/f78/ssl-led-adoption-aug2020.pdf
[4] U.S. Department of Energy, Energy Information Administration. (2023). *National Energy Modeling System*; https://www.eia.gov/outlooks/aeo/nems/documentation/

Subsector	Stocks	Service Demands	Device Efficiency	Device Costs
Residential General Service Lighting	DOE 2020	EIA NEMS	EIA NEMS	EIA NEMS
Residential Linear Fluorescent Lighting	DOE 2020	EIA NEMS	EIA NEMS	EIA NEMS
Residential Reflector Lighting	DOE 2020	EIA NEMS	EIA NEMS	EIA NEMS
Residential Refrigeration	NREL ResStock	NREL ResStock	EIA NEMS	EIA NEMS
Residential Room Air Conditioning	NREL ResStock	NREL ResStock	NREL ResStock	Wilson et al., 2024
Residential Single Family Space Heating	NREL ResStock	NREL ResStock	NREL ResStock	Wilson et al., 2024
Residential Multi Family Space Heating	NREL ResStock	NREL ResStock	NREL ResStock	Wilson et al., 2024
Residential Water Heating	NREL ResStock	NREL ResStock	EIA NEMS	E3 Buildings Pro Forma[5]
Commercial Air Conditioning	EIA CBECS 2018[6]	EIA NEMS	EIA NEMS, E3 Buildings Pro Forma for heat pumps	E3 Buildings Pro Forma
Commercial Cooking	EIA CBECS 2018	EIA NEMS	EIA NEMS	EIA NEMS
Commercial General Service Lighting	DOE 2020	EIA NEMS	EIA NEMS	EIA NEMS
Commercial HID Lighting	DOE 2020	EIA NEMS	EIA NEMS	EIA NEMS
Commercial Linear Fluorescent Lighting	DOE 2020	EIA NEMS	EIA NEMS	EIA NEMS
Commercial Refrigeration	EIA CBECS 2018	EIA NEMS	EIA NEMS	EIA NEMS
Commercial Ventilation	EIA CBECS 2018	EIA NEMS	EIA NEMS	EIA NEMS
Commercial Space Heating	EIA CBECS 2018	EIA NEMS	EIA NEMS, E3 Buildings Pro Forma for heat pumps	E3 Buildings Pro Forma
Commercial Water Heating	EIA CBECS 2018	EIA NEMS	EIA NEMS, E3 Buildings Pro Forma for heat pumps	E3 Buildings Pro Forma
Transportation Light Duty Cars	FHWA 2021[7]	FHWA 2021	BTS for existing ICE vehicle stock[8],	Slowik et al., 2022

[5] E3 Buildings Pro Forma estimates the cost and efficiencies of building appliances based on a range of state, utility, federal, and proprietary surveys of equipment characteristics and installation costs

[6] U.S. Department of Energy, Energy Information Administration. (2022). *Commercial Building Energy Consumption Survey*; https://www.eia.gov/consumption/commercial/data/2018/

[7] U.S. Department of Transportation, Federal Highway Administration. (2022). *Highway Statistics 2021*; https://www.fhwa.dot.gov/policyinformation/statistics/2021/

[8] U.S. Department of Transportation, Bureau of Transportation Statistics. (2023). *National Transportation Statistics 2021*; https://www.bts.gov/topics/national-transportation-statistics

Subsector	Stocks	Service Demands	Device Efficiency	Device Costs
			NHTSA for future year ICE vehicles[9], Slowik et al., 2022 for EVs[10]	
Transportation Light Duty Trucks	FHWA 2021	FHWA 2021	BTS for existing ICE vehicle stock, NHTSA for future year ICE vehicles, Slowik et al., 2022 for EVs	Slowik et al., 2022
Transportation Light Medium Duty Trucks	2021 VIUS[11]	FHWA 2021	EIA AEO 2023[12]	Mullholland, 2022[13]
Transportation Medium Duty Trucks	2021 VIUS	FHWA 2021	EIA AEO 2023	Slowik et al., 2023[14]
Transportation Heavy Duty Trucks (Short-haul)	2021 VIUS	FHWA 2021	EIA AEO 2023	Slowik et al., 2023
Transportation Heavy Duty Trucks (Long-haul)	2021 VIUS	FHWA 2021	EIA AEO 2023	Slowik et al., 2023
Transportation Buses	FHWA 2021	FHWA 2021	ANL 2021[15]	Slowik et al., 2023

Section 5: Energy Only Subsectors

Overview

Energy only subsectors represent the final energy demands and direct GHG emissions for categories where comprehensive data on equipment stock, efficiencies, and service demands are not readily available. These include manufacturing and non-manufacturing industrial sectors, off-road transportation and aviation, and miscellaneous energy end-uses in residential and commercial

[9] U.S. Department of Transportation, National Highway Traffic Safety Administration. (2022). *CAFE Compliance and Effects Modeling System: 2022 Final Rule for Model Years 2024-2026 Passenger Cars and Light Trucks Central Analysis*; https://www.nhtsa.gov/file-downloads?p=nhtsa/downloads/CAFE/2022-FR-LD-2024-2026/Central%20Analysis/

[10] Slowik, P., Isenstadt, A., Pierce, L., Searle, S. (2022). *Assessment of Light-Duty Electric Vehicle Costs and Consumer Benefits in the United States in the 2022-2035 Time Frame*; https://theicct.org/wp-content/uploads/2022/10/ev-cost-benefits-2035-oct22.pdf

[11] U.S. Census Bureau. (2023). *2021 Vehicle Inventory and Use Survey*; https://www.census.gov/programs-surveys/vius.html

[12] U.S. Department of Energy, Energy Information Administration. (2023). *Annual Energy Outlook 2023*; https://www.eia.gov/outlooks/aeo/

[13] Mulholland, E. (2022). *Cost of Electric Commercial Vans and Pickup Trucks in the United States Through 2040*; https://theicct.org/wp-content/uploads/2022/01/cost-ev-vans-pickups-us-2040-jan22.pdf

[14] Slowik et al. (2023). *Analyzing the Impact of the Inflation Reduction Act on Electric Vehicle Uptake in the United States*; https://theicct.org/wp-content/uploads/2023/01/ira-impact-evs-us-jan23-2.pdf

[15] U.S. Department of Energy, Argonne National Laboratory. (2023). *Vehicle Technologies and Hydrogen and Fuel Cell Technologies Research and Development Benefits Analysis*; https://vms.taps.anl.gov/reports/u-s-doe-vto-hfto-r-d-benefits-analysis-mdhd/

buildings. For all energy only subsectors, starting year energy demands are benchmarked to historical consumption. For industrial subsectors, business-as-usual changes in future year energy demand are applied by subsector and fuel type based on changes forecasted in EIA Annual Energy Outlook 2023. Changes in future year aviation energy demand are also taken from Annual Energy Outlook, while energy demand growth for miscellaneous residential and commercial end-uses is projected using the households and commercial square footage growth rates, respectively. Table *3* lists the default energy only subsectors used in Pathways.

Table 3: Energy Only Subsectors in Pathways

Subsector	Growth Rate
Residential Other	Households
Commercial Other	Commercial Square Footage
Transportation Aviation	EIA AEO23 Demand Growth for Jet Fuel
Transportation Marine	N/A
Transportation Rail	N/A
Industry Aluminum	EIA AEO23 Demand Growth by Individual Fuel and Subsector
Industry Cement and Lime	
Industry Chemicals	
Industry Food	
Industry Glass	
Industry Iron and Steel	
Industry Metal Based Durables	
Industry Other	
Industry Paper	
Industry Plastics	
Industry Refining	
Industry Wood Products	
Industry Agriculture	
Industry Construction	
Industry Mining and Upstream Oil and Gas	

Once the baseline growth in energy demand is determined, users can specify either energy efficiency measures to reduce final energy consumption or fuel-switching measures to convert energy demand from one fuel to another. A third option for some stationary sources of CO_2 emissions is to apply CCS. The share of final emissions from a specific fuel and subsector that will be captured annually is specified by the user along with the technical characteristics of the CCS equipment like capital and operating costs, capture rate, and energy demands. The section below walks through the calculations for final energy demands in the energy only subsectors.

Energy Demand Calculations for Energy Only Subsectors

As mentioned in the overview, the final energy demands in energy only subsectors account for both fuel-switching measures to convert energy demand from one fuel to another, and energy efficiency measures to reduce the final energy consumption. The final result is $EifI$, the final energy demand in year i for fuel type f across the subsector.

Key inputs for the energy demand calculations in energy only subsectors include:

- $EifI0$, the default energy demand in year i for fuel type f
- $Wifg$, the percentage of energy demand in year i to be converted from fuel type f to fuel type g
- $Vifg$, the energy efficiency factor in year i when converting from fuel type f to fuel type g (e.g. if switching from a natural gas boiler to an electric heat pump that is 3X more efficient, this value would be 300%)
- Rif, the energy efficiency reduction fraction for energy efficiency measures. This represents the % of final energy demand that will be reduced as a result of the measure

Intermediate calculated values include:

- $EifI$, the energy demand in year i for fuel type f **after** fuel switching has been accounted for but **before** energy efficiency measures have been applied

Step 1: account for fuel-switching

First, fuel-switching is applied to the default energy demand trajectories for each fuel. This calculation:

1. starts with the default energy demand trajectory, $EifI0$,
2. subtracts energy demands that will be switching from fuel type f to other fuel types, and then
3. adds fuel demands that will be switching from other fuel types to fuel type f, accounting for the conversion efficiency.

The intermediate energy demand accounting for fuel switching, $EifI$, is calculated as shown in Equation 3.1:

$$EifI, = EifI0 - gEifI0 * Wifg + gEifI0 * Wigf \div Vigf \qquad 0.9$$

Step 2: account for energy-efficiency measures

After fuel-switching has been accounted for, energy efficiency measures are applied to the intermediate energy demands, $EifI$, to produce the final energy demands, $EifI$. The energy efficiency reduction fraction, Rif, is applied to calculate the final energy demands, $EifI$, as shown in Equation 3.2:

$$EifI, = Eif * (1 - Rif) \qquad 0.10$$

Emissions resulting from these energy demands are dependent on the energy supply and are described in section 5. In cases where CCS is applied within a subsector, energy demands associated with CCS operations are also accounted for.

Costs for Energy Only Subsectors

Although device stocks are not explicitly modeled for energy only subsectors, the capital costs that would be associated with equipment upgrades are represented as levelized annual costs on a dollars per MMBtu basis. These include:

- **Fuel-switching costs:** annual levelized costs representing capital investments needed to purchase equipment associated with fuel-switching (e.g. the levelized incremental capital cost of an industrial heat pump replacing a natural gas boiler).
- **Efficiency costs:** annual levelized costs representing capital investments needed to purchase equipment associated with energy efficiency measures (e.g. the levelized incremental capital cost of efficient boilers relative to conventional boilers).

Annual costs that are accounted for in energy only subsectors include:

- **Fuel costs:** annual costs associated with fuel consumption in the subsector. Fuel costs are calculated by multiplying the final energy demand by the fuel cost per MMBtu of the fuel consumed.

If CCS is applied in the subsector, additional CCS costs will also be accounted for. These are described further in Section 7: Energy Supply.

Data Sources

Table *4* lists the default data sources for key inputs to the energy only subsectors.

Table 4: Energy Only Default Data Sources

Subsector	Base Year Energy Demand	Energy Efficiency Costs	Electrification Costs	CCS Costs
Residential Other	EIA SEDS[16]	Schiller et al., 2020[17] and Frick et al., 2021[18]	Smillie et al., 2024[19]	N/A
Commercial Other	EIA SEDS			
Transportation Aviation	EIA SEDS / NJ DEP GHG Inventory	N/A	N/A	N/A
Transportation Marine				
Transportation Rail	EIA SEDS			

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[16] U.S. Department of Energy, Energy Information Administration. (2023). *State Energy Data System: 1960-2021 (complete)*; https://www.eia.gov/state/seds/seds-data-complete.php

[17] Schiller, S., Hoffman, I., Murphy, S., Leventis, G., Schwartz, L. (2020). *Cost of saving natural gas through efficiency programs funded by utility customers 2012-2017*; https://eta-publications.lbl.gov/sites/default/files/cose_natural_gas_final_report_20200513.pdf

[18] Frick, N., Murphy, S., Miller, C., Pigman, M. (2021). *Still the One: Efficiency Remains a Cost-Effective Electricity Resource*; https://eta-publications.lbl.gov/sites/default/files/cose_cspd_analysis_2021_final_v3.pdf

[19] S. Smillie, D. Alberga, R. Loken, S. Bharadwaj, T. Clark, A. Mahone, "Measuring Economic Potential for Decarbonization Industrial Heat," Energy and Environmental Economics, Inc., October 2024; https://www.ethree.com/wp-content/uploads/2024/10/CAELP-E3-Industrial-Electrification-Report.pdf

<table>
<tr><th>Subsector</th><th>Base Year Energy Demand</th><th>Energy Efficiency Costs</th><th>Electrification Costs</th><th>CCS Costs</th></tr>
<tr><td>Industry Aluminum</td><td rowspan="15">NREL IEDB 2018[20], EIA SEDS</td><td rowspan="12">Schiller et al., 2020 and Frick et al., 2021</td><td rowspan="12">Zuberi et al., 2022[21] and DOE 2023[22]</td><td rowspan="12">NETL 2014[23]</td></tr>
<tr><td>Industry Cement and Lime</td></tr>
<tr><td>Industry Chemicals</td></tr>
<tr><td>Industry Food</td></tr>
<tr><td>Industry Glass</td></tr>
<tr><td>Industry Iron and Steel</td></tr>
<tr><td>Industry Metal Based Durables</td></tr>
<tr><td>Industry Other</td></tr>
<tr><td>Industry Paper</td></tr>
<tr><td>Industry Plastics</td></tr>
<tr><td>Industry Refining</td></tr>
<tr><td>Industry Wood Products</td></tr>
<tr><td>Industry Agriculture</td><td rowspan="3">N/A</td><td rowspan="3">Levelized cost of electrification for heavy-duty trucking used as proxy for off-road industrial equipment</td><td>N/A</td></tr>
<tr><td>Industry Construction</td><td>N/A</td></tr>
<tr><td>Industry Mining and Upstream Oil and Gas</td><td>NETL 2014</td></tr>
</table>

Section 6: Emissions Only Subsectors

Overview

Emissions only subsectors represent GHG emissions from non-energy and/or non-combustion related sources and emissions sinks from land use and forestry. For these sources, annual emissions are entered into the model directly as metric tons by pollutant type. The four pollutant types represented in Pathways are CO_2, CH_4, N_2O, and CO_2e (CO_2e is used for fluorinated gases like HFCs, PFCs, SF_6, and NF_3). Base year emissions sources and sinks are benchmarked to state-level data from EPA[24]. Table *5* lists the default emissions only sectors and subsectors used in Pathways.

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[20] U.S. Department of Energy, National Renewable Energy Laboratory. (2019). *2018 Industrial Energy Data Book*; https://data.nrel.gov/submissions/122

[21] Zuberi, M., Hasanbeigi, A., Morrow, W. (2022). *Electrification of U.S. Manufacturing with Industrial Heat Pumps*; https://eta-publications.lbl.gov/sites/default/files/us_industrial_heat_pump-final.pdf

[22] U.S. Department of Energy. (2023). *Pathways to Commercial Liftoff: Industrial Decarbonization*; https://liftoff.energy.gov/wp-content/uploads/2023/09/20230918-Pathways-to-Commercial-Liftoff-Industrial-Decarb.pdf

[23] U.S. Department of Energy, National Energy Technology Laboratory. (2014). *Cost of Capturing CO2 from Industrial Sources*; https://www.netl.doe.gov/projects/files/CostofCapturingCO2fromIndustrialSources_011014.pdf

[24] U.S. Environmental Protection Agency. (2023). *Inventory of U.S. Greenhouse Gas Emissions and Sinks by State: 1990-2021*; https://www.epa.gov/ghgemissions/state-ghg-emissions-and-removals

Table 5: Emissions Only Subsectors in Pathways

Sector	Subsector	Pollutant
Agriculture	Liming	CO_2
	Urea Fertilization	CO_2
	Enteric Fermentation	CH_4
	Manure Management CH_4	CH_4
	Rice Cultivation	CH_4
	Residue Burning CH_4	CH_4
	Manure Management N_2O	N_2O
	Soil Management	N_2O
	Residue Burning N_2O	N_2O
Coal Mining	Active Coal Mines	CH_4
	Abandoned Coal Mines	CH_4
Natural Gas and Oil Systems	Natural Gas Systems CO_2	CO_2
	Petroleum Systems CO_2	CO_2
	Abandoned Oil and Gas Wells CO_2	CO_2
	Natural Gas Systems CH_4	CH_4
	Petroleum Systems CH_4	CH_4
	Abandoned Oil and Gas Wells CH_4	CH_4
	Natural Gas Systems N_2O	N_2O
	Petroleum Systems N_2O	N_2O
Industrial Processes and Product Use (IPPU)	Cement Production	CO_2
	Lime Production	CO_2
	Other Process Uses of Carbonates	CO_2
	Glass Production	CO_2
	Soda Ash Production	CO_2
	Carbon Dioxide Consumption	CO_2
	Titanium Dioxide Production	CO_2
	Aluminum Production CO_2	CO_2
	Iron and Steel Production CO_2	CO_2
	Ferroalloy Production CO_2	CO_2
	Ammonia Production	CO_2
	Urea Consumption	CO_2
	Phosphoric Acid Production	CO_2
	Petrochemical Production CO_2	CO_2
	Carbide Production and Consumption CO_2	CO_2
	Lead Production	CO_2
	Zinc Production	CO_2
	Magnesium Production and Processing CO_2	CO_2
	Petrochemical Production CH_4	CH_4
	Carbide Production and Consumption CH_4	CH_4
	Iron and Steel Production CH_4	CH_4
	Ferroalloy Production CH_4	CH_4
	Adipic Acid Production	N_2O
	Nitric Acid Production	N_2O

Sector	Subsector	Pollutant
	N2O from Product Uses	N2O
	Caprolactam and Others Production	N2O
	Electronics Industry N2O	N2O
	ODS Substitutes	CO2e
	HCFC-22 Production	CO2e
	Magnesium Production and Processing	CO2e
	Aluminum Production	CO2e
	Electronics Industry	CO2e
	Electrical Transmission and Distribution	CO2e
Waste	Waste Combustion CO2	CO2
	Landfills	CH4
	Wastewater Treatment CH4	CH4
	Composting CH4	CH4
	Anaerobic Digestion	CH4
	Waste Combustion CH4	CH4
	Wastewater Treatment N2O	N2O
	Waste Combustion N2O	N2O
	Composting N2O	N2O
Land-Use, Land-Use Change, and Forestry (LULUCF)	LULUCF CH4 Sources	CH4
	LULUCF N2O Sources	N2O
	LULUCF Carbon Stock Change	CO2

After the baseline trend for future year non-energy and/or non-combustion emissions has been determined, the user can specify annual emissions reductions as a percentage below the baseline trend for individual sources along with measure costs on a $/ton of pollutant basis.

Calculations

Emissions Calculations for Emissions Only Subsectors

The final emissions for an emissions only subsector, γip, are calculated for each year i and pollutant p. Tracked pollutants typically include the most common greenhouse gases (i.e. CO2, CH4, and N2O). The final emissions, γip, are calculated as shown in Equation 4.1:

$$\gamma ip = \gamma ip0 - \alpha ip \qquad 0.11$$

where:

- $\gamma ip0$ is the default emission value for year i and pollutant p, and
- αip is the quantity of emissions to be reduced via mitigation measures for year i and pollutant p.

In some cases, CCS may be applied to an emissions only subsector (e.g. cement production). Impacts from CCS are described further in section 5.

Cost Calculations for Emissions Only Subsectors

Annual costs associated with emissions reductions in emissions only subsectors are tracked within the model. These **emissions only reduction costs** are calculated by multiplying the annual emissions reductions, αip, by the input cost on a $/ton basis.

If CCS is applied in the subsector, additional CCS costs will also be accounted for. These are described further in section 5.

Data Sources

Table 6 lists the default data sources for key inputs to the emissions only subsectors.

Table 6: Emissions Only Default Data Sources

Sector	Sources	Growth Rate	Mitigation Potential and Costs
Agriculture	All agriculture sources	EPA State-Level Non-CO2 Report[25]	EPA State-Level Non-CO2 Report
Coal Mining	All coal mining sources	EPA State-Level Non-CO2 Report	EPA State-Level Non-CO2 Report
Natural Gas and Oil Systems	CH4 emissions sources	EPA State-Level Non-CO2 Report	EPA State-Level Non-CO2 Report

[25] U.S. Environmental Protection Agency. (2023). *U.S. State-level Non-CO_2 GHG Mitigation Report*; https://www.epa.gov/global-mitigation-non-co2-greenhouse-gases/us-state-level-non-co2-ghg-mitigation-report

Sector	Sources	Growth Rate	Mitigation Potential and Costs
	CO2 emissions sources	Aligned with methane growth	NETL 2014 for CCS on natural gas processing facilities
Industrial Processes and Product Use (IPPU)	ODS Substitutes	BAU forecast from EPA regulatory impact analysis for HFC rulemaking[26]	Emissions reductions forecast from EPA HFC rulemaking
	Cement and Lime Production CO2	Aligned with energy demand growth rates from EIA AEO23	NETL 2014 for CCS on cement production
	Iron and Steel Production CO2	Aligned with energy demand growth rates from EIA AEO23	NETL 2014 for CCS on iron and steel production
	All other IPPU sources	EPA State-Level Non-CO2 Report	EPA State-Level Non-CO2 Report
Waste	CH4 emissions sources	EPA State-Level Non-CO2 Report	EPA State-Level Non-CO2 Report
Land-Use, Land-Use Change, Forestry (LULUCF)	Carbon sinks	Midpoint of BAU range for national sinks from 2021 Long-Term Strategy report[27]	Fargione et al., 2018[28]

Section 7: Energy Supply

Pathways generates annual energy demands by fuel type, stocks and sales of energy consuming devices, and GHG emissions from non-energy/non-combustion sources. The energy demands by fuel type from Pathways can be passed to a set of energy supply optimization tools like E3's RESOLVE electricity sector capacity expansion model and E3's fuels optimization module. RESOLVE calculates optimal long-term electricity generation and transmission investments subject to reliability, policy, and technical constraints. The fuels optimization module calculates what production and allocation of low carbon fuels like biofuels, electrolytic fuels, and fossil fuels with negative emissions technology, provides the lowest cost portfolio that meets final energy demands and economy-wide emissions targets. Both RESOLVE and the fuels optimization tool provide

[26] U.S. Environmental Protection Agency. (2022). *Regulatory Impact Analysis for Phasing Down Production and Consumption of Hydrofluorocarbons (HFCS)*; https://www.epa.gov/system/files/documents/2022-07/RIA%20for%20Phasing%20Down%20Production%20and%20Consumption%20of%20Hydrofluorocarbons%20%28HFCs%29.pdf

[27] U.S. Department of State and the U.S. Executive Office of the President. (2021). *The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050*; https://www.whitehouse.gov/wp-content/uploads/2021/10/US-Long-Term-Strategy.pdf

[28] Fargione, J. et al. (2018). *Natural Climate Solutions for the United States*; https://www.science.org/doi/10.1126/sciadv.aat1869

emissions rates and prices for electricity and fuels, respectively, that are used to calculate final economy-wide emissions and costs.

Pathways can still be used to calculate economy-wide results on its own without the use of energy supply optimization models, but requires the user to enter predetermined annual emissions rates and prices for electricity and emissions rates, prices, and fuel blends for all liquid and gaseous fuel types. The default assumptions for fuel prices in Pathways are taken from the Reference case forecast in EIA AEO23.

Calculation of Economy-wide Emissions

Once the economy-wide energy supply has been determined for a scenario, economy-wide emissions can be calculated within the PATHWAYS model. Economy-wide emissions include direct emissions from combusted fuels, indirect emissions from electricity, non-energy/non-combustion emissions, and any negative emissions that occur through CCS or negative emissions technologies (e.g. direct air capture). Emissions are calculated for each subsector that is modeled. Non-energy/non-combustion emissions are calculated as described in section 4. Other types of modeled emissions and their calculations are described in the subsequent sections.

Calculation of Emissions from Fuels

The final energy demands for stock rollover subsectors and energy only subsectors are represented by $Eifs$ and $EifI$ respectively for each year i for fuel type f. The final energy demand for a general subsector year i for fuel type f will henceforth be denoted by Eif.

Energy demands for each fuel type f can potentially be served by a number of different candidate fuels c (e.g. energy demands for the "Natural Gas" fuel type might be served by candidate fuels "Fossil Natural Gas" or "Renewable Natural Gas"). The share of fuel demand in year i for fuel type f that is served by each candidate fuel c is denoted by ρifc, and may be determined by either the user directly as an input or by an optimization calculation in a subsequent energy supply tool. For many candidate fuels, ρifc does not change over time. However, in some instances, it may vary with time (e.g. a declining emissions factors for grid electricity). The subsector energy demands for each final fuel are translated to subsector energy demands for each candidate fuel as shown in Equation 5.1:

$$Eic = f(Eif * \rho ifc) \qquad 0.12$$

The emissions factors, βicp, are known for each year i, candidate fuel c, and pollutant p (i.e. each GHG modeled). Subsector emissions, γip, for each year i pollutant p are calculated as shown below:

$$\gamma_{ip} = \sum_c (E_{ic} * \beta_{icp}) \qquad 0.13$$

Captured Emissions from CCS and Negative Emissions Technologies

Final subsector emissions account for any negative emissions that are captured through CCS. CCS can be applied to both energy only subsectors and emissions only subsector as specified by the user. CCS is assumed to capture CO2. Key CCS inputs for energy only subsectors include:

- E_{if}, final energy demand for a general subsector year i for fuel type f (output of prior model calculations)
- τ_{if}, the percentage of operations that CCS will be applied to in year i for the combustion of fuel type f (e.g. for an energy only subsector, CCS might be applied to 90% of operations where coal is being combusted)
- μ_{if}, the capture rate for CCS applied to in year i for the combustion of fuel type f
- β_f, the gross CO2 emission factor for fuel type f (i.e. the metric tons of CO2 emitted per MMBtu of fuel type f consumed)

The emissions captured in year i, γ_i^{CCS}, are calculated as shown in Equation 5.3:

$$\gamma_i^{CCS} = \sum_f (E_{if} * \beta_f * \tau_{if} * \mu_{if}) \qquad 0.14$$

For emissions only subsectors, the CCS will be applied to a fraction of the subsector emissions. In this case, the CCS will not be capturing emissions from combusted fuels. The captured emissions are instead calculated as shown in Equation 5.4:

$$\gamma_i^{CCS} = \gamma_i * \tau_i * \mu_i \qquad 0.15$$

where:

- γ_i are the CO2 emissions for the emissions only subsector in year i absent any CCS,
- τ_i is the percentage of operations that CCS will be applied to in year i, and
- μ_i is the capture rate for CCS applied to in year i

CCS equipment also demands energy to operate. Emissions associated with these energy demands are accounted for in the subsector where the CCS is applied.

In some cases, other negative emissions technologies (NETs) may also be represented (e.g. direct air capture). NETs are treated in the same way as CCS, except that the captured emissions from NETs are specified directly as a model input rather than being calculated, as they are not tied directly to emissions from other subsectors. Energy demands and costs for NETs are calculated using the same methodology as described for CCS.

Additional CCS Energy Demands

If CCS is applied in the subsector, then the additional energy demands associated with running the CCS equipment will also be accounted for. Key inputs to calculate these energy demands are:

- ε_{if}^{CCS}, the energy demand required to operate any CCS equipment in year i of fuel type f per metric ton of captured CO2
- γ_i^{CCS}, the metric tons of captured CO2 in year i across the subsector

The additional energy demand to run the CCS equipment, E_{if}^{CCS} is calculated as shown in Equation 5.5:

$$E_{if}^{CCS} = \varepsilon_{if}^{CCS} * \gamma_i^{CCS} \qquad 0.16$$

Additional CCS Costs

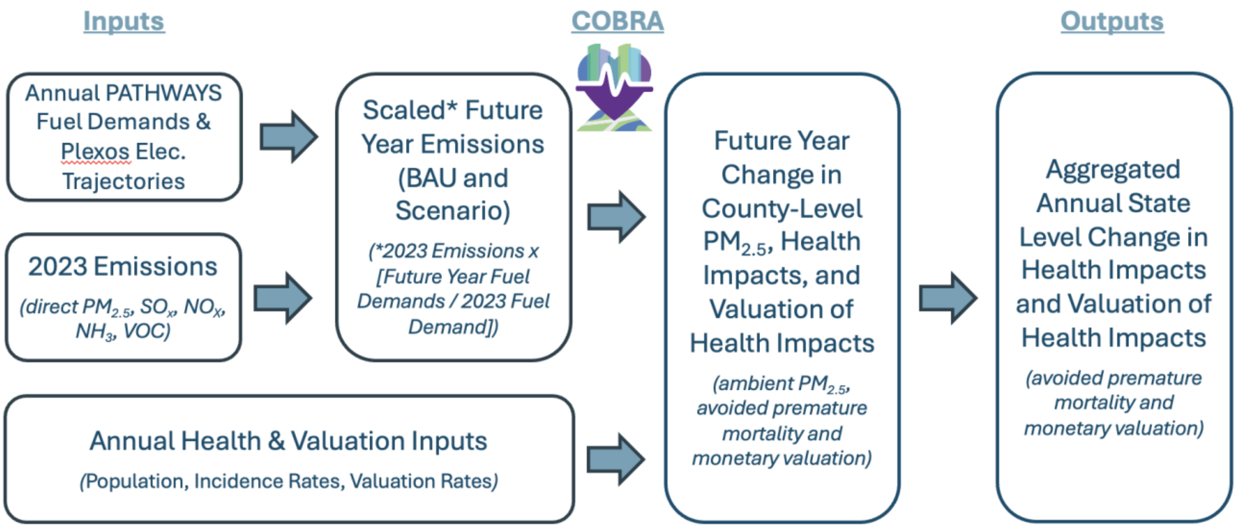
If CCS is applied in the subsector, then the additional costs associated with purchasing and running the CCS equipment will also be accounted for. These include:

- **CCS capital costs:** the annual levelized cost of incremental CCS capacity. This is calculated by levelizing the overnight capital cost of the equipment based on an assumed financing rate and financing lifetime.
- **CCS operation and maintenance (O&M) costs:** the annual variable costs associated with operating and maintaining the CCS equipment.
- **Fuel costs:** annual costs associated with fuel consumption in the by the CCS equipment.

Section 8: Air Quality Modeling

A visual representation of the workflow to determine co-pollutant and health impacts is shown in Figure 2 below.

Figure 2: Co-Pollutant Health Impact Methodology Workflow



To conduct this analysis, E3 estimated future changes in emissions that contribute to $PM_{2.5}$ concentrations and are inputs to COBRA: primary (directly emitted) $PM_{2.5}$ and precursors to secondary $PM_{2.5}$ formed in the atmosphere (sulfur dioxide, nitrogen oxides, ammonia, and volatile organic compounds). The emissions dataset input to COBRA is county-level by emissions category of each of the five pollutants. COBRA provides a 2023 emissions dataset, which E3 modified based on modeled scenarios before applying in COBRA. Modeled sectors include electricity, residential and commercial buildings, transportation, and industry.

For non-electricity sector fuel combustion emissions, E3 used a mapping between COBRA emissions categories and Pathways sector-fuel demands to scale 2023 COBRA emissions based on ratio of Pathways fuel consumption for each corresponding sector-fuel in each future year relative to 2023. For electricity sector emissions, E3 applied reductions in electricity-sector emissions at the state and fuel level (coal, gas oil) based on PLEXOS outputs. Lastly, without further information to adjust emissions that occur via other mechanisms beyond fuel combustion, these other non-fuel combustion emissions are assumed to stay constant at the 2023 level; examples of these emissions categories include industrial processes and manufacturing, solvent utilization, waste disposal & recycling, agriculture & forestry, dust and fires.

Using these emissions forecasts, E3 ran COBRA for each scenario to estimate county-level changes in $PM_{2.5}$ concentrations and population exposure, associated changes in premature mortalities and morbidities related monetary valuation of those health impacts. Lastly, key results are aggregated to state level.

Section 8: Peak Electricity Demand

The electricity system modeling accounted for bottom-up changes in technology adoption across sectors. The annual electricity demand projections were paired with hourly load shapes for different end-uses[29]. Resource portfolios were then developed to meet this hourly demand. In doing so, the unique needs in each scenario, as they relate to the differences in load shapes, peak load timing and peak load were met. Details follow.

Models for Hourly Load Estimation

E3 used a combination of in-house models to simulate hourly load shapes for EV charging, electrified heating and cooling, and all remaining end-uses. These models are described below.

EV Load Shape Tool (EVLST)

To develop hourly load shapes associated with each charging management strategy, E3 leveraged its proprietary EV Load Shape Tool (EVLST), to create diversified charging load profiles. The EVLST is a bottom-up simulation model, starting with a statistically robust sample of driving patterns for a vehicle class using a Markov Chain Monte Carlo sampling process of vehicle trip data. Charging decisions for hundreds of drivers are simulated based on the availability of chargers in various locations, vehicles' charging needs, electricity rates, and managed charging strategies.

EVLST produces system-wide diversified charging load shapes. These load shapes represent the average charging behavior of vehicles across the broad PJM region rather than the charging behavior of a specific vehicle. Using EVLST, E3 developed standard hourly charging load shapes for light-duty, medium-duty (parcel van), and heavy-duty (transit bus) vehicles for the PJM region. These shapes are intended to provide a reasonable representation of expected EV charging load shapes in PJM. For vehicle types that charge in multiple locations (home, work, and public), EVLST produces a breakdown of where the charging occurs in every hour.

EVLST models three representative vehicle types: personal light-duty vehicles, parcel van, and transit bus. To replicate an unmanaged charging profile, vehicles are responsive to the average cost to charge in a location but are not sensitive to time varying costs to charge. The drivers will choose to avoid expensive public charging if they can wait to charge for a lower cost at home. Drivers will not, however, respond to time-of-use rates faced at home. For managed load shapes, customers are responsive to time-varying prices they are exposed to. Additionally, EVLST models a Vehicle-to-Grid (VGI) aggregator smoothing out rebound peaks and orchestrating charging during off-peak hours.

RESHAPE

RESHAPE was designed to simulate heat pump operations given sensible space heating and water heating demands in a variety of building typologies across the residential and commercial building

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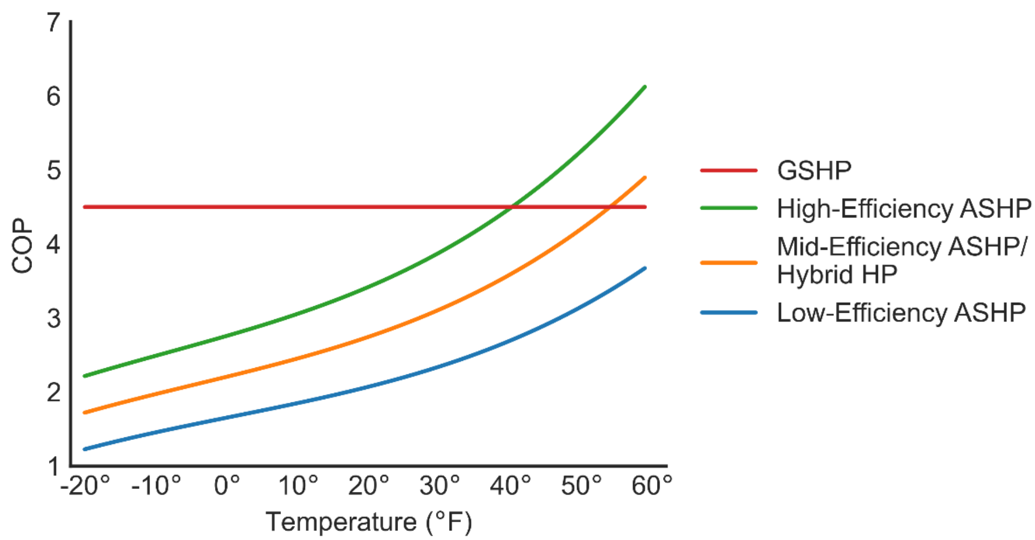
[29] Loads were grossed up by 6.5% to account for transmission and distribution losses

sectors. Using these simulations, RESHAPE was parametrized to produce 33 historical weather years (1990-2022) of shapes for these subsectors.

RESHAPE's sensible space heating demands were benchmarked to replicate the seasonality of monthly residential and commercial gas sales as reported by the US Energy Information Administration (EIA) in New Jersey for 2022. By using this benchmarking approach, it was assumed that seasonal gas sales were representative of the seasonality of space-heating. Furthermore, because gas space heating appliance efficiencies are largely insensitive to temperature, it was assumed that the seasonal gas throughput is representative of sensible heat demand.

Figure 3: Heat Pump Coefficient of Performance as a Function of Temperature



RESHAPE can simulate a variety of different heat pump technologies, including whole-building air source heat pumps, hybrid heat pumps, and ground source heat pumps. Particularly, RESHAPE can model several different efficiencies of air source heat pumps, as shown in the figure above. The following devices were modeled in RESHAPE:

+ A low-efficiency ASHP. This ASHP meets all heating demands above 20 ˚F, below which backup electric resistance supplements ASHP output.
+ A mid-efficiency ASHP. This ASHP meets all heating demands below the 99th percentile of heating demands, above which backup electric resistance supplements ASHP output.
+ A high-efficiency ASHP. This ASHP meets all heating demands, with no backup electric resistance.
+ A residential hybrid HP. This hybrid HP meets all heating demands below the 95th percentile of heating demands, above which a backup gas furnace entirely replaces the heat pump's operation.
+ A commercial hybrid HP. This hybrid HP meets all heating demands below the 99th percentile of heating demands, above which a backup gas furnace entirely replaces the heat pump's operation.

To align with Pathways[30] whole-building heat pump efficiencies, a weighted-average heat pump shape was derived by mixing different ASHP technologies together. These weighted-average shapes were designed to have the same 2022 annual efficiency as those heat pumps in Pathways.

Hybrid heat pump sizes in RESHAPE were designed to align the percentage of backup heating demand assumed in Pathways.

Ground source heat pump and electric resistance shapes were assumed to be equivalent to the sensible heating demand shape derived from RESHAPE, since these technologies' efficiencies vary little with temperature.

RECLAIM

RECLAIM is E3's artificial neural network (ANN) regression model used to extend a relatively short record of historical data over a longer historical period using a longer period of weather data. This model was used to simulate a load shape to simulate all remaining end-uses, informed by the existing system load.

The process of developing this load shape began with the collection of recent historical hourly load data. Typically, E3 uses between 4 – 10 years of recent historical data, depending on data availability and the extent of changes that occur on a system. In this study E3 used six years of data, spanning 2016 – 2022, excluding 2020 to avoid training the model on any load shape anomalies resulting from the COVID-19 pandemic. The historical load impact of behind-the-meter (BTM) solar generation is removed to simulate gross load. BTM solar is modeled as a resource in PLEXOS and not as a load modifier.

Historic hourly temperature data from the ERA5 database were used for the five most populated New Jersey counties to capture historic temperature conditions across New Jersey; these included Bergen, Essex, Hudson, Middlesex, and Ocean County. A 33-year period from 1990 to 2022 was considered in this study. RECLAIM generates hourly load profiles, representing how electric demands would behave under a wide range of plausible weather conditions observed in this 33-year period.

The following independent variables are used in RECLAIM:

+ Hourly temperature (including lag and lead terms) for five locations
+ Month
+ Day-type (weekday/weekend/holiday)
+ Revolution angle of earth relative to the sun (mathematical representation of seasonality)
+ Rotation angle of earth (mathematical representation of day and night cycle)

[30] Pathways is E3's in-house model used for economywide energy demand and emissions accounting.

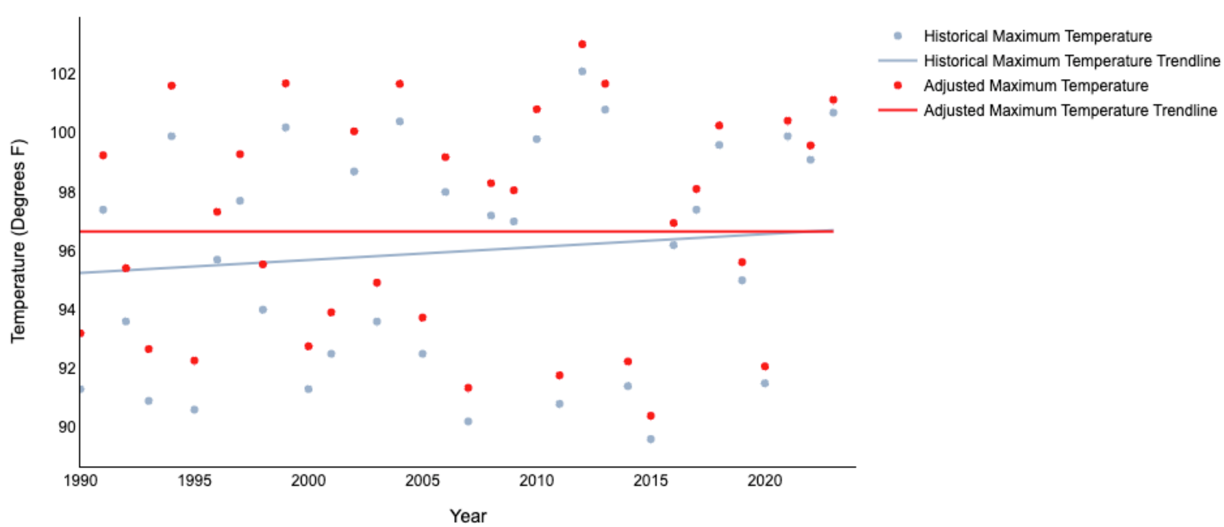
E3 trains RECLAIM using these independent variables and hourly load. The model, once trained, then intakes the same set of independent variables for the 33 historic weather years to generate a synthetic load for all represented conditions.

The hourly outputs of the ANN are then scaled to match the annual energy demand forecast for all end uses but electric vehicles and building heating and cooling whose treatment is described above.

Temperature Detrending

The study period in this EMP is 2025-2050. We do not have a perfect weather forecast for this period. Temperatures over 1990-2022 are thus modeled to account for the wide range of weather events that may be experienced in the future. However, it is important to correct for the climate-change-induced warming that has occurred over this period. The max temperatures for each year in this period were first identified. Then, with linear regression, the annual average increase in temperatures was identified. Hourly temperatures were then adjusted upward using this annual average increase times the number of years that have lapsed between 2022 and the past year of interest. This effectively allowed us to capture interannual weather variability while accounting for warming that has already occurred. Historical annual max temperatures before and after adjustment are shown in Figure 4.

Figure 4: Annual Average Daily Maximum Temperatures in Raw and Adjusted Weather Data



Interactions Between Models Used

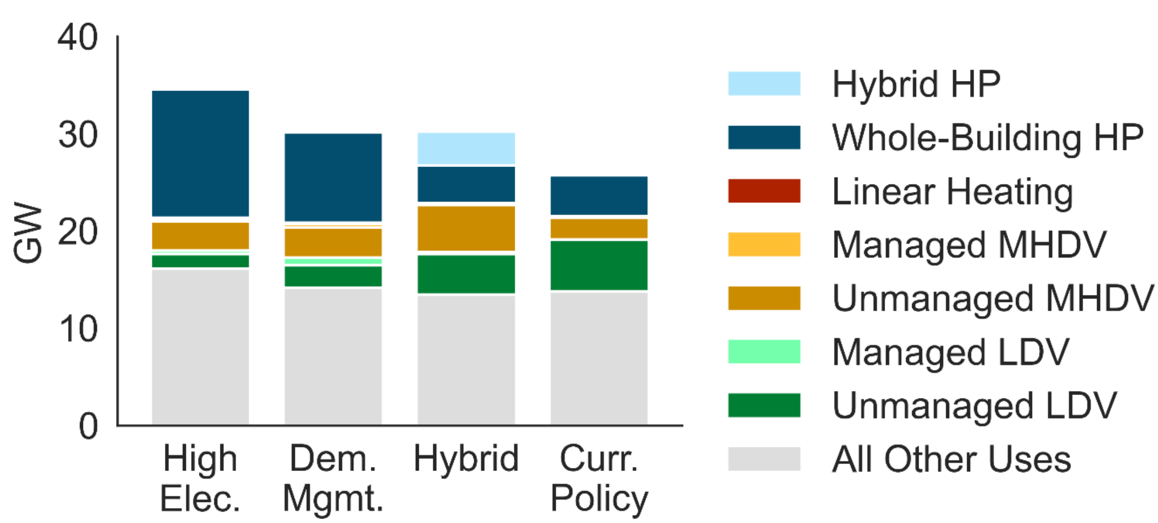
The annual demands estimated by Pathways get combined with the hourly load shapes developed by the models described above to produce hourly loads. Hourly loads then get input into the electric sector models. First, RECAP calculates the Planning Reserve Margin (PRM) required to maintain reliability given these load shapes. RECAP also calculates the Effective Load Carrying Capability (ELCC) of different resource types based on how their availability compares to the critical periods of need corresponding to these load shapes. The loads, PRMs and ELCCs then feed into PLEXOS that builds the resource portfolios. These optimized portfolios are then fed back into RECAP to confirm reliability. Finally, it is confirmed that the emissions from the electric sector are within the limit to ensure compliance with the economy-wide emissions target.

Peak Electric Demand

This analysis included a detailed look at the timing of electric loads and which of those may be flexible under different scenarios. In this IEP, the term "flexible loads" refers to those loads that can be shifted to another time in the day or shed during extreme conditions. Daily and hourly shiftable loads were calculated by assuming that a portion of EV charging and non-heating building loads are flexible and can be distributed across the day to mitigate peak impacts. It was assumed that these types of flexible loads will be driven in part by alternative rate structures, such as time-of-use (TOU) rates, or programs that encourage charge management. The *Demand Management* scenario incorporated higher load flexibility assumptions compared to the *High Electrification* scenario. A detailed breakdown of the key load flexibility assumptions and their evolution over the model horizon is provided in the technical appendix.

The annual load forecast for 2025 was multiplied by load shapes developed across 33 weather years to account for inter-annual variability. The summer and winter peak in each of the 33 weather years was then identified, resulting in a distribution of peak loads for each season. Finally, the median (or 1-in-2) summer and winter peak load forecast were calculated from their respective distributions for the year 2025.

Figure 5: Median Winter Peak Components After Load Flexibility by Scenario



This process was then repeated for future years through 2050.

Figure 6: Seasonal Median Peak Load Comparison

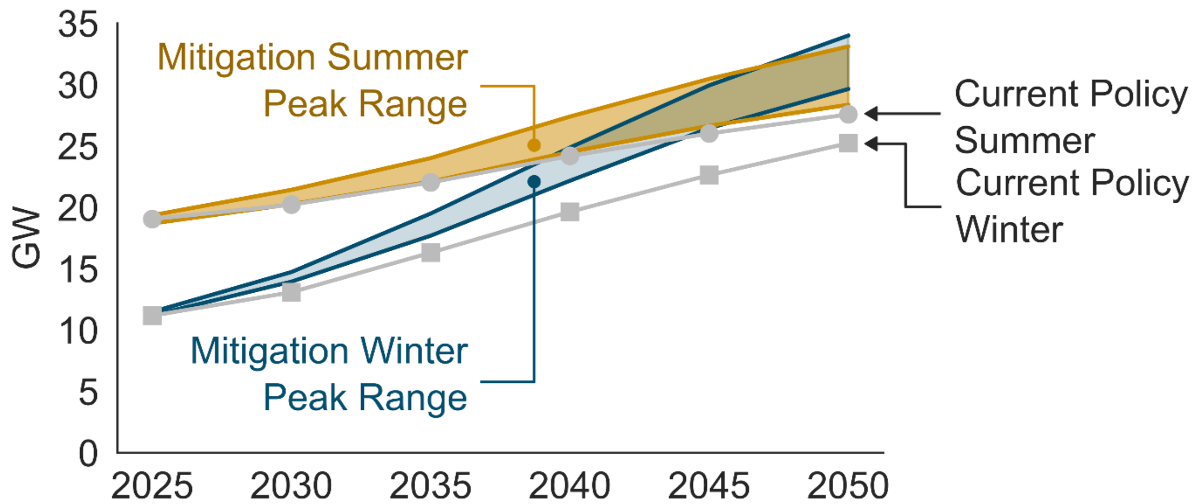
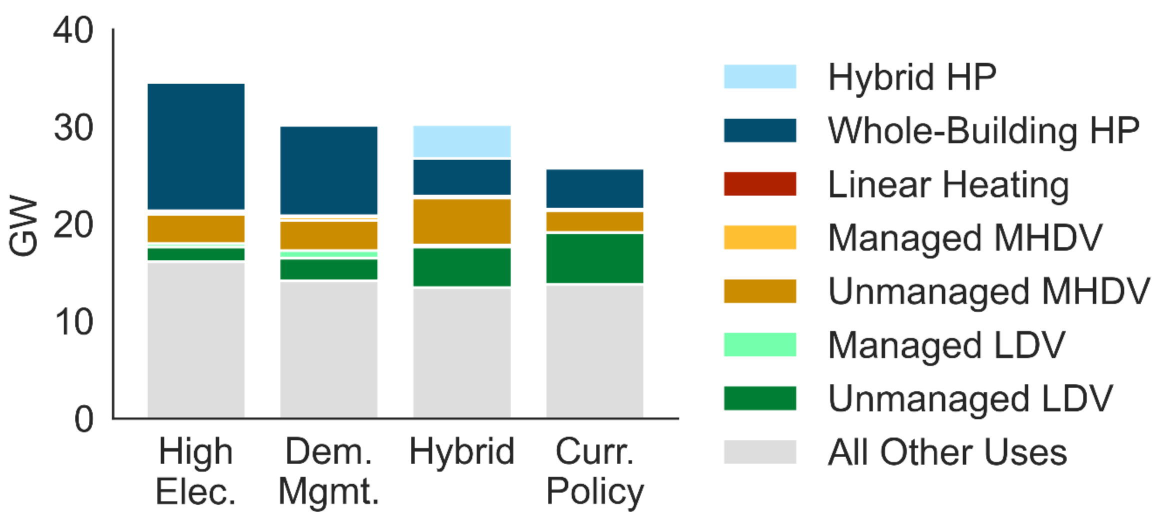


Figure 6 shows a comparison of the seasonal peak load forecasts of the Current Policy scenario and the mitigation scenarios, with the colored bands representing the range of median peaks across all mitigation scenarios. In all cases, both seasons' peaks grow over time. Peaks under the Current Policy scenario indicate that New Jersey will likely remain a summer peaking system. However, under the mitigation scenarios, New Jersey will likely transition to being dual- or winter-peaking in the mid- to late-2040s. Regardless of the specific assumptions in each of the mitigation scenarios, heating electrification causes winter peak loads to grow to similar levels as summer peaks. Discussed below, the mitigation scenarios manage this peak growth in several ways, with specific impacts on peak growth rate and timing.

Figure 7: Median Winter Peak Components After Load Flexibility by Scenario[31]



The type and composition of electrification and load management strategies influence the magnitude and load contribution to the peaks in each scenario. Figure 7 shows the behavior of each scenario's load components during their respective median winter peak load hours. The *High Electrification* scenario results in the highest peaks due to high rates of whole-building space-heating electrification and low amounts of EV charge management. Both the *Demand Management* and *Hybrid Electrification* scenarios mitigate some of this peak load growth through different strategies. The *Demand Management* scenario has high rates of EV charge management, spreading some evening EV charging into the earliest morning hours, and implements weatherization measures to reduce building contributions to peak. The *Hybrid Electrification* scenario substantially reduces peak electric heating in the coldest hours of the year through high rates of hybrid heating, relying on backup fuel during those hours instead of the heat pump. For both of these scenarios, their respective load management strategies result in slow winter peak load growth and an overall dual-peaking system. As a result, in both the *Demand Management* and *Hybrid Electrification* scenarios, peak load is reduced relative to the High Electrification scenario.

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[31] Whole-building HPs, Hybrid HPs, and Linear Heating refer to residential and commercial air-source heat pumps, residential and commercial air-source heat pumps with fuel backup, and residential and commercial electric resistance heaters and ground source heat pumps, respectively. All Other Uses captures end uses not included in any of the listed categories, including cooking, lighting, and industrial electrification, among others.

Electric Sector Modeling

Section 1: Overview of Models

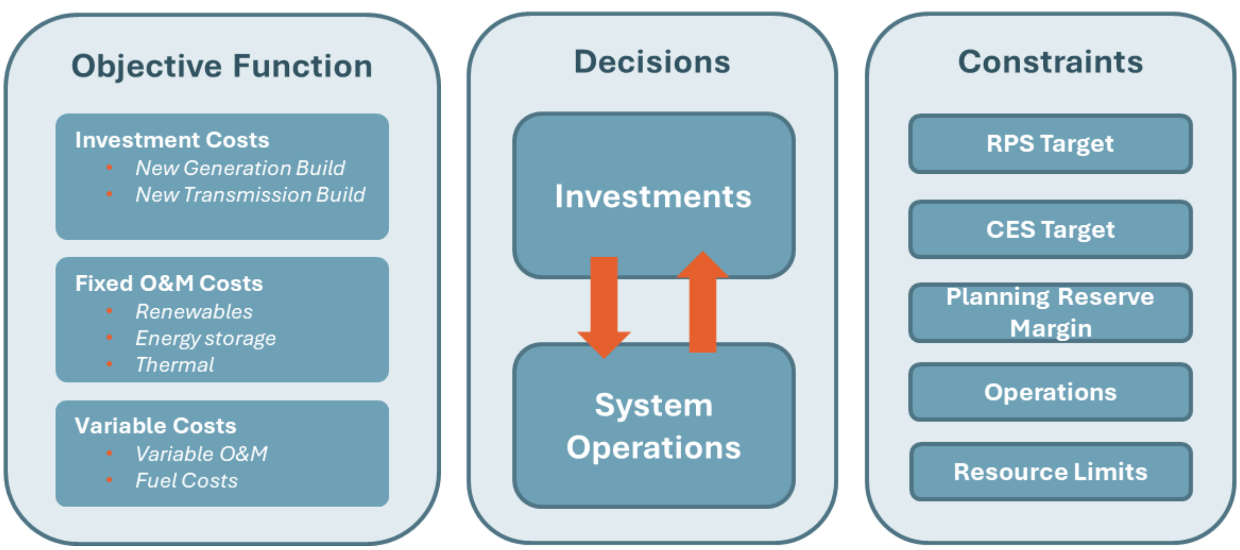
PLEXOS LT for Capacity Expansion Modeling

E3 performed resource portfolio optimization in this study using PLEXOS LT, an electricity system capacity expansion model that identifies the least-cost long-term combination of generation and transmission investments subject to reliability, policy, and operational constraints. PLEXOS is a widely used commercially available software package from Energy Exemplar for electricity and energy system modeling. PLEXOS LT is the long-term plan phase of PLEXOS used for capacity expansion modeling.

PLEXOS LT considers investment costs, fixed costs, and production costs to simultaneously optimize long-term capacity expansion and dispatch decisions. This allows the model to directly capture dynamic trade-offs between investments and dispatch, such as energy storage investments versus renewable curtailment and/or investments in supplementary renewable capacity. PLEXOS LT also captures the reliability contributions of all resources to the system and can ensure that demand can be met during the most challenging periods via a planning reserve margin constraint.

Figure 8 provides an overview of the PLEXOS LT model including the objective function, key model decisions, and key constraints.

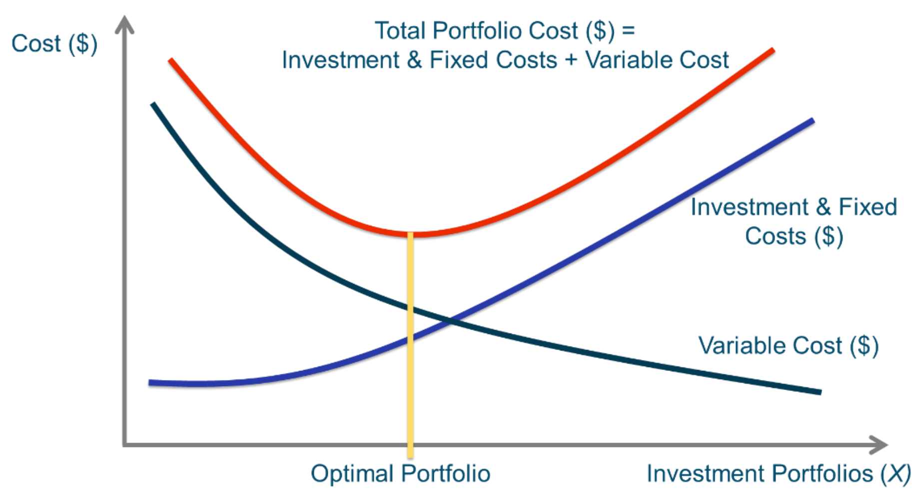
Figure 8: Overview of the PLEXOS LT Model



Objective Function

The objective function minimizes the net present value (NPV) of electricity system costs over the planning horizon, subject to constraints. Forward-looking costs include investment costs, fixed costs, and production costs. Investment costs include the capital costs of new generation, storage, and transmission resources. Fixed costs include fixed operations and maintenance (FO&M) costs of existing and new resources. Finally, production costs include variable operation and maintenance (VO&M) costs of existing and new resources, fuel costs, the cost of imports from external zones, and the value of power exported to other zones. As discussed in subsequent sections, E3 has modeled zones outside of New Jersey with a user-defined resource fleet; for these zones only the production costs are considered in the cost minimization. Figure 9 depicts an example optimal portfolio for a capacity expansion problem's objective function.

Figure 9: Illustrative Objective Function of Capacity Expansion Problem



The objective function is also subject to investment and operational constraints that are described in subsequent sections. Investment constraints include maximum resource potential for addition/retirement candidates (max/min units built/retired), resource adequacy constraints (the planning reserve margin), and other potential policy-related constraints such as the Renewable Portfolio Standard (RPS) and Clean Electricity Standard (CES) procurement requirements, Operationally, the model is constrained by the hourly energy balance in each modeled period, resource limits set by energy, fuel, emissions, and other limits on generation, storage, and transmission.

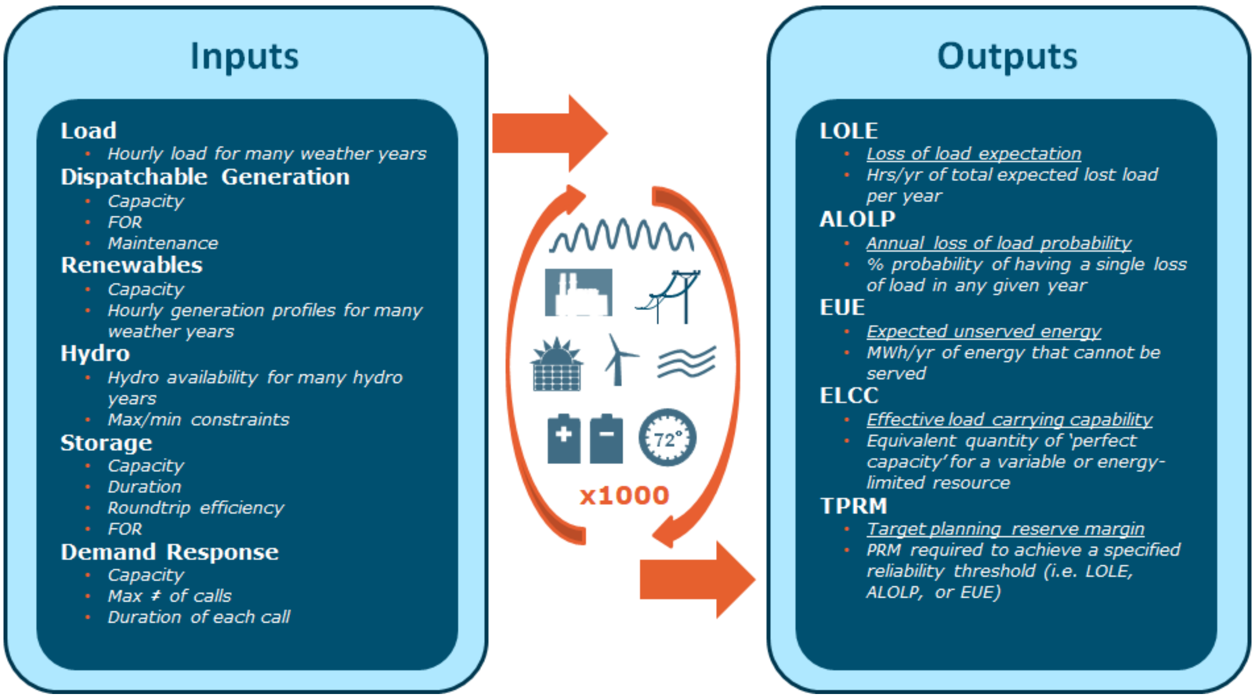
RECAP for Reliability Modeling

E3's **Renewable Energy Capacity Planning Model (RECAP)** is a loss-of-load-probability model designed to evaluate the resource adequacy of electric power systems, including systems with high penetrations of renewable energy and other dispatch-limited resources such as hydropower, energy storage, and demand response. RECAP was initially developed for the California Independent

System Operator (CAISO) in 2011 to facilitate studies of renewable integration and has since been adapted for use in many jurisdictions across North America.

RECAP evaluates resource adequacy through time-sequential simulations of thousands of years of plausible system conditions to calculate a statistically significant measure of system reliability metrics as well as individual resource contributions to system reliability. The modeling framework is built around capturing correlations among weather, load, and renewable generation. RECAP also introduces stochastic forced outages of thermal plants and transmission assets and time-sequentially tracks hydro, demand response, and storage state of charge. Figure 10 provides an overview of RECAP's key inputs and outputs.

Figure 10: RECAP Model Overview



Section 2: Inputs and Assumptions

Capacity Expansion Model Configuration

E3 configured PLEXOS LT to optimize capacity additions and resource dispatch from 2025 to 2050 in a single step to ensure the model makes optimal investment decisions that are not short sighted. This, however, results in a computationally intensive optimization problem. To ensure the capacity expansion problem is computationally tractable while still providing accurate and actionable results, PLEXOS performs several modifications to the system's representation. These modifications are described in the following sections.

Day Sampling and Operations

Sampling days within each future year ensures that the model captures variations in load and resources while ensuring the size of the optimization problem is tractable, compared to simulating every hour of the horizon. E3 configured PLEXOS LT to sample two representative days per month in each future year, with each day consisting of 12 2-hour "blocks". After sampling, PLEXOS LT rescales load and renewable profiles to ensure that the total annual energy remains in line with the original inputs.

Within each sampled day, existing, planned, and candidate resources are dispatched to meet load at least-cost while respecting long-term expansion constraints. PLEXOS LT was configured to perform economic dispatch in each modeled "block" of the sampled day. Unit commitment of resources was not performed due to the large impact on model runtime; the practice of modeling economic dispatch but not unit commitment is common in capacity expansion studies of this scale. PLEXOS LT results are reported on an hourly basis for every year of the modeled time horizon.

Regions Modeled and Transmission

NJ is a part of PJM, specifically its EMAAC (Eastern Mid-Atlantic Area Council) region. NJ, and thus PJM also meaningfully interact with NYISO. Both PJM and NYISO were modeled in this study to capture the interactions between NJ and the two major ISOs it is connected to. Details follow:

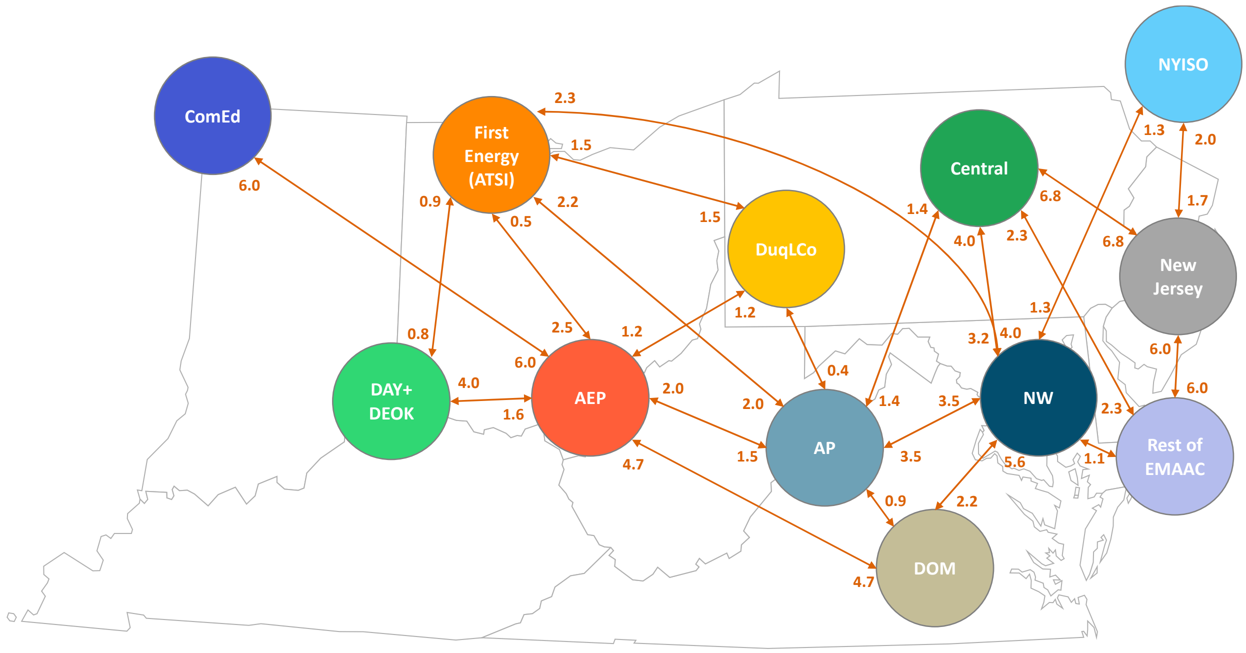
Topology and Transmission Limits

The transmission network was modeled at the regional level with all resources inside the region connected to a single notional node. Figure 11 below shows the transmission limits across regions within PJM and corresponding links to NYISO. Power flow limits were defined according to Energy Exemplar's internal research and analysis. E3 conducted an independent analysis to determine import and export limits between NYISO and New Jersey based on EPA's documentation of their IPM model[32]. E3 split PJM's EMAAC region into two regions, "New Jersey" and "Rest of EMAAC" to model certain NJ-specific policies and considerations. E3 calculated the total net interchange between the two new regions as informed from PJM's Data Miner 2[33].

[32] https://www.epa.gov/system/files/documents/2023-03/Chapter%203%20-%20Power%20System%20Operation%20Assumptions.pdf

[33] https://dataminer2.pjm.com/feed/state_net_interchange

Figure 11: Topology and Transmission Limits across PJM regions



Modeled Region	Utility
New Jersey	Atlantic City Electric
	Jersey Central Power & Light
	Public Service Electric & Gas
	Rockland Electric Company
Rest of EMAAC	Delmarva Power & Electric Light Company
	PECO Energy Company
Central	Metropolitan Edison Company (Med-Ed)
	Penn Power & Light Company
	UGI Corporation
Northwest (NW)	Baltimore Gas & Electric Company
	Pennsylvania Electric Company
	Potomac Electric Power Company (PEPCO)
Dominion (DOM)	Virginia Power Company (Dominion)
Allegheny Power (AP)	Allegheny Power System (APS)
DuqLCo	Duquesne Light Company (DLCO)
First Energy (ATSI)	First Energy American Transmission Systems, Inc.
AEP	American Electric Power Co., Inc (AEP)
	Eastern Kentucky Power Cooperative (EKPC)
	Ohio Valley Electric (OVEC)
DAY+DEOK	Dayton P&L
	Duke Energy Ohio/Kentucky (DEOK)
ComEd	Commonwealth Edison Co.

Transmission Expansion

Two types of transmission expansion were included in the main scenarios:

1. **Interconnection**: The 230 kV spur line cost that is incurred by all new renewable projects (except rooftop BTM solar) were accounted for. These costs are resource tier-specific and based on data from NREL's Regional Energy Deployment System (ReEDS) Model.
2. **Local network upgrade**: This represents upgrades to the "bulk grid" that are needed once headroom on the existing transmission system is exhausted. It is assumed that the headroom is exhausted after the first tier of solar is integrated. Integrating one additional GW of solar after this costs $5,197/MW-mile informed by recent projects in PJM as shown in Table 7. Every additional GW is assumed to cost 15% more than it did for the previous GW to reflect challenges of continuing to expand the transmission network within a specific region informed by a recent presentation from NYISO[34]. The interconnection and local network upgrade costs applied to each resource tier is shown in Table 16.

Table 7: Recent Transmission Project Costs in PJM

Upgrade ID	Line Cost (2023$MM)	Line Length (miles)	Line Voltage (kV)	Est. Capacity (MW)	Est. Unit Cost ($/MW-mile)	Awardee	Page Number of Source
B3800.7	$ 213	38	500	1,100	$ 5,100	PSEG	18
B3800.32	$ 407	59	500	1,100	$ 6,273	BGE	21
B3800.43	$ 177	32	500	1,100	$ 5,102	PSEG	27
B3800.356	$ 88	17	500	1,100	$ 4,812	Dominion	53
B3800.357	$ 102	20	500	1,100	$ 4,700	Dominion	53
Average					**$5,197**		

Role of Inter-zonal Transmission and Firm Imports for Reliability

The modeling representation captures the ability of New Jersey to continue to interact with the rest of PJM and NYISO to the extent optimal during certain seasons or times of day. To identify an in-state reliability requirement, this study assumed 7 GW of firm imports– informed by the PJM Capacity Emergency Transfer Limit (CETL)– could be leveraged to ensure the state's electricity system remains reliable under increasing demand while recognizing its ability to continue to import power from the rest of PJM. This is less than the 8.7 GW CETL for the broader EMAAC reported by PJM in the 2025-2026 RPM Base Residual Auction planning parameters[35]. Weather, resource availability, and load can vary across a large geographical footprint. There are opportunities for excess generation to

[34] https://dps.ny.gov/system/files/documents/2024/06/capacity-expansion-results-for-eppac_nyiso.pdf
[35] https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-planning-period-parameters-for-base-residual-auction.ashx

exist in one part of the system that can help meet a deficit in another and avoid the need for each state to overbuild its own resource portfolio.

In this study, transmission expansion between New Jersey and its neighbors was not modeled as a candidate for selection by the model. If inter-regional transmission expansion can occur, NJ may be able to expand its reliance on imported energy and capacity, which may in turn help reduce costs and direct land use impacts in NJ (e.g. if less in-state solar, nuclear and battery storage is required). However, imported power from other parts of PJM will have associated emissions impacts unless paired with additional investments in new renewable resources such as wind in neighboring states. One option for pursuing additional imported clean power with dedicated transmission was examined in a sensitivity, illustrated in a later section titled – " **Error! Reference source not found.**".

Clean Energy Policies

Renewable Portfolio Standard and Clean Electricity Standard

E3 modeled PJM and NYISO in PLEXOS. New Jersey's resource portfolio was optimized in each scenario. The rest of PJM and NYISO had the same resource portfolio and load in all scenarios, corresponding to E3's latest view of their load and resource forecasts, informed by their respective policies. The varied policies and targets of states within PJM were taken into consideration when modelling PJM's resource portfolio. In the long term, it is assumed that PJM achieves 53% renewable generation as a share of total load by 2050. It was also assumed that PJM's coal fleet is fully retired after 2040, while gas capacity continues to grow given robust long-term growth in demand.

E3's representation of NYISO was informed by New York's electricity[36] targets established in the Climate Leadership and Community Protection Act (CLPCA), as modeled in the Scoping Plan. E3 assumed that the 70% RPS target is met by 2030, including the 6 GW storage mandate. E3 also assumed NY meets the 9 GW Offshore Wind target by 2035 and the 100% Zero Emissions Electricity target by 2040. All oil-fired generation was assumed to retire by 2040, and all gas-fired generators are retrofit to burn 100% hydrogen by 2040.

To meet NJ's 50% RPS and 100% CES targets, E3 modeled in-state candidate resources to be described in detail later. In addition, the model was also free to purchase unbundled Renewable Energy Credits (RECs) if more economic than building renewables to meet the RPS and CES targets until 2045 in the base case. E3 assumed a cost of $40/MWh for unbundled RECs.

EPA Restrictions on New Gas

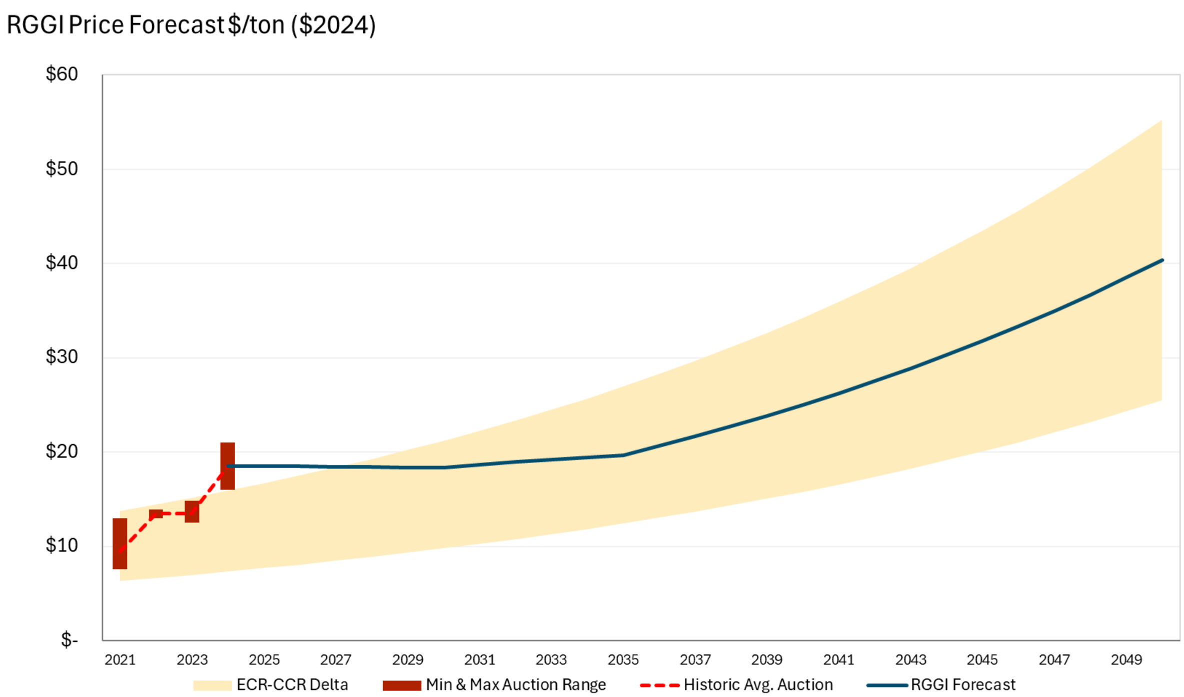
In April 2024, the EPA issued final carbon pollution standards for power plants using fuels with GHG emissions, based on the Clean Air Act Section 111. E3 modelled the standards as follows: 40% capacity factor limit on all new natural gas-fired units. This reflects the assumption that new gas plants are more likely to limit generation rather than adopt carbon capture sequestration

[36] https://climate.ny.gov/resources/scoping-plan/

technologies due to cost and siting challenges for sequestration. Existing natural gas facilities are exempt from the standards.

Regional Greenhouse Gas Initiative

Figure 12: RGGI Price Forecast



The Regional Greenhouse Gas Initiative (RGGI) is a cap-and-trade market in the US Northeast to reduce emissions from the power sector. It covers 11 states (including NJ) that cover parts of PJM, NYISO and ISO-New England. All these states were not modeled in PLEXOS. Thus, in lieu of modeling the cap trade program, E3 modeled a RGGI allowance price adder. This price adder is applied to the operational cost of all fossil generators in the RGGI states that were modeled.

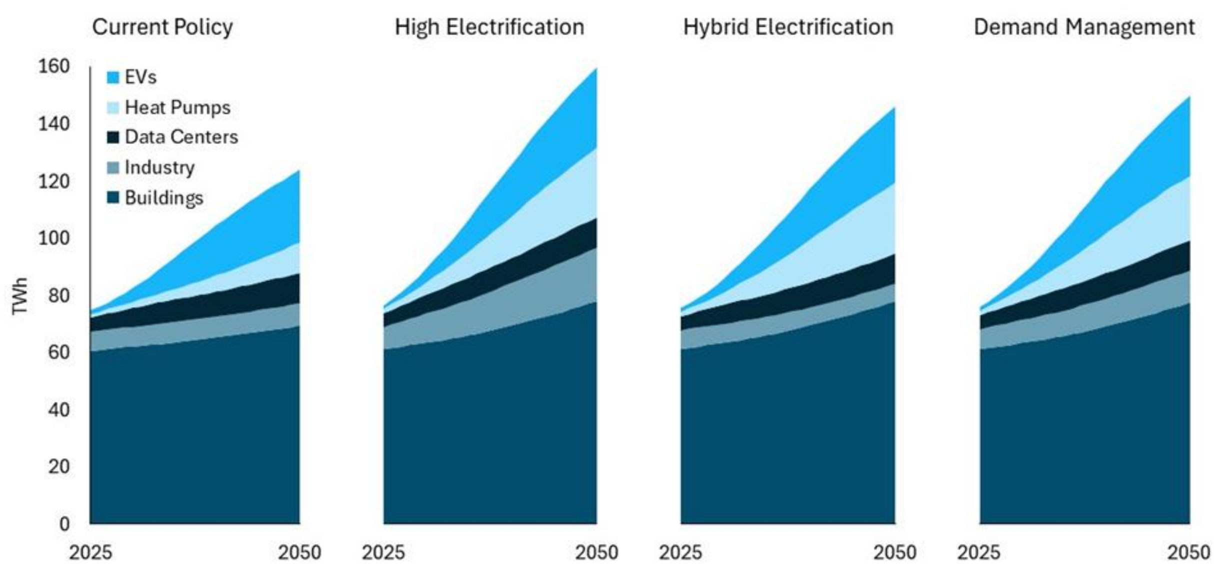
The RGGI allowance price projection begins in 2024 with the average of the first two auction prices in 2024, which are above the upper Cost Containment Reserve (CCR) trigger price. From 2024 to 2030, prices are expected to trend toward a weighted average of 75% CCR and 25% Emissions Containment Reserve (ECR) trigger prices, returning below the CCR but remaining within the higher end of the ECR-CCR range. Between 2030 and 2035, prices are projected to move toward the midpoint of the CCR and ECR range, assuming market actions guide prices toward equilibrium. Throughout the entire period, it is assumed that both the ECR and CCR will escalate at 7% per year, consistent with current RGGI practices.

Electricity Demand

Annual Loads

Electricity demand increases in all scenarios due to the electrification of building appliances, industrial equipment, and vehicles as shown in Figure 13. Heat pumps and electric vehicles are the largest source of load growth, and overall electricity demand increases between 66-109% by 2050 across the four scenarios. The development of this data is explained in more detail in the Pathways appendix.

Figure 13: Annual Electricity Demand by Source and Scenario Through 2050



Median Peak Loads

Weather-dependent load shapes were developed using the models described above. For a given scenario and model year, hourly loads were generated by multiplying the annual loads in Figure 13 by the appropriate shapes across all 33 weather years. These hourly loads by end-use were then aggregated to calculate the systemwide hourly load. For each weather year, summer and winter peaks were estimated by finding the highest load in each season, resulting in 33 summer and winter peaks. For each season, the peak value closest to the median of their respective distributions was determined. The highest peak of the two seasons was set as the median annual peak. This process was repeated for each scenario and model year.

Table 8: Managed Charging Assumptions for Electric Vehicles in 2050

	Current Policy	Hybrid Electrification	High Electrification	Demand Management
2050	3%	12%	25%	50%

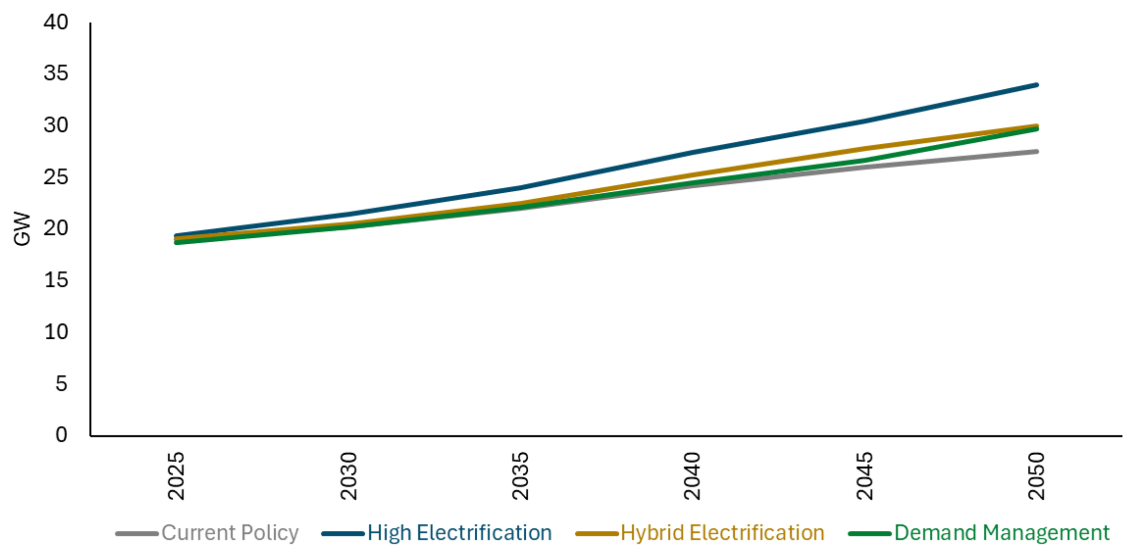
Table 9: Building Flexibility Assumptions for Demand Management Scenario in 2050

Sector, Season	2050
Commercial, Summer	1%
Commercial, Winter	1%
Residential, Summer	13%
Residential, Winter	12%

After selecting the median peak, building load flexibility was applied to non-heating building loads in the Demand Management scenario only. This flexibility was treated as a simple rescaling of the building load contributions to the median peak. As a result, this method does not consider the impact of building flexibility in adjacent non-peak hours. A more thorough analysis, which might optimize building load flexibility alongside electric-sector capacity expansion and operation, may reveal potentially higher or lower levels of building flexibility in New Jersey than what was assumed in this study.

The higher of the median summer and winter peaks is plotted in Figure 14.

Figure 14: Median Peak Load by Scenario Through 2050



Load Assumptions for External Regions

The figures below depict the peak load (GW), and annual load (GWh) modelled for the sample years of 2025, 2035 and 2050 for NYISO and the rest of PJM (excluding New Jersey). The rest of PJM load was informed by the PJM 2024 Load Forecast report[37] while the NYISO Load was informed by the NY Scoping Plan[38].

Figure 15: Peak Load in the Rest of PJM and NYISO

Peak Load (GW)	Rest of PJM	NYISO
2025	147.5	32.6
2035	173.7	36.5
2050	198.2	46.6

Figure 16: Annual Load in the Rest of PJM and NYISO

Annual Load (GWh)	Rest of PJM	NYISO
2025	806,755	156,142
2035	1,023,106	198,337
2050	1,238,761	262,431

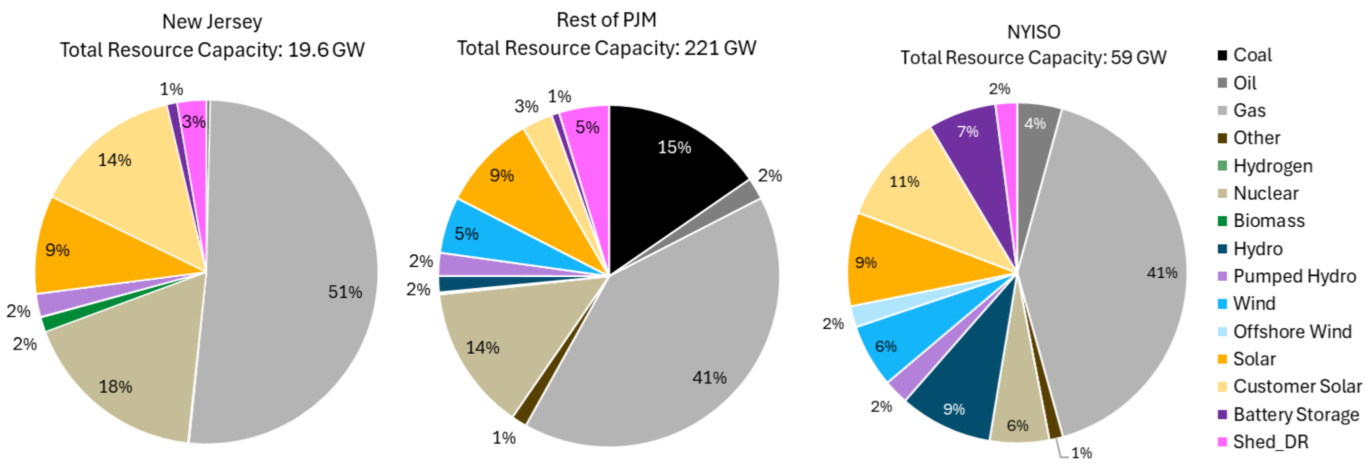
[37] https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx

[38] https://climate.ny.gov/-/media/Project/Climate/Files/NYS-Climate-Action-Council-Final-Scoping-Plan-2022.pdf

Existing Resources

The existing resources for PJM and NYISO were based on the EIA-860M Operating, Planned and Cancelled worksheets from August 2022. E3 reconciled the gap between 2022 and 2024 as it relates to resource additions and retirements using Velocity Suite.

Figure 17: Existing Resource Portfolio by Region



Planned Resource Builds

Planned Resource Builds in NJ

Planned builds in this context imply resource builds that are user-defined, i.e not optimized by the model. E3 implemented minimum builds in PLEXOS for several resource types to ensure compliance with policy targets established by the state.

The Solar Act of 2021 established a goal of installing 3.75 GW of incremental solar by 2026, split into 300 MW of behind-the-meter solar, 150 MW of community solar, and 300 MW of grid supply solar per year. After benchmarking existing solar capacity in PLEXOS against New Jersey's Clean Energy Program Solar Activity Report from March 31, 2024, E3 enforced the annual build requirements required by the Act in 2025 and 2026.[39] Beyond 2026, E3 gradually reduced the market growth rate by 1% per year until a steady state of approximately 1% per year was reached in all scenarios but Demand Management. In the Demand Management scenario, demand-side measures were assumed to play a bigger role. To reflect this, the annual growth rate was assumed to decay with a one-year lag and assumed to stabilize at a steady state of approximately 2% growth per year. These build trajectories were also enforced in PLEXOS. The model also had the option to select additional

[39] https://www.njcleanenergy.com/renewable-energy/project-activity-reports/project-activity-reports

distributed solar resources above this hard-coded baseline but it preferred utility-scale solar given its lower cost and higher capacity factor.

For offshore wind, the planned build trajectories were informed by BPU. In the Current Policy scenario, a 3.5 GW by 2035 target was modeled. In all other scenarios, additional solicitations were modeled to ensure the state meets its target of 11 GW by 2040.

E3 also required at least 2 GW of battery storage capacity by 2030 to comply with the state's policy target. This led to 1.8 GW of planned additions on top of exiting battery storage. Planned builds for all these resource types were enforced as minimum build constraints. So, the model was free to build more, if economic.

Table 10: Cumulative Planned Resource Builds (MW)

Resource Type	Distributed Solar*		Utility-Scale Solar	Offshore Wind		Battery Storage
Scenarios	Default	Demand Management	All	Default	Current Policy	All
2025	376	376	231	-	-	-
2030	2,077	2,298	462	1,510	1,510	1,809
2035	2,802	3,388	462	5,500	3,500	1,809
2040	3,026	4,004	462	11,000	3,500	1,809
2045	3,258	4,674	462	11,000	3,500	1,809
2050	3,498	5,402	462	11,000	3,500	1,809
Total	**3,499**	**5,402**	**462**	**11,000**	**3,500**	**1,809**

** NOTE: AC capacity is shown above. Distributed solar includes both behind-the-meter and front-of-the-meter distributed solar PV.*

Planned Resource Builds in the rest of PJM and NYISO

The resource builds and retirements in the rest of PJM and NYISO were user-defined, informed by exogenous analyses to manage model complexity. These resource portfolios were held consistent across all scenarios. E3 accounted for the differing clean energy policy goals across states in PJM. Several states have renewable energy standards, however some policies are limited to the short term while states like DC and VA are committed to 100% RPS by 2032 and 2050 respectively. Effectively, PJM excluding NJ is assumed to achieve an RPS of 54% by 2050.

NYISO's long-term resource portfolio was informed by the Scoping Plan[36] developed to meet targets established in the CLCPA. These include a 70% CES by 2030 and a 100% GHG-free generation requirement by 2040. The 2040 target requires all gas-powered generation to be replaced by green hydrogen and for NY to become a net exporter.

Figure 18: Total Installed Capacity in PJM excluding New Jersey

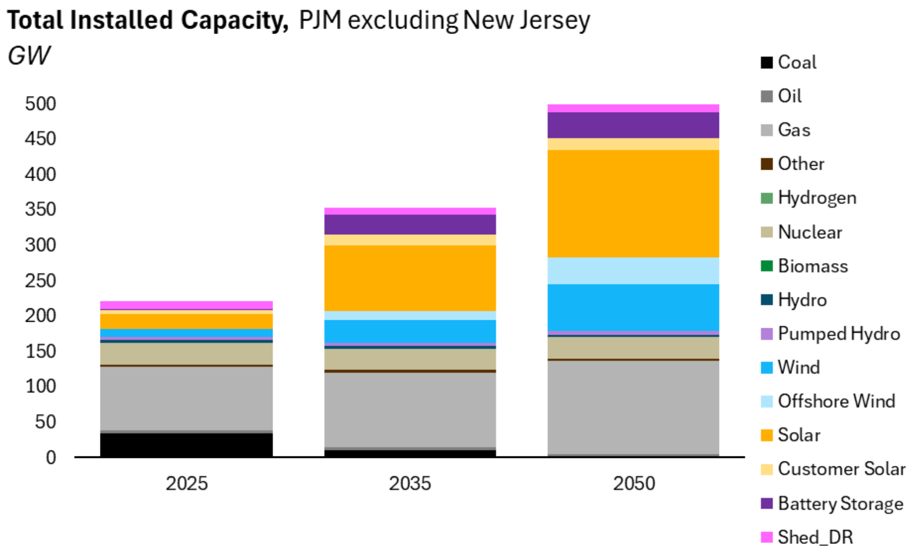
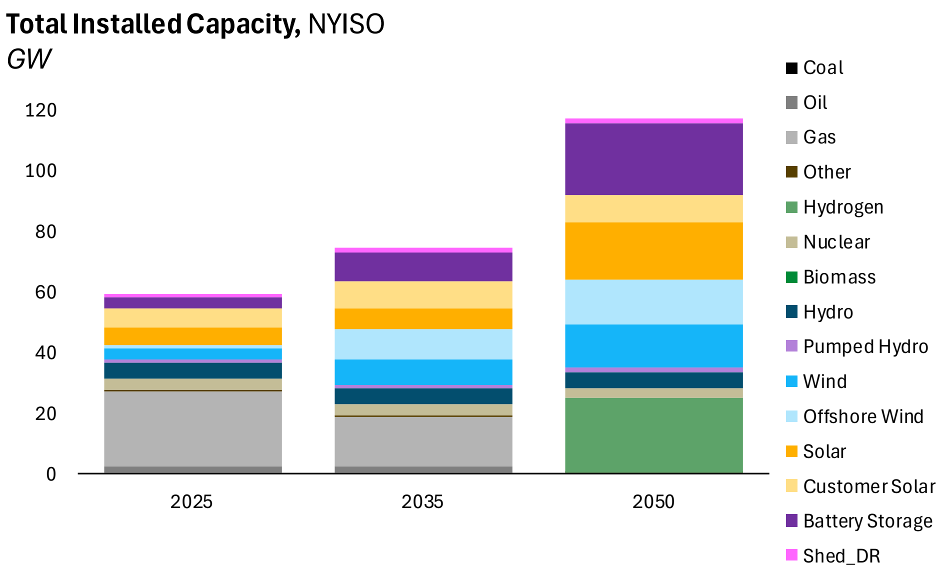


Figure 19: Total Installed Capacity in NYISO



Candidate Resources

Candidate resources could be selected by the capacity expansion model to meet growing demand, replace retiring resources, or ensure compliance with policy targets. These resources are grouped into the following categories:

1. Candidate Renewable Resources
2. Candidate Storage Resources
3. Candidate Thermal Resources

Candidate Renewable Resources

Candidate renewable resources available under all scenarios and sensitivities included utility-scale solar, and offshore wind. New Jersey lacks land-based wind potential. E3 assumed availability of land-based wind in Pennsylvania to be procured by and delivered to New Jersey in a sensitivity. The cost of building or upgrading existing transmission infrastructure to connect these resources to load centers in New Jersey are reflected in the local network upgrade costs (see Table 16). The assumptions underpinning the offshore wind resources modeled for this study were developed as part of ongoing offshore wind research performed by BPU in parallel with this EMP.

Resource Potentials and Tiers

Total resource potentials, i.e., maximum build limits, for utility-scale solar and onshore wind are based on the findings of a detailed geospatial analysis conducted by the Princeton Zero-Carbon Energy Systems Research and Optimization (ZERO) Lab as part of a study on rapid decarbonization of the PJM Interconnection.[40] The analysis involved screening out lands deemed unsuitable for construction (e.g., wetlands), in addition to administratively protected areas and cultural landmarks.[41] Offshore wind assumptions were developed and provided by BPU, informed by research performed in parallel to the EMP. The total potential for each resource type show in Table 11 below is split into tiers based on the level of transmission cost adder.

[40] *Cleaner, Faster, Cheaper* (Xu et al., 2022): https://zenodo.org/records/7423519
[41] *Wind and Solar Candidate Project Areas for Princeton REPEAT* (Leslie et al., 2021): https://zenodo.org/records/5021146

Table 11: Renewable Resource Potentials and Characteristics

Resource Name	Planned/ Candidate	Capacity Potential* (MW)	AC Capacity Factor	Economic Life	Notes
Solar BTM	5-6.3 GW Planned, Rest Candidate	No Limit	18%	30	Behind-the-meter solar PV typically deployed on residential and commercial rooftops.
Solar DGPV	2.2-2.8 GW Planned, Rest Candidate	No Limit	21%	30	Front-of-the-meter solar PV typically deployed on warehouse rooftops, parking lot canopies, or the ground.
Solar UPV (Tier 1)	462 MW Planned, Rest Candidate	1,126	26%	30	Utility-scale solar PV tiers are identical in terms of resource quality (i.e., capacity factor) but vary by grid interconnection (i.e., spur line construction) and local network upgrade costs.
Solar UPV (Tier 2)	Candidate	4,883	26%	30	
Solar UPV (Tier 3)	Candidate	6,989	26%	30	
Solar UPV (Tier 4)	Candidate	6,379	26%	30	
Solar UPV (Tier 5)	Candidate	5,524	26%	30	
PA Onshore Wind (Tier 1)	Candidate	600	35%	30	Out-of-state resource approximately 50 miles away in Eastern Pennsylvania. Incurs additional transmission cost adder (see Table 16 below).
PA Onshore Wind (Tier 2)	Candidate	3,700	35%	30	Out-of-state resource approximately 150 miles away in Central Pennsylvania. Incurs additional transmission cost adder (see Table 16 below).
PA Onshore Wind (Tier 3)	Candidate	3,700	35%	30	Out-of-state resource approximately 300 miles away in Western Pennsylvania. Incurs additional transmission cost adder (see Table 16 below).
Offshore Wind (Tier 1)	Planned	3,500	43%	30	Tier sized based on POIs within ~10 miles of shore.
Offshore Wind (Tier 2)	Planned	3,500	43%	30	Tier size based on 3,500 MW SAA2 injection.
Offshore Wind (Tier 3)	4 GW Planned, Rest Candidate	No Limit	43%	30	OSW in excess of the 11 GW target was allowed to be selected if economic

** NOTE: AC capacity is shown above. To calculate the DC capacity of solar resources, multiply the AC capacity by the inverter load ratio (ILR) of the applicable resource type noted below.*

Solar and Wind System Parameters

Three types of solar resources were modeled in this study. Behind-the-meter solar refers to both residential and commercial rooftop installations ranging from a few kilowatts to 1 megawatt in nameplate capacity. Distributed solar refers to front-of-the-meter commercial solar exceeding 1 megawatt in nameplate capacity as well as community solar projects, which are identified in the Solar Activity Report[42]. Utility-scale solar refers to large-scale installations that feed directly into the grid. The modeling parameters assumed for each to simulate hourly generation profiles with are shown in Table 12.

Table 12: Solar PV Modeling Parameters

Parameter	Solar BTM	Solar DGPV	Solar UPV
Array Type	Fixed Roof Mount	Fixed Open Rack	Single-Axis Tracking
DC-to-AC Ratio	1.15	1.30	1.30
Inverter Efficiency	96%	96%	96%
Losses	14.08%	14.08%	14.08%
Azimuth	180 ̊	180 ̊	180 ̊
Tilt	20 ̊	30 ̊	30 ̊
Ground Coverage Ratio	N/A	0.3	0.30

** NOTE: the inverter efficiency and system loss parameters above are default assumptions in NREL's PVWatts model.*

With the parameters shown in Table 12, E3 simulated hourly generation profiles for each solar PV technology configuration using NREL's System Advisor Model (SAM) and historical weather data from the National Solar Radiation Database (NSRDB)[43]. While multiple weather years were modeled in RECAP, 2022 was the weather year chosen for PLEXOS to ensure load shapes are aligned with current end uses before incremental impacts of electrification can be introduced. Renewable profiles were developed accordingly. To accurately reflect the impacts of shading and infrequent maintenance on the output of residential systems, E3 scaled solar BTM generation profiles to match the AC capacity factor from PJM's 2024 Load Forecast[44].

E3 used offshore wind generation profiles generated as part of ongoing state research on offshore wind development. Ramboll, another consultant for the state, combined multiple data sources to establish an offshore wind generation profile that matches the month-hour averages modeled by NREL while capturing the higher mean wind speeds indicated by LiDAR measurements in the region[45]. Modeling parameters used are shown in Table 13.

[42] https://www.njcleanenergy.com/renewable-energy/project-activity-reports/project-activity-reports
[43] The specific dataset used for this analysis was the Physical Solar Model (PSM) V3, which contains sub-hourly meteorological conditions at a 2x2 km resolution from 1998-2022: https://nsrdb.nrel.gov/data-sets/us-data
[44] https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx
[45] Ramboll started with a profile from NREL's WIND Toolkit for 2013, but adjusted to match the monthly profile from a more recent dataset, NOW-23.

Table 13: Offshore Wind Modeling Parameters

Parameter	Value
Hub Height	150 m (above mean sea level)
Rotor Diameter	240 m
Turbine Capacity	15 MW
Power Curve	NREL IEA-Task37, adjusted for 5.5% turbulence intensity
Turbine Interaction Losses	20%
Technical Losses	9.6%
Location	Lat: 39.33, Lon: -73.95
Weather Dataset	NREL WIND Toolkit (2013), adjusted to match the NOW-23 monthly profile

** NOTE: assumed wake losses carry significant uncertainty due to the magnitude of proposed buildout and ongoing research into cluster wakes.*

NREL's Wind Integration National Dataset (WIND) Toolkit[46] is typically used to simulate onshore wind profiles. However, the WIND Toolkit does not cover 2022, the weather year in PLEXOS. E3 thus developed an onshore wind generation profile based on actual wind generation reported in PJM's Mid-Atlantic region in 2022. E3 confirmed that wind curtailment in 2022 was low. Actual generation was thus a reasonable proxy for hourly potential. In addition, E3 accounted for the fact that some of these wind turbines are old and improvements in turbine technology may lead to increased capacity factors from future projects.[47] The annual capacity factor of 35% after adjustment aligns with Energy Exemplar's default assumption for candidate resources in the Mid-Atlantic region, which is derived using the WIND Toolkit.

Candidate Storage Resources

E3 modeled both 4- and 8-hour lithium-ion battery storage in PLEXOS, allowing the model to select which resource cost-optimally contributed to system reliability under high penetrations of intermittent renewable resources. No limits were placed on the total capacity of battery storage that could be selected by the model.

Table 14: Candidate Storage Resources

Technology Type	Duration	Round-Trip Efficiency	Economic Life	Scenarios
Lithium-Ion Battery	4-hour	85%	20	All
Lithium-Ion Battery	8-hour	85%	20	All

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[46] https://www.nrel.gov/grid/wind-toolkit.html

[47] Hourly capacity factors were calculated by dividing hourly generation data from PJM's DataMiner 2 tool (https://dataminer2.pjm.com/feed/wind_gen/definition) by monthly installed capacity (from Velocity Suite) for the Mid-Atlantic region. The capacity factor in 2022 was estimated to be 30%. To account for turbine improvements, E3 adjusted the profile upward by 5% for new, candidate wind to attain an annual capacity factor of 35%. No violations of hourly generation exceeding nameplate capacity were found.

Candidate Gas and Nuclear Resources

New Nuclear Reactors were available to the model all scenarios. A sensitivity was conducted where Combustion or Combined Cycle gas Turbines could be selected by the model – burning natural gas in the near-mid-term and required to be retrofit to burn a clean fuel by 2050.

Table 15: Candidate Gas and Nuclear Resources

Resource Name	Fuel Type	Heat Rate (Btu/kWh)	CO2 Emissions Rate (lb/MMBtu)	VO&M Charge ($/MWh)	Economic Life	Scenarios
New Nuclear Reactor	Uranium	10,447	N/A	4.48	50	All
Combustion Turbine	Natural Gas*	9,905	118.86	6.71	30	With New Clean Fuel Combustion Turbines Sensitivity
Combined Cycle Gas Turbine	Natural Gas*	6,363	118.86	2.52	30	With New Clean Fuel Combustion Turbines Sensitivity

** If selected, this resource type was assumed to be retrofitted to burn a clean fuel by 2050.*

Resource Costs

E3 developed resource costs for each candidate resource using an in-house levelized cost calculator known as RECOST. The “Moderate” scenario from NREL’s 2023 Annual Technology Baseline (ATB) served as a starting point for these assumptions, but E3 made several updates to reflect recent market conditions and other considerations specific to New Jersey. Offshore wind costs were developed by the state’s offshore wind consultant, Ramboll.

RECOST calculates a unit’s levelized fixed costs based on its economic life and weighted-average cost of capital (WACC) for each year of the modeling horizon. Fixed costs include capital expenditures (CAPEX); fixed operation and maintenance (FO&M); interconnection costs; local network upgrade costs; investment tax credits; property taxes; and warranty, augmentation, and periodic replacement costs. PLEXOS was also provided with variable operation and maintenance (VO&M) by resource type. These costs inform resource additions and dispatch in the model.

The levelized fixed cost of the resources shown below decline steadily until 2046, which is the last year projects were eligible to receive the full investment tax credit (ITC) or production tax credit (PTC). From 2047 to 2048, projects may receive a reduce ITC or PTC, but by 2049, Recost assumes both tax credits have fully expired.

Figure 20: Levelized Fixed Cost of Solar Technologies

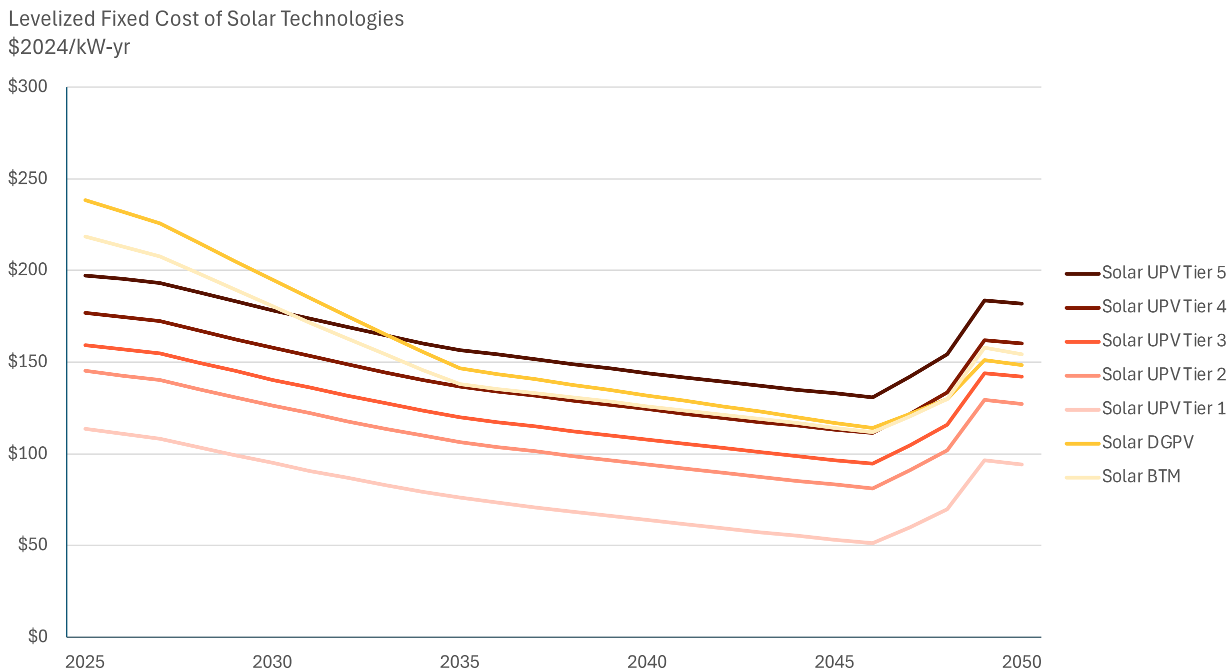


Figure 21: Levelized Fixed Cost of Wind Technologies

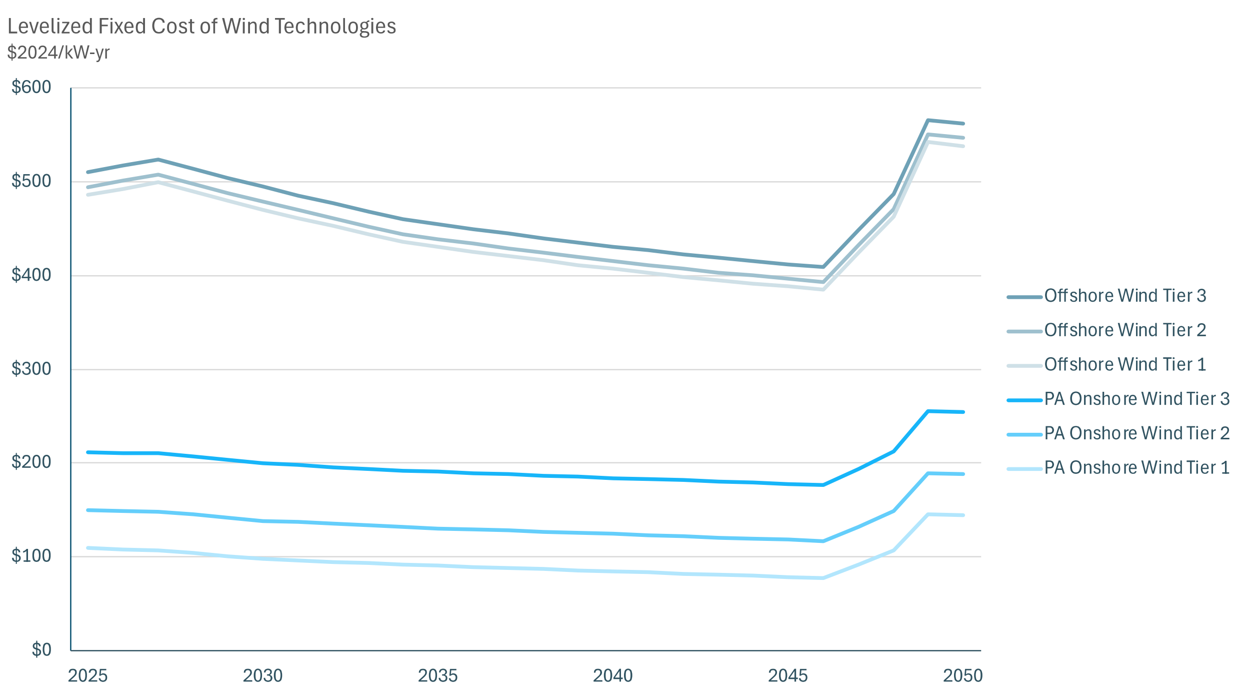


Figure 22: Levelized Fixed Cost of Storage Technologies

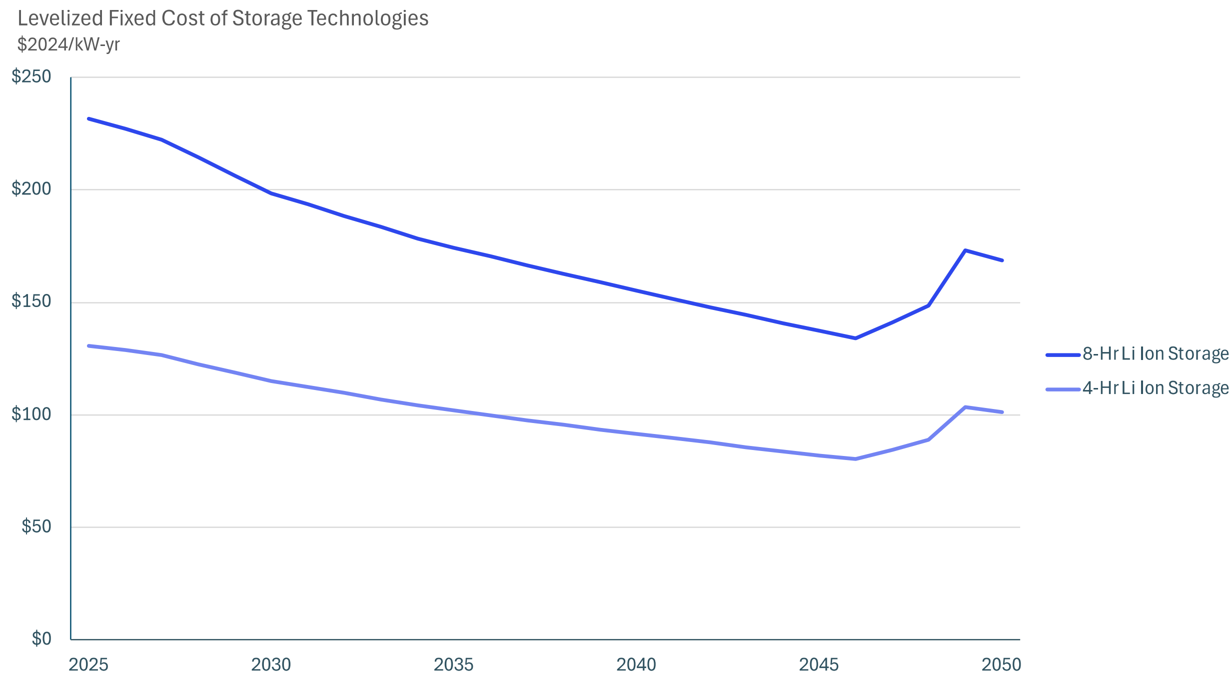
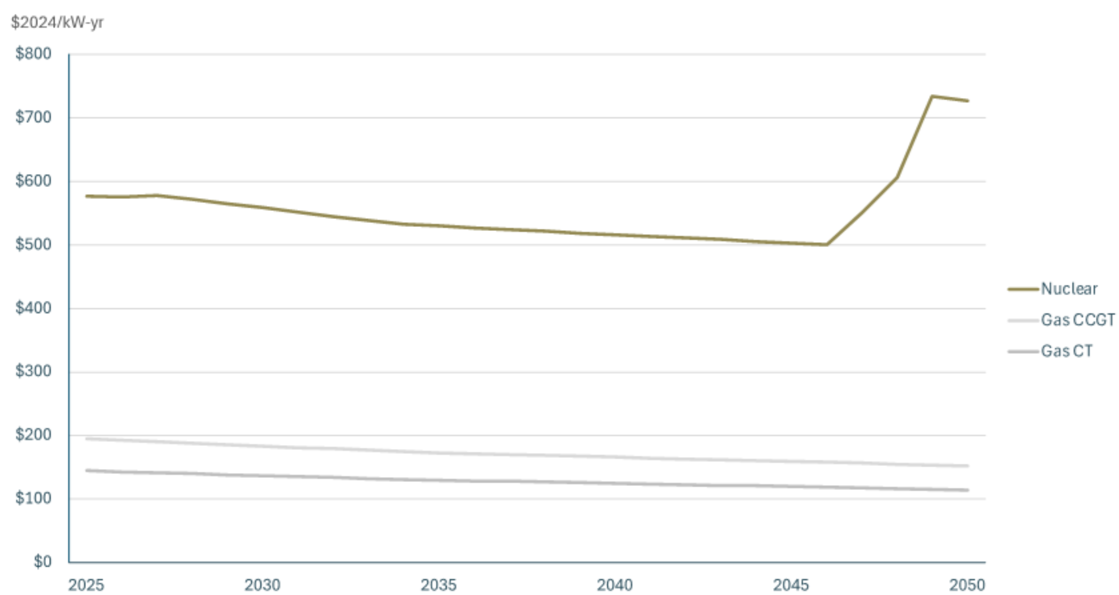


Figure 23: Levelized Fixed Cost of Gas and Nuclear Technologies



Transmission Cost Adders

The interconnection cost and local network upgrade costs show in Table 16 were directly added to the resource costs to ensure that the model sees the transmission investments it would need to make to integrate a resource.

The **Interconnection cost** estimates the cost of building a 230 kV spur line from the candidate resource site to the nearest grid interconnection point. Interconnection cost varies between tiers of the same resource (i.e., solar UPV, onshore wind, and offshore wind) to represent the variation in distance between the candidate resource site and the nearest grid interconnection point as well as the remaining headroom on the existing infrastructure. Interconnection costs for each tier of solar UPV and onshore wind were informed by NREL ReEDS database.[48] These costs, as well as each tier's share of the overall resource potential, are based on a granular geospatial analysis of potential sites that NREL conducted using its Renewable Energy Potential (reV) model.[49]Interconnection costs for offshore wind were determined by estimating the distance from shore for the resources in each tier and applying a construction cost that aligns with New Jersey's State Agreement Approach (SAA) for Offshore Wind Transmission.[50] Storage and thermal resources are assigned a uniform interconnection cost of $50/kW based on a review of all complete and active storage and gas projects in New Jersey.[51]

A **local network upgrade cost** is applied to all tiers of onshore and offshore wind, plus tiers of solar UPV beyond the first. In the case of solar UPV and offshore wind, this additional cost is designed to reflect upgrades to the grid once existing headroom is exhausted. For onshore wind, this captures the cost of building or upgrading transmission from the location in Pennsylvania where the wind farms are built to load centers in New Jersey. Details can be found in Table 16.

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48 https://www.nrel.gov/docs/fy21osti/78195.pdf

49 https://www.nrel.gov/docs/fy19osti/73067.pdf

50 See Table 6 (Cost Assumptions for Baseline Scenario Transmission Facilities) on page 51 of : https://www.brattle.com/wp-content/uploads/2022/10/New-Jersey-State-Agreement-Approach-for-Offshore-Wind-Transmission-Evaluation-Report.pdf

51 E3 reviewed the stated interconnection cost for current and active storage and gas projects in NJ from LBNL's Queued Up study: https://emp.lbl.gov/queues

Table 16: Transmission Cost Adders

Resource Type	Interconnection Cost ($/kW)	Local Network Upgrade Cost ($/kW)	Total Cost Adder ($/kW)	Details
Solar BTM	$0	$0	$0	No interconnection or local network upgrade costs incurred by behind-the-meter resources.
Solar DGPV	$24	$0	$24	Front-of-the-meter solar installed at commercial and industrial properties does not incur an additional local network upgrade cost due to its proximity to load.
Solar UPV (Tier 1)	$53	$0	$53	No additional local network upgrade cost incurred since sufficient headroom exists for near term additions.
Solar UPV (Tier 2)	$161	$280	$440	Local network upgrade cost starts at $5,200/MW-mile and compounds 15% for each additional GW of headroom required on the grid. Builds are assumed to be evenly distributed between northern and southern halves of the state to mitigate local network upgrades required. Assumes builds occur 50 miles from load center.
Solar UPV (Tier 3)	$243	$370	$613	
Solar UPV (Tier 4)	$337	$489	$826	
Solar UPV (Tier 5)	$433	$647	$1,079	
PA Onshore Wind * (Tier 1)	$81	$260	$341	Local network upgrade cost based on the estimated cost of building or upgrading 50 miles of transmission lines from eastern PA to load centers at $5,200/MW-mile.
PA Onshore Wind * (Tier 2)	$81	$780	$861	Local network upgrade cost based on the estimated cost of building or upgrading 150 miles of transmission lines from central PA to load centers at $5,200/MW-mile.
PA Onshore Wind * (Tier 3)	$81	$1,560	$1,641	Local network upgrade cost based on the estimated cost of building or upgrading 300 miles of transmission lines from western PA to load centers at $5,200/MW-mile.
Offshore Wind (Tier 1)	$153	$241	$394	Interconnection costs based on POIs within ~10 miles of shore at $18M/mile (from SAA Table 5). Local network upgrade cost assumed to be 100% of SAA baseline network upgrade costs (from SAA Table 7).
Offshore Wind (Tier 2)	$251	$241	$492	Interconnection costs based on POIs within ~15 miles of shore at $18M/mile (from SAA Table 5). Local network upgrade cost assumed to be 100% of SAA baseline network upgrade costs (SAA Table 7).
Offshore Wind (Tier 3)	$367	$313	$680	Interconnection costs based on POIs within ~23 miles of shore at $18M/mile (from SAA Table 5). Local network upgrade cost assumed to be 130% of SAA baseline network upgrade costs (SAA Table 7).

** This resource was only available to the model in the With Out-of-State Land-based Wind sensitivity*

Tax Credits and Financing Assumptions

Tax credits established under the Inflation Reduction Act (IRA) were assumed, as shown in Table 17. The last year in which developers are eligible to receive the full value of the Investment Tax Credit (ITC) and Production Tax Credit (PTC) is 2046. The tax credits are reduced to 75% of their full value in 2047, 50% in 2048, and 0% thereafter. In determining eligibility for bonus provisions of the tax credits, E3 assumed that new projects met prevailing wage and apprenticeship requirements. The nominal after-tax weighted average cost of capital (WACC) varied by resource type, ranging between 8-8.5%.

Table 17: Tax Credit Assumptions

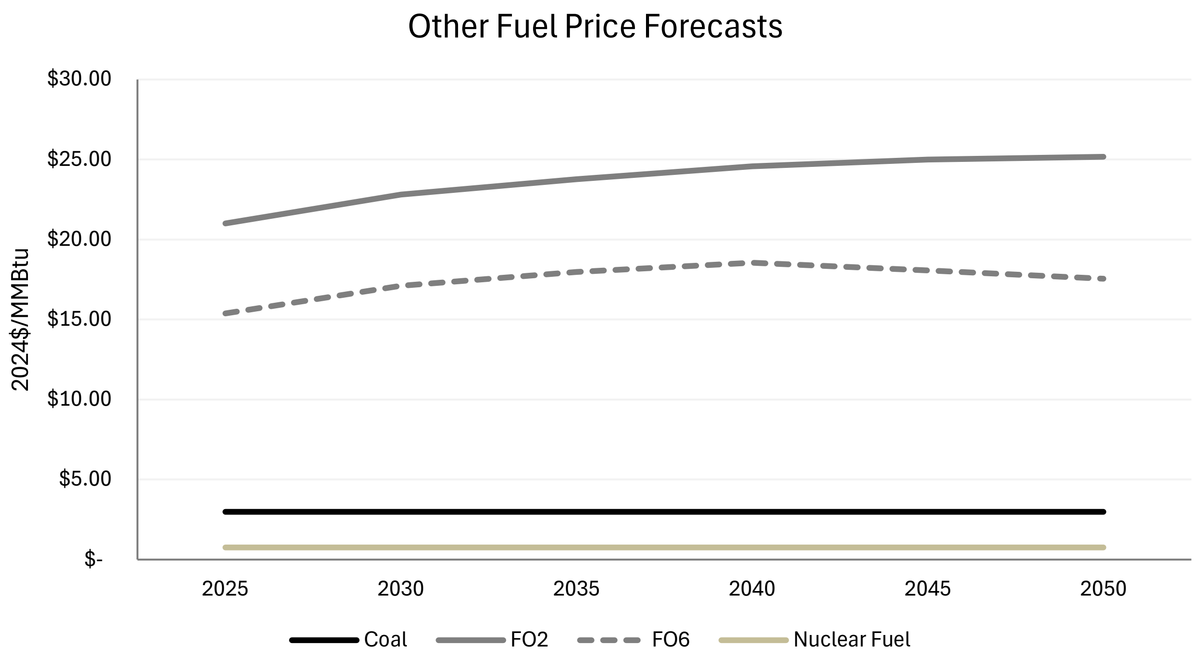
Resource Type	Units	Value	Notes
Solar BTM	%	30%	48 and 48D ITC, effective immediately
Solar DGPV	$/MWh	$25	43 and 45Y PTC, effective immediately
Solar UPV	$/MWh	$25	43 and 45Y PTC, effective immediately
Onshore Wind	$/MWh	$25	43 and 45Y PTC, effective immediately
Offshore Wind	%	30%	48 and 48D ITC, effective immediately
Battery Storage	%	30%	48 and 48D ITC, effective immediately
Nuclear	%	30%	48D ITC, effective 2025

Fuel Price Projections

Coal, Oil, & Uranium Fuel Prices

Monthly fuel oil price projections were based on EIA Short Term Energy Outlook (STEO), EIA Annual Energy Outlook (AEO), and ICE/NYMEX market data. Coal prices were forecasted by U.S. census regions using the same EIA sources, with unit-specific adders based on EIA-923 fuel receipt data. Nuclear fuel prices were informed by the Nuclear Energy Institute's "Nuclear by the Numbers" report.

Figure 24: Coal, Oil, & Nuclear Fuel Price Forecasts



Natural Gas Prices

E3 forecasted gas prices specific to each gas hub. Forecasts for Transco Zone 6 Non-NY, Transco Zone 6 NY, Transco Zone 5, and TETCO M3 Hubs utilize heating degree day data from New Jersey, Virginia, Pennsylvania, Michigan, and Illinois to model price variations. This data is combined with monthly natural gas price forecasts at the Dominion hub to capture price impacts related to cold weather events. For all other hubs, natural gas prices were developed using SNL forward price curves for the near term (2024–2030), gradually transitioning to align with the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) long-term gas price forecast by 2040.

Natural gas prices in New Jersey are assumed to be the average of the Transco Zone 6 NY and non-NY hub prices. The monthly prices in NJ are shown as a multiplier of the annual average. Monthly multipliers across the model horizon do not change materially.

Figure 25: NJ Annual Average Gas Price Forecast

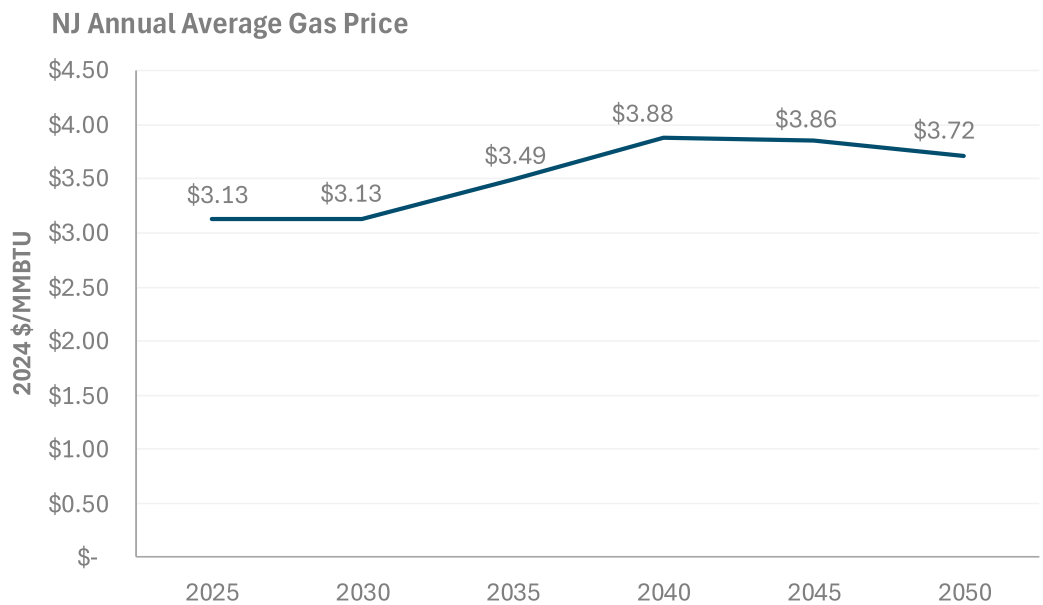


Figure 26: Monthly Multipliers for NJ Annual Avg Gas Prices

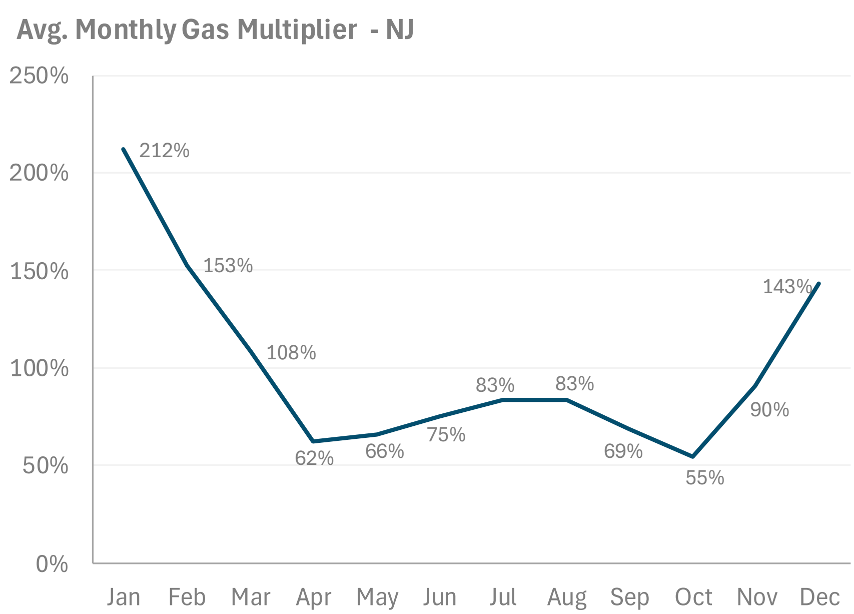
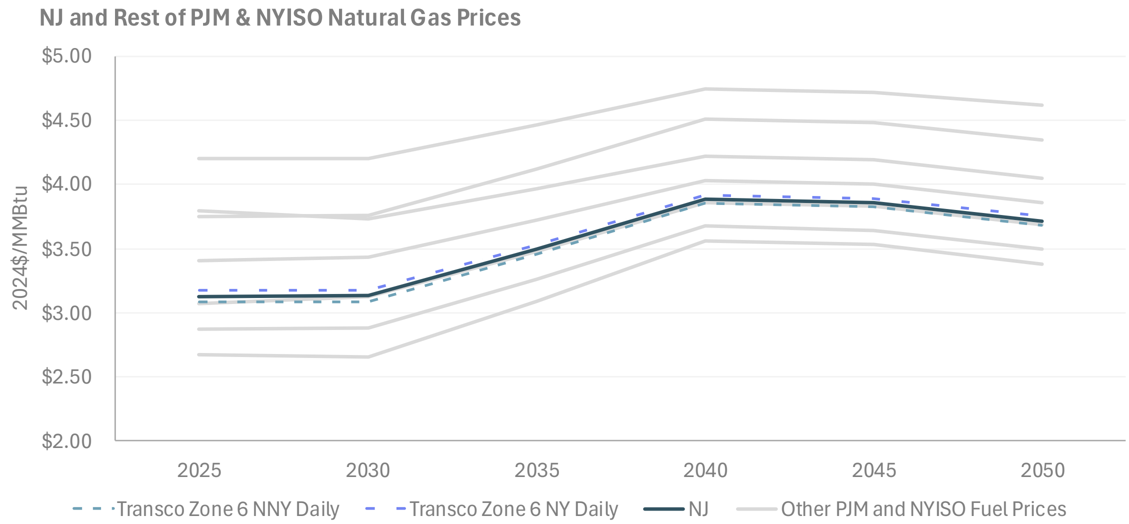


Figure 27: Annual Avg Gas Price Forecast Across All Regions



Section 3: Additional Electric Sector Sensitivity Results

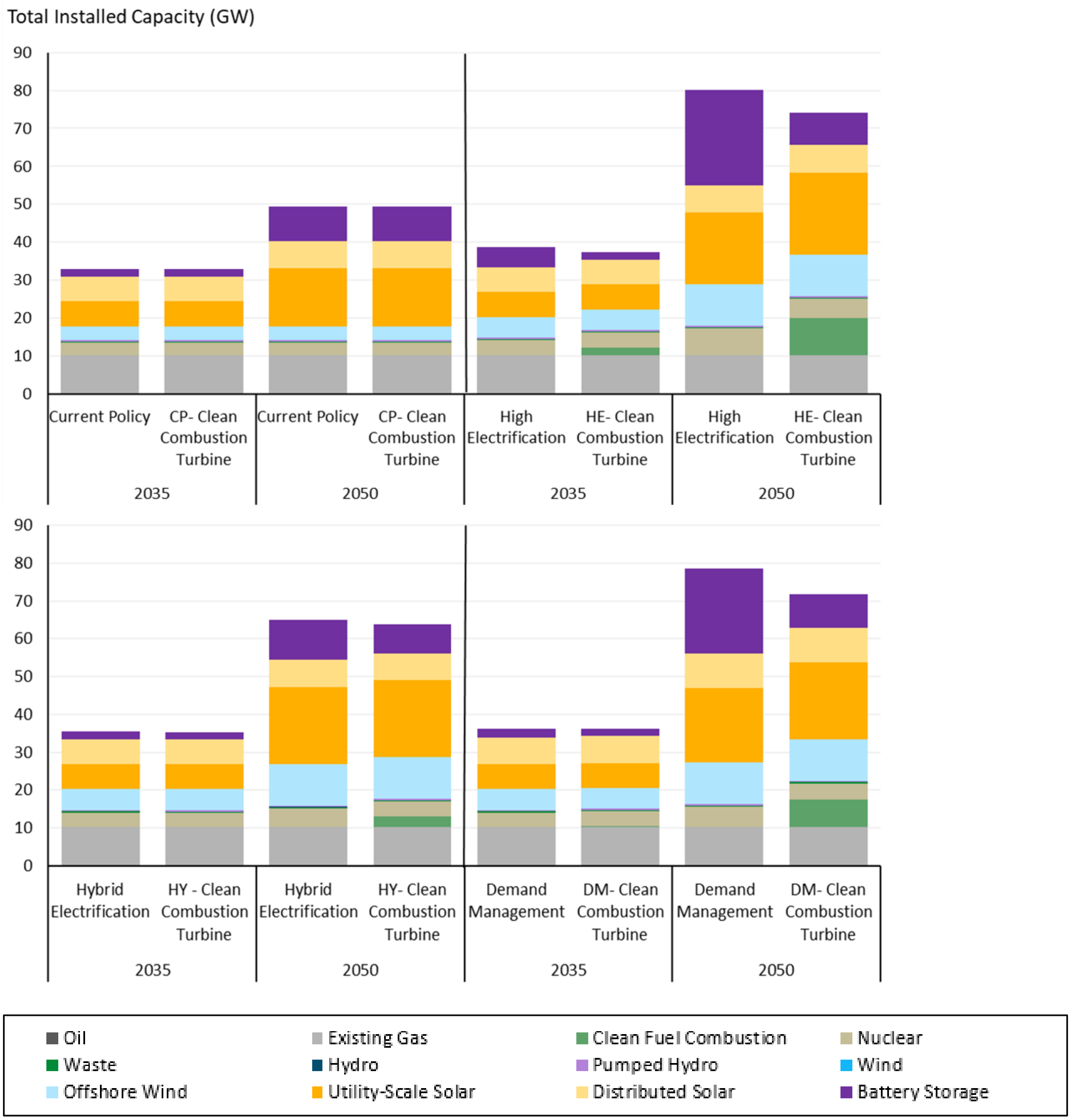
The resource options that will be available to the state in the long term are uncertain. To assess the potential impact of resources that are not considered in the core scenarios, several additional sensitivities were examined. These sensitivities explored how clean fuel combustion capacity and out-of-state land-based wind, if available, might facilitate achievement of New Jersey's clean energy goals.

With New Clean Fuel Combustion Turbines

This sensitivity was studied to illustrate the extent to which battery storage and nuclear fleet expansion can be limited if low carbon fuels (e.g. renewable natural gas and low-carbon hydrogen) and CTs to combust them are available and pursued by New Jersey.

Resource portfolio impacts are presented in Figure 28. Clean fuel CTs have the greatest impact in the *High Electrification* scenario. In this scenario, 10 GW of clean fuel CTs help avoid 17 GW of storage and 2 GW of nuclear energy. Incremental solar capacity (3 GW), coupled with purchases of unbundled RECs and additional imported power, offset the reduction in nuclear generation. In the *Demand Management* scenario, 7 GW of clean fuel CTs help offset 1 GW of nuclear capacity and 13 GW of battery storage. Clean fuel CTs have a relatively small impact on the Hybrid scenario since the peak load and resource builds are relatively small and the reliability challenge less severe; 3 GW of clean fuel CTs help offset 3 GW storage and 1 GW nuclear. Finally, clean fuel CTs have no impact on the *Current Policy* scenario.

Figure 28: Total Installed Capacity with New Clean Fuel Combustion Turbines Compared to Base Case



With Out-of-State Land-based Wind

In this sensitivity, as shown in Figure 29, up to 8 GW of out-of-state land-based wind (e.g. in Pennsylvania or neighboring PJM states) with an associated transmission cost adder to deliver the power to New Jersey was offered to the model as a candidate resource.

All 8 GW of land-based wind made available to the model are economically chosen across all mitigation scenarios by 2050. In the *Current Policy* scenario, 4.5 GW wind is chosen. This wind resource helps economically replace some solar and nuclear capacity, reducing the in-state land use impacts and cost impacts associated with building large amounts of solar and nuclear in the base case. Across the mitigation scenarios, 1-2 GW of nuclear and 2-4 GW of solar builds are avoided with 8 GW of wind. In the *Current Policy* scenario, 4.5 GW of wind helps reduce solar builds by 6 GW and storage builds by 1 GW.

Figure 29: Total Installed Capacity with Out-of-State Wind Compared to Base Case