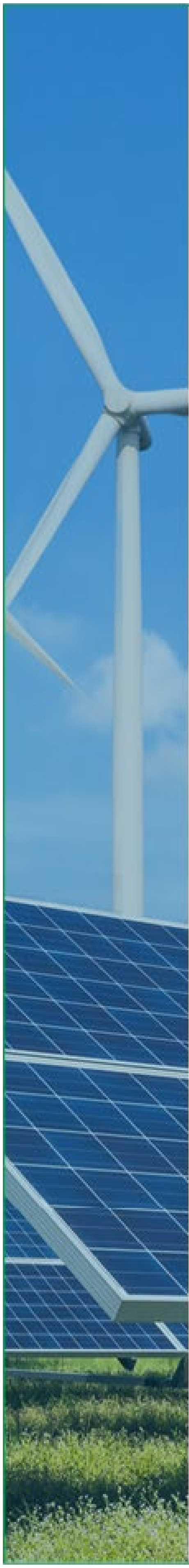


Appendix D: Modeling and Methodologies

2023-2042 System & Resource Outlook

A Report from the New York Independent System Operator

July 22, 2024

Appendix D: Modeling and Methodologies

This appendix describes the model preparation, framework, and assumptions that make up the three reference cases—Base, Contract, and Policy Cases. The Contract Case builds on the assumptions in the Base Case. Similarly, the Policy Case builds on the Contract Case but includes additional assumptions specific to the adoption of state policy mandates.

Outlook Models: Overview

Section 31.3.1 of Attachment Y provides that each cycle of the Economic Planning Process will align with the Reliability Planning Process. Such alignment requires that the ten-year study period covered by the most recently approved Comprehensive Reliability Plan (CRP) shall be the first ten years of the twenty-year study period of the System & Resource Outlook study period.

Outlook Reference Cases

Three reference cases build upon each other through changes in the modeling assumptions to present different potential futures. Such changes include: changes in the amount of generating resources, differing load assumptions, and other changes in the system and modeling assumptions. Figure D-1 outlines the fundamental characteristics of each of the reference cases used in this Outlook.

Figure D-1: 2023-2042 System & Resource Outlook Reference Cases

Base Case		Contract Case		Policy Case (Lower Demand, Higher Demand, State Policy Scenarios)	
Demand: 2023 Gold Book Baseline forecast	**Supply:** Consistent with inclusion rules for NYISO Reliability Planning Processes	**Demand:** 2023 Gold Book Baseline forecast	**Supply:** Resource additions consistent with awarded resources from NYSERDA LSR database	**Demand:** 2023 Gold Book Lower/Higher Demand Policy forecasts, Climate Action Council Integration Analysis	**Supply:** Resource additions and retirements optimized via capacity expansion modeling

The data for the Base Case simulations is largely derived from the 2023-2032 CRP, 2023 Gold Book, and the Outlook Assumptions Matrix documents. Major components of the database include generator heat and emissions rates, unit capacities, renewable generation profiles, energy and peak demand forecasts, load shapes, fuel and emissions allowance price forecasts, transmission constraint modeling, interchange values (e.g., simulated and actual), and Operation and

Maintenance (O&M) costs. Additional details on the specific assumptions for this Outlook can be found in Appendix B: Production Cost Assumptions Matrix and Appendix C: Capacity Expansion Assumptions Matrix.

The primary differences between the Contract Case and the Base Case are the inclusion of (i) announced Renewable Energy Certificates (REC) and Offshore Renewable Energy Certificates (OREC) awards to generators and (ii) New York State Public Service Commission (NYPSC) approval of local transmission and distribution projects as of the lockdown date (i.e. October 30, 2023).

The Policy Case includes assumptions that go beyond the Contract Case assumptions and that are specific to accommodating state policies, including the CLCPA mandates and updated load forecasts and shapes.[1] In the Policy Case, the NYISO used a capacity expansion model to simulate generation expansion and retirements to evaluate achievements of these state policy mandates. The capacity expansion model incorporates assumptions from the Base and Contract Case databases as a starting point and includes additional assumptions as applicable in the Policy Case to simulate the evolution of the capacity and generation mix over the study period.

Owing to the uncertainty of the pathways to the future system, the NYISO assessed multiple scenarios in the Policy Case. For this Outlook, the NYISO, together with input from stakeholders, selected three scenarios to examine the impact of various assumption changes in the Policy Case. The three scenarios are referred to as "Lower Demand scenario," "Higher Demand scenario," and "State Scenario."[2] The capacity expansion model included simulations for the 20-year study period and the production cost models to five-year increments within the study period (i.e., study years 2025, 2030, 2035, and 2040), as well as the final year of the study period (i.e., study year 2042). Results for 2025, 2030, 2035, 2040, and 2042 are reported for this Outlook.

Outlook Models

All three reference cases include production cost simulations.[3] For the Base Case and Contract Case, the NYISO primarily uses production cost to inform the cases and subsequent analyses. In addition to production cost simulations, the Policy Case also leverages capacity expansion modeling to examine different pathways for full achievement of identified policy mandates. Capacity expansion modeling is the first step in the Policy Case, followed by production cost simulations and subsequent analyses as applicable to each scenarios.

[1] 2023-2042 System & Resource Outlook forecast assumptions.
[2] See Appendix C: Capacity Expansion Assumptions Matrix for additional detail on each scenario.
[3] In the Policy Case, production cost simulations were conducted for the Lower and Higher Demand scenarios.

The databases and model resolution for the capacity expansion and production cost models are unique and distinct. As further described below, the production cost model includes detailed representation of the New York power system. Although the capacity expansion model leverages information from the production cost model, its resolution is much less granular due to the intricacies of the model.

As the Policy Case is the only case that utilizes both models, a visual representation of the interplay between these two models is included below.

Figure D-2: 2023-2042 Outlook Policy Case Databases

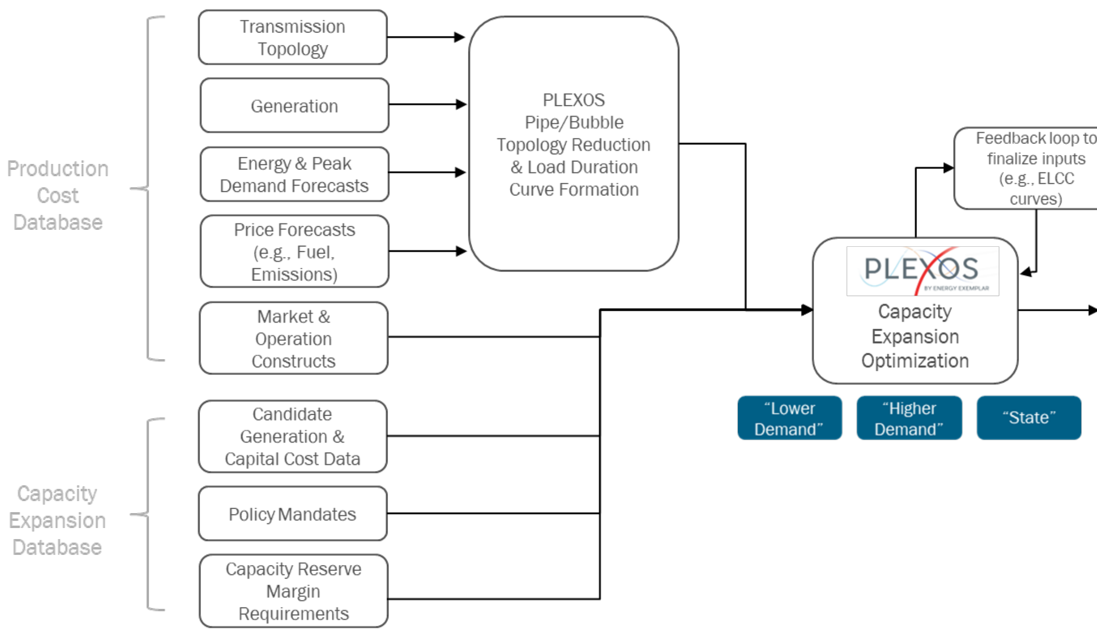
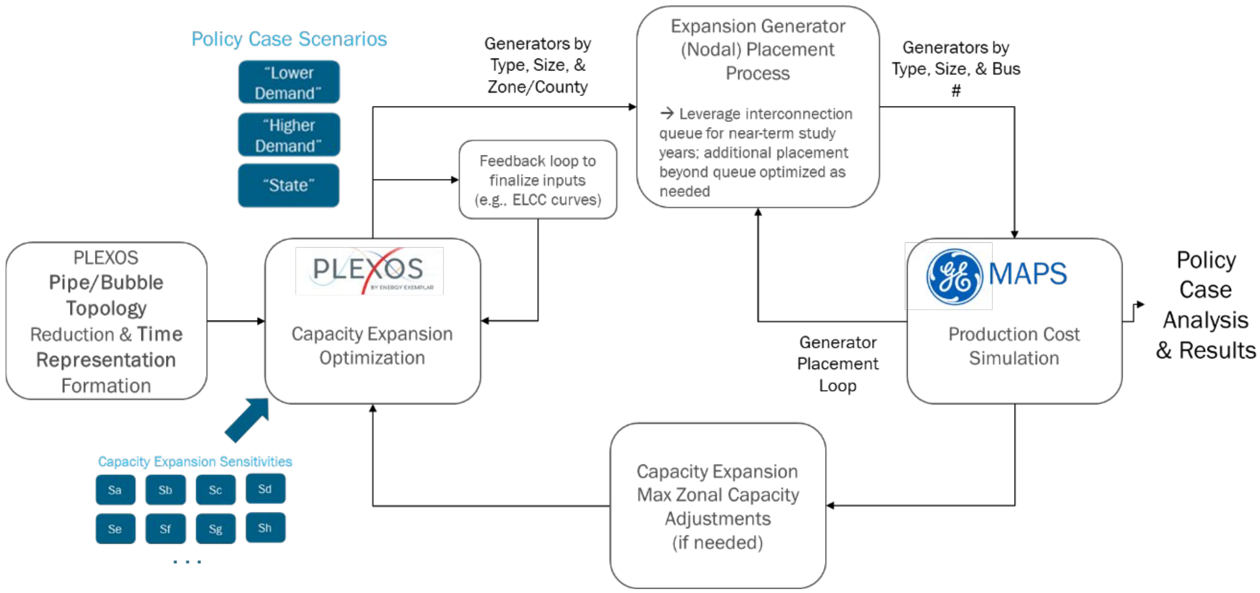


Figure D-3: 2023-2042 Outlook Policy Case Process Flow[4]



[4] For this Outlook, the NYISO performed the production cost and capacity expansion simulations using GE MAPS and PLEXOS, respectively.

Generator Placement Methodology

Zonal capacity expansion buildout results for the policy scenarios are fed into the production cost model for hourly analysis. These zonal buildouts for various generator types are converted to nodal placement in the production cost model utilizing the methodology in the following section:

Resource Placement

The NYISO uses its interconnection queue[5] (01/31/2024) to obtain points of interconnection (POIs) for LBW, UPV and ESR units. For New York zones without any available interconnection projects in the queue, the NYISO leveraged NYSERDA's Large Scale Renewable (LSR) supply curve database to inform locations where wind and solar resources are likely to be built and the nearest probable POI. For offshore wind resources, specific POIs identified for offshore wind from past economic and public policy studies are utilized.

Dispatchable emission-free resources are placed on electrical locations on the bulk system (230 kV and above) according to the zonal buildout from the capacity expansion scenarios.

In addition to generator buildouts in New York, the Policy Case also considers buildouts in neighboring systems that are fed into both the capacity expansion and production cost models as firm generator additions. These additions reflect "policy futures" in the neighboring systems surrounding the NYISO with increased renewable buildout, generator retirements, and increased demand. Since the Outlook models do not secure any lower kV lines in the neighboring systems' representation, the generator additions are spread across all buses in the respective external area. This logic is used to place generic resources in external regions at all load buses in a particular zone. Offshore wind resources are located at onshore POIs based on publicly available information.

Resource Sizing

The capacity assumed for new generator additions is proportional to the proposed capacity of projects proposed in the interconnection queue for the zone. For zones without any interconnection queue projects available, the capacity is informed by the site capacity for LBW and UPV from NYSERDA's LSR supply curve database.

External generic resource capacity for each technology type is modeled as a single unit per external zone. This capacity is then spread across all buses in the zone utilizing a logic that divides the capacity according to the interconnecting bus load ratio share.

[5] https://www.nyiso.com/interconnections

Baseline Assumptions for Outlook Reference Cases

New York Transmission Model

The Outlook production cost analysis utilizes a bulk power system representation based on the latest available (2022[6]) FERC 715 filing powerflow base cases, which include the power system in the United States and Canadian Provinces East of the Rocky Mountains, excluding the Western Electricity Coordinating Council and Texas. The Outlook model, however, only includes an active and detailed representation of the power systems and electricity markets of the NYISO, ISO-New England, IESO, and PJM Interconnection control areas. The transmission representation of the three neighboring systems is derived from the most recent 2022 Reliability Needs Assessments (RNA) base case and includes changes expected to significantly impact congestion within the NYCA.

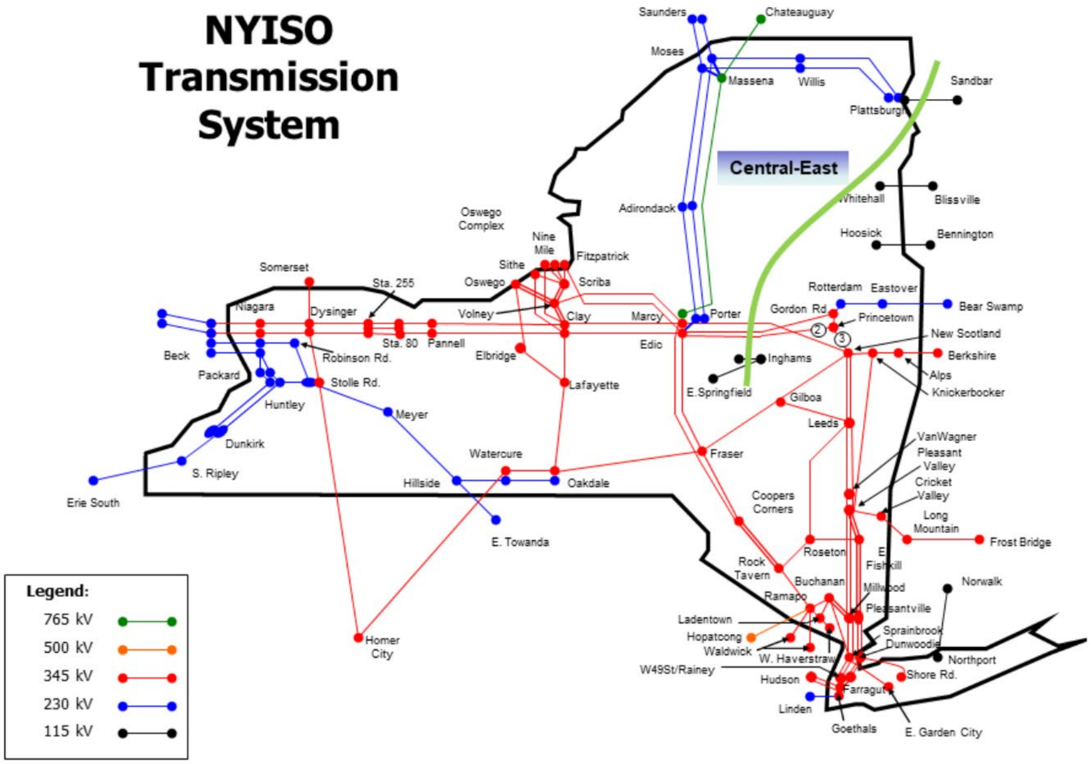
New York Control Area Transfer Limits

The Outlook utilizes normal transfer criteria for MAPS software simulations to determine system production costs. Normal thermal interface transfer limits for the Outlook are not directly utilized from the thermal transfer analysis performed using TARA software.[7] Instead, the Outlook uses the most severely limiting monitored lines and contingency sets identified from analysis using TARA software and from historical binding constraints.

For voltage- and stability-based limits, the normal and emergency limits are assumed to be the same. For NYCA interface stability transfer limits, the limits are consistent with the operating limits.[8] The NYISO modeled the Central East interface with a unit-sensitive nomogram that reflects the algorithm used by NYISO Operations.[9] Adjustments were made to this nomogram to accommodate new transmission projects that impact the interface limit.

[6] https://www.nyiso.com/documents/20142/1403621/2022-FERC-715-Part-4-Transmission-Planning-Criteria.zip
[7] PowerGEM's Transmission Adequacy and Reliability Assessment (TARA) software is a steady-state power flow software tool with modeling capabilities and analytical applications.
[8] https://www.nyiso.com/documents/20142/3691079/NYISO_InterfaceLimtsandOperatingStudies.pdf/
[9] https://www.nyiso.com/documents/20142/3692791/Central-East-Voltage-Limit-Study-2024-FINAL.pdf/

Figure D-4: NYISO Transmission System



New York Control Area System Changes, Upgrades and Resource Additions

System changes modeled for 2023 and beyond included in the Base Case are as follows:

- Conforming the modeling of the PJM/NYISO interface to the current NYISO-PJM Joint Operating Agreement;
- Modeling the seasonal (winter) bypass of the Marcy South Series Compensation (MSSC);
- Placing in service the series reactor on the following 345 kV cables: 71, 72, M51, M52;
- Bypassing the series reactor on the following 345 kV cables: 41, 42, Y49;
- Modeling the selected Segments A and B transmission projects to address the AC Transmission Public Policy Transmission Needs as in-service (2024);
- Modeling NYPA's Smart Path Project as in-service (2026);
- Modeling the Champlain Hudson Power Express transmission project as in-service (2026); and
- Modeling the selected project to address the Long Island Offshore Wind Export Public Policy Transmission Need as in-service (2030).

In addition to these transmission upgrades in the Base Case, the Contract and Policy Cases assume additional transmission changes as follows:

- Modeling the Clean Path New York (CPNY) HVDC transmission line as in-service (2027); and
- Modeling the NYPSC-approved Phase 1 and 2 transmission projects by various Transmission Owners as in-service based on their identified in-service date (2026-2029).

Generation Capacity Mix

The capacity forecast used in the Base Case was based on the 2023 Gold Book. Figure D-5 presents annual NYCA capacity for the Base Case.

Figure D-5: NYCA Capacity (MW)

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2025	3,937	785	7,273	2,161	1,702	5,186	4,782	52	0	9,486	5,033	40,397
2030	3,937	785	7,273	2,161	1,702	5,186	4,782	52	0	9,447	5,033	40,358
2035	3,937	785	7,273	2,161	1,702	5,186	4,782	52	0	9,447	5,033	40,358
2040	3,937	785	7,273	2,161	1,702	5,186	4,782	52	0	9,447	5,033	40,358
2042	3,937	785	7,273	2,161	1,702	5,186	4,782	52	0	9,447	5,033	40,358

The Contract Case includes approximately 16 GW of incremental renewable capacity awarded or contracted up through the 2022 NYSERDA REC and OREC Solicitations. Figures D-6 and D-7 break out the capacity by in-service year and zone. Approximately 2,500 MW of projects with awards and/or contracts are in service or sufficiently advanced in development and are, therefore, already included in the Base Case. The Policy Case builds off the Contract Case and assumes all resources in that case as firm generation. Additional generation capacity is added to the Policy Case, as informed by the capacity expansion model and further described below.

Figure D-6: Contract Case Renewable Capacity Additions by Online Year

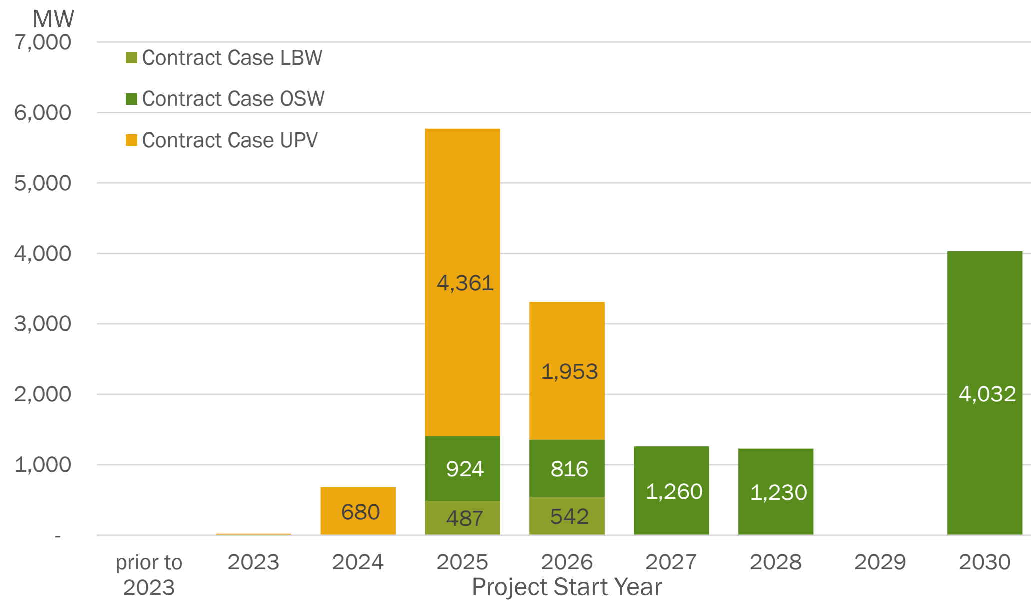
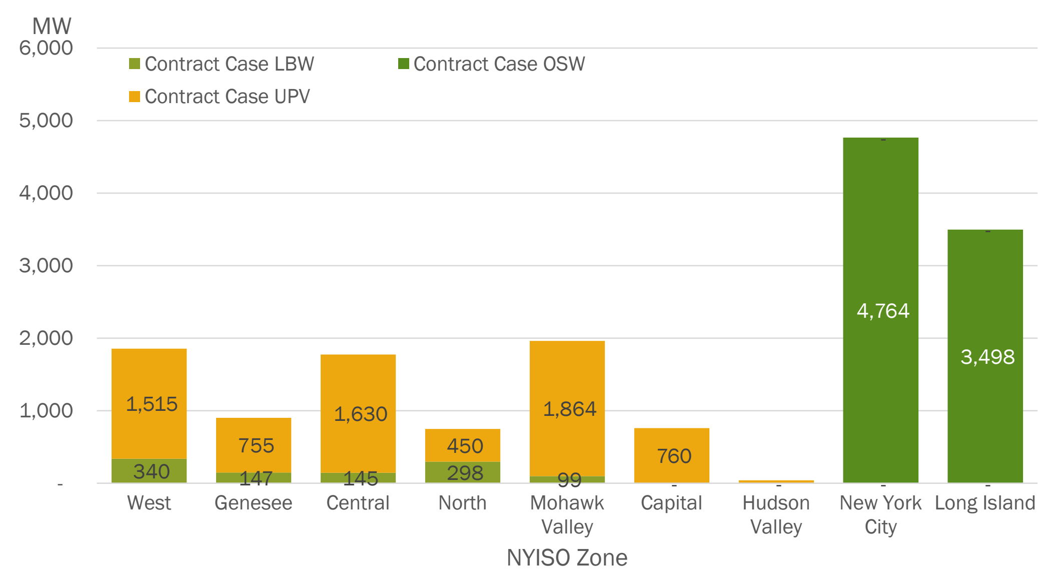


Figure D-7: Contract Case Renewable Capacity Additions by Zone



Energy Demand & Peak Forecasts

One of the primary benefits of production cost modeling is that it allows for hourly and nodal representation of the diversity in load that occurs over the course of a day, season, or years throughout the state. This allows the model to determine the most economic mix of generation to serve the input demand. Over the course of the study period, the load evolves throughout the seasons and years, and the increase in weather-dependent, electrified end uses causes the system to shift from a summer-peaking system to a winter-peaking system.

This Outlook uses four unique energy and peak demand forecasts among the reference cases (five scenarios in total). The Base and Contract Cases assume the same load forecast, which is based on the 2023 Gold Book and accounts for the impact of certain programs, such as energy efficiency and electrification. Each of the three scenarios in the Policy Case assumes a unique load forecast with the primary intent of assessing various potential future conditions based on a wide range of energy and peak demand forecasts.[10]

Zonal forecasts for the Base and Contract cases are presented in Figure D-8 and Figure D-9. Figure D-8 presents the annual zonal energy in gigawatt-hours (GWh) and Figure D-9 presents the summer non-coincident peak demand in megawatts (MW).

Figure D-8: Base & Contract Cases: Annual Zonal Energy (GWh)

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2025	14,800	10,740	16,490	5,880	7,220	11,560	8,960	2,820	5,540	48,480	19,900	152,390
2030	15,070	10,800	18,430	6,630	7,000	12,160	9,060	2,960	5,830	48,950	20,770	157,660
2035	16,930	12,030	20,050	6,810	8,040	14,200	10,700	3,470	6,830	53,710	24,140	176,910
2040	19,590	13,860	22,590	7,050	9,580	16,830	12,920	4,070	8,160	60,790	28,590	204,030
2042	20,450	14,460	23,420	7,130	10,090	17,710	13,650	4,240	8,650	63,590	29,990	213,380

Figure D-9: Base & Contract Cases: Summer Non-Coincident Peak Demand by Zone (MW)

Year	A	B	C	D	E	F	G	H	I	J	K
2025	2,778	2,187	2,953	710	1,460	2,456	2,156	628	1,423	11,300	5,032
2030	2,741	2,203	3,164	803	1,408	2,507	2,195	631	1,394	11,070	5,065
2035	2,902	2,332	3,324	812	1,507	2,650	2,401	678	1,508	11,900	5,264
2040	3,159	2,492	3,566	837	1,673	2,886	2,626	718	1,632	12,560	5,570
2042	3,234	2,544	3,626	843	1,721	2,973	2,694	730	1,680	12,830	5,676

The following figures include the NYCA Annual Energy (TWh), Summer Coincident Peak (GW), and Winter Coincident Peak (GW) values for the scenarios evaluated in this Outlook.

[10] Each of these load forecasts account for varying impacts of energy efficiency, electrification, and large loads. As selected by NYSERDA and the New York State Department of Public Service (DPS) with input of the Energy Policy Planning Advisory Council (EPPAC) based on its advisory capacity, the State scenario also includes impacts of flexible loads, such as LDV EVs and electrolysis, which were informed by the Integration Analysis. See the 2023-2042 System & Resource Outlook forecast assumptions for the detailed forecasts.

Figure D-10: Base, Contract, and Policy Cases: NYCA Annual Energy (TWh)

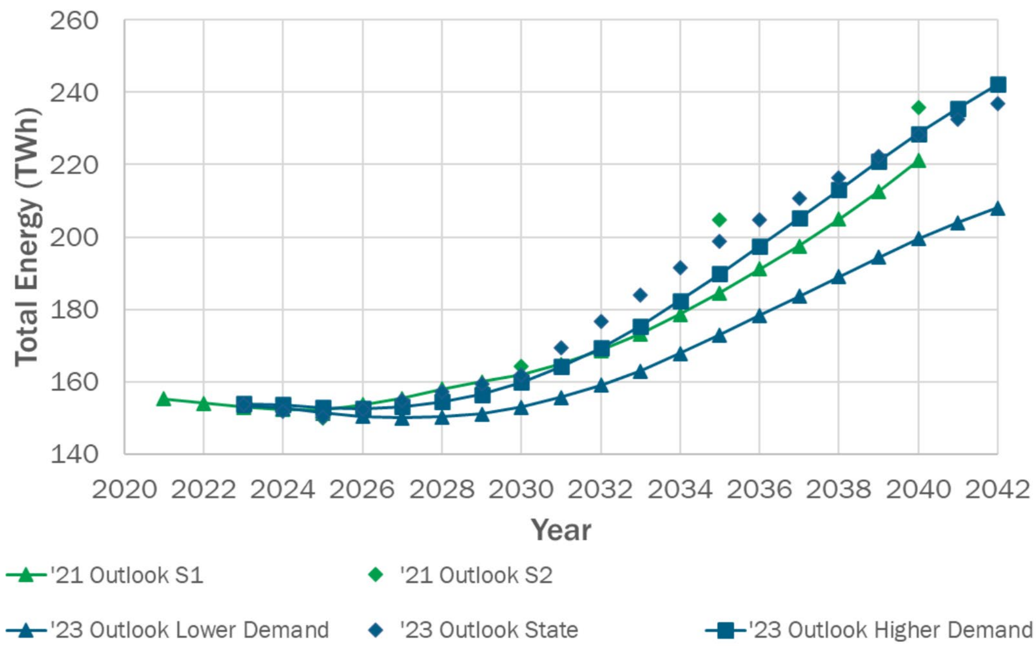


Figure D-11: Base, Contract, and Policy Cases: NYCA Summer Coincident Peak Demand (GW)

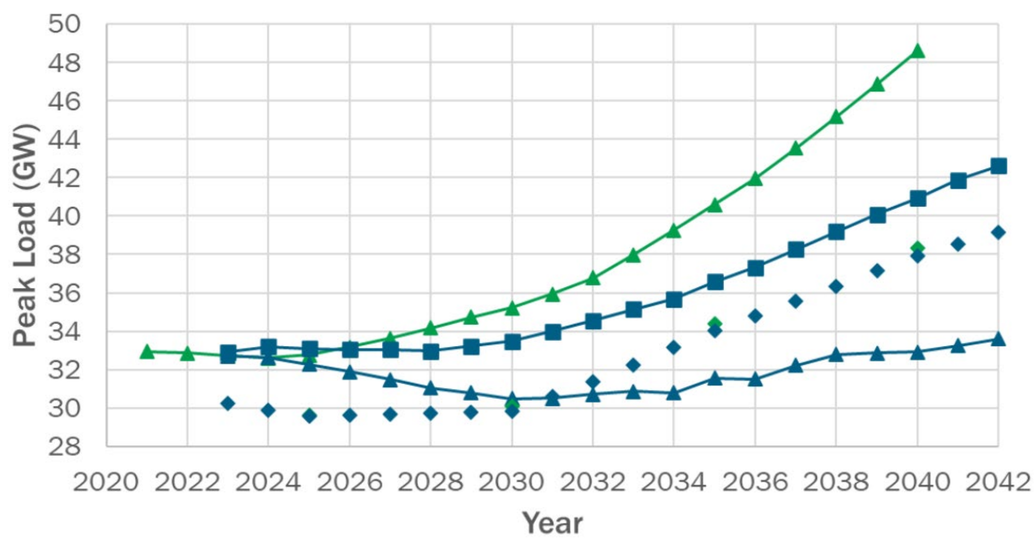
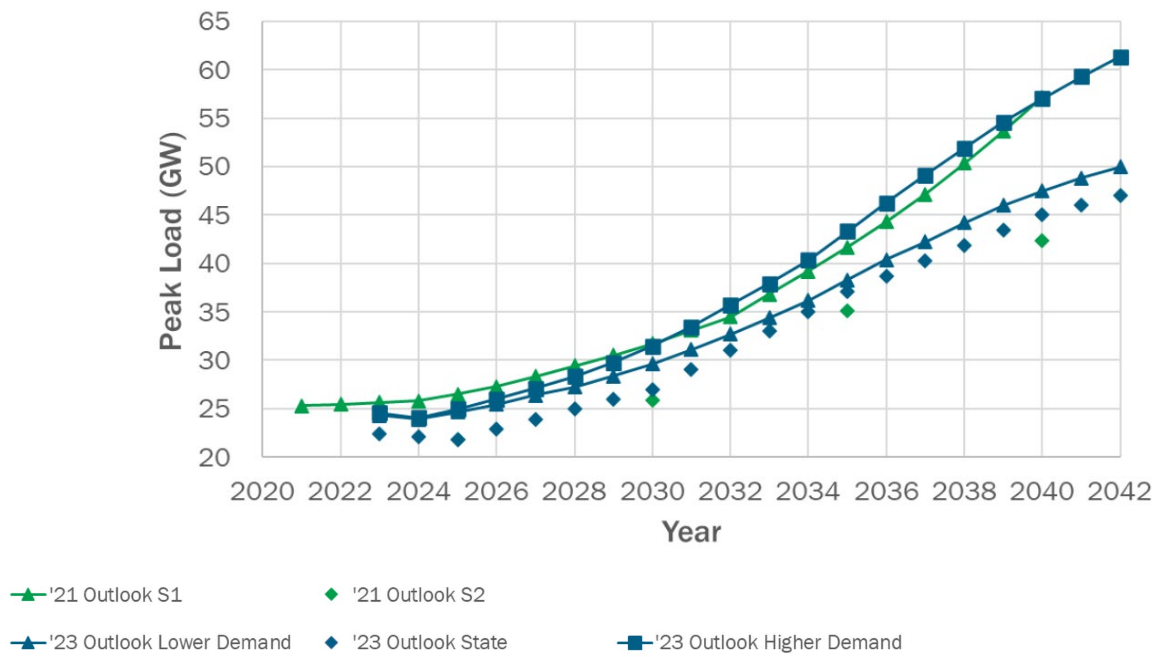


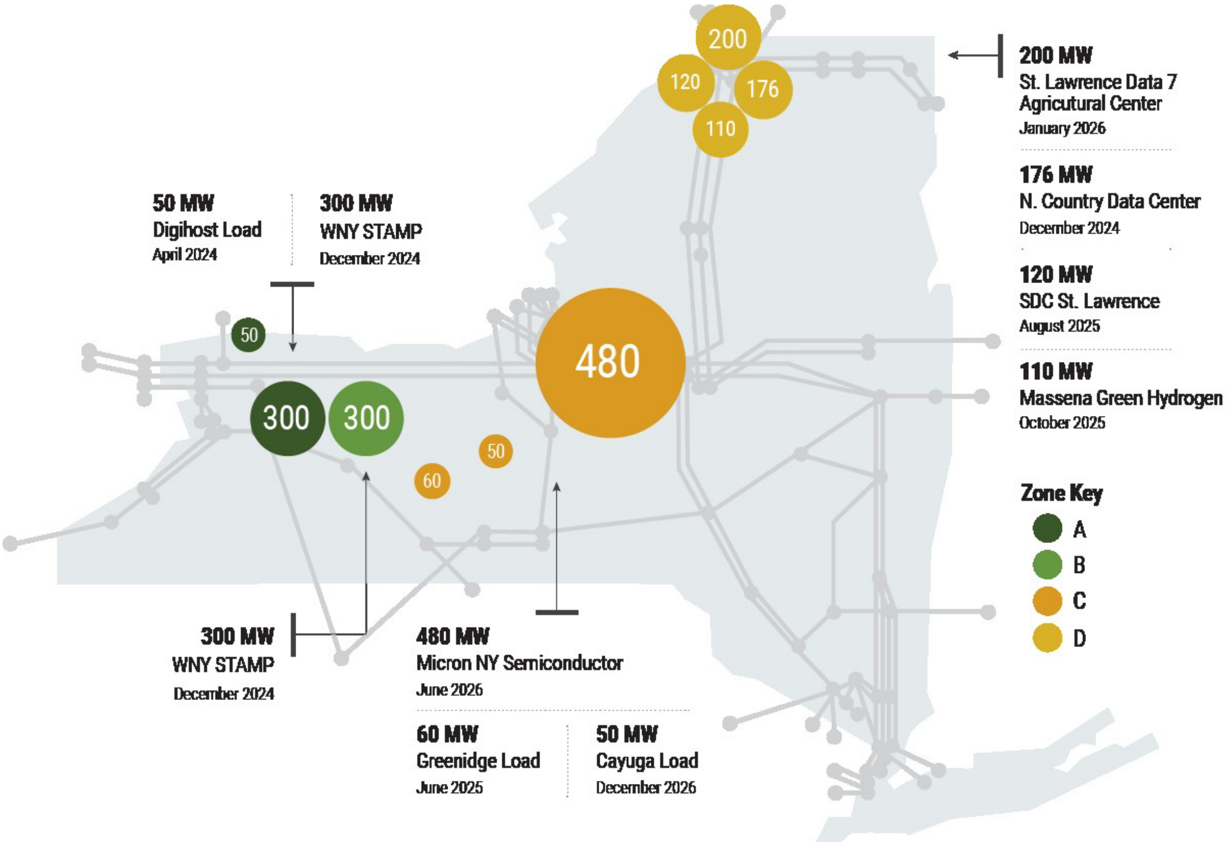
Figure D-12: Base, Contract, and Policy Cases: NYCA Winter Coincident Peak Demand (GW)



Large Load Forecasts

The term "large loads" refers to individual load interconnections contained in the 2023 Gold Book forecast that are modeled as separate loads connected to specific nodes in the production cost model. For this Outlook, the large loads assume a flat load shape with a high load factor to reflect a typical industrial load operation. The large load impacts assumed in this Outlook are shown below.

Figure D-13: New York Large Loads



Large loads are included in all of the Outlook cases. The Baseline forecast from the *2023 Gold Book*[11] is assumed in the Base, Contract, and Lower Demand Policy Case scenarios. The Higher Demand Policy Case scenario leverages the Higher Demand forecast from the *2023 Gold Book* to assess higher energy impacts from large loads. The annual energy contributions from these two forecasts are included below.

[11] *2023 Gold Book.*

Figure D-14: Large Load Forecasted Energy Contributions

Large Load Energy Forecasts (GWh)		
Year	Baseline	Higher Demand
2025	6,180	7,190
2030	10,030	17,680
2035	10,030	18,100
2040	10,030	18,100
2042	10,030	18,100

Simultaneous Weather Year Representation

Utilization of simultaneous load and renewable profiles is an important modeling enhancement new to this Outlook and allows more accurate representation of the increasingly important interactions between load and renewable production. The NYISO created load shapes for the Base Case, Lower Demand, and Higher Demand scenarios based on the 2018 weather year and evolved these shapes to align with the expected loads of the future system. All renewable resources in the model—offshore wind (OSW), land-based wind (LBW), and utility-scale solar (UPV)—use a 2018 weather year shape from the DNV database (See Appendix E: Renewable Profiles & Variability for more details). BTM-PV shapes were obtained from internal load forecasting and production system data. Hydroelectric generation-based profiles are based on 2018 hourly output modified to a lower long-term energy target as described below.

Renewable Profile Model Integration

The zonal- and county-level profiles for renewable resources are capacity-weighted average hourly profiles consisting of the sites in the particular zone or county, respectively.

All generators included in the Base and Contract Cases, specifically existing or planned wind and solar projects, are modeled consistently in the capacity expansion and production cost models using representative site-level shapes at the resource level. In the Policy Case, zonal aggregate shapes for OSW, LBW, and UPV are used in the capacity expansion model to represent production from candidate resources.[12] The candidate generators selected by the capacity expansion model are modeled in the production cost model using the aggregated county-level shapes, as appropriate, to their assumed placement in the nodal model.

[12] https://www.nyiso.com/documents/20142/44393357/04b_NYISO_Zonal_LBW_UPV_OSW_Shapes_2000-2023_For_Posting.xlsx

Fuel Price Forecasts

The price forecasts for natural gas, oil, and uranium in the Outlook[13] are based on the U.S. Energy Information Administration's (EIA)[14] current national long-term forecast of delivered fuel prices, which is released each spring as part of its Annual Energy Outlook[15]. The same fuel forecast is utilized for all reference cases.

New York Fuel Forecast

In developing the New York fuel forecast, regional adjustments were made to the EIA fuel forecast to reflect fuel prices in New York. Key sources to estimate the relative differences for fuel-oil prices in New York are the Monthly Utility and non-Utility Fuel Receipts and Fuel Quality Data reports based on the information collected through Form EIA-923.[16] The regional adjustments for natural gas prices are based on a comparative analysis of monthly national delivered prices published in EIA's Short Term Energy Outlook and spot prices at the selected trading hubs. The base annual forecast series from the Annual Energy Outlook are adjusted to reflect the New York prices relative to the national delivered prices as described below.

Natural Gas

For the 2023-2042 Outlook, the New York Control Area is divided into four (4) gas regions: Upstate (Zones A to E), Midstate (Zones F to I), Zone J, and Zone K.

Given that gas-fueled generators in a specific NYCA zone acquire their fuel from several gas-trading hubs, each regional gas price is estimated as a weighted blend of individual hubs based on the sub-totals of the generators' annual generation (*i.e.*, megawatt-hour) levels. The regional natural gas price blends for the regions are as follows:

- Upstate (Zones A to E) – Dominion South (92%), Tennessee Zone 4 200L (6%), & Iroquois (2%);
- Midstate (Zones F to I) – Tennessee Zone 6 (38%), Iroquois Zone 2 (35%), Tetco M3 (22%), Algonquin (5%);
- Zone J – Transco Zone 6 (100%); and
- Zone K – Transco Zone 6 (51%) & Iroquois Zone 2 (49%).

The forecasted regional adjustment, which reflects the differential between the blended regional price and the national average, is calculated as the three-year weighted average of the ratio

[13] 2023-2042 Reference Case Input Assumptions
[14] www.eia.doe.gov
[15] Prices are reported in nominal dollars.
[16] Prior to 2008, this data was submitted via FERC Form 423. 2008 onwards, the same data are collected on Schedule 2 of the new Form EIA-923. See http://www.eia.doe.gov/cneaf/electricity/page/ferc423.html. These figures are published in Electric Power Monthly.

between the regional price and the national average delivered price from the Short-Term Energy Outlook.[17] Forecasted fuel prices for the gas regions are shown in Figure D-15 through Figure D-18.

Fuel Oil

Based on EIA forecasts published in its Electric Power Projections by Electricity Market Module Regions (see Annual Energy Outlook 2023, Reference Case), price differentials across regions can be explained by a combination of transportation/delivery charges and taxes. Regional adjustments were calculated based on the relative differences between EIA's national and regional forecasts of Distillate Oil (Fuel Oil #2) and Residual Oil (Fuel Oil #6) prices. For illustrative purposes, forecasted prices for Distillate Oil and for Residual Oil are shown in Figure D-15 through Figure D-18.

Coal

The data from EIA's Electric Power Projections by Electricity Market Module Regions was also used to arrive at the forecasted regional delivered price adjustment for coal.[18] However, there have been no coal plants in service in New York since 2020, and the coal price forecast is only applied to units in external areas.

Seasonality and Volatility

All average monthly fuel prices, with the exception of coal and uranium, display somewhat predictable patterns of fluctuations over each 12-month period. In order to capture such seasonality, the NYISO estimated seasonal factors using standard statistical methods.[19] The multiplicative factors were applied to the annual forecasts to yield forecasts of average monthly prices.

The data used to estimate the 2023 seasonal factors are as follows:

- Natural Gas: Raw daily prices from S&P Global/Platts for the various trading hubs incorporated in the regional price blends.
- Fuel Oil #2: EIA's average daily prices for New York Harbor Ultra-Low Sulfur No. 2 Diesel Spot Price. The Outlook assumes the same seasonality for both types of fuel oil.
- The seasonalized time series represent the forecasted trend of average monthly prices. Because the Outlook uses weekly prices for its analysis, the monthly forecasted prices are interpolated to yield 53 weekly prices for a given year. Furthermore, price "spikes" are layered on these forecasted weekly prices to capture typical intra-month volatility, especially in the winter months. The "spikes" are calculated as five-year averages of

[17] The raw hub-price is "burdened" by an appropriate level of local taxes and approximate delivery charges. In light of the high price volatility observed during winter months, the "basis" calculation excludes data for January, February, and December.
[18] The published figures do not make a distinction between the different varieties of coal—i.e., bituminous, sub-bituminous, and lignite.
[19] This is a two-step process. First, deviations around a centered 12-month moving average are calculated over the 2018-2022 period. Second, the average values of these deviations are normalized to estimate monthly/seasonal factors.

deviations of weekly (weighted-average) spot prices relative to their monthly averages. The "spikes" for a given month are normalized such that they sum to zero.

Figure D-15: Forecasted Fuel Prices for Zones A-E

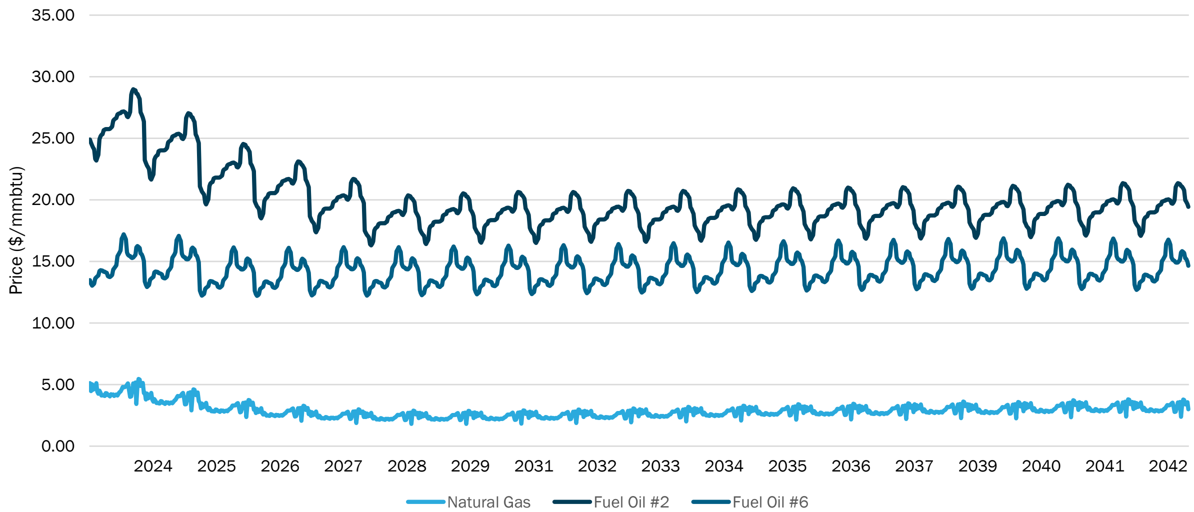


Figure D-16: Forecasted Fuel Prices for Zones F-I

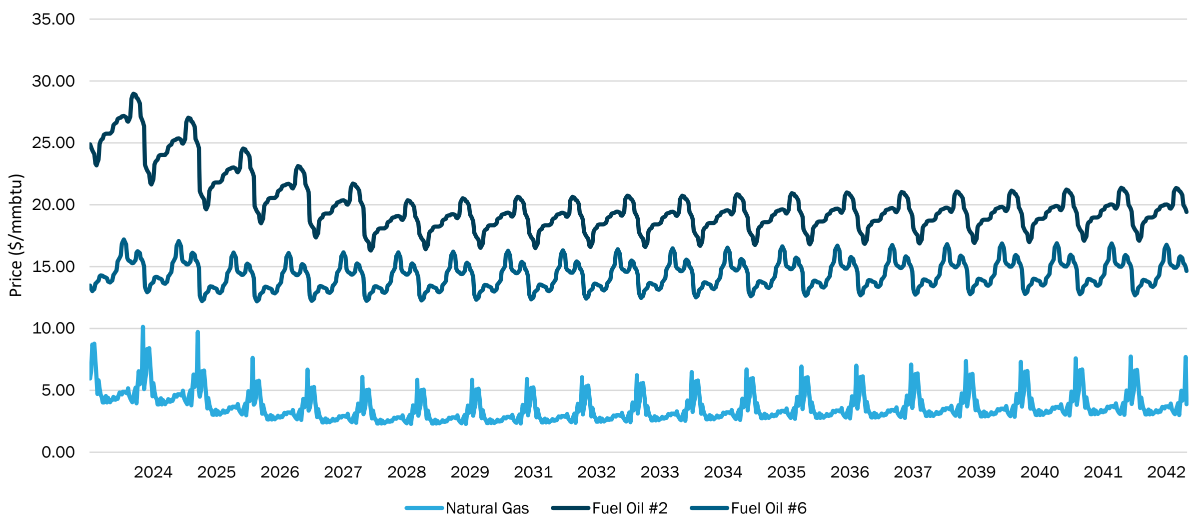


Figure D-17: Forecasted Fuel Prices for Zone J

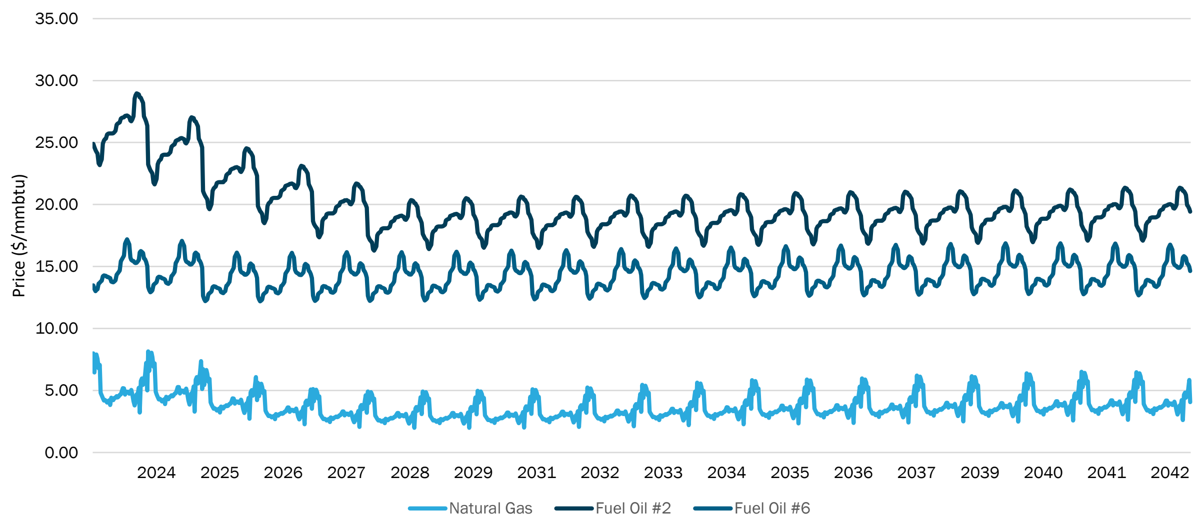
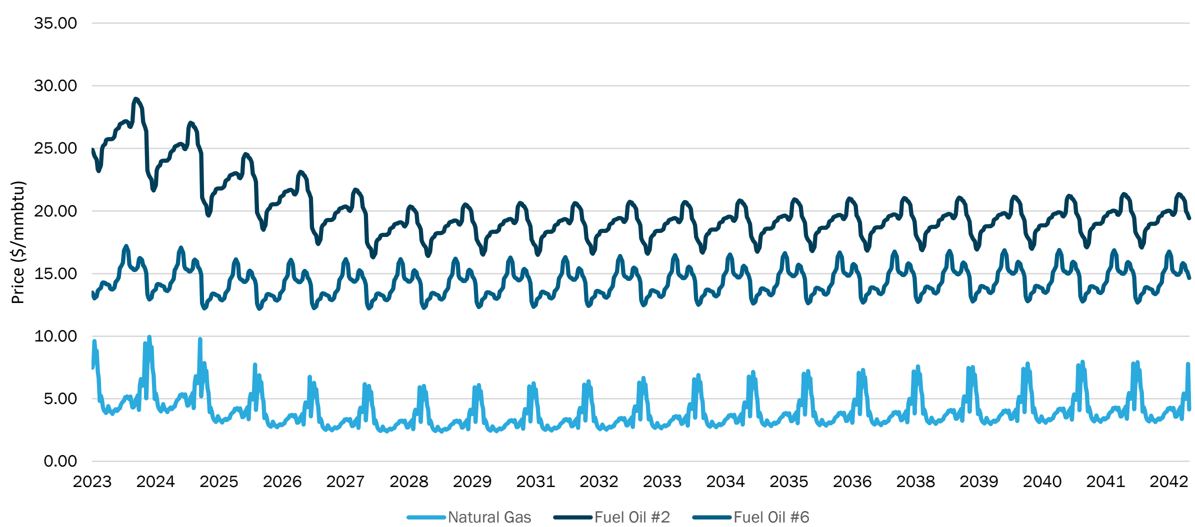


Figure D-18: Forecasted Fuel Prices for Zone K



External Areas Fuel Forecast

Fuel forecasts for the three external systems modeled—ISO-New England, PJM Interconnection and IESO Ontario—were also developed. For each of the fuels, the ISO-New England North, ISO-New England South, PJM-East, and PJM-West forecasts are based on the EIA data obtained from the same sources as those used for New York. With respect to the IESO Ontario control area, the relative price of natural gas is based on spot-market data for the Dawn hub obtained from S&P Global. The Outlook does not model any IESO Ontario generation as being fueled by either oil or coal.

Figure D-19: External Areas Fuel Forecast Regional Multiplier

Fuel	PJM-East	PJM-West	ISONE-North	ISONE-South	IESO
Natural Gas	0.900	0.800	1.300	1.200	0.975
Fuel Oil #2	1.160	1.109	0.597	0.597	1.125
Fuel Oil #6	1.160	1.109	0.597	0.597	n/a
Coal	1.438	0.949	1.500	1.500	n/a

Figure D-20: Forecasted Fuel Prices for PJM East

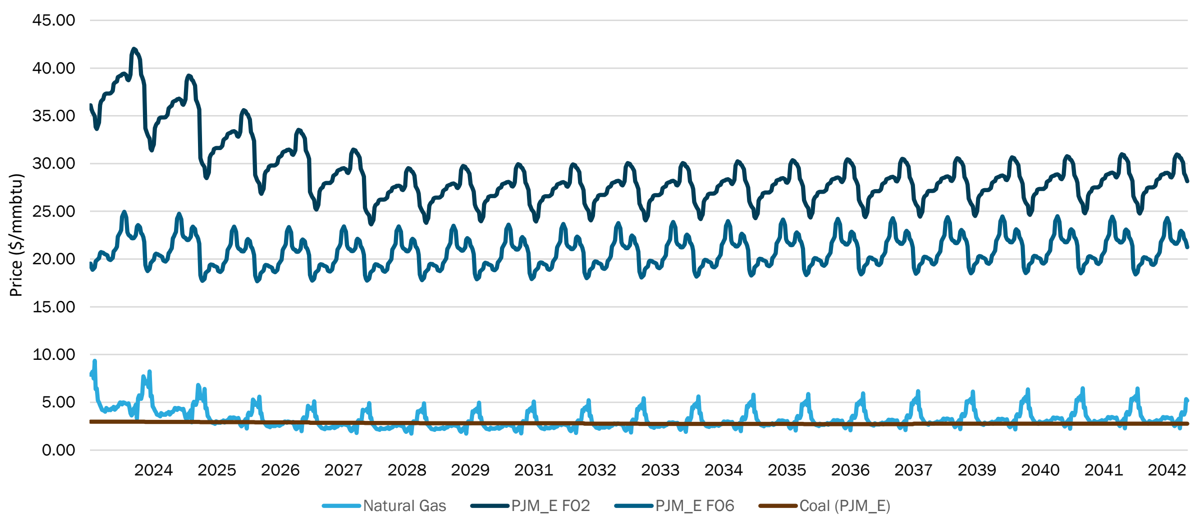


Figure D-21: Forecasted Fuel Prices for PJM West

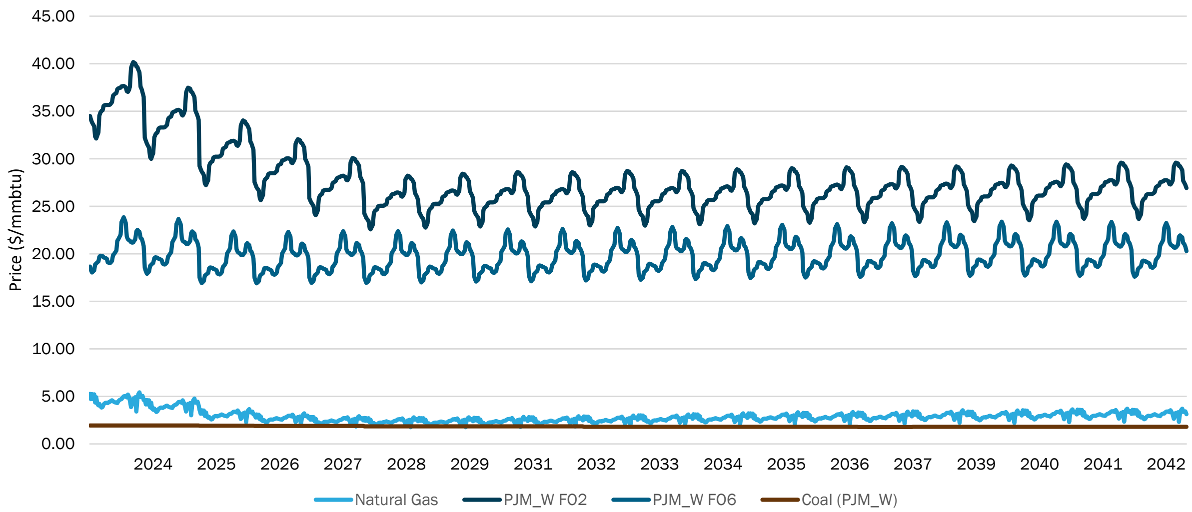


Figure D-22: Forecasted Fuel Prices for ISO-NE

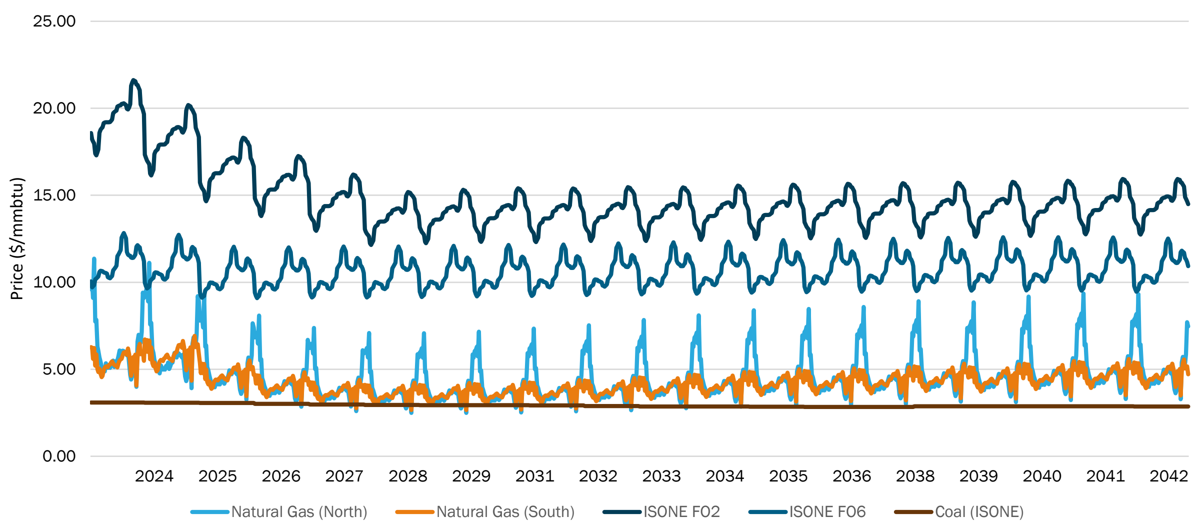
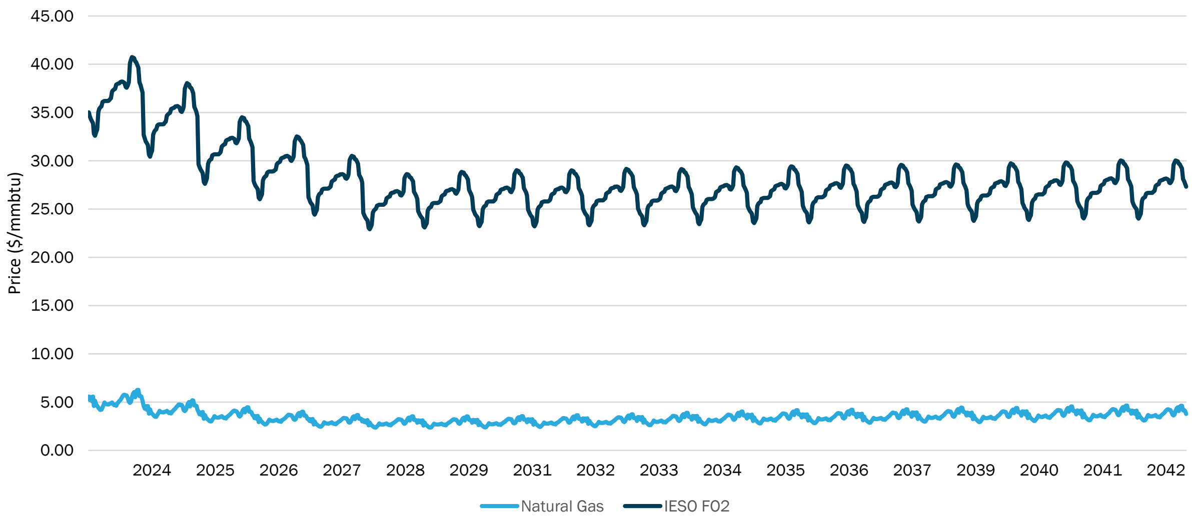


Figure D-23: Forecasted Fuel Prices for IESO



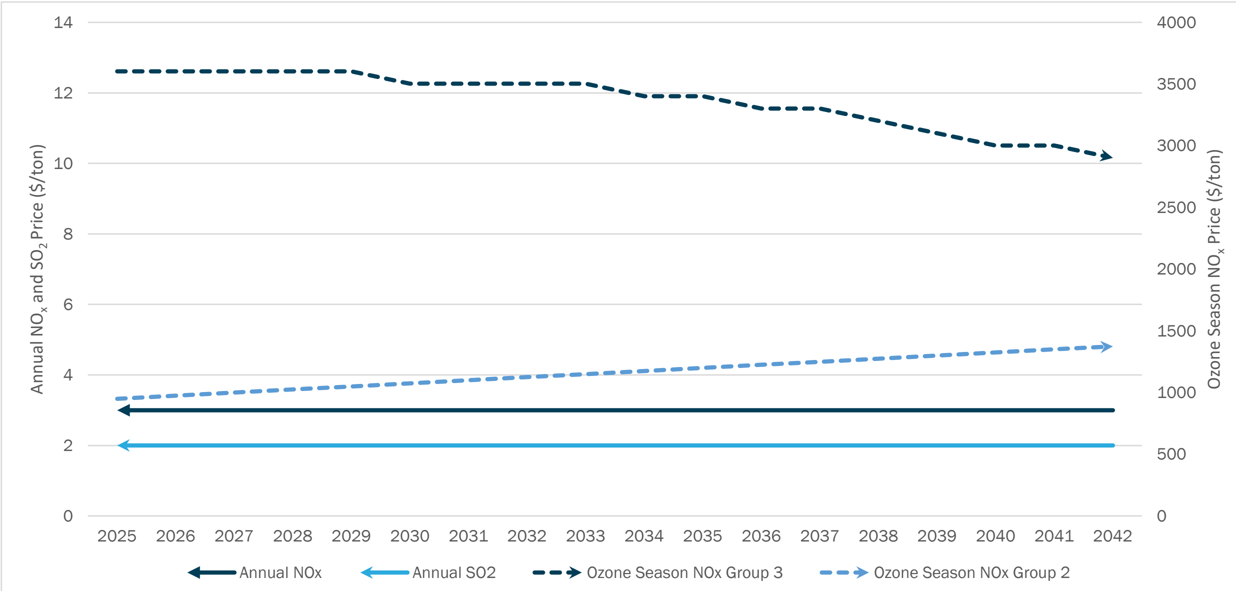
Emissions Allowance Price Forecasts

The cost of emission allowances is an increasing portion of generator production costs. Currently, all New York fossil-fuel generators greater than 25 MW (nameplate) and most generators in many surrounding states are required to procure allowances in amounts equal to their emissions of sulfur dioxide (SO_2), nitrous oxides (NO_X), and/or carbon dioxide (CO_2). The allowance price forecasts[20] for annual and seasonal NO_X and SO_2 emissions are developed using representative prices.[21]

The Cross-State Air Pollution Rule (CSAPR) annual NO_X and SO_2 allowances price forecasts reflect persistent oversupply of these programs, as emissions are well below the collective cap. The ozone season NO_X program has seen significant changes since it began. These stricter ozone season rules created separate groups, such as Group 2 and Group 3, with increasing levels of required emissions reductions among the affected states. Past iterations have generally, after an initial increase in price, led to price declines as market participants adjust to new operational limits. The forecast reflects the expectation that stricter ozone season NO_X limit in the Cross-State Air Pollution Rule Update and subsequent Good Neighbor Plan for the 2015 Ozone NAAQS Rule will continue to be manageable program-wide. Since the forecasts were created, legal challenges to the Good Neighbor Plan have barred the EPA from enforcing a majority of the more stringent reduction requirements, leading to lower prices than those included in the Group 2 and Group 3 forecasts.

[20] https://www.nyiso.com/documents/20142/26278859/System_Resource_Outlook-Emissions_Price_Forecast.xlsx
[21] Allowance price forecasts are informed by representative allowance market prices as of the lockdown date for this Outlook (October 15, 2023).

Figure D-24: NO_X and SO_2 Emission Allowance Price Forecasts ($nominal/ton)



The Regional Greenhouse Gas Initiative (RGGI) program for capping CO_2 emissions from power plants[22] includes the six New England states, as well as New York, Maryland, Delaware, and New Jersey (collectively, the "RGGI States"). During the program review that was completed in 2017, the RGGI States agreed to an emissions cap reduction from 78 million tons in 2020 to 55 million tons in 2030. New Jersey reentered the program in 2020 with a budget of 20 million tons, and Virginia entered in 2021 with a budget of approximately 27 million tons. As of May 2024, Pennsylvania has been barred from RGGI participation and Virginia exited the program after three years at the end of 2023. These states' participation continues to be the subject of legal challenges in both states. For the purposes of this Outlook, Pennsylvania is assumed to not join RGGI and Virginia is assumed to remain in RGGI for the full study period.

Starting in 2021, an Emission Containment Reserve provides price support by holding back allowances from auction if prices do not exceed predefined threshold levels. The RGGI States also continue to implement a Cost Containment Reserve (CCR) that helps reduce prices by providing additional allowances to auction when prices reach the high CCR trigger price. Additionally, the states have agreed to adjust banked allowances by reducing the budgets in 2021-2025 by approximately 19 million tons per year. The 2021 program review is ongoing as states agree what

[22] New York began regulating most generators of 15 MW (nameplate) or more in 2021 under RGGI.

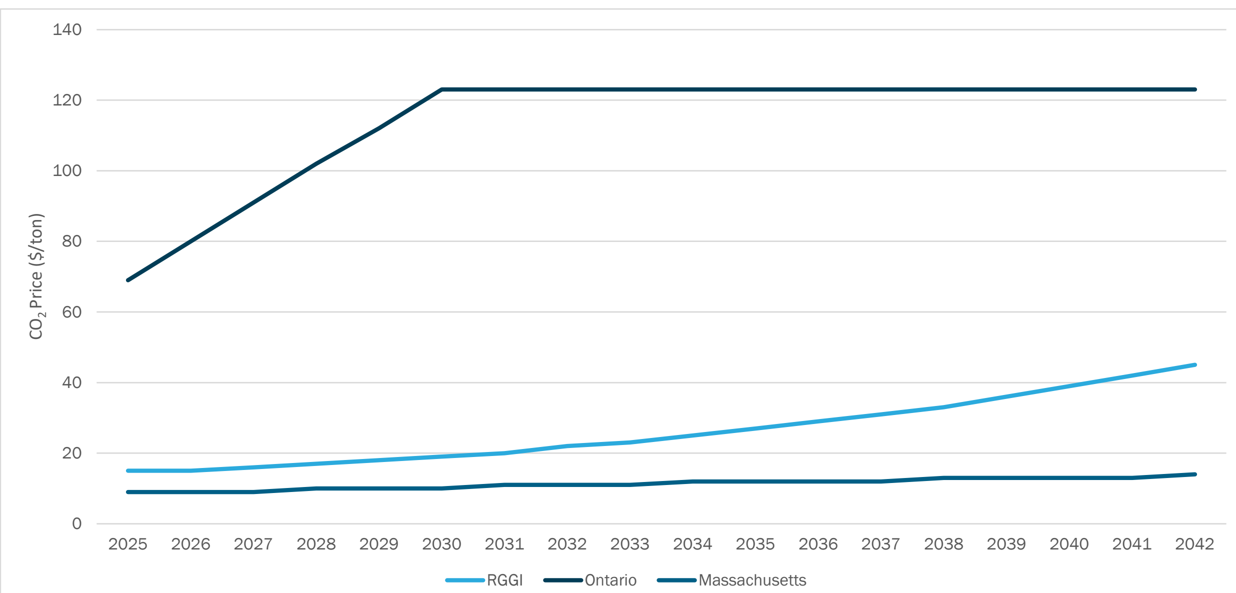
cap reductions and other program designs to implement in future years. As of May 2024, RGGI prices are at all-time highs exceeding $22/ton, as events since the forecast was produced has tended to push the actual market price higher than forecasted.

Massachusetts began implementing its own single state cap-and-trade program in 2018, which is similar to RGGI but with more restrictive caps applicable to generators located in Massachusetts.[23] Massachusetts allowance prices assumed in this study are incremental to RGGI allowance prices imposed upon Massachusetts's emitting generators.

The study also assumes a distinct CO_2 allowance price forecast applicable to IESO (Ontario) generation based upon CO_2 prices in *Canada's A Healthy Environment and a Healthy Economy*.[24] Power sector compliance obligations are in the form of indexed rate-based standards, where the baseline rate drops to 310 tonne/GWh (683 lb/MWh) in 2023. New to this Outlook, in recognition that only emissions associated with operations above the baseline rate require compliance obligations, the assumed allowance price will be reduced to only account for the proportion of total Ontario emissions from the 2021 Benchmark that were above the baseline rate.

Figure D-25 below shows the CO_2 emission allowance price forecasts by year in $/ton.

Figure D-25: CO_2 Emission Allowance Price Forecast ($nominal/ton)



[23] https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774
[24] https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/healthy-environment-healthy-economy.html

External Area Model

PJM, ISO-NE, and IESO are actively modeled in the production cost simulation. The Hydro-Québec (HQ) system is not explicitly modeled since it is asynchronously tied to the New York bulk system. Proxy buses representing the direct ties from HQ to NYISO, HQ to IESO, and HQ to ISO-NE are modeled. Figure D-26 through Figure D-28 list the additions, retirements, and rerates for the external control areas by fuel source by year as reported by the external control areas in their respective planning documents. Figure D-29 presents the aggregate capacities by unit type.

Figure D-26: PJM Unit Additions and Retirements

Year	Source	Additions	Retirements
2023	Fossil Fuel	1,200	5,804
	Wind	188	
2024	Fossil Fuel		131
2025	Solar	4,666	
	Fossil Fuel		170

Figure D-27: ISO-NE Unit Additions and Retirements

Year	Source	Additions	Retirements
2023	Solar	110	
	Fossil Fuel		295
2024	Solar	190	
	Offshore Wind	800	
	Fossil Fuel		215
	Other		6
2025	Solar	100	
	Fossil Fuel		230
	Other		59
2026	Fossil Fuel		4
	Other		6

Figure D-28: IESO Unit Additions and Retirements

Year	Source	Additions	Retirements
2024	Nuclear		1,030
2025	Nuclear		2,060

Figure D-29: Control Area Capacity (MW)

Summer Capacity (MW)	2025	2026	2027	2028	2029	2030
NYISO	**40,397**	**40,358**	**40,358**	**40,358**	**40,358**	**40,358**
Combined Cycle	11,185	11,185	11,185	11,185	11,185	11,185
Steam Turbine (Oil and Gas)	10,573	10,573	10,573	10,573	10,573	10,573
Conventional Hydro	4,868	4,868	4,868	4,868	4,868	4,868
Combustion Turbine	4,170	4,131	4,131	4,131	4,131	4,131
Steam Turbine (Nuclear)	3,342	3,342	3,342	3,342	3,342	3,342
Wind	2,951	2,951	2,951	2,951	2,951	2,951
Solar	1,428	1,428	1,428	1,428	1,428	1,428
Pumped Storage	1,405	1,405	1,405	1,405	1,405	1,405
Other Steam Turbine	213	213	213	213	213	213
Offshore Wind	130	130	130	130	130	130
Landfill Gas	110	110	110	110	110	110
Internal Combustion Turbine	22	22	22	22	22	22
PJM	**198,724**	**198,554**	**198,554**	**198,538**	**198,538**	**198,554**
Combined Cycle	58,490	58,490	58,490	58,490	58,490	58,490
Steam Turbine (Coal)	37,537	37,537	37,537	37,537	37,537	37,537
Steam Turbine (Nuclear)	33,418	33,418	33,418	33,418	33,418	33,418
Combustion Turbine	29,031	29,014	29,014	29,014	29,014	29,014
Wind	11,902	11,902	11,902	11,902	11,902	11,902
Solar	9,591	9,591	9,591	9,591	9,591	9,591
Steam Turbine (Oil and Gas)	6,248	6,095	6,095	6,095	6,095	6,095
Pumped Storage	5,182	5,182	5,182	5,182	5,182	5,182
Other Steam Turbine	3,295	3,295	3,295	3,295	3,295	3,295
Conventional Hydro	2,928	2,928	2,928	2,912	2,912	2,928
Internal Combustion Turbine	670	670	670	670	670	670
Landfill Gas	432	432	432	432	432	432
ISO-NE	**31,446**	**31,157**	**31,146**	**31,174**	**31,174**	**31,146**
Combined Cycle	12,488	12,410	12,410	12,410	12,410	12,410
Steam Turbine (Oil and Gas)	3,943	3,943	3,943	3,943	3,943	3,943
Steam Turbine (Nuclear)	3,380	3,380	3,380	3,380	3,380	3,380
Combustion Turbine	3,350	3,198	3,198	3,198	3,198	3,198
Wind	2,058	2,058	2,058	2,058	2,058	2,058
Conventional Hydro	1,961	1,961	1,961	1,988	1,988	1,961
Pumped Storage Hydro	1,860	1,860	1,860	1,860	1,860	1,860
Other Steam Turbine	1,052	992	986	986	986	986
Solar	607	607	607	607	607	607
Steam Turbine (Coal)	538	538	538	538	538	538
Internal Combustion Turbine	144	144	139	139	139	139
Landfill Gas	66	66	66	66	66	66
IESO	**34,509**	**32,445**	**32,445**	**32,472**	**32,472**	**32,445**
Steam Turbine (Nuclear)	11,929	9,865	9,865	9,865	9,865	9,865
Conventional Hydro	7,313	7,313	7,313	7,340	7,340	7,313
Combined Cycle	6,885	6,885	6,885	6,885	6,885	6,885
Wind	4,925	4,925	4,925	4,925	4,925	4,925
Steam Turbine (Oil and Gas)	2,018	2,018	2,018	2,018	2,018	2,018
Combustion Turbine	492	492	492	492	492	492
Solar	478	478	478	478	478	478
Other Steam Turbine	294	294	294	294	294	294
Pumped Storage Hydro	175	175	175	175	175	175

Production Cost Model Specifics

The NYISO's Production Cost Model (PCM) is run in GE's Multi Area Production Simulation (MAPS) software. The PCM comprises of nodal representations of NYISO, ISO-New England, IESO, and PJM Interconnection systems. Neighboring systems surrounding New York only have major interface flows secured, whereas the New York electric system is modeled with major interfaces and bulk and local lines secured. The PCM also contains N-1 monitored contingency ("mon-con") pairs for binding elements in the New York system that have been identified with running a N-1 contingency screening analysis or were identified as limiting in historical congestion analysis.[25]

The PCM includes detailed generator models for all generators that participate in the NYISO's market. Fossil-fuel generators are modeled with discrete heat rates that relate fuel input (heat input) to generator and emissions output. Renewable generation from solar and wind resources are modeled using a fixed hourly shape based on historical weather year and county or zonal averages. Hydro resources are modeled as fixed hourly resources as described in more detail below.

Hydro Modeling Improvements

In consideration of stakeholder feedback, the NYISO re-evaluated how New York hydro resources are modeled and subsequently updated its model for this Outlook study. Previous models assumed some pondage capability of hydro resources that could be optimized by the simulation software to dispatch hydro resources optimally. Thus, all hydro resources received a monthly energy target, as well as minimum and maximum generation capabilities. This Outlook PCM instead assumes most hydro resources in New York, except for Niagara, to have limited pondage capability.

Therefore, these resources were modeled in all PCMs as fixed hourly injections with annual shapes that reflects average generation levels informed by historical operation of the resources. The shapes are based on 2018 operation data, and annual generation targets are based on 15-year averages of historical generation as reported in EIA Form 923. This assumption takes away some of the flexibility available to the simulation software to optimize resources to better accommodate fixed energy injections like wind and solar.

[25] The NYISO posts quarterly reports on historic congestion on its public website. Further information on this reporting can be found here: https://www.nyiso.com/documents/20142/1400863/2024-Q1.zip

REC Contract Prices

NYSERDA regularly publishes updated REC contract information including prices, that the NYISO uses to model awarded and contracted projects.[26] In particular, REC prices are included as negative bid adders in the Contract and Policy Cases to represent impact of out-of-market payments. To perform this calculation, the NYISO used the aggregate premium of "Index REC Strike" price to "Fixed RECs" by technology, published by NYSERDA in the Large-Scale Renewable Project Database ("LSRDB"),[27] to adjust negative bid adder for the Index RECs. This methodology is consistent with the methodology used by the NYISO in the 2021-2040 System & Resource Outlook. REC prices for LBW, OSW, and UPV were estimated using this methodology based on the LSRDB and other contracting information publicly available. Details on the REC prices are included in Appendix B: Production Cost Assumptions Matrix.

Premiums by technology type calculated in the 2021-2040 System & Resource Outlook were used in this Outlook because nearly all projects have converted their fixed contracts to index contracts since the prior Outlook. The negative bid adders represent the resource's willingness to produce even at negative market prices so long as the market losses are covered by the out-of-market payments under the REC contract.

Hurdle Rates & Interchange

Hurdle rates set the conditions under which economic interchange occurs between neighboring systems in the model. They represent a minimum savings level that needs to be achieved before energy will transact across the interface. Hurdle rates help ensure that the production cost simulation is reasonably consistent with the historical pattern of internal NYCA generation and imports. Hurdle rates are used to reflect actual interregional energy market transaction costs. The NYISO uses a hurdle rate tuning process during the benchmarking stage of modeling to align the base model imports and exports with historic performance.

Two independent hurdle rates are used in the Outlook, one for the commitment of generation and a separate one for the dispatch of generation. Both commitment and dispatch hurdle rates are held constant throughout the 2023-2042 study period. The hurdle rate values produce results consistent with NYCA historic total import levels.

During the tuning process, the NYISO modeled the flow on the Cross Sound Cable (CSC) to allow

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[26] Large-Scale Renewable Projects Reported by NYSERDA: Beginning 2004, https://data.ny.gov/Energy-Environment/Large-scale-Renewable-Projects-Reported-by-NYSERDA/dprp-55ye/data.
[27] *Id.*

up to 330 MW from ISO-NE to Long Island. The flow on the Linden VFT was modeled to allow up to 315 MW in both directions. The NYISO modeled Neptune to hold contract flows into Long Island equal to the capacity of the line of 660 MW and HTP flows to allow up to 660 MW of flow from PJM into New York City.

The hourly interchange flow for each interface connecting the NYISO with neighboring systems was priced at the LBMP of its corresponding proxy bus for purposes of calculating the import and export cost component of NYCA-wide production cost. The summation of all 8,760 hours determined the annual cost of the energy for each interface. The figure below lists the proxy bus location for each interface assumed in this Outlook.

Figure D-30: Interchange LBMP Proxy Bus Area

Interface	Proxy Bus
PJM	Keystone
Ontario	Bruce
Quebec	Chateauguay and Cedars
Neptune	Raritan River
New England	Sandy Pd
Cross Sound Cable	New Haven Harbor
HTP	Bergen
VFT	Linden 138 kV
Northport Norwalk Cable	Norwalk Harbor

Capacity Expansion Modeling

The NYISO used a capacity expansion model in the Policy Case to project potential resource mixes to comply with New York's policy mandates over the Outlook's 20-year study period. The resulting generation capacity mix from the capacity expansion model is then assumed as firm generation for further assessment in production cost simulations for the Policy Case.

The level of detail in the production cost model is computationally infeasible to apply to the capacity expansion model. Thus, the NYISO simplified certain modeling assumptions. While the production cost model has nodal topology with hourly granularity, the capacity expansion model instead leverages a zonal pipe-and-bubble topology and assumes simplifications in time representation for the study period. Time Representation

The capacity expansion model leveraged select representative days, weighted according to their frequency, to represent each model year. Extensive research was conducted to inform the time representation methodology used in this Outlook. The NYISO primarily relied upon the "Grid in Transition" study[28] conducted by Brattle for the NYISO and EPRI's US-REGEN model[29] to inform its method.

The representative days for this Outlook are selected to consider energy demand, wind (LBW and OSW) profiles, and solar profiles. Combinations of these three factors, such as high, low, and average output, were used to reflect a year's variety of system conditions. In addition, peak and near peak representative days were selected to preserve some of the relative "extreme" conditions. This method seeks to preserve annual energy total, seasonal peak loads, and variable performance of renewable resources to drive new resource additions and the future generation mix based on these different system conditions (e.g., load levels and relative renewable energy output).

Representative days are solved individually and chronologically throughout the study period. This method preserves the chronology, including the state-of-charge of battery storage resources, within each day to provide reasonable representation of the unique characteristics of battery storage resources.

- In the 2023-2042 Outlook, each year is represented by the following "types" of days in the capacity expansion model, totaling 13 unique representative days annually. Peak summer day (weighted 1x),
- Peak winter day (weighted 1x),

[28] NYISO Grid in Transition Study: Detailed Assumptions and Modeling Description
[29] U.S. Regional Economy, Greenhouse Gas and Energy Model

- Near peak summer day (weighted 5x),
- Near peak winter day (weighted 5x),
- Moderate day (weighted based on grouping), and
- 8 groups to represent each combination of high/low energy, wind, and solar profiles (also weighted based on grouping)

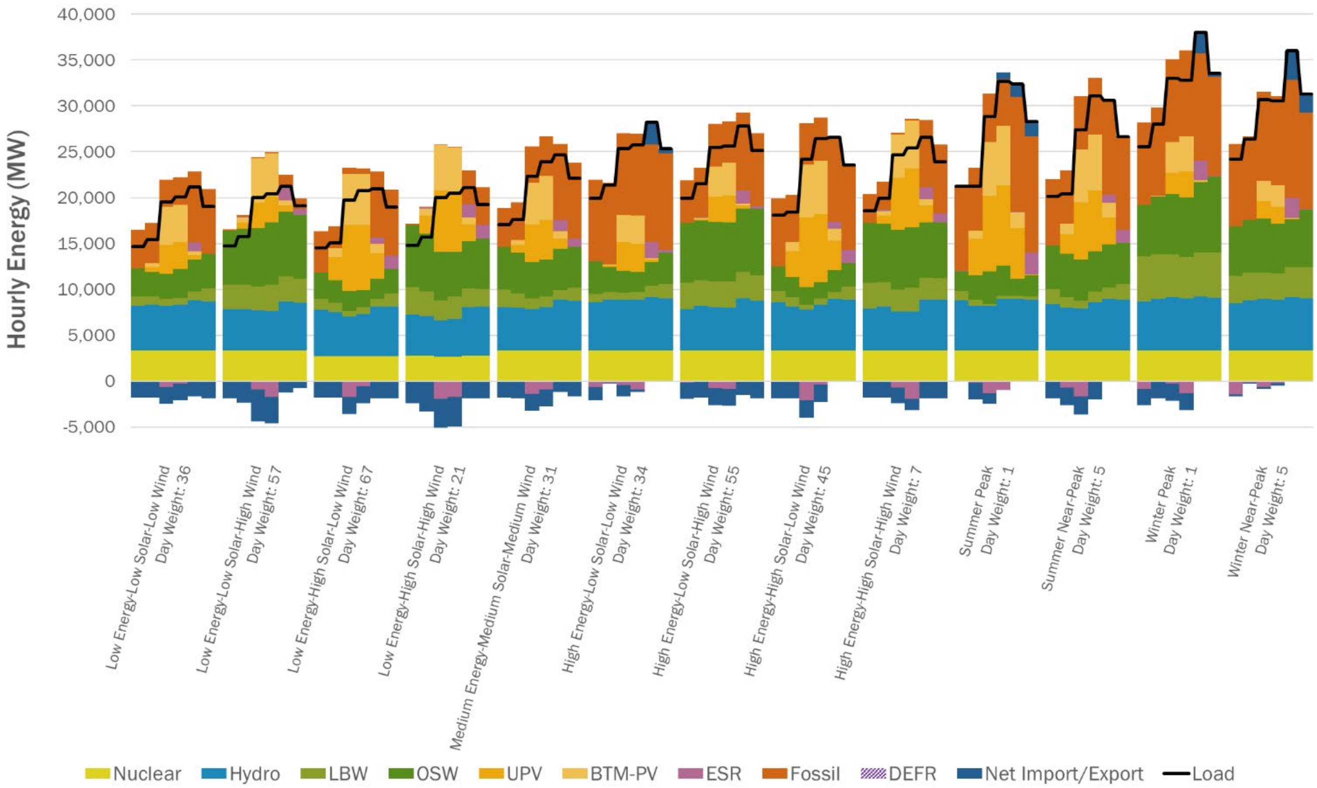
The moderate day and 8 combination days are weighted by analyzing the load, wind, and solar profiles in each study year. After selecting out the peak and near peak days, the remaining days are clustered into groups of most similar days. The average day of the group becomes the representative day for that combination, and the weight is the number of days in that group. The weight is, therefore, also the number of times that type of day occurs each year, thus preserving the annual energy most closely.

Each representative day is split into six four-hour periods, such that the model solves 78 unique time intervals in a given year.[30] Each unique time interval is representative of the average system conditions (e.g., demand, wind production, and solar production) across the predefined four-hour period for the days that comprise the type of representative day.

An illustrative example of the representative days used in this Outlook is included below for the Lower Demand scenario. The unique representative days and their corresponding weighting for a given year (i.e.., number of times that day occurs in that year) are shown below, along with the daily generation mix for each representative day. The magnitude of wind and solar output each unique day are a key driver towards generator-type addition. Results show that dispatchable resources (e.g., fossil, DEFRs, and/or storage) are beneficial to meeting demand when the baseload generators and renewable output is not sufficient.

[30] This simplifying assumption was adopted in consideration of the computational run-time for the model.

Figure D-31: Illustrative Example of Representative Days, Lower Demand Scenario 2035

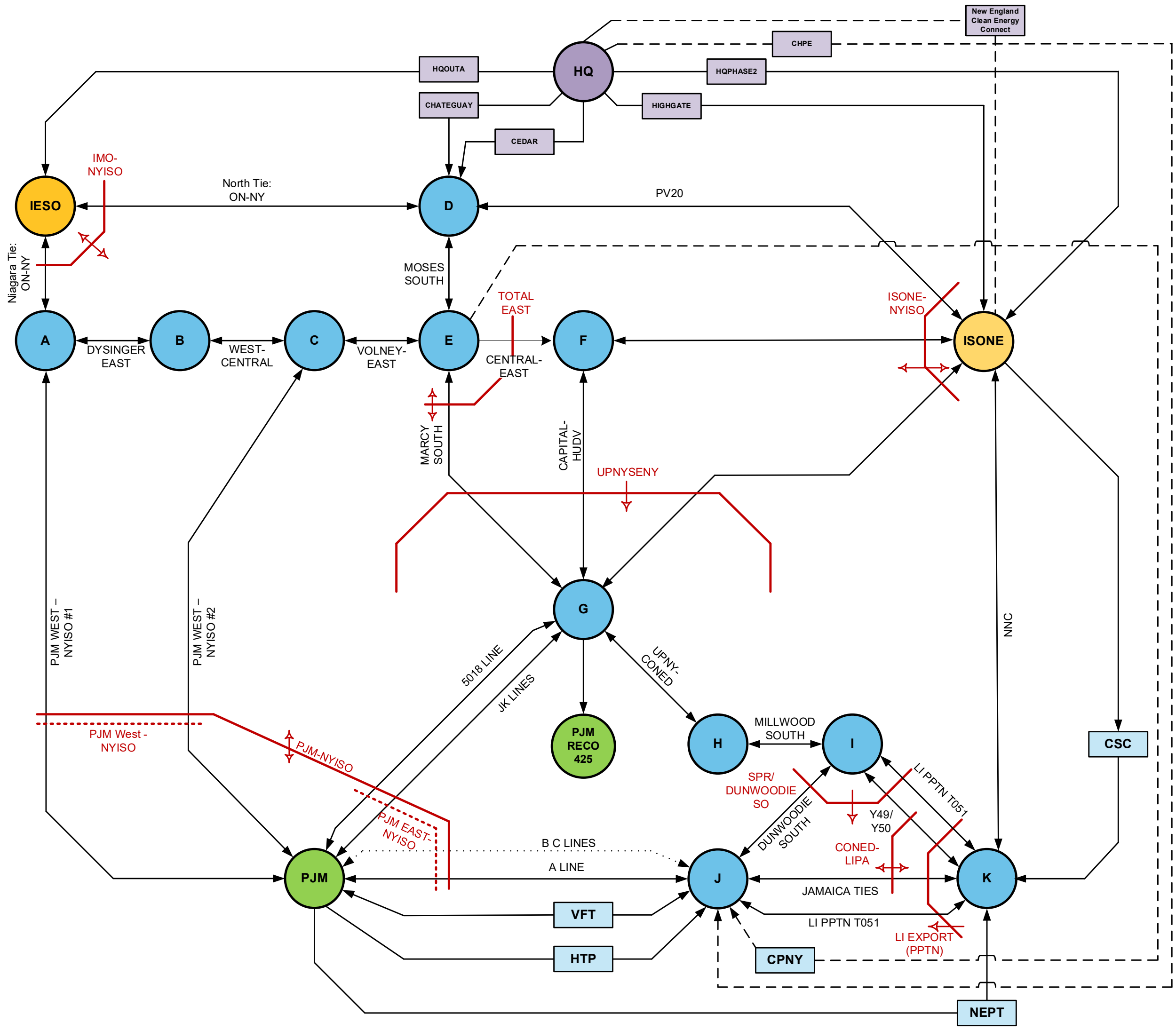


Network Topology

The transmission network in the capacity expansion model is a pipe-and-bubble representation of the NYCA transmission network assumed in the Contract Case and includes a simplified representation of ties to neighboring systems (e.g., PJM, IESO, ISO-NE). In this model, interzonal lines and bulk interfaces are preserved to create the pipe-and-bubble equivalent model of the NYCA.

Transmission expansion is not enabled as a modeling option in the capacity expansion model for this Outlook. The pipe-and-bubble equivalent model used in the capacity expansion model is included in the figure below.

Figure D-32: Capacity Expansion Model "Pipe-and-Bubble" Representation



External System Model

The capacity expansion model used in the 2021-2040 System & Resource Outlook limited its "pipe-and-bubble" representation to the NYCA only. In this Outlook, the modeled system in the capacity expansion model was expanded to include simplified representation of New York's neighboring systems (e.g., PJM, ISO-NE, and IESO[31]), as outlined in the figure above. The external systems (e.g., demand forecast and generation mix) were informed by publicly available reports to reflect policy future systems for each respective area. The ISO-NE system was highly informed by the *2021 Future Grid Reliability Study*[32] and *2023 ISO-CELT*.[33] The PJM system was informed by the

[31] For purposes of modeling in the System & Resource Outlook, HQ is modeled as having a fixed hourly schedule to import into the NYCA.
[32] https://www.iso-ne.com/system-planning/system-plans-studies/economic-studies/
[33] https://www.iso-ne.com/system-planning/system-plans-studies/celt

Clean Attribute Procurement Senior Task Force,[34] *Annual Load Forecast Report*,[35] and *Energy Transition* in PJM reports. The IESO system was informed by the *2022 Annual Planning Outlook*.[36]

Generation Capacity

The Contract Case database serves as the starting point for the Policy Case in the Outlook. Existing generation capacity, planned generation builds, and scheduled generation retirements assumed in the capacity expansion model for the Policy Case align with the Contract Case database. Prescribed "policy" retirements are considered in this Outlook for the Policy Case. In this Outlook, the NYPA small gas plants are assumed to be firm retirements in model year 2031.

The capacity expansion model allows for retirement of existing generators throughout the model's horizon for the Policy Case, excluding the State scenario that assumes age-based retirements for existing fossil-fuel units.[37] The capacity expansion model considers each generator's fixed and variable operating and maintenance costs over the entire model horizon when determining whether to retire the generator in a particular year of the study period. The capacity expansion model co-optimizes generation capital and production costs to determine a least cost future generation mix.

Candidate Technologies

Several modeling simplifications are used for the representations of potential future generators to make the global optimization easier to solve. Generator expansion is enabled at the zonal level, such that one representative generator per type is allowed for each applicable NYCA zone. The capacity expansion model assumes linear expansion[38] for the new generators, such that the candidate generator can increase its capacity each year up to its maximum resource potential (MW), if imposed.[39] The generator builds resulting from the capacity expansion model optimization are then translated into discrete generators in the production cost modeling for the Policy Case. Additional detail on the process of generator placement between capacity expansion and production cost modeling is included in an earlier section of this appendix. This Outlook considers the following generator types available for generation expansion:

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[34] https://www.pjm.com/committees-and-groups/task-forces/capstf
[35] https://pjm.com/-/media/library/reports-notices/load-forecast/2023-load-report.ashx
[36] https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook
[37] In the State scenario, existing units are assumed to have prescribed retirement dates with phase-in of age-based retirements for fleet of generators past age-based threshold (60 years) still in operation.
[38] Linear expansion allows for partial unit retirements and generation additions by 1 MW increments in order to reduce computational complexity.
[39] Zonal capacity limitations are assumed for candidate LBW, OSW, and UPV generators and are based on the 2040 limitations for the applicable generator type, per the supply curve analysis undertaken by NYSERDA and consultants in 2023.

- Offshore wind (OSW)
- Land-based wind (LBW)
- Utility PV (UPV)
- 4-hour battery storage
- 8-hour battery storage
- Dispatchable Emission-Free Resource (DEFR)

Generation expansion in the capacity expansion model is limited to renewable generation, battery storage, and DEFR generators to provide insight into the potential resource mix to comply with state policies. Fossil-fuel, nuclear, BTM-PV[40], and hydro generation were not candidate generator types eligible for generation expansion in this Outlook.

The characteristics and capabilities of existing technologies (i.e., renewables and battery storage) cannot solve for the 2040 zero emissions CLCPA mandate without significant capacity additions above and beyond the required capacity margins. Therefore, DEFR generation options were included in the capacity expansion model. Additional detail on the candidate DEFR options is included in Appendix C: Capacity Expansion Assumptions Matrix and Appendix F: Dispatchable Emission-Free Resources.

Generator Costs (Capital, FOM, VOM, Fuel)

Capital costs for LBW, UPV, OSW, and batter storage resource (BSR) candidate generators are modeled on a zonal basis according to the NYSERDA Supply Curve Analysis.[41] For LBW, UPV, and OSW, these capital costs also break out into multiple buckets. An example of these cost buckets is as follows - “X1” capacity of LBW is available in a particular zone at “Y1” capital cost plus another “X2” of LBW is available at “Y2” cost, where cost Y2 is higher than cost Y1. Modeling a resource supply curve provides some insight into the impact of potential cost increases in a zone as the better sites are developed first. This level of granularity in assumed capital cost gives the model more options for choosing the optimal resource mix. In the State scenario, these costs are further defined at the county level for LBW and UPV based on county level information in the NYSERDA Supply Curve Analysis.

Declining Capacity Value Curves

As new resources are added to the system that lack of dispatchability, their contribution to capacity margins may decrease with each potential addition of more resources with similar

[40] BTM-PV penetration is assumed to increase throughout the study period consistent with the load forecast for each scenario.
[41] NYSERDA Large Scale Renewables Supply Curve Analysis, *available at* https://dps.ny.gov/system/files/documents/2023/09/eppac-sept-28-agenda-and-slides.pdf.

characteristics. In order to capture this impact as more complementary resources are selected, marginal ELCC curves were developed for LBW, OSW, UPV, and BSR resources.

For this Outlook, marginal ELCC curves for LBW, OSW, UPV, and BSRs are based on hourly input load forecast and resource contribution (by technology type) to quantify the capacity value for that resource type at varying levels of installed capacity.[42] The marginal ELCC values are based on the load levels and capacity mix specific to each scenario for model year 2030 and are applied on a NYCA-wide and Locality-specific basis, as applicable to the resource type.

The Lower & Higher Demand Policy scenarios assume unique marginal ELCC curves for the summer and winter seasons based on the methodology prescribed above. The State scenario assumes annual curves consistent with the Integration Analysis.

Constraints

Policy Mandates

In this Outlook, the Policy Case models select policy mandates for the electric sector as "achieved" in its capacity expansion model to inform of potential capacity and generation mixes for the three scenarios evaluated.[43] The capacity expansion model considers existing generation, as well as candidate resources, to satisfy these constraints for the study period. The policy-based constraints modeled in the capacity expansion model for this Outlook are outlined in the figure below.

[42] As each Policy Case scenario assumes a unique energy demand forecast, each scenario utilizes unique ELCC curves for its respective resource mix.
[43] The model does not attempt to achieve 85% green-house gas emission reduction by 2050.

Figure D-33: Policy Mandates Assumed in Capacity Expansion Model

<table>
<tr><th>Policy Mandate</th><th>Lower Demand Policy Scenario</th><th>Higher Demand Policy Scenario</th><th>State Scenario</th></tr>
<tr><td>BTM-PV capacity</td><td colspan="3">6 GW by 2025
10 GW by 2030</td></tr>
<tr><td rowspan="2">Energy storage capacity</td><td colspan="3">1.5 GW by 2025</td></tr>
<tr><td colspan="2">3 GW by 2030</td><td>6 GW by 2030</td></tr>
<tr><td>“70x30”</td><td colspan="3">70% renewable energy by 2030[44]</td></tr>
<tr><td>Offshore wind capacity</td><td colspan="3">9 GW by 2035</td></tr>
<tr><td>“0x40”</td><td colspan="2">Zero-emissions grid by 2040 and beyond</td><td>Zero-emissions grid by 2040 and beyond; including net zero imports overall from IESO, PJM, and ISO-NE beginning in 2040</td></tr>
</table>

Policy constraints that prescribe minimum amounts of installed capacity by resource type (e.g., energy storage and offshore wind targets) can only be satisfied by each respective resource type. The policy constraints specific to energy can be satisfied by the qualifying resource types, as applicable to each constraint. For example, the 70x30 constraint must be satisfied by generation from LBW, OSW, UPV, BTM-PV, hydro, and imports from HQ. For comparison, the zero-emissions grid by 2040 constraint can be satisfied by qualifying renewable resources, as well as nuclear and DEFRs.

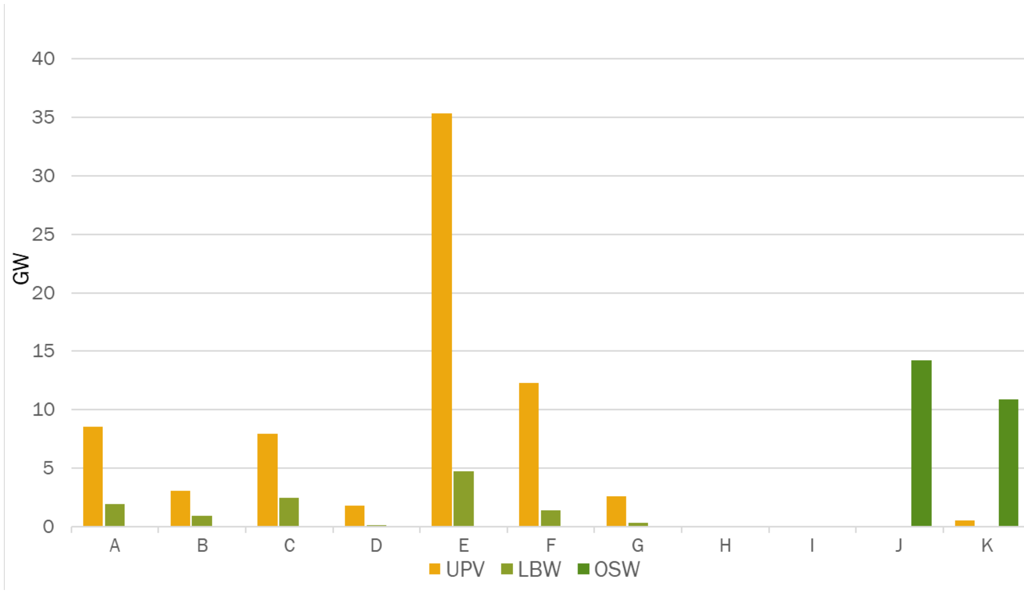
Maximum Resource Potential

As noted above, maximum resource potentials are implemented in the capacity expansion model for applicable resources (e.g., LBW, OSW, and UPV) to impose a limitation on new capacity. The maximum potentials are informed by NYSERDA's Large Scale Renewables Supply Curve effort and are imposed for each applicable resource type location in consideration of factors such as

[44] The formula used for modeling the 70x30 target in the State scenario is: $\frac{Renewable\ Generation}{Load\ forecast + Electrolysis\ load + Net\ storage\ load}$ per DPS memo on modeling assumptions update.

physical land constraints, protected lands and sensitive areas, and project density.[45] Site specific resource potentials are aggregated at the county and zonal level for use in this Outlook. The figure below highlights the resource potentials assumed in this Outlook.

Figure D-34: Capacity Expansion Model Maximum Potential by Resource Type



Capacity Margin Targets

The capacity expansion model includes the construct of capacity reserve margin targets (e.g., Installed Reserve Margin and Locational Capacity Requirements) to set a minimum boundary on the amount of firm capacity needed on the system throughout the Outlook's study period. In this Outlook, NYCA-wide and Locality-specific capacity margin targets are assumed for each year of the study period.[46] For model years 2030 and beyond, adjustments to the locational requirements are assumed as a proxy to address major topology and system changes.[47]

The Lower and Higher Demand scenarios base their capacity margin targets on the NYISO market requirements used in the 2023-2024 Capability Year. This method aligns with what was assumed in the capacity expansion model for the 2021-2040 System & Resource Outlook.

The capacity margin targets for the State scenario are informed by the Integration Analysis per direction from NYSERDA and DPS. Specific to the State scenario assumptions, E3 performs reliability modeling using its in-house loss of load probability (LOLP) model, RECAP. In assessing the reliability needs of Scenario 2, E3 identified that the UCAP reserve margin would need to

[45] https://dps.ny.gov/system/files/documents/2023/09/eppac-sept-28-agenda-and-slides.pdf
[46] The UCAP equivalent of the capacity margin targets is modeled.
[47] Methodology for adjustment to the locational requirements was informed by the NYISO's TSL floor methodology.

increase from 10% today to about 18% in 2050 in order to maintain the same reliability standard, defined as a loss-of-load expectation (LOLE) of 0.1, or 1 day in every 10 years. This increase in the reserve margin is required to maintain the same reliability due to changes in the composition of electric sector demand under Scenario 2: as the system shifts to become winter-peaking, the interannual variability of peak demand increases significantly, due to both higher variability in winter temperatures compared to summer, and a broader range of potential impacts on end use demand due to declining heating coefficient of performance (COPs) as a function of temperature.

E3 performed this reliability modeling at the statewide level. To extend the increase in reserve margin requirements to local capacity zones, E3 scaled the LCRs by the ratio of the target statewide capacity reserve margin in each year by the starting point statewide capacity reserve margin. By 2050, each LCR was scaled up by (118%/110%). Between 2020 and 2050, the capacity reserve margin and LCRs were linearly interpolated between their starting point values today and the identified 2050 values to account for the gradual transition of seasonal system peaks.

The figures below include a summary of the seasonal peak load and minimum capacity margin targets assumed for the Policy Case scenarios for model years 2025 and 2030.

Figure D-35: 2025 Capacity Margin Targets for Policy Case Scenarios

2025 Policy Cases

G-J		Lower Demand Policy Case	Higher Demand Policy Case	State Scenario
Winter	Peak Load (MW)	10,818	10,963	9,305
	Minimum Capacity Margin (%)	80	80	81
	Minimum Capacity Margin (MW)	8,677	8,793	7,538
Summer	Peak Load (MW)	15,678	16,259	13,994
	Minimum Capacity Margin (%)	81	81	81
	Minimum Capacity Margin (MW)	12,758	13,232	11,388

J		Lower Demand Policy Case	Higher Demand Policy Case	State Scenario
Winter	Peak Load (MW)	7,838	7,928	7,101
	Minimum Capacity Margin (%)	78	78	79
	Minimum Capacity Margin (MW)	6,140	6,210	5,618
Summer	Peak Load (MW)	11,236	11,700	10,233
	Minimum Capacity Margin (%)	80	80	80
	Minimum Capacity Margin (MW)	9,029	9,402	8,223

K		Lower Demand Policy Case	Higher Demand Policy Case	State Scenario
Winter	Peak Load (MW)	3,387	3,461	3,223
	Minimum Capacity Margin (%)	94	94	95
	Minimum Capacity Margin (MW)	3,183	3,253	3,060
Summer	Peak Load (MW)	5,330	5,369	5,081
	Minimum Capacity Margin (%)	98	98	98
	Minimum Capacity Margin (MW)	5,199	5,236	4,955

Figure D-36: 2030 Capacity Margin Targets for Policy Case Scenarios

2030 Policy Cases

G-J		Lower Demand Policy Case	Higher Demand Policy Case	State Scenario
Winter	Peak Load (MW)	12,884	13,729	11,910
	Minimum Capacity Margin (%)	87	87	87
	Minimum Capacity Margin (MW)	11,155	11,999	10,412
Summer	Peak Load (MW)	14,592	16,335	13,841
	Minimum Capacity Margin (%)	89	91	89
	Minimum Capacity Margin (MW)	13,045	14,788	12,291

J		Lower Demand Policy Case	Higher Demand Policy Case	State Scenario
Winter	Peak Load (MW)	9,453	9,973	8,729
	Minimum Capacity Margin (%)	84	84	84
	Minimum Capacity Margin (MW)	7,895	8,415	7,328
Summer	Peak Load (MW)	10,530	11,830	10,104
	Minimum Capacity Margin (%)	87	88	86
	Minimum Capacity Margin (MW)	9,118	10,417	8,689

K		Lower Demand Policy Case	Higher Demand Policy Case	State Scenario
Winter	Peak Load (MW)	4,180	4,586	3,865
	Minimum Capacity Margin (%)	63	66	61
	Minimum Capacity Margin (MW)	2,633	3,039	2,371
Summer	Peak Load (MW)	5,042	5,304	4,728
	Minimum Capacity Margin (%)	70	71	68
	Minimum Capacity Margin (MW)	3,506	3,768	3,191

Flexible Load (State Scenario only)

The preliminary State scenario incorporates a mechanism for flexible charging of light-duty electric vehicles (LDVs) on a zonal basis. The model endogenously optimizes the timing of LDV charging to align with peak renewable generation periods. The magnitude of flexible load from LDV charging is informed by Scenario 2 from NYSERDA's Integration Analysis. Summer and Winter peaks were reported for the Integration Analysis cases "With Medium End-Use Flexibility" and "Without End-Use Flexibility." The difference between these cases is the presence of flexible LDV charging. Therefore, it is assumed that the difference in peaks between these cases represents the peak shaving capability of flexible LDV charging. The difference grows throughout the study horizon as more and more LDVs are assumed to enter the market and participate in a flexible charging program.

A free, 100% efficient battery was used to implement flexible LDV charging into the model. The purpose of a battery is to move energy from one hour to another. This creates load in the hour energy was moved from and creates negative load in the hour the energy is moved to. It is important to note that the flexible load "battery" object is not meant to represent an actual battery, rather it is a means to simulate an amount of flexible LDV charging load.

A constraint is modeled to force the daily charging of the flexible load battery to equal the daily discharge. The ensures that the LDV charging load within a given day remains consistent.

Headroom (State Scenario only)

Headroom, used in the State scenario only, is a constraint within the capacity expansion model that represents the projected capability of the local transmission system to support additional renewable generation. Headroom is a proxy representation of local transmission capability that is present before reaching the bulk power system, which facilitates energy transfers between zones in the model. Within CGPP, the Joint Utilities evaluate their local system headroom and provide this information to the NYPSC. For headroom evaluations in CGPP, "local transmission" includes transmission lines and substations that generally serve local load and transmission lines that transfer power to other utility service areas and operate at less than 200 kV. This is in contrast to the facilities that the NYPSC characterizes as "bulk transmission" that transfer power across or between utility service areas at 200 kV or above.

Within the capacity expansion model, the headroom constraint includes zonal headroom values for the existing system and has the capability to add headroom at a specific cost. Existing headroom, which was assessed by local utilities as part of CGPP, represents current local transmission capability plus the consideration of firm future transmission upgrades. Additional headroom is allowed to "expand" at an assumed cost to accommodate more generation output within a zone.

Headroom has the potential to impact capacity expansion results in that it adds an additional cost that would need to be incurred in order to add new generation within a zone. This cost of additional headroom may force generation resources, which would have been economic in a particular zone from a generator capital cost perspective, to be built in another zone due to the cost of additional headroom.

As directed by state entities involved in CGPP, the cost of additional headroom is modeled as $389/kW for the first 1 GW of additional headroom, plus a 15% compounding cost for every additional 1 GW of headroom required thereafter. The resulting cost curve per zone is shown in the figure below.

Figure D-37: Headroom Cost Curve for Preliminary "State Scenario"