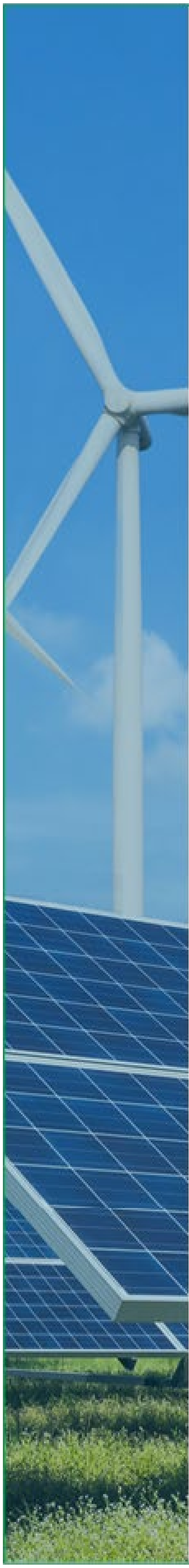


New York ISO
Independent System Operator

Appendix I: Transmission Congestion Analysis

2023-2042 System & Resource Outlook

A Report from the New York Independent System Operator

July 22, 2024

Appendix I: Transmission Congestion Analysis

Overview

This appendix provides detailed analyses of transmission congestion in the Base, Contract, and Policy Cases for the 2023-2042 System & Resource Outlook (Outlook).

In order to assess and identify the most congested elements of the grid, both positive and negative congestion on constrained elements is taken into consideration. Whether congestion is positive or negative is relative to a reference point on the system. All metrics are referenced to the Marcy 345 kV substation near Utica, New York. In the absence of losses, any location with a locational-based marginal price (LBMP) greater than the Marcy LBMP has positive congestion, and any location with an LBMP lower than the Marcy LBMP has negative congestion. Negative congestion typically happens due to transmission constraints that prevent lower cost resources from being delivered towards the Marcy bus.

Historic Congestion

Historic congestion assessments are based on actual market operation and have been conducted at the NYISO since 2005 with metrics and procedures developed in consultation with stakeholders. Four congestion metrics were developed to assess historic congestion: Bid-Production Cost (primary metric), Load Payments, Generator Payments, and Congestion Payment. Appendix A of Section 31.7 of Attachment Y to the NYISO OATT states that the following historic Day-Ahead Market congestion-related data be reported: (i) LBMP load costs (energy, congestion, and losses) by Load Zone; (ii) LBMP payments to generators (energy, congestion, and losses) by Load Zone; (iii) congestion cost by constraint; and (iv) congestion cost of each constraint to load (commonly referred to in the Outlook as "demand$ congestion" by constraint). The results of the historic congestion analyses are posted on the NYISO's website[1].

Historic congestion costs by zone, expressed as Demand$ Congestion, are presented in Figure I-1, indicating that the highest congestion occurred in New York City and Long Island for the historic five-year period (2018-2022).

[1] NY Power System Information - NYISO

Figure I-1: Historic Zonal Demand$ Congestion (2018-2022)

Zone	2018	2019	2020	2021	2022
West	$ 65	$ 88	$ 49	$ 63	$ 81
Genesee	$ 10	$ 2	$ 5	$ 11	$ 30
Central	$ 37	$ 24	$ 17	$ 39	$ 68
North	$ 15	$ 6	$ 10	$ 18	$ 23
Mohawk Valley	$ 7	$ 5	$ 3	$ 11	$ 32
Capital	$ 80	$ 70	$ 55	$ 175	$ 463
Hudson Valley	$ 50	$ 44	$ 33	$ 100	$ 245
Millwood	$ 16	$ 13	$ 11	$ 33	$ 81
Dunwoodie	$ 34	$ 30	$ 21	$ 60	$ 150
New York City	$ 405	$ 320	$ 200	$ 566	$ 1,273
Long Island	$ 303	$ 220	$ 242	$ 523	$ 807
NYCA Total	**$ 1,024**	**$ 823**	**$ 644**	**$ 1,598**	**$ 3,253**

Figure I-2 below ranks historic congestion costs, expressed as Demand$ Congestion, for the top NYCA constraints from 2018 to 2022. The top congested paths are shown below.

Figure I-2: Historic Demand$ Congestion by Constraint (2018-2022)

Demand Congestion (Nominal $M)	Historic					Total
	2018	2019	2020	2021	2022	
CENTRAL EAST	540	516	402	1,155	2,513	5,126
DUNWOODIE TO LONG ISLAND	133	82	98	90	223	625
EDIC MARCY	107	4	2	1	11	125
LEEDS PLEASANT VALLEY	9	20	1	22	29	81
GREENWOOD	62	25	22	22	27	159
PACKARD HUNTLEY	41	9	3	1	0	53
DUNWOODIE MOTTHAVEN	65	28	4	11	11	118
CHESTR-SHOEMAKR_138	0	19	10	10	72	112
UPNY-ConEd	0	0	3	5	0	9
VOLNEY SCRIBA	1	3	1	1	1	6

Projected Future Congestion

Future congestion for the Base Case study period was determined from production cost simulations. As discussed in the “Historic Congestion” section above, congestion is reported as Demand$ Congestion. Production cost simulations are highly dependent upon many long-term assumptions—each of which affects the study results. Detailed input assumptions for are included in Appendix B: Production Cost Assumptions Matrix.

When comparing historic congestion costs to projected congestion costs, it is important to note that there are significant assumptions not included in projected congestion costs using production cost simulations. Such assumptions include: (a) virtual bidding, (b) transmission outages, (c) pricecapped load, (d) generation and demand bid price, (e) Bid Production Cost Guarantee payments, (f) co-optimization with ancillary services, and (g) real-time events and forecast uncertainty. As in prior Economic Planning Process cycles, the projected congestion is less severe than historical levels due to the absence of the above-referenced assumptions in the production cost simulations.

Figure I-3 presents the projected congestion for select years of the study period by load zone. Year-to-year changes in congestion reflect changes in the model, which consist of transmission topology changes, resource additions and retirements, and load changes. These assumptions are discussed in Appendix B: Production Cost Assumptions Matrix.

Figure I-3: Projected Base Case Zonal Demand$ Congestion

Demand Congestion ($M)	2025	2030	2035	2040	2042
West	$ 5	$ 1	$ 10	$ 35	$ 12
Genesee	$ 0	$ 6	$ 19	$ 55	$ 89
Central	$ 19	$ 38	$ 108	$ 301	$ 411
North	$ 2	$ 0	$ 1	$ 3	$ 3
Mohawk Valley	$ 1	$ 3	$ 27	$ 174	$ 258
Capital	$ 19	$ 0	$ 8	$ 16	$ 48
Hudson Valley	$ 7	$ 8	$ 24	$ 56	$ 85
Millwood	$ 3	$ 1	$ 5	$ 12	$ 17
Dunwoodie	$ 7	$ 2	$ 11	$ 27	$ 42
NY City	$ 94	$ 13	$ 88	$ 194	$ 296
Long Island	$ 119	$ 7	$ 1	$ 81	$ 230
NYCA Total	$ 276	$ 78	$ 303	$ 953	$ 1,491

Based on the positive Demand$ Congestion costs, the highest projected congested paths are shown below in Figure I-4.

Figure I-4: Projected Base Case Demand$ Congestion by Constraint

Demand Congestion ($M)	2025	2030	2035	2040	2042
COFFEEN 115 GLENPARK 115	$ 0	$ 0	$ 19	$ 144	$ 210
ELWOOD-PULASKI_69	$ 6	$ 5	$ 18	$ 93	$ 183
FARRAGUT 345.00-FGT_X5 138.00	$ -	$ 4	$ 9	$ 56	$ 95
ASTORIA 345 RAINEY 345	$ -	$ 4	$ 19	$ 57	$ 71
PILGRIM-HAUPPAUGE_138	$ 1	$ 5	$ 11	$ 34	$ 82
CENTRAL EAST	$ 83	$ 22	$ 6	$ 4	$ 3
SUGARLOAF 138 RAMAPO 138	$ 28	$ 24	$ 26	$ 20	$ 20
VOLNEY SCRIBA	$ 7	$ 10	$ 16	$ 27	$ 31
E179THST HELLGT ASTORIAE	$ 1	$ 1	$ 5	$ 24	$ 37
RAMAPO-TALLMAN_138	$ 6	$ 2	$ 2	$ 33	$ 13

Relaxation Analysis

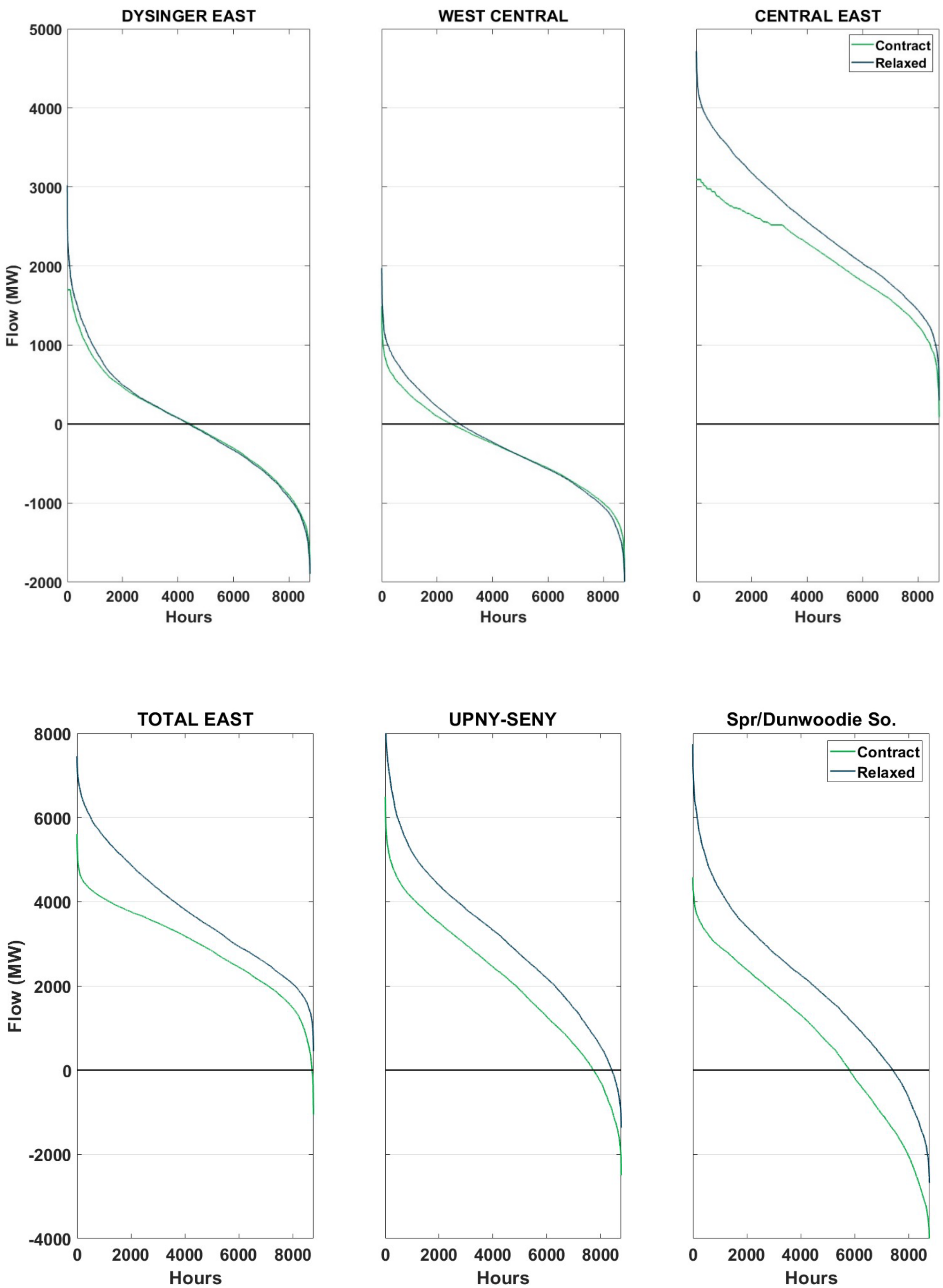
The relaxation analysis looks at differences in flow patterns and congestion in the system when certain lines or interface limits are relaxed (i.e., removed). This type of sensitivity analysis shows what the flow on the line or interface would be if it was not secured and the corresponding flows on other lines and interfaces increase or decrease. It also helps in identifying what the next limiting element on the system will be if the current element being studied were upgraded.

The relaxation analysis also highlights where power wants to flow in the system. If a fully relaxed "copper sheet" case is considered, the increase in flows on the major lines and interfaces indicate how much power moves across those lines to serve load across the whole system.

Other metrics, such as differences in overall system-wide curtailment of renewables, indicate how much renewable generation was held back due to congestion on the system. Comparisons are conducted by calculating a metric before and after the line limits are relaxed. (i.e., sensitivity to relaxed case). The section below shows results from the relaxation analysis carried out for the Contract Case and the Lower Demand and Higher Demand scenarios in the Policy Case.

The following figures compare the flow duration curves of the Contract Case and its corresponding relaxation case analysis.

Figure I-5: Contract Case Major Interfaces 2030 Flow Duration Curves

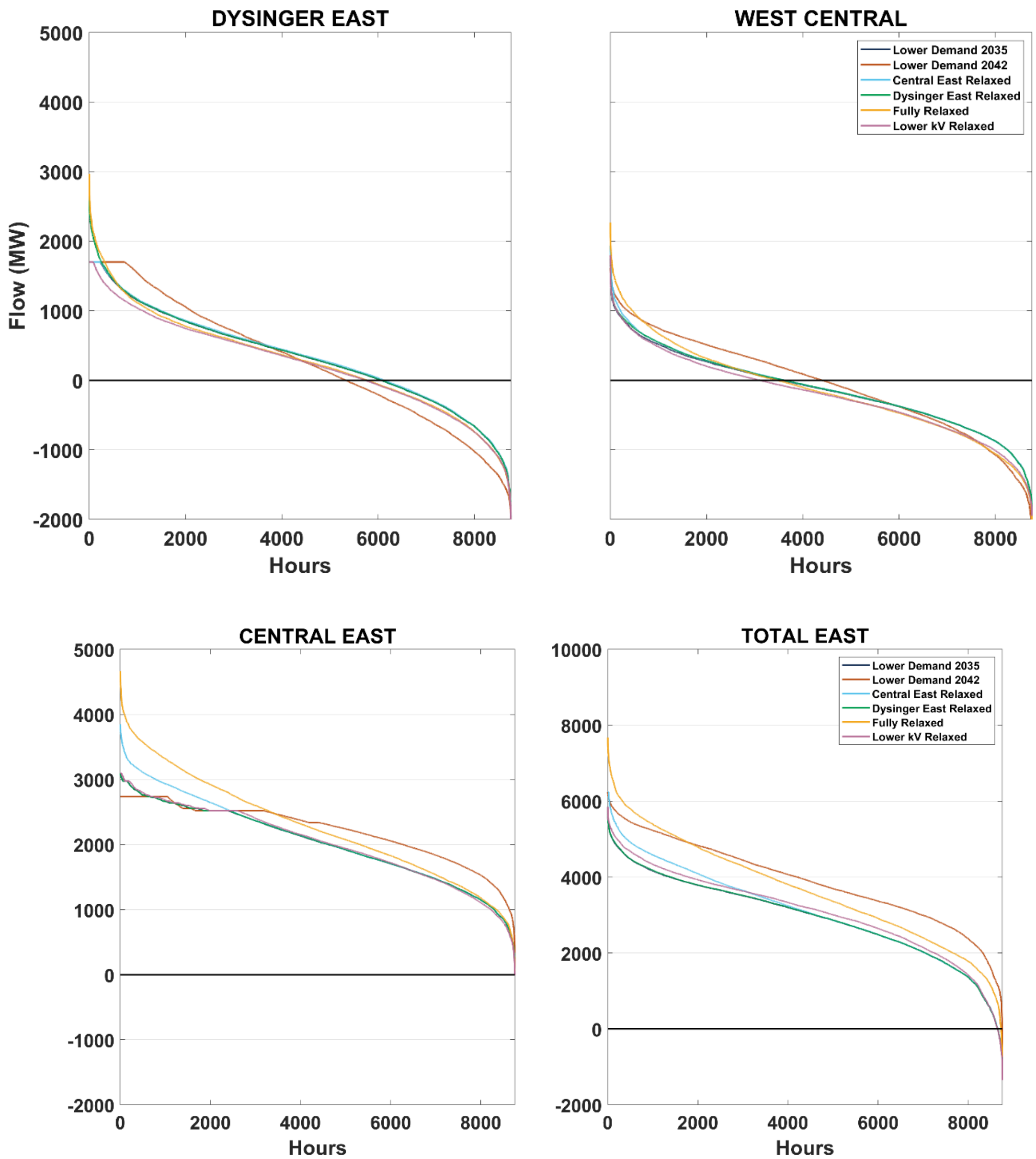


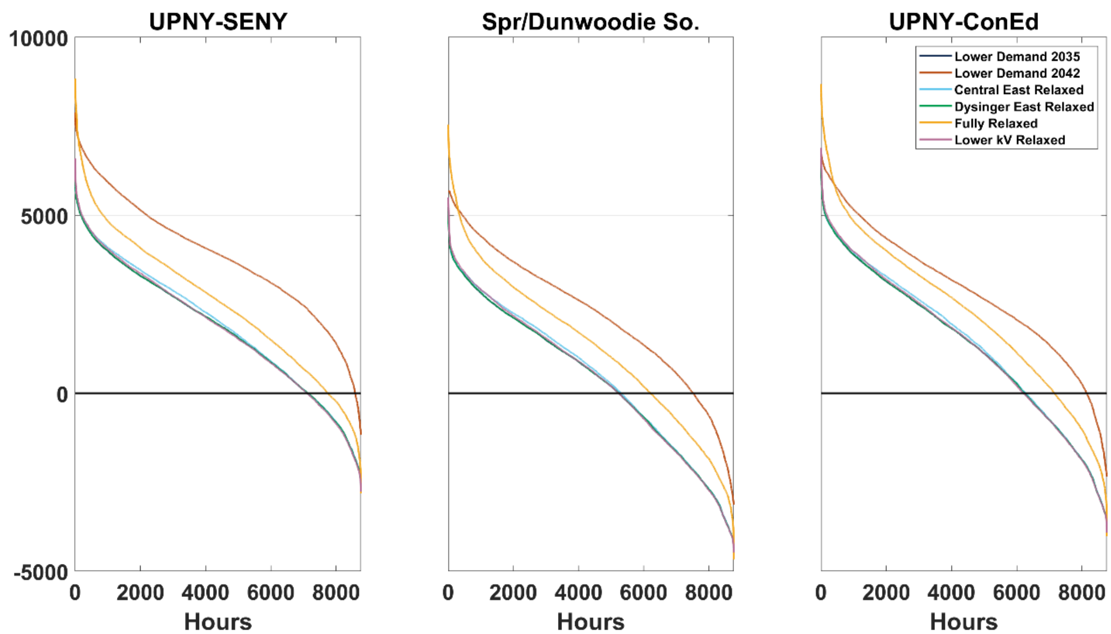
For each major NYCA interface, the relaxed constraints result in increased flows. The flow differences on Dysinger East and West Central are smaller than the rest of the interfaces. Central East, Total East, UPNY-SENY, and Sprainbrook-Dunwoodie South have a more substantial difference in flow between the Contract Case and the relaxation case. In the Contract Case, Central East is one of the most congested interfaces, so it is logical that it gets utilized more heavily in the relaxation case. High-load Zones J and K and high renewable generation in Zones A through E drive flow in the direction from upstate to downstate.

The flow duration curves in Figures I-6 and I-7 below show the differences in flows on major interfaces across New York for two of the Policy Case scenarios (Lower and Higher Demand). For purposes of this analysis, various sensitivities were conducted to assess the potential increase in flows on the interfaces. Increase in flows when interface limits are relaxed indicate that the system would transport more power generally from upstate to downstate if additional transmission capacity is available. In particular, Central East shows increased flow when the interface limit is switched from a voltage stability limit to a thermal only limit.[2] This result is also observed in the "copper sheet" case when all internal New York limits are relaxed. Therefore, this relaxation analysis shows that as the bulk interfaces carry the majority of the power from areas of renewable generation to downstate load centers, increasing the transmission capability on these lines will be essential to maximizing deliverability of renewable resources to efficiently meet policy mandates.

[2] The thermal limit for Central East is higher, or less limiting, than the voltage limit on that interface.

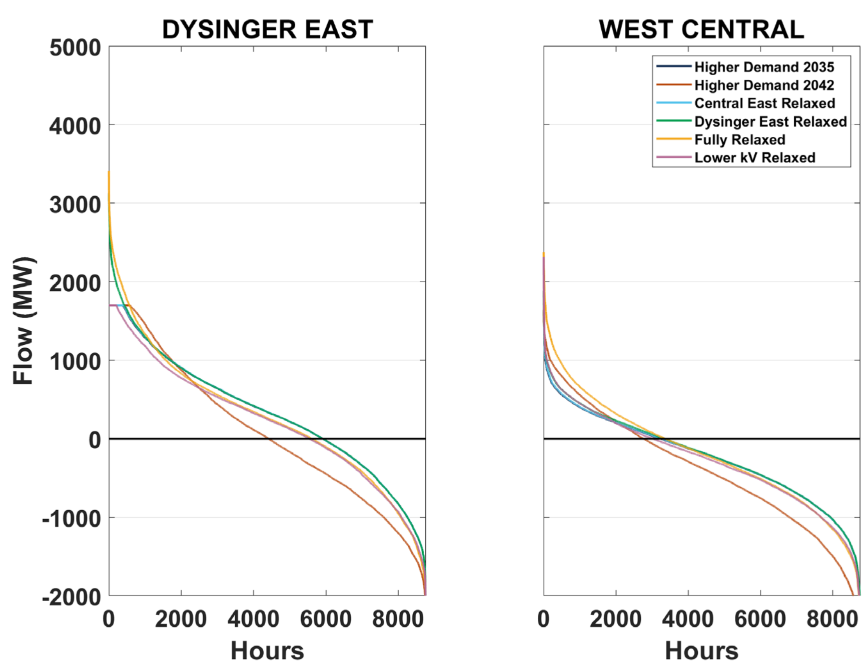
Figure I-6: Lower Demand Policy Scenario - Major Interfaces Flow Duration Curves

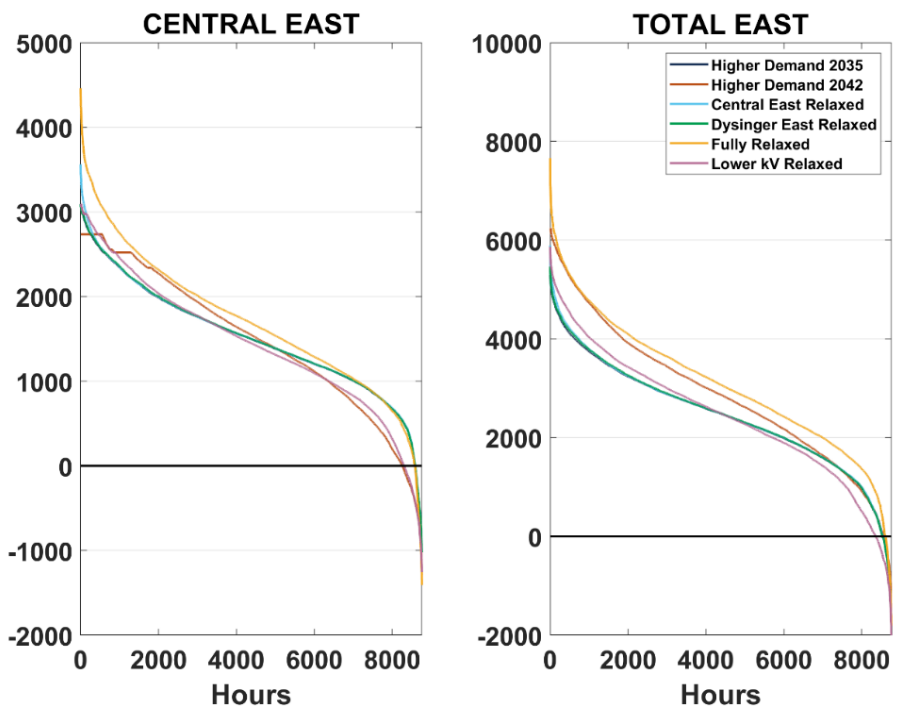


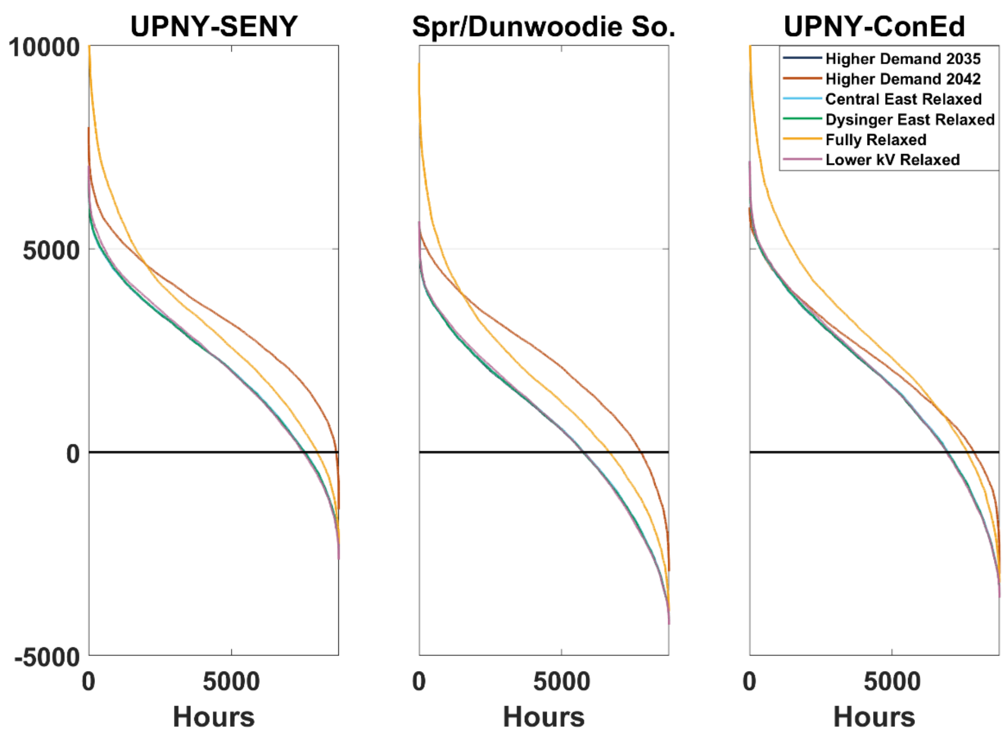


In both the Lower and Higher Demand scenarios, Dysinger East and West Central exhibit bi-directional flows in 2035. Relaxation of the Dysinger East line does not significantly reduce curtailment in any of the NYCA zones. It instead results in increased imports from IESO through Zone A and a small increase in NYCA-wide imports from PJM.

Figure I-7: Higher Demand Policy Major Interfaces Flow Duration Curves







The results for year 2042 in the Higher Demand scenario shows slightly lower flows across Central East than both year 2035 in the Higher Demand scenario and year 2042 for the Lower Demand scenario due to resource additions downstream of Central East interface. Additionally, Dysinger East and West Central show increased negative flows in year 2042 for the Higher Demand scenario relative to the other cases.

The relaxation analysis shows that resolution of lower kV or bulk transmission system constraints amounts to savings in renewable energy curtailment, which is shown in Figure I-8 below. Specifically, the table shows a range of sensitivities conducted on the Higher and Lower Demand scenarios and associated NYCA-wide curtailment results. The lower kV relaxed and “copper sheet” cases show the highest savings in terms of curtailment reduction. Relieving Central East voltage limitations and only securing the thermal limit for the interface also produces curtailment savings in both Policy Case scenarios.

Figure I-8: NYCA-Wide Renewable Energy Curtailment for 2035 Policy Case Sensitivities

Case	NYCA-Wide Renewable Curtailment (GWh)	Curtailment (%)
Higher Policy 2035	5912	6.06%
Higher Policy with LKV Relaxed 2035	4083	4.19%
Higher Policy Coppersheet 2035	1506	1.54%
Higher Policy + CE Thermal Limit 2035	5872	6.02%
Higher Policy + DE Relaxed 2035	5922	6.07%
Lower Policy 2035	2039	2.16%
Lower Policy with LKV Relaxed 2035	1761	1.86%
Lower Policy Coppersheet 2035	791	0.85%
Lower Policy + CE Thermal Limit 2035	1821	1.93%
Lower Policy + DE Relaxed 2035	2037	2.16%

For the Higher and Lower Demand scenarios in the Policy Case, the NYISO performed the analysis by relaxing the lower kV system for simulation year 2042. This assumption is consistent with the prior Outlook Policy Case for the later years in the study. Lower kV systems are undergoing continual upgrades by transmission and distribution owners. Therefore, it is unrealistic to assume that the conditions that exist today will remain the same for a study year that is so far out in the future. Additionally, the placement of new renewable generation also affects the lower kV system congestion and flows. Since the assumptions for exact nodal placement of these new resources are highly uncertain, securing the lower kV system would only constrain the model on the lower kV side and produce results that are not indicative of other large bulk issues. The table below shows the NYCA-wide curtailment results for the Policy Case scenarios with the lower kV transmission system relaxed.

Figure I-9: NYCA-Wide Renewable Energy Curtailment for 2042 Policy Case Sensitivities

Case	NYCA-Wide Renewable Curtailment (GWh)	Curtailment (%)
Higher Policy with LKV Relaxed 2042	10216	6.81%
Lower Policy with LKV Relaxed 2042	3257	2.66%

The table below shows the congestion metrics for major interfaces in all the sensitivity cases. The most binding interface is Central East in most cases followed by Dysinger East.

Figure I-10: Major Interface Congestion for 2035 Policy Case Sensitivities

Case	Interfaces	Limiting Hours
Higher Policy 2035	CENTRAL EAST	143
	DYSINGER EAST-OP	390
	MOSES SOUTH-OP	0
	Spr/Dunwoodie So.-PL	1
	TOTAL EAST	0
	UPNY-ConEd-OP	0
	UPNY-SENY-OP	0
	WEST CENTRAL-OP	0
Higher Policy with LKV Relaxed 2035	CENTRAL EAST	321
	DYSINGER EAST-OP	215
	MOSES SOUTH-OP	0
	Spr/Dunwoodie So.-PL	6
	TOTAL EAST	0
	UPNY-ConEd-OP	0
	UPNY-SENY-OP	0
	WEST CENTRAL-OP	0
Higher Policy + CE Thermal Limit 2035	CENTRAL EAST	0
	DYSINGER EAST-OP	415
	MOSES SOUTH-OP	0
	Spr/Dunwoodie So.-PL	1
	TOTAL EAST	0
	UPNY-ConEd-OP	0
	UPNY-SENY-OP	0
	WEST CENTRAL-OP	0
Higher Policy + DE Relaxed 2035	CENTRAL EAST	149
	DYSINGER EAST-OP	0
	MOSES SOUTH-OP	0
	Spr/Dunwoodie So.-PL	0
	TOTAL EAST	0
	UPNY-ConEd-OP	0
	UPNY-SENY-OP	0
	WEST CENTRAL-OP	0
Higher Policy Coppersheet 2035	CENTRAL EAST	0
	DYSINGER EAST-OP	0
	MOSES SOUTH-OP	0
	Spr/Dunwoodie So.-PL	0
	TOTAL EAST	0
	UPNY-ConEd-OP	0
	UPNY-SENY-OP	0
	WEST CENTRAL-OP	0

Case	Interfaces	Limiting Hours
Lower Policy 2035	CENTRAL EAST	1412
	DYSINGER EAST-OP	228
	MOSES SOUTH-OP	0
	Spr/Dunwoodie So.-PL	0
	TOTAL EAST	0
	UPNY-ConEd-OP	0
	UPNY-SENY-OP	0
	WEST CENTRAL-OP	0
Lower Policy with LKV Relaxed 2035	CENTRAL EAST	1620
	DYSINGER EAST-OP	86
	MOSES SOUTH-OP	0
	Spr/Dunwoodie So.-PL	0
	TOTAL EAST	0
	UPNY-ConEd-OP	0
	UPNY-SENY-OP	0
	WEST CENTRAL-OP	0
Lower Policy + CE Thermal Limit 2035	CENTRAL EAST	0
	DYSINGER EAST-OP	245
	MOSES SOUTH-OP	0
	Spr/Dunwoodie So.-PL	0
	TOTAL EAST	18
	UPNY-ConEd-OP	0
	UPNY-SENY-OP	0
	WEST CENTRAL-OP	0
Lower Policy + DE Relaxed 2035	CENTRAL EAST	1416
	DYSINGER EAST-OP	0
	MOSES SOUTH-OP	0
	Spr/Dunwoodie So.-PL	0
	TOTAL EAST	0
	UPNY-ConEd-OP	0
	UPNY-SENY-OP	0
	WEST CENTRAL-OP	0
Lower Policy Coppersheet 2035	CENTRAL EAST	0
	DYSINGER EAST-OP	0
	MOSES SOUTH-OP	0
	Spr/Dunwoodie So.-PL	0
	TOTAL EAST	0
	UPNY-ConEd-OP	0
	UPNY-SENY-OP	0
	WEST CENTRAL-OP	0

The results for year 2042 for both Policy Case scenarios show high levels of curtailment of renewables even though only the bulk system is secured. This indicates there are transmission enhancement opportunities on the bulk side that can further reduce curtailment.

As shown in the figure below, the majority of congested lines in year 2042 are located in Zones J and K. With the lower kV lines relaxed and the downstate 138 kV lines secured, these transmission facilities appear to be the next limiting elements downstream of the bulk system into the load centers.

Figure I-11: Policy Case Congestion by Constraint 2042

Lines	Higher Demand 2042 Sum of Limiting Hours	Lower Demand 2042 Sum of Limiting Hours
RAINEY8W 138.00-VERNON-W 138.00	7510	7033
HG TAP 138.00-15055 SR 138.00	7520	6140
W49 ST 1 138.00-ASTOR T5 138.00	7890	7033
FOX HILL 138.00-GRENWOOD 138.00	6424	3737
RAINEY8E 138.00-VERNON-E 138.00	4331	2694
GRENWOOD 138.00-KENTTAP 138.00	2440	1459
VERNON-W 138.00-KENTTAP 138.00	2309	1337
RULND RD 138.00-STERLING 138.00	3176	1161
E179 ST 138.00-15055 SR 138.00	2799	1568
FARRAGUT 345.00-FGT_X5 138.00	1384	611
KINGS 138.00-PILGRIM 138.00	2353	1324
PILGRM P 138.00-HAUPAGUE 138.00	3288	2430
BAGATELL 138.00-BETHPAGE 138.00	4429	2320
SGRLF138 138.00-STFOREST 138.00	1042	1248
RAMP138 138.00-TALLMAN 138.00	356	957
ASTANNEX 345 E13ST 47 345 1	4554	3401
FRESH KI 138.00-WILOWBK1 138.00	1532	1757
FRESH KI 138.00-WILOWBK2 138.00	195	257
HILSD230 230.00-HILSD230 230.00	1690	2006
CENTRAL EAST	1154	2956
Cross Sound Cable	4391	5701
SYO_SHRD 138.00-SYOSSET 138.00	4116	2333
PRNCTWN 345.00-N.SCOT77 345.00	2280	892
GOWNUSR1 138.00-GRENWOOD 138.00	1459	954
HAUPAGUE 138.00-PILGRM P 138.00	1130	970
NRTHPT P 138.00-NRTHPT1 138.00	715	1058
LCST GRV 138.00-NEWBRGE 138.00	4293	3487
ASTANNEX 345 E13ST 48 345 1	1536	1178
OAKDL230 230.00-OAKDL115 115.00	1081	963
KENTTAP 138.00-VERNON-W 138.00	198	244
QUENBRDG 138.00-VERNON-E 138.00	255	74
E.G.C.-2 138.00-NEWBRGE 138.00	3482	2482
STOLE345 345.00-STOLE115 115.00	1811	1030
HTP	2548	2227
DYSINGER EAST-OP	586	730
LEEDS 3 345.00-N.SCOT77 345.00	981	26

Figure I-12: Tier 4 HVDC Transmission Performance Policy Case Scenarios[3]

Case	Year	Champlain Hudson Power		Clean Path NY	
		Energy (GWh)	(%)	Energy (GWh)	(%)
Lower Demand	2030	10,398	95%	1,693	15%
	2035	10,344	94%	2,517	22%
	2042	10,357	95%	6,034	53%
Higher Demand	2030	10,397	95%	1,687	15%
	2035	10,337	94%	2,360	21%
	2042	10,341	94%	5,403	47%

[3] Assumes sufficient transmission expansion occurs between 2035 and 2042 to relieve transmission constraints at lower voltage levels, resulting in greater renewable energy available for transfer across the bulk system.

Spillage Analysis

To supplement the curtailment calculations as part of the congestion analysis, a simplified spillage analysis was performed on the Contract and Policy Cases. Spillage calculations are performed via spreadsheet analysis that sums the scheduled generation within the NYCA and compares that to the net load on an hourly basis. The intent of the spillage analysis is to quantify how much excess energy might be produced compared to NYCA load. In actual operations, any excess energy would be exported, if possible, but the spillage analysis does not consider imports or exports.

Net load is used for the spillage analysis and is defined as the gross load in the NYCA minus the load served by behind-the-meter solar generation. The sum of scheduled generation for the spillage analysis includes utility scale solar (UPV), land-based wind (LBW), offshore wind (OSW), run-of-river hydro, and nuclear generation, as well as downstate must-run units due to local reliability rules that are assumed to operate at minimum generation levels.

In the figures below, the hourly average net load is compared to the hourly average curtailment, and the average spillage is calculated for each hour from 2030 in the fully relaxed Contract Case. Similarly, the net load is compared to the hourly average curtailment and spillage from year 2035 in the fully relaxed Lower Demand and Higher Demand scenarios.

Figure I-13: Contract Relaxation Case Hourly Mean Spillage and Curtailment in 2030

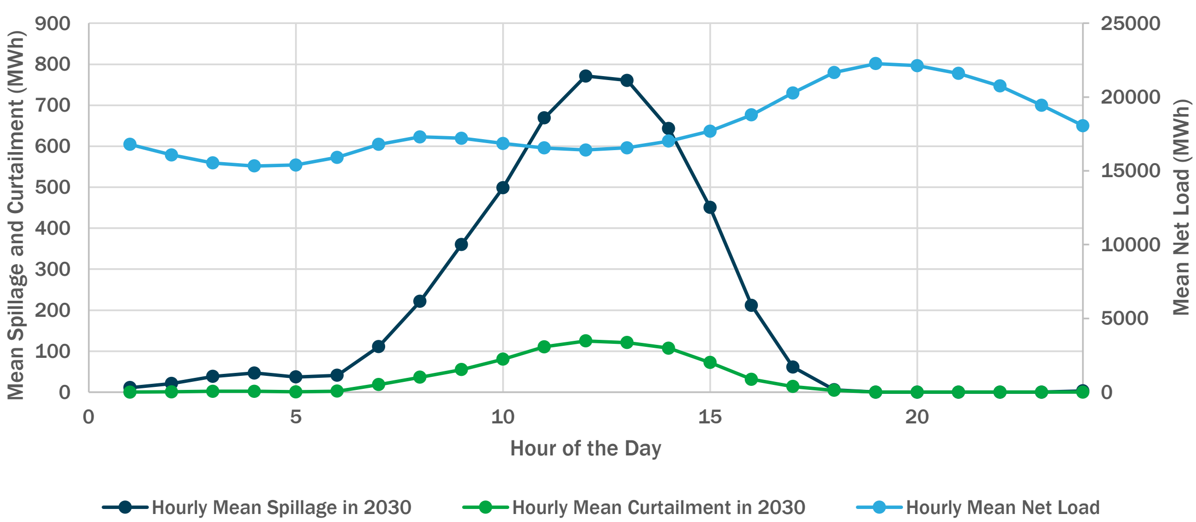


Figure I-14: Lower Demand Policy Relaxation Case Hourly Mean Spillage and Curtailment in 2035

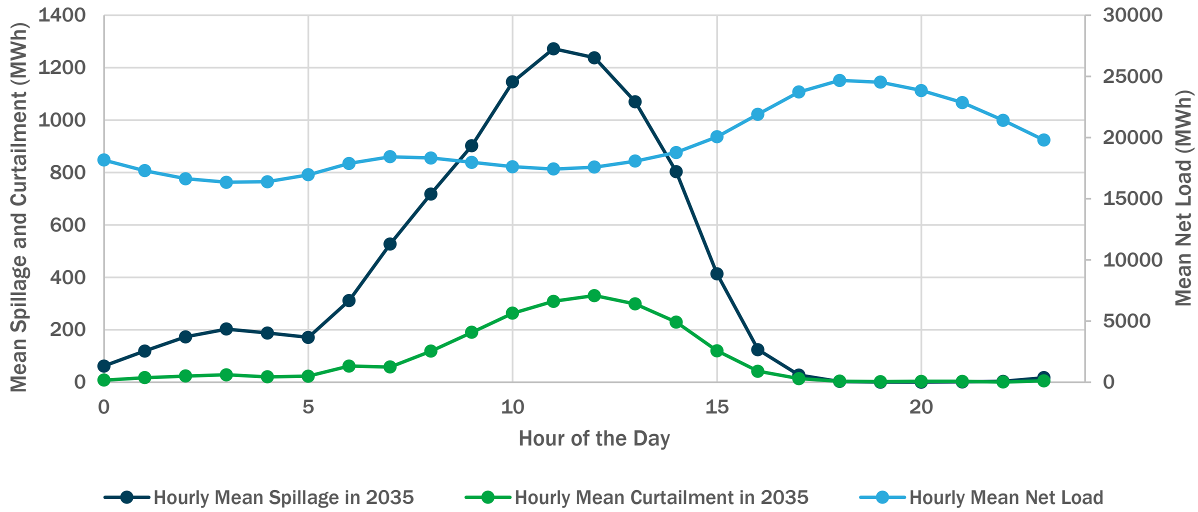
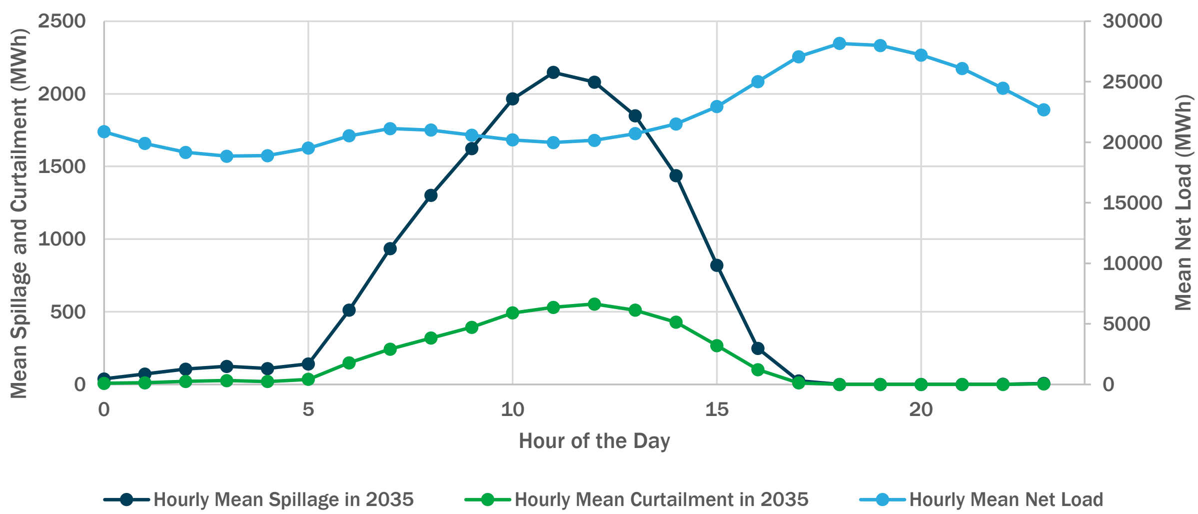


Figure I-15: Higher Demand Policy Relaxation Case Hourly Mean Spillage and Curtailment in 2035



Across all three evaluated scenarios, spillage and curtailment peak during the mid-day period when the sun is shining. High solar irradiance periods cause UPV generation to increase and net load to decrease due to a portion of load being served by behind-the-meter solar generation. The combination of low load and high concurrent renewable generation drives spillage and curtailment upward. The magnitude of curtailment is, in part, less than that of spillage because in the production cost simulation, there is an opportunity for the renewable energy to be exported to neighboring systems. Spillage does not consider any interchange of energy between neighboring systems.

In the following figures, the monthly average net load in is compared to the monthly average curtailment, and the average spillage is calculated for each month from 2030 in the fully relaxed Contract Case. Similarly, the net load is compared to the monthly average curtailment and spillage from year 2035 in the fully relaxed Lower Demand and Higher Demand scenarios.

Figure I-16: Contract Relaxation Case Monthly Mean Spillage and Curtailment in 2030

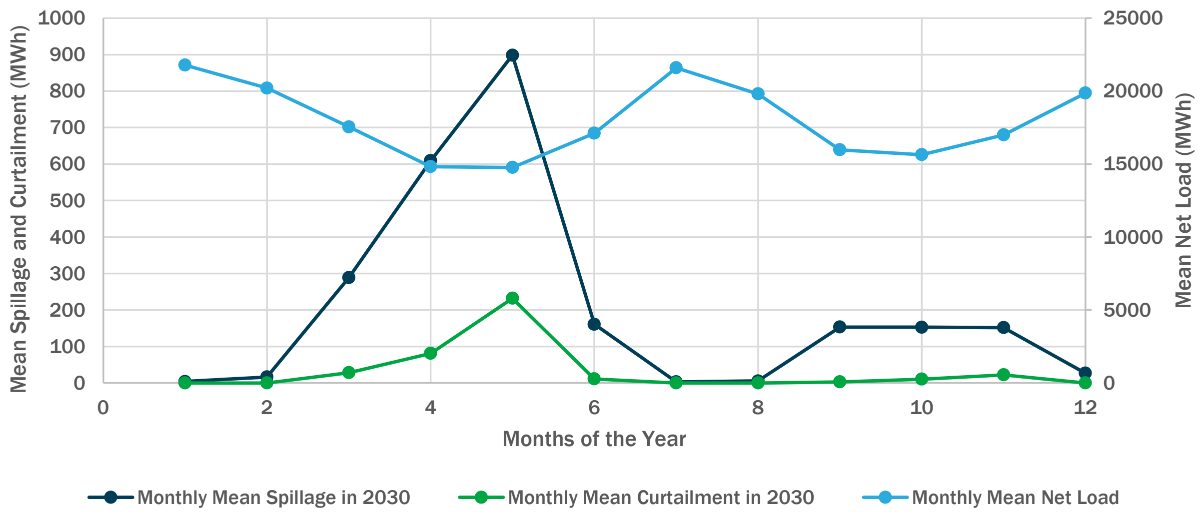


Figure I-17: Lower Demand Policy Relaxation Case Monthly Mean Spillage and Curtailment in 2035

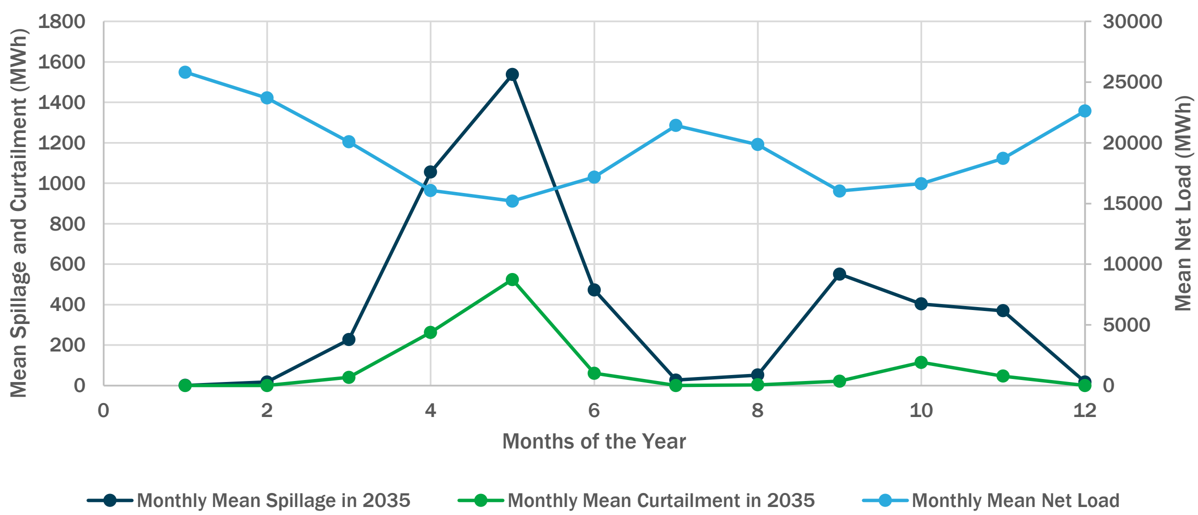
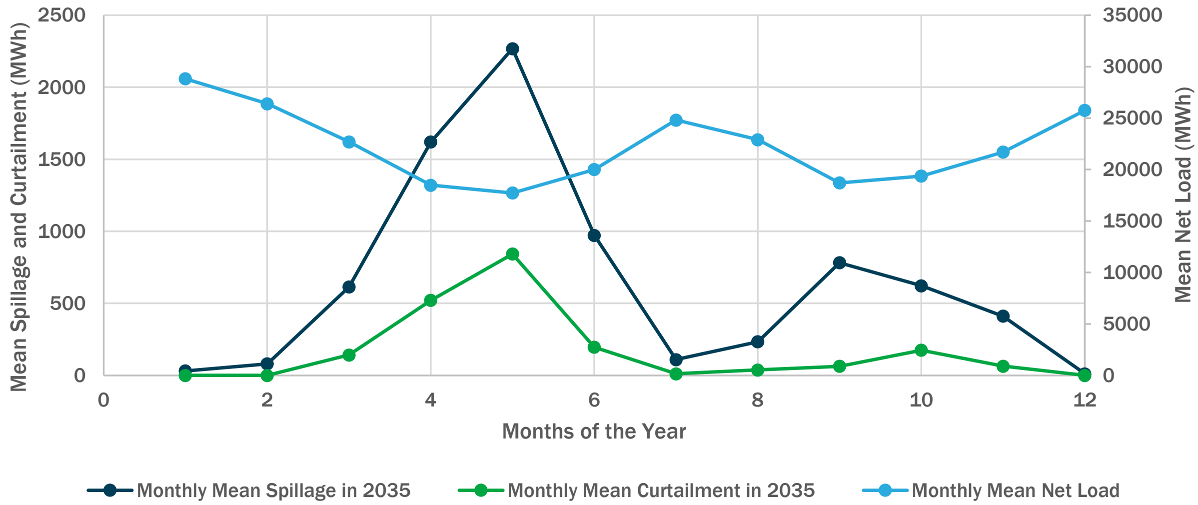


Figure I-18: Higher Demand Policy Relaxation Case Monthly Mean Spillage and Curtailment in 2035



Winter and summer months show the least amount of curtailment and spillage because load levels are high enough to absorb all the intermittent renewable energy production. The shoulder months, however, exhibit the most curtailment and spillage due to lower load levels.

The following figures show an annual comparison between curtailment in the Contract and Policy Cases and spillage. Spillage is calculated for each year and case individually as load levels change and the magnitude of installed renewable resources change.

Figure I-19: Contract Case Annual Curtailment and Spillage Comparison

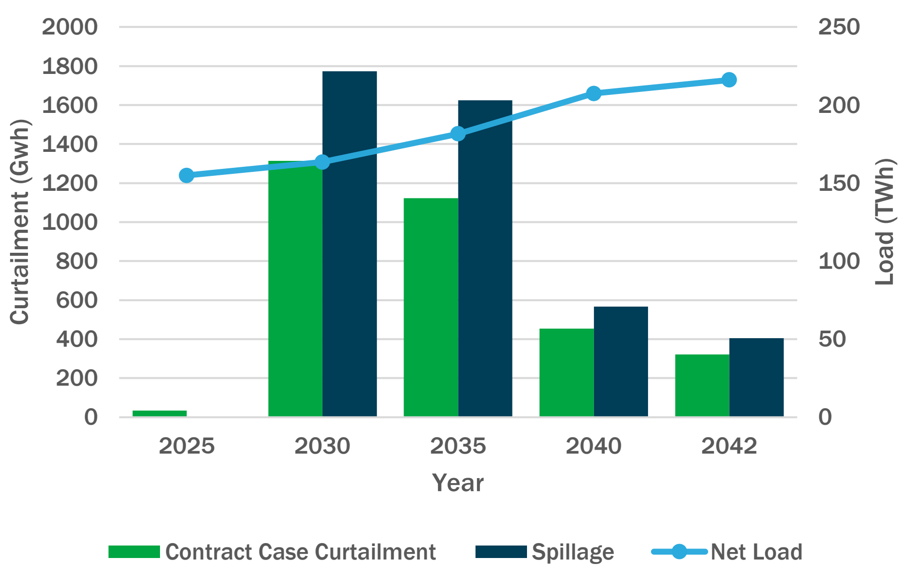


Figure I-20: Lower Demand Policy Annual Curtailment and Spillage Comparison

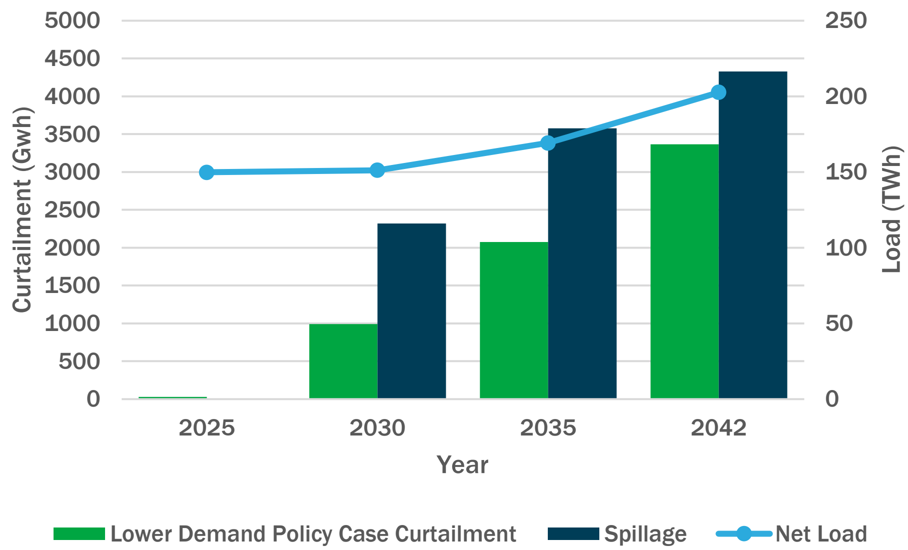
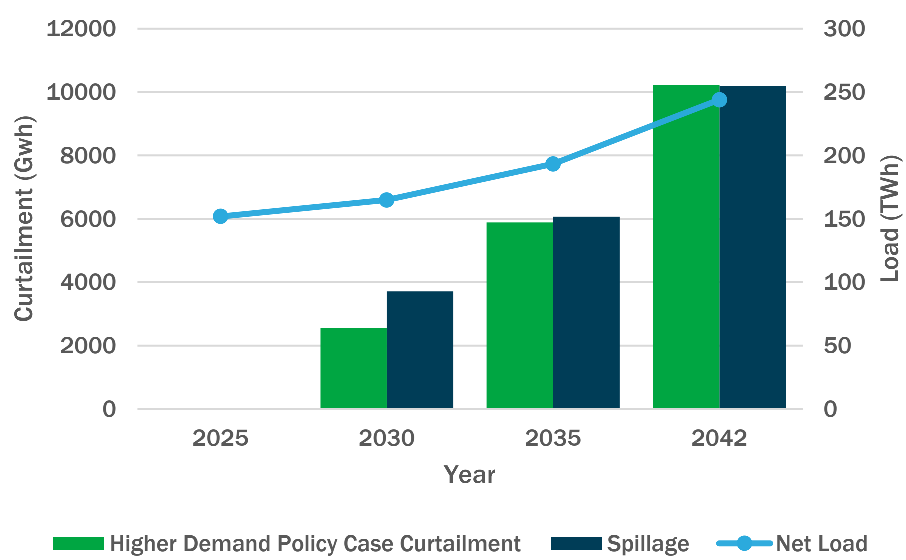


Figure I-21: Higher Demand Policy Annual Curtailment and Spillage Comparison



Little to no curtailment among the cases was observed in year 2025 due to the lack of intermittent resources compared to the load. By year 2030, renewable buildout outpaces load growth and, therefore, curtailment and spillage increase in both the Contract and Policy Cases. For the Contract Case, there are no further renewable builds beyond 2030, so load growth drives curtailment and spillage down over time. The Lower and Higher Demand scenarios assume further renewable buildout to meet policy mandates. As more renewables are added to the system, the quantity of spilled energy curtailment increases throughout the study horizon.

The following figures show a zonal comparison of curtailment in the fully relaxed Contract and

Policy Cases. The fully relaxed case sensitivities remove all internal New York transmission constraints and only include import/export limits and external constraints, which is an alternative way to estimate spillage.

Figure I-22: Contract Relaxation Case Curtailment by Zone by Generation Type in 2030

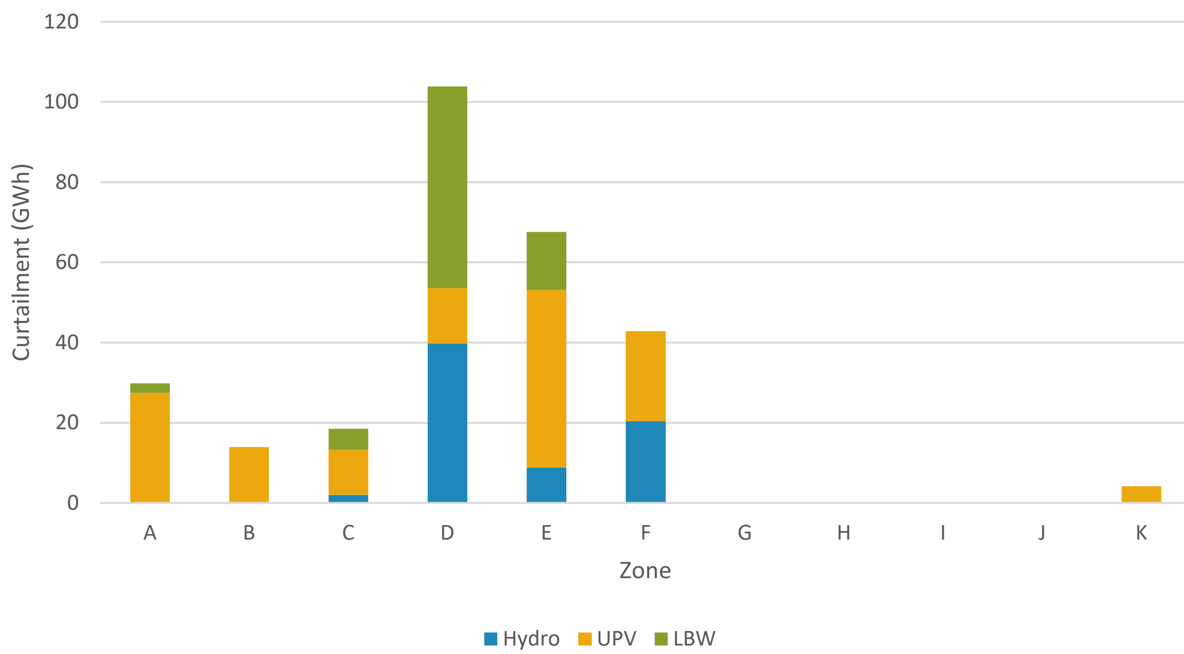


Figure I-23: Lower Demand Policy Relaxation Case Curtailment by Zone by Generation Type in 2035

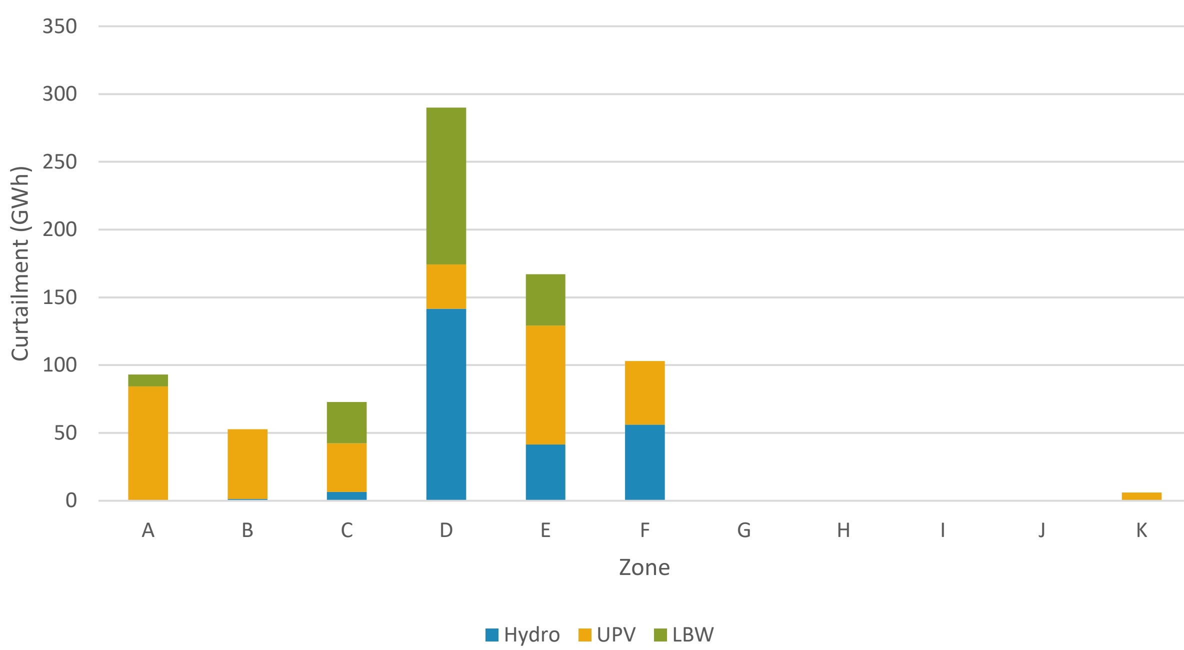
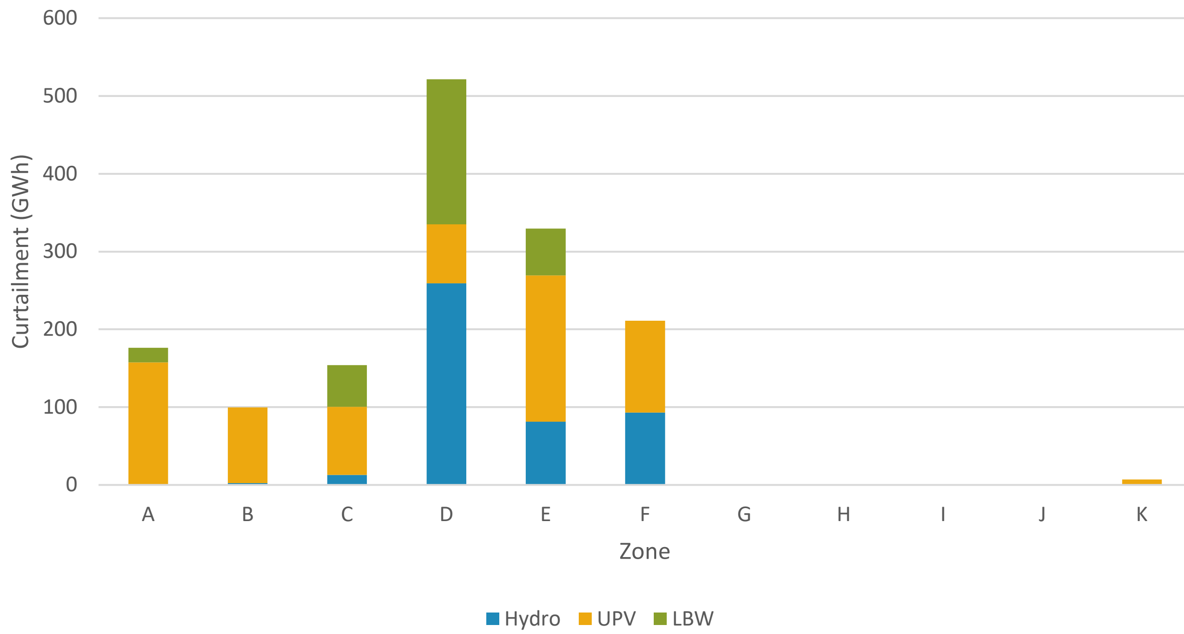


Figure I-24: Higher Demand Policy Relaxation Case Curtailment by Zone by Generation Type in 2035



Zones with lower load and higher renewable penetration exhibit higher levels of curtailment. The distribution of curtailment between generation types within a zone is proportional to the amount of capacity that exists in that zone.