NEPOOL Participants Committee Report

February 2021

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EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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Regular Operations Report - Highlights

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: December 2020 Energy Market value totaled $450M
  - January 2021 Energy market value over the period was $354M, down $96M from December 2020 and up $57M from January 2020
    - January natural gas prices over the period were 5.4% lower than December average values
    - Average RT Hub Locational Marginal Prices ($37.16/MWh) over the period were 11% lower than December averages
      - DA Hub: $36.78/MWh
    - Average January 2021 natural gas prices and RT Hub LMPs over the period were up 41% and up 42%, respectively, from January 2020 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 98.4% during January, down from 98.5% during December*
    - The minimum value for the month was 92.6% on Monday, January 18th

Data through January 27th

*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

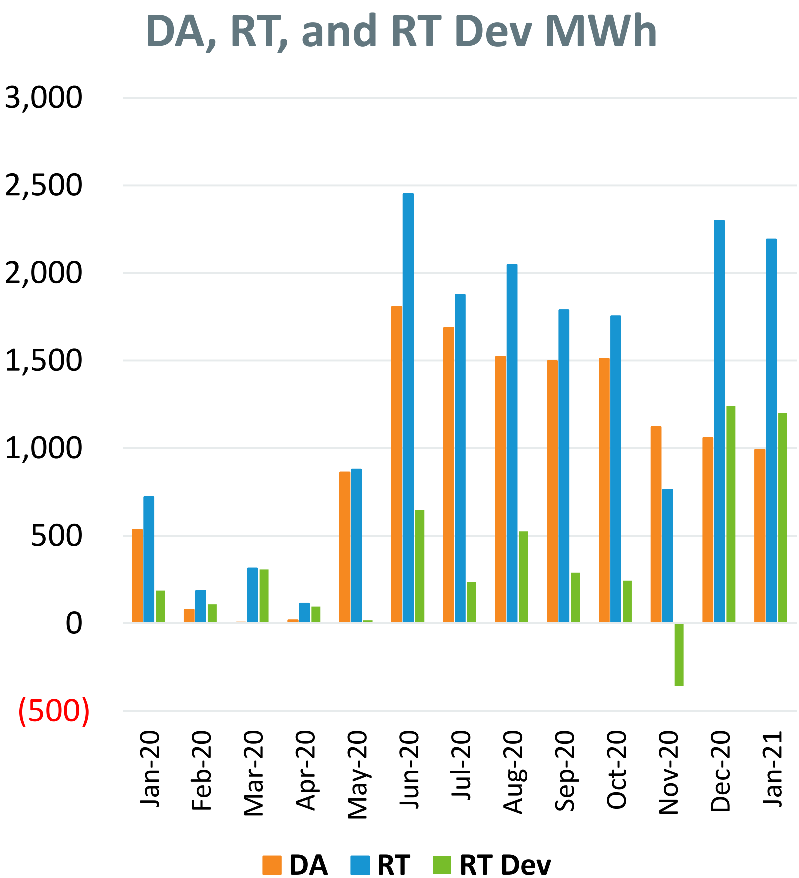
Underlying natural gas data furnished by: ICE Global markets in clear view

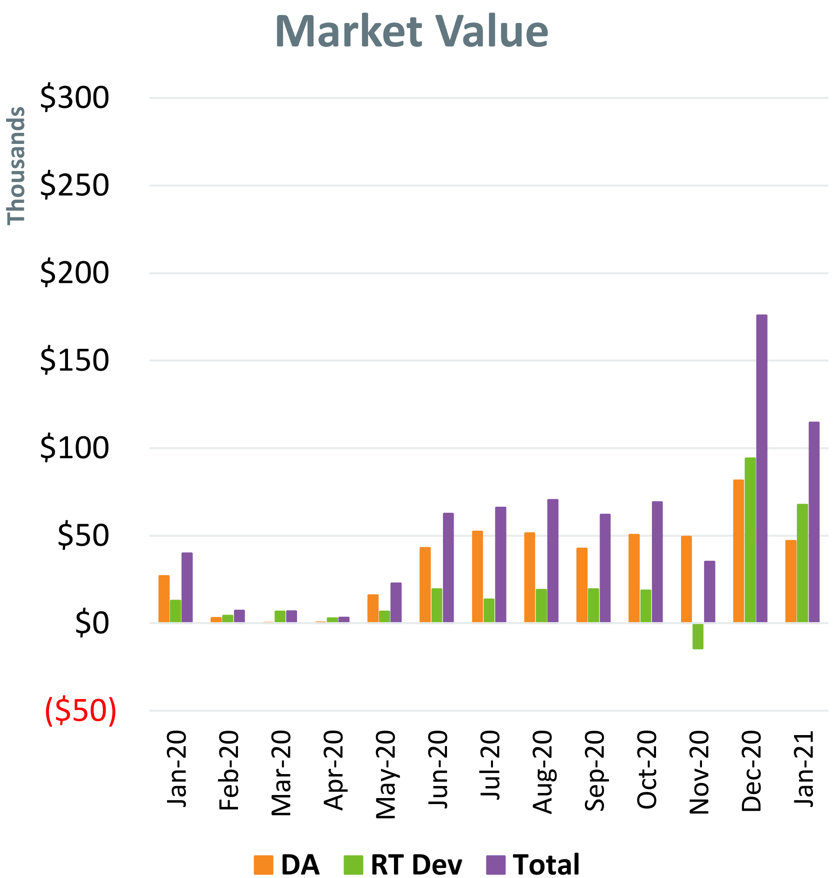
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - January 2021 NCPC payments totaled $3.1M over the period, down $0.5M from December 2020 and up $1.3M from January 2020
    - First Contingency payments over the period totaled $1.8M, down $0.1M from December
      - $1.5M paid to internal resources, down $0.4M from December
        - » $540K charged to DALO, $563K to RT Deviations, $371K to RTLO*
      - $290K paid to resources at external locations, up $236K from December
        - » Virtually all charged to DALO at external locations
    - Second Contingency payments totaled $1.2M, down $403K from December
    - Distribution payments totaled $72K, up $65K from December
    - Voltage payments were zero
  - NCPC payments over the period as percent of Energy Market value were 0.9%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $194K; Rapid Response Pricing (RRP) Opportunity Cost - $165K; Posturing - $12K; Generator Performance Auditing (GPA) - $0**

Price Responsive Demand (PRD) Energy Market Activity by Month





Note: DA and RT (deviation) MWh are settlement obligations and reflect appropriate gross-ups for distribution losses.

Forward Capacity Market (FCM) Highlights

- CCP 12 (2021-2022)
  - Third and final annual reconfiguration auction (ARA3) will be held on March 1-3, and results will be posted no later than March 31
- CCP 13 (2022-2023)
  - Second annual reconfiguration auction (ARA2) will be held on August 2-4, and results will be posted no later than September 1
- CCP 14 (2023-2024)
  - First annual reconfiguration auction (ARA1) will be held on June 1-3, and results will be posted no later than July 1

CCP – Capacity Commitment Period
ICR – Installed Capacity Requirement

FCM Highlights, cont.

- CCP 15 (2024-2025)
  - FCA 15 will model the same zones as FCA 14
    - Export-constrained zones: Maine nested inside Northern New England
    - Import-constrained zone: Southeast New England
  - Preparations are ongoing for the auction that will commence on February 8
- Mock Auction was successfully conducted on Monday, February 1st
  - 100 unique participating companies
  - Conducted a 4 round mock auction
  - Power Auctions staff was remote; ISO staff was in a hybrid posture (some on-site and others off-site)
  - No major issues were encountered

FCM Highlights, cont.

- CCP 16 (2025-2026)
  - The qualification process has started, and training materials are under development
  - Topology certifications were sent to the TOs on October 1, 2020
    - Transmission Owners to identify in-service dates for new transmission projects and revisions to previously certified projects
    - Approved projects to be shared with the RC at their January 2021 meeting
  - Capacity zone development discussions began at the November 19, 2020 PAC meeting
    - All subsequent reconfiguration auctions model the same zones as the FCA
  - FCA 16 dynamic delist bid threshold price to be determined and posted to the ISO-NE website no later than early March

Highlights

- Forward Capacity Auction #15 will begin on February 8
- Future Grid Reliability Study Phase 1 work by ISO-NE has commenced
- Boston 2028 RFP and Order 1000 Lessons Learned Update is planned for the February 17 PAC meeting, but may be deferred until March
- Transmission Planning for the Clean-Energy Transition study results are expected in Q2
- RSP21 Public Meeting is set for October 6, but the venue and format have yet to be decided

Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
  – Discussions are ongoing with industry experts regarding emerging technologies/trends and methods of incorporating these into the forecast
- The 2021 load forecast development process continues
  – Upcoming meetings include: Energy-Efficiency Forecast Working Group (2/12), Load Forecast Committee (2/19), and Distributed Generation Forecast Working Group (2/22)
  – In the March/April timeframe, PAC will discuss the preliminary ten-year forecast
  – Publication of the final ten-year forecast will be in the May CELT report

FERC Order 1000

- Qualified Transmission Project Sponsor (QTPS)
  - 25 companies have achieved QTPS status
  - 2021 Annual QTPS Certification
    - All 25 QTPSs submitted completed Annual QTPS Certification forms to the ISO prior to the close of the Certification Window on January 31
    - The ISO is reviewing the information provided in the submitted forms, will determine whether the QTPSs continue to meet the Attachment K requirements, and will notify the QTPSs as to their status for 2021

Highlights

- The power system operated reliably with no supplemental commitments during the late January cold weather
  - No major generator outages or reductions
  - No major transmission system outages
  - Regular communications with gas pipeline operations improves the ISO's situational awareness; No issues were noted
  - Peak load on 1/29 was 18,703 MW in hour ending 18 with a high temperature for the day of 17°F
- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning February 13, 2021.
- The lowest 50/50 and 90/10 Preliminary Spring Operable Capacity Margins are projected for week beginning May 8, 2021.

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (2.0°F) Max: 52°F, Min: 7°F Precipitation: 2.02” (1.34” Below Normal) Normal: 3.36” Snow: 5.8”	Hartford	Temperature: Above Normal (2.8°F) Max: 48°F, Min: 1°F Precipitation: 2.43” (0.80” Below Normal) Normal: 3.23” Snow: 5.0”

Peak Load:	18,703 MW	01/29/2021	18:00 (ending)

Emergency Procedure Events (OP-4, M/LCC 2, Minimum Generation Emergency)

Procedure	Declared	Cancelled	Note
None			

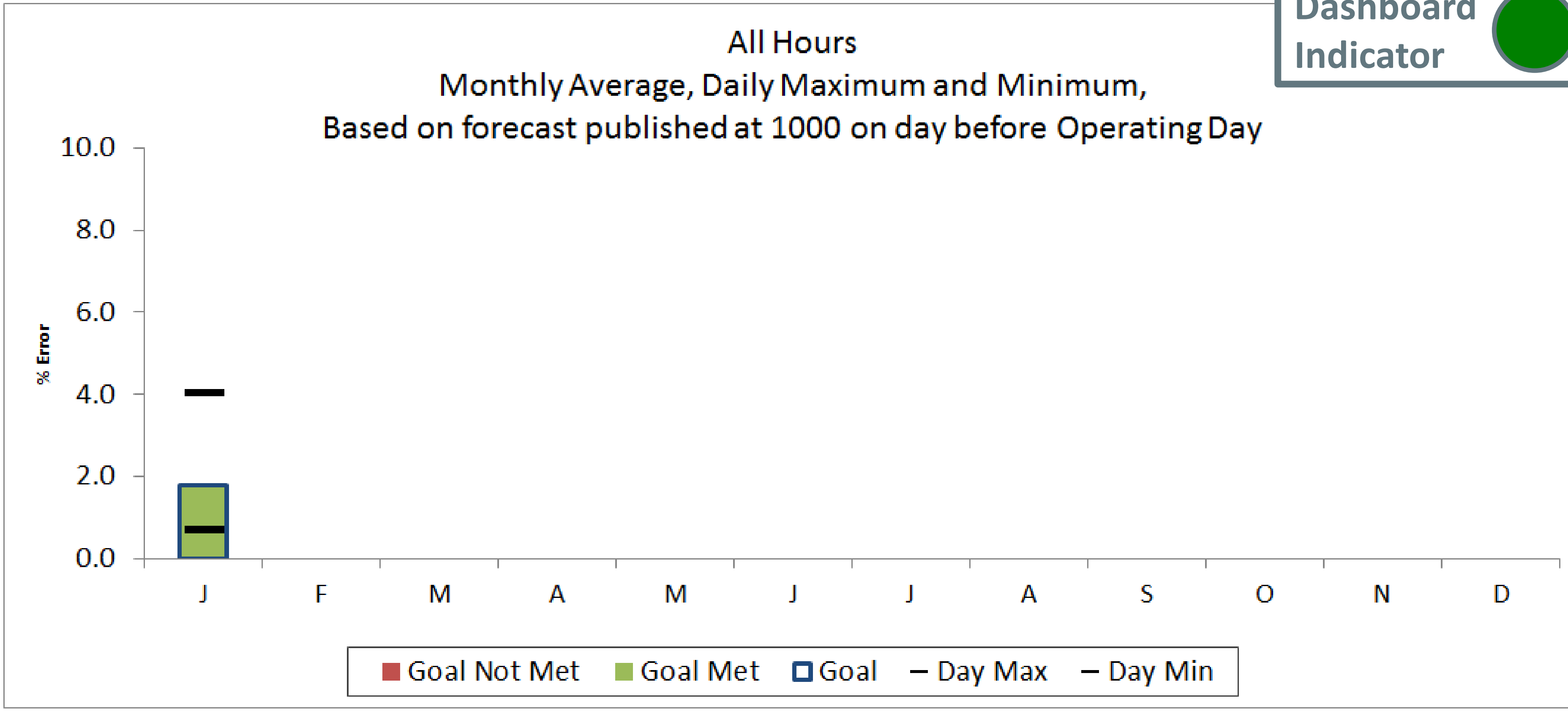
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
01/16/2021	ISONE	660
01/16/2021	NBPSO	700

2021 System Operations - Load Forecast Accuracy

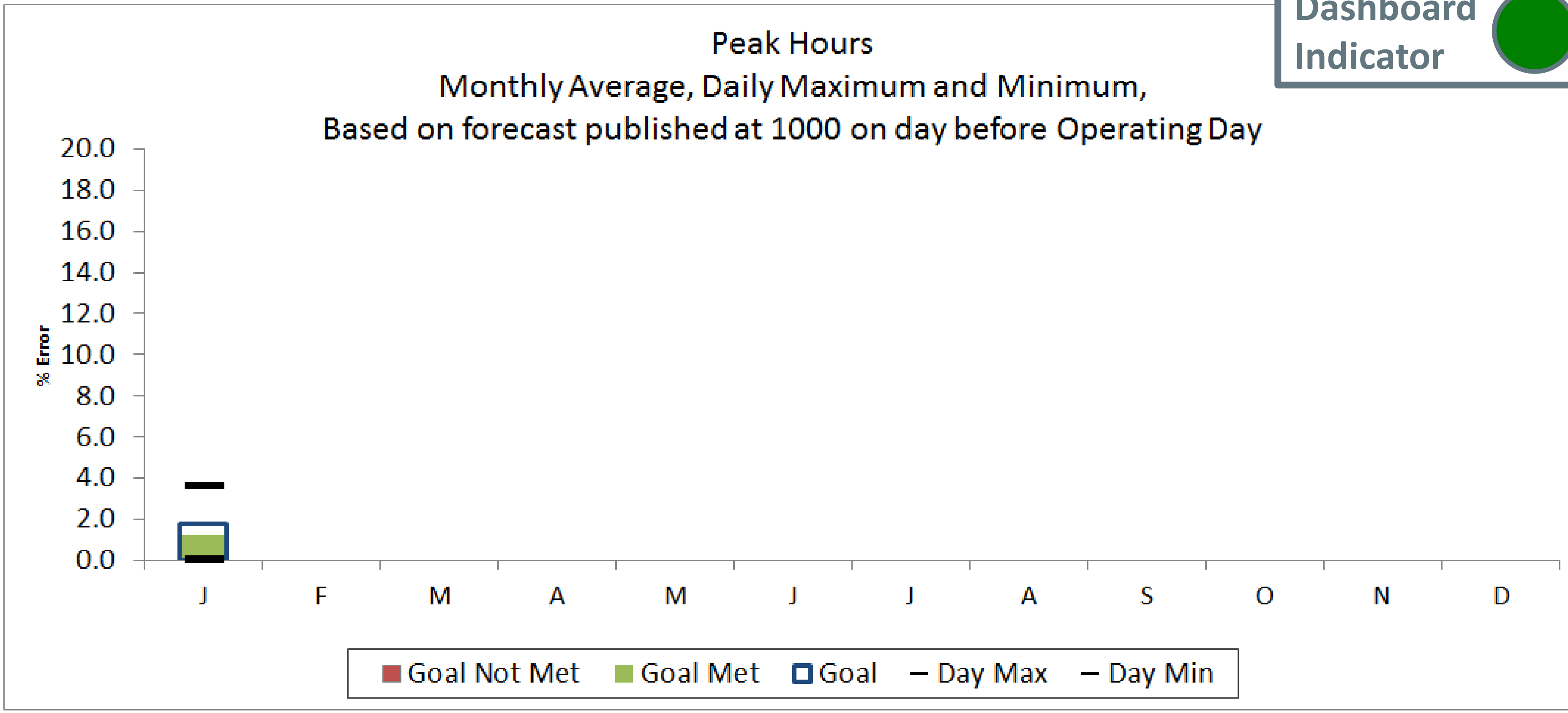
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04												4.04
Day Min	0.70												0.70
MAPE	1.72												1.72
Goal	1.80												

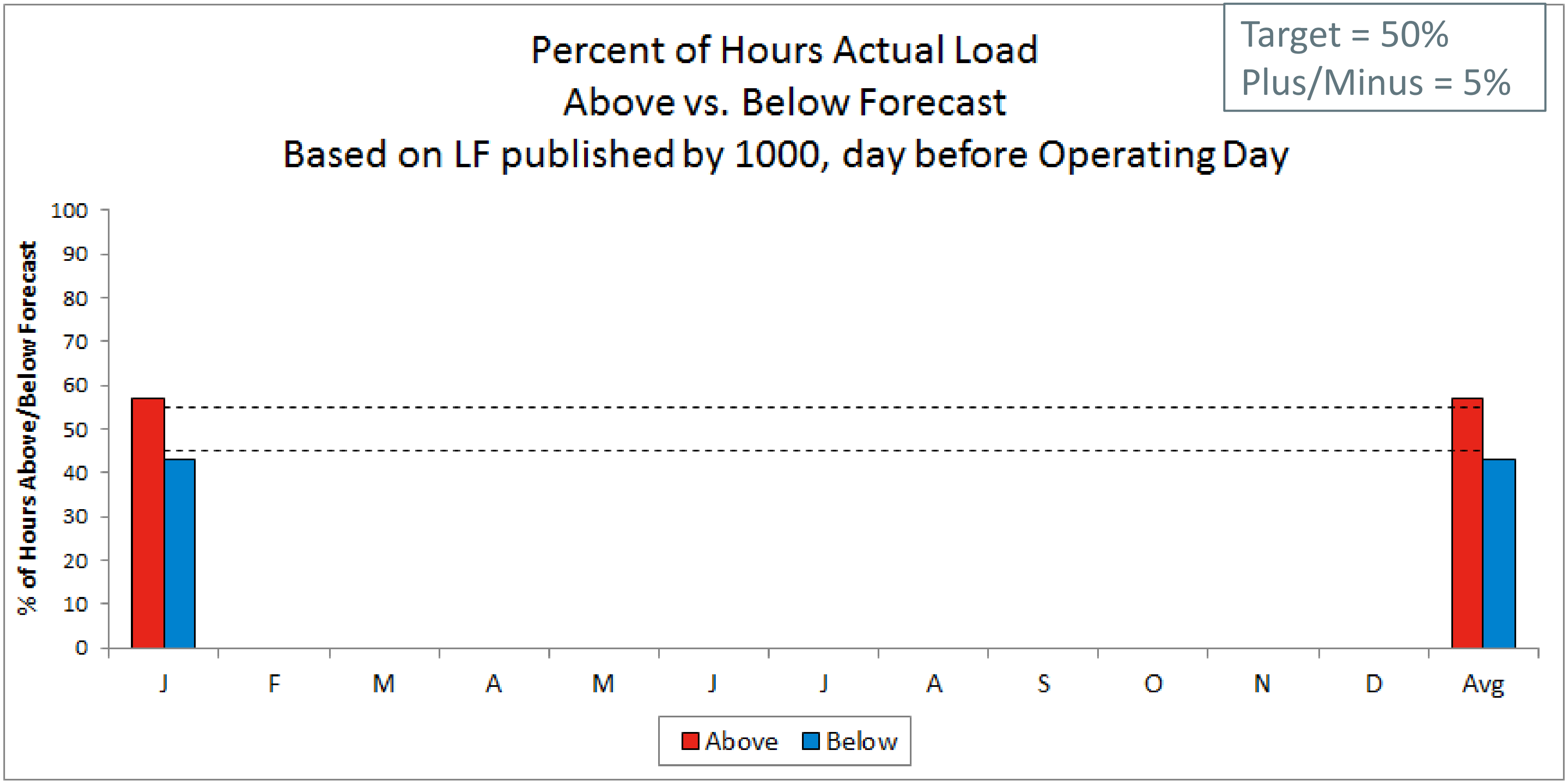
2021 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



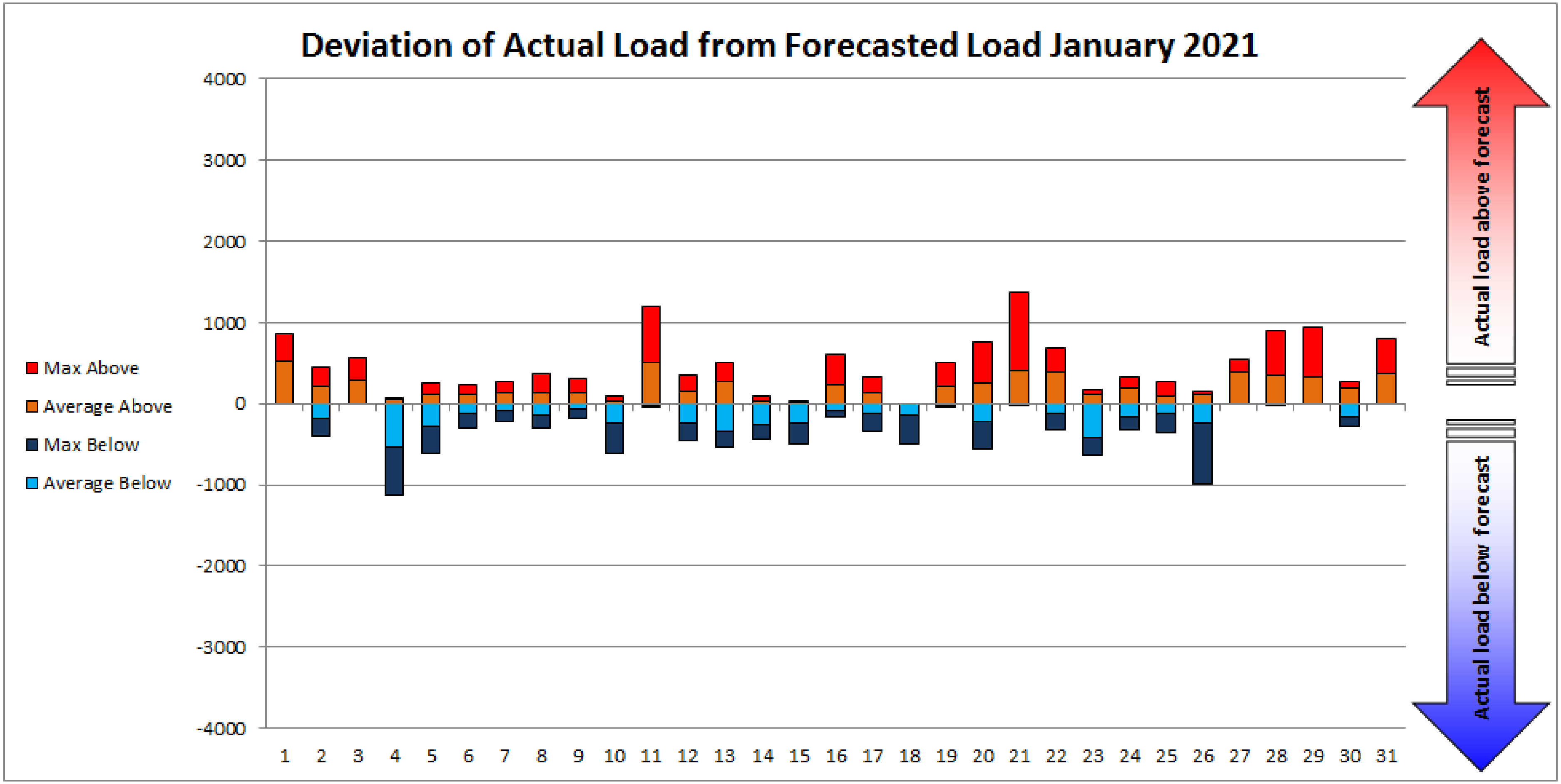
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.61												3.61
Day Min	0.02												0.02
MAPE	1.26												1.26
Goal	1.80												

2021 System Operations - Load Forecast Accuracy cont.

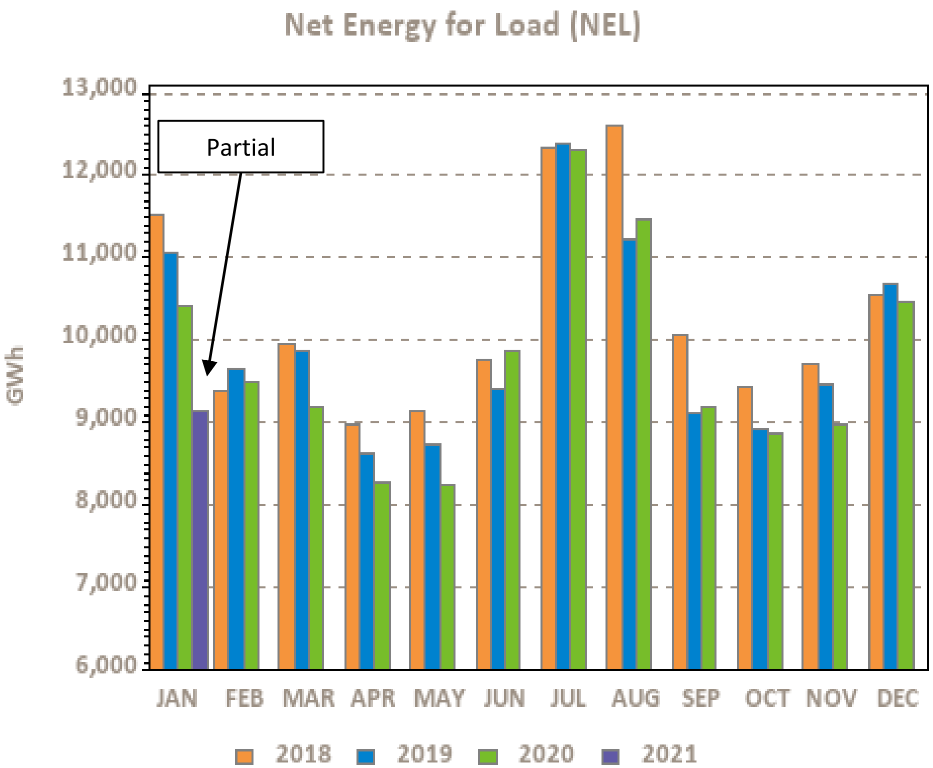


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	57.1												57
Below %	42.9												43
Avg Above	209.5												210
Avg Below	-147.6												-148
Avg All	60												60

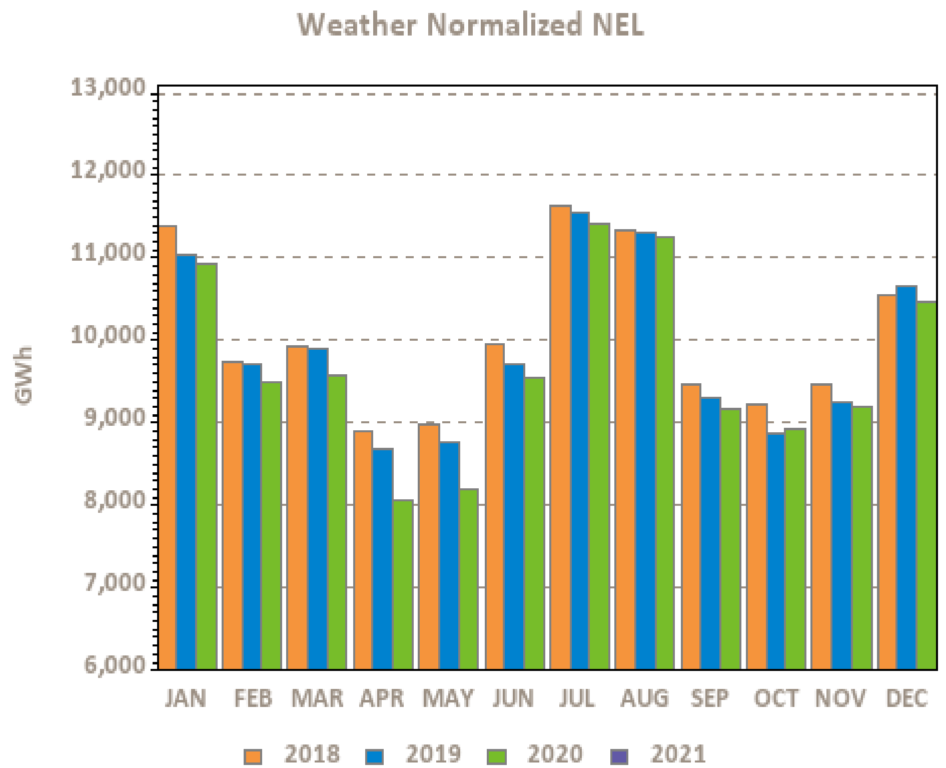
2021 System Operations - Load Forecast Accuracy cont.



Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL



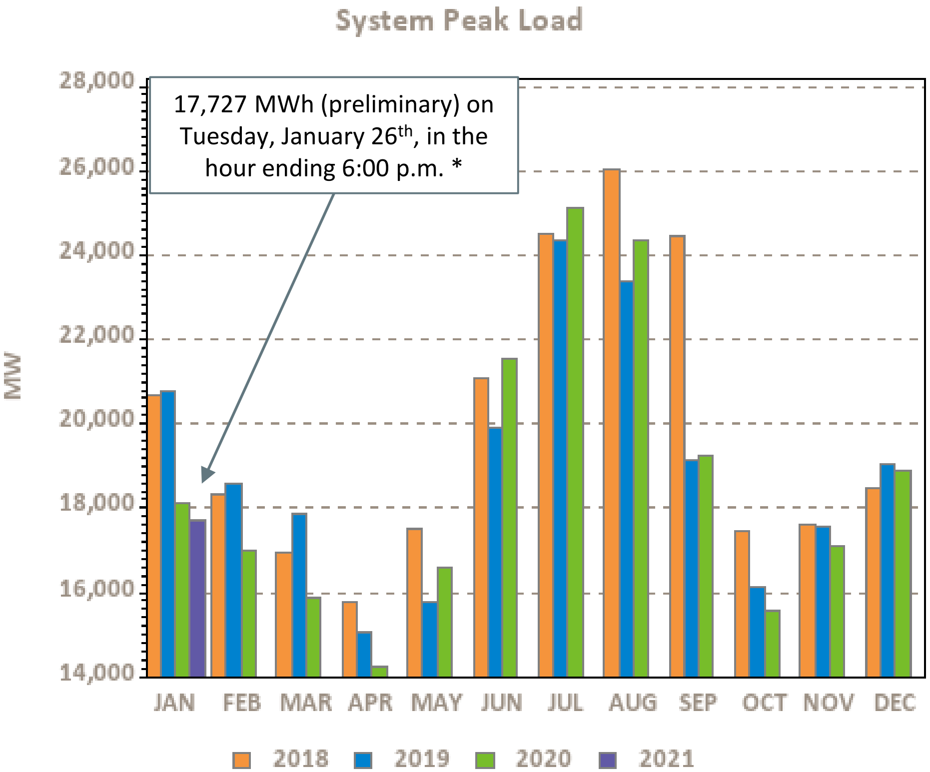
Ann Tot (TWh): 123.5 119.2 116.8 9.1



Ann Tot (TWh): 120.6 118.8 116.3 pending

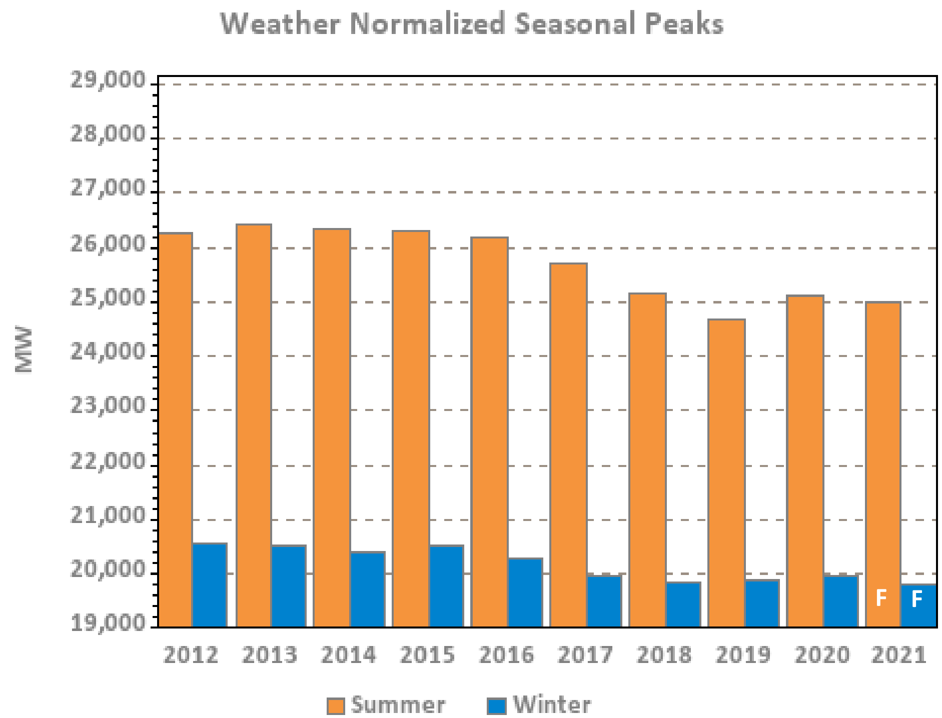
NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History



Revenue quality metered value

* Likely to be succeeded by higher load later in the month. Data here is through Jan. 26th

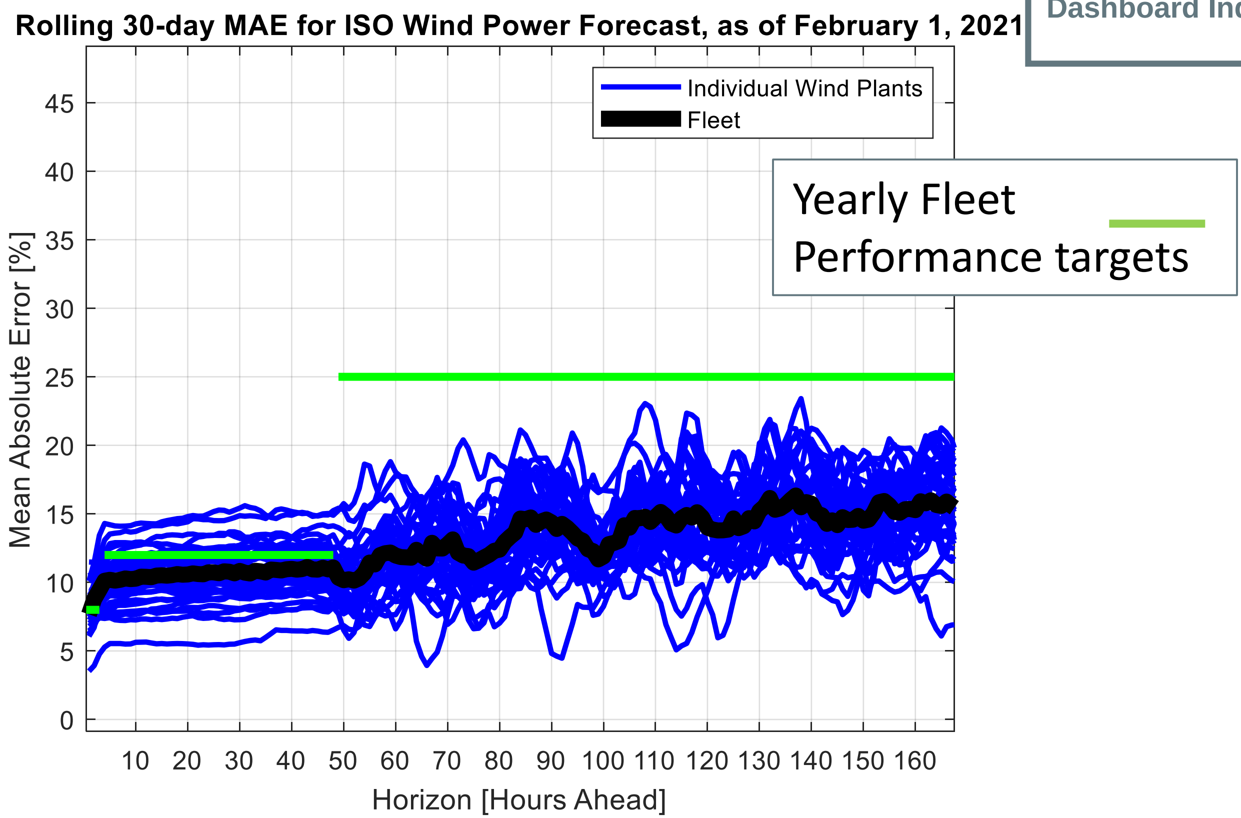


Winter beginning in year displayed

F – designates forecasted values, which are updated in April/May of the following year; represents "net forecast" (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand)

Wind Power Forecast Error Statistics: Medium and Long Term Forecasts MAE

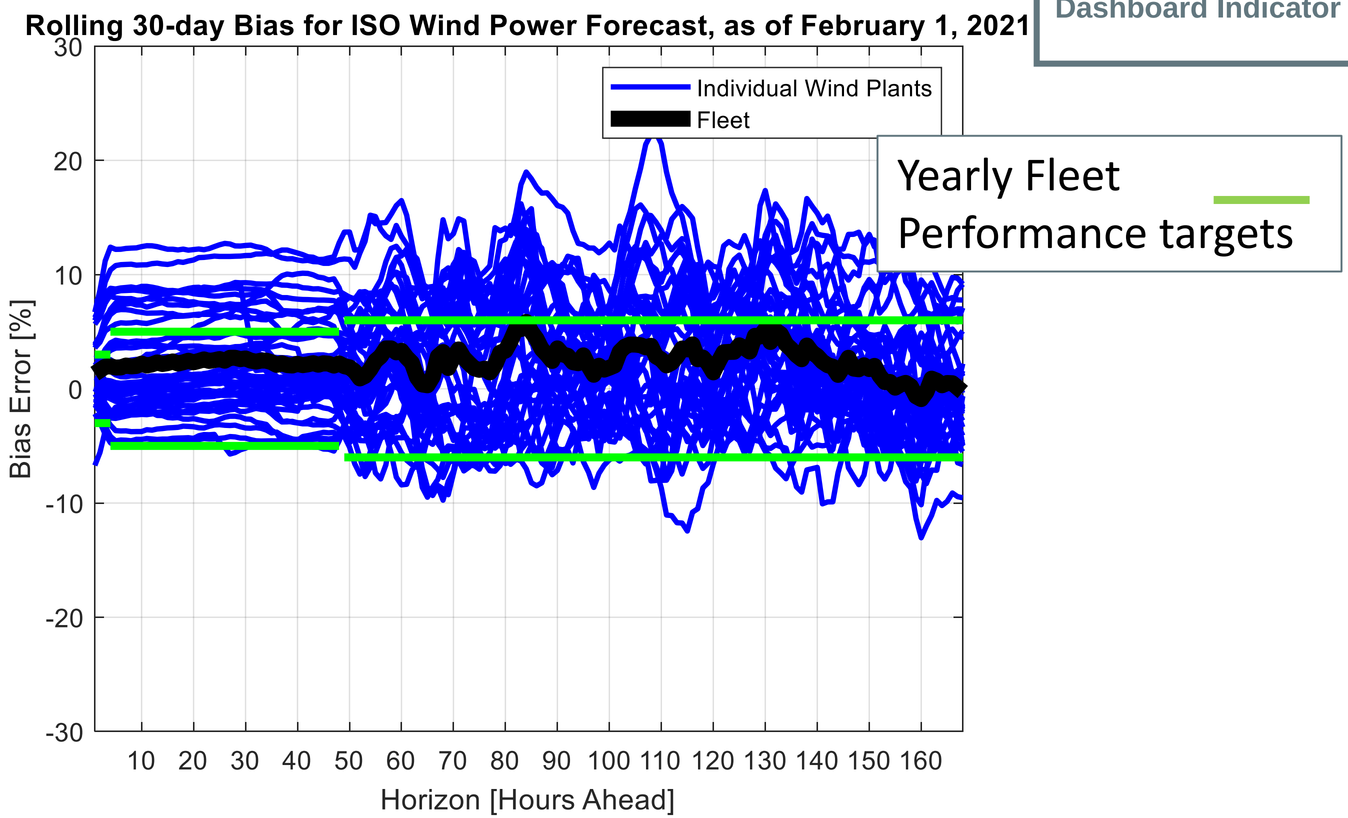
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV-GL forecast is very good compared to industry standards, and monthly MAE is within the yearly performance targets.

Wind Power Forecast Error Statistics: Medium and Long Term Forecasts Bias

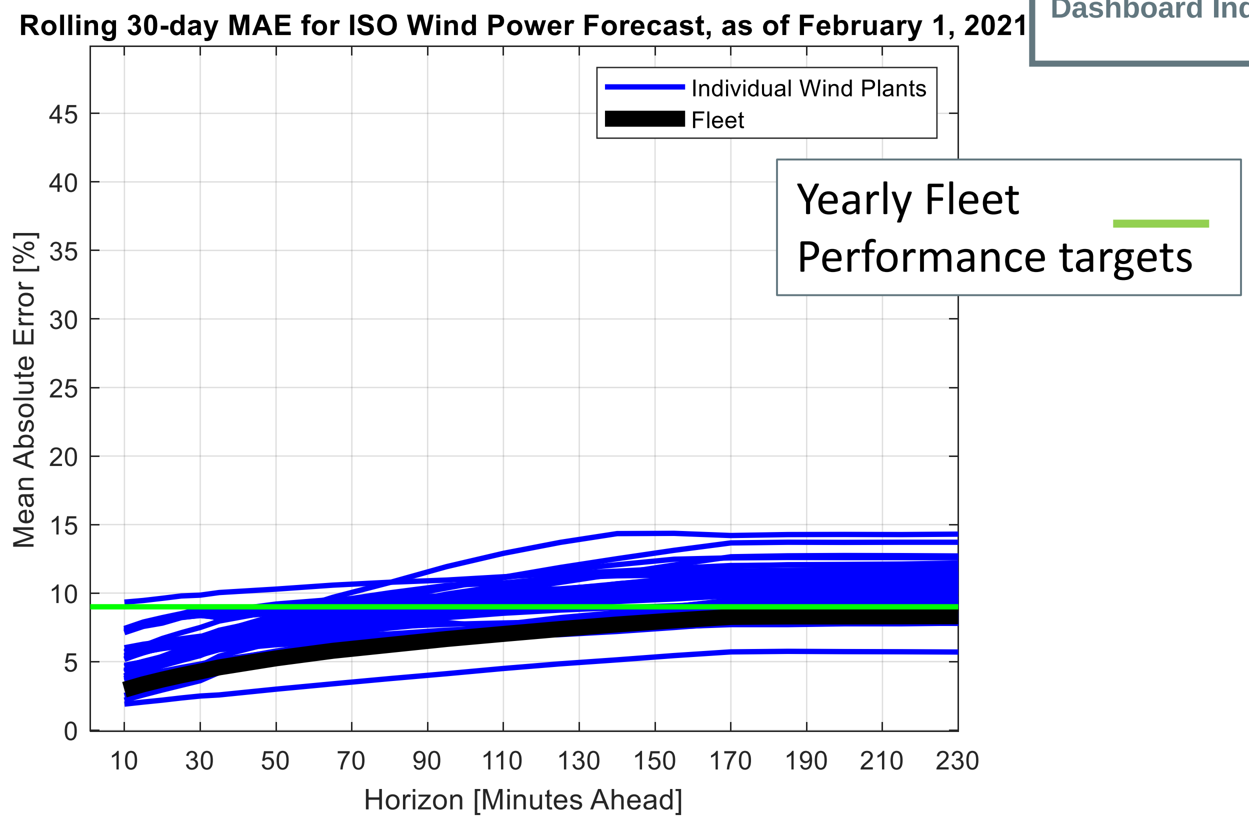
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV-GL forecast compares well with industry standards, and monthly Bias is mostly within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator



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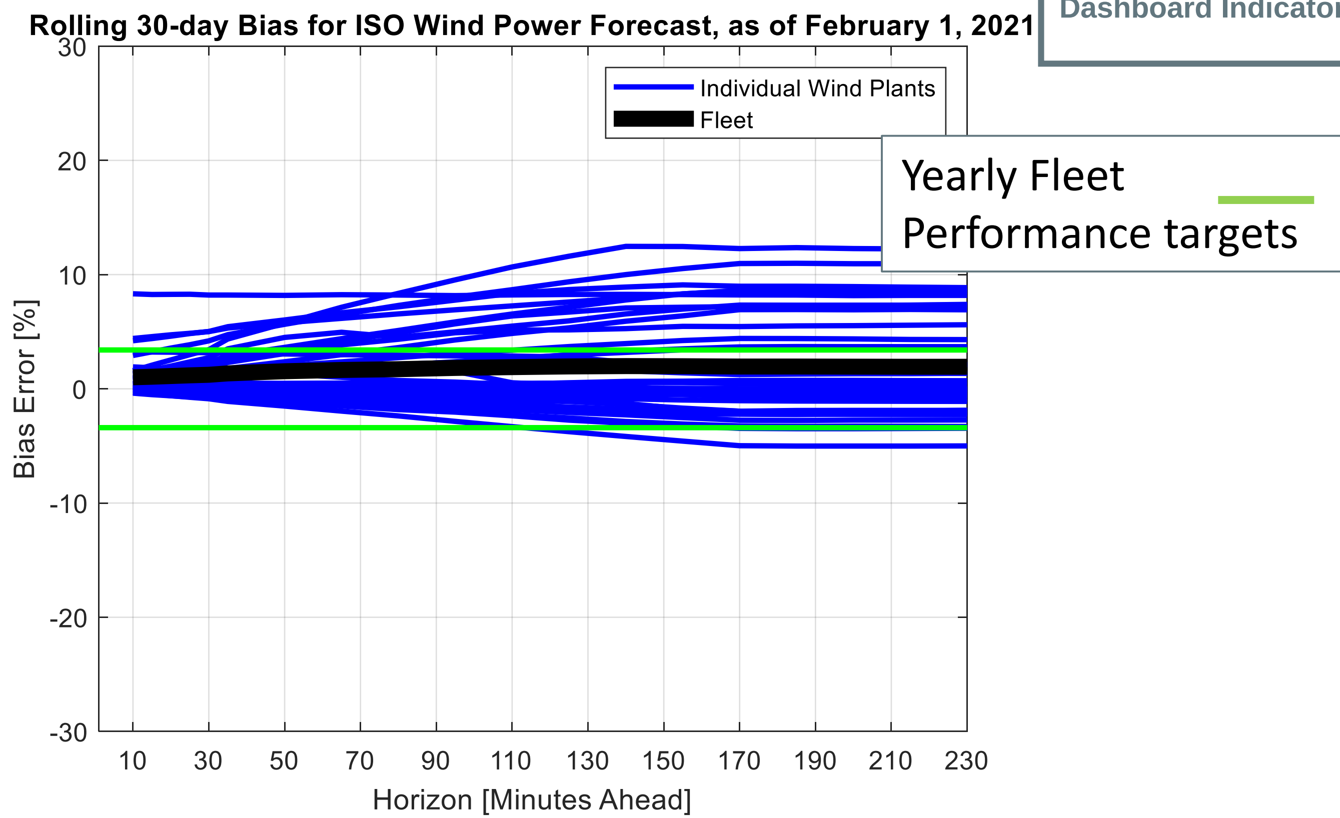

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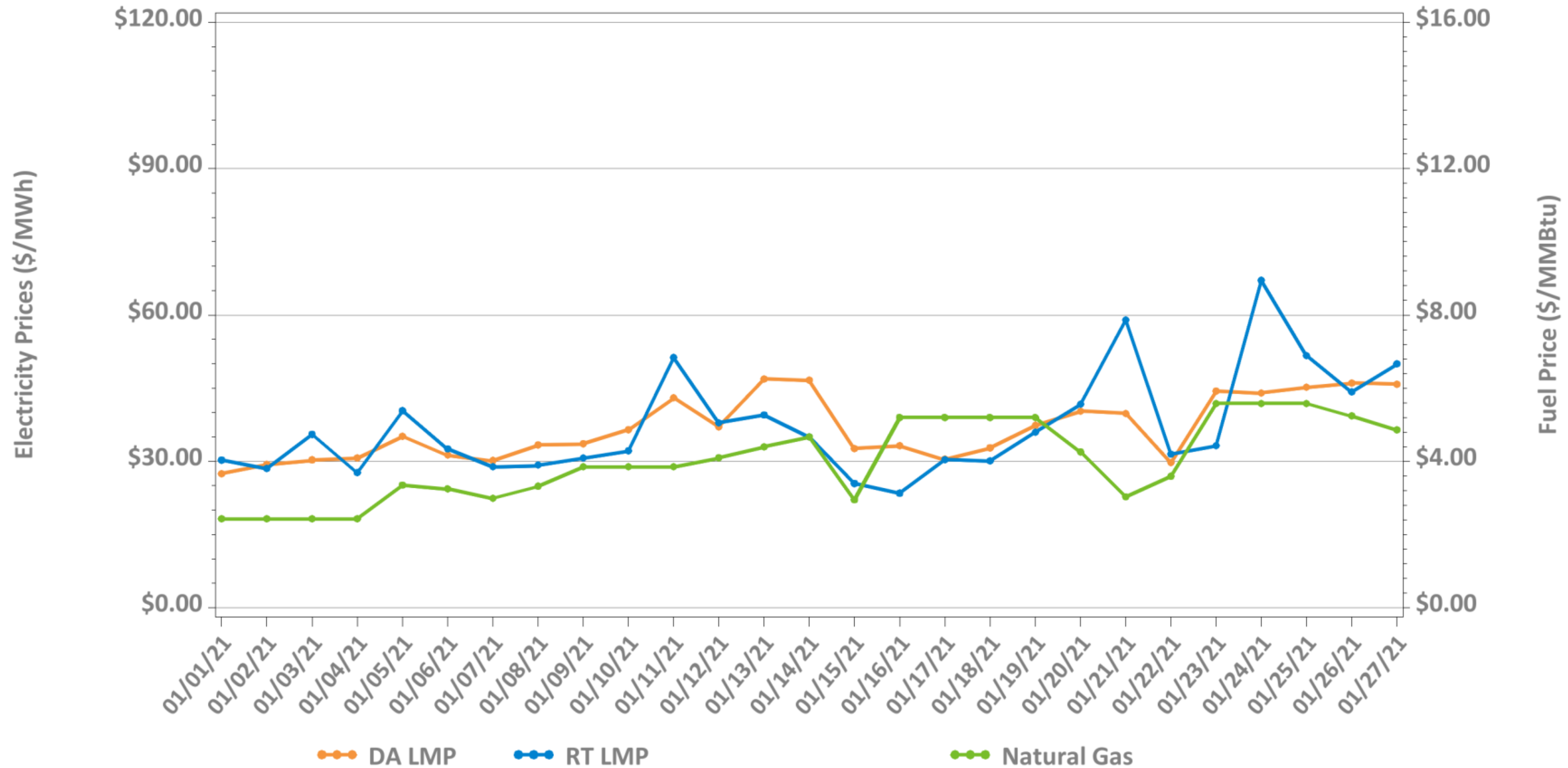
MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: January 1-27, 2021

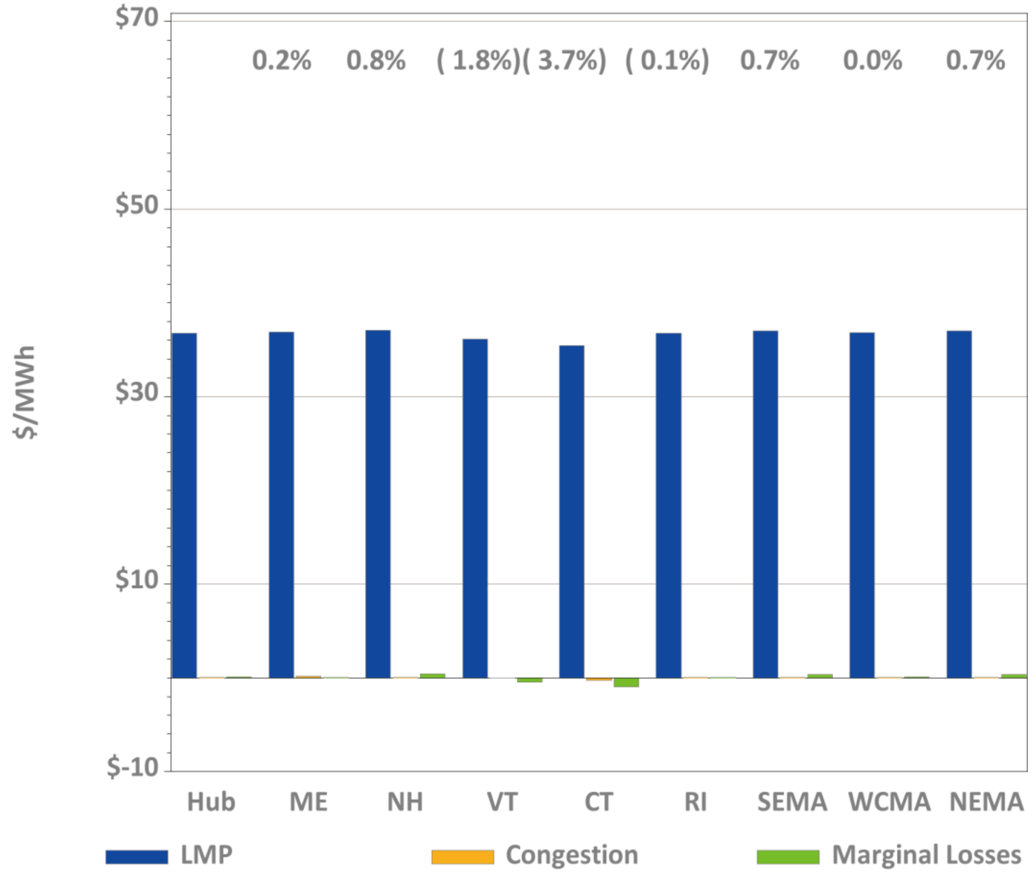


Underlying natural gas data furnished by:

ice Global markets in clear view

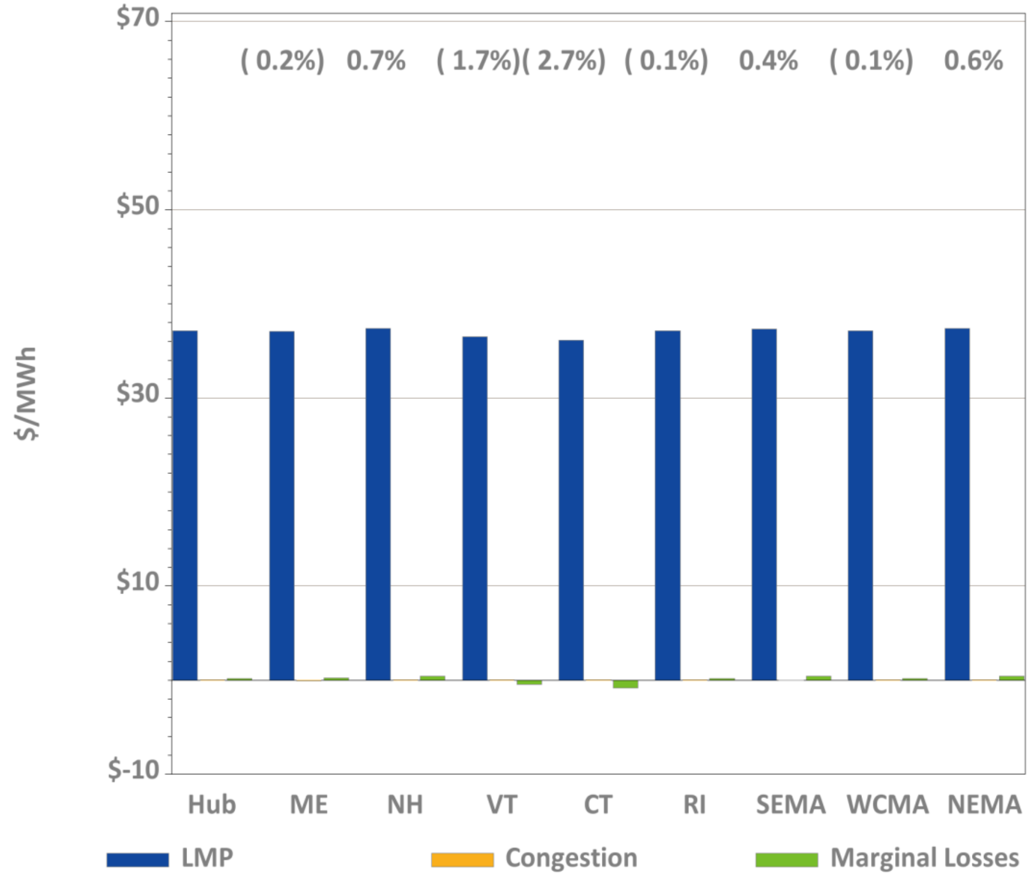
Average price difference over this period (DA-RT): $-0.38
Average price difference over this period ABS(DA-RT): $5.52
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 15%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, January 2021



ME - Maine
NH – New Hampshire
VT – Vermont
CT – Connecticut
RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

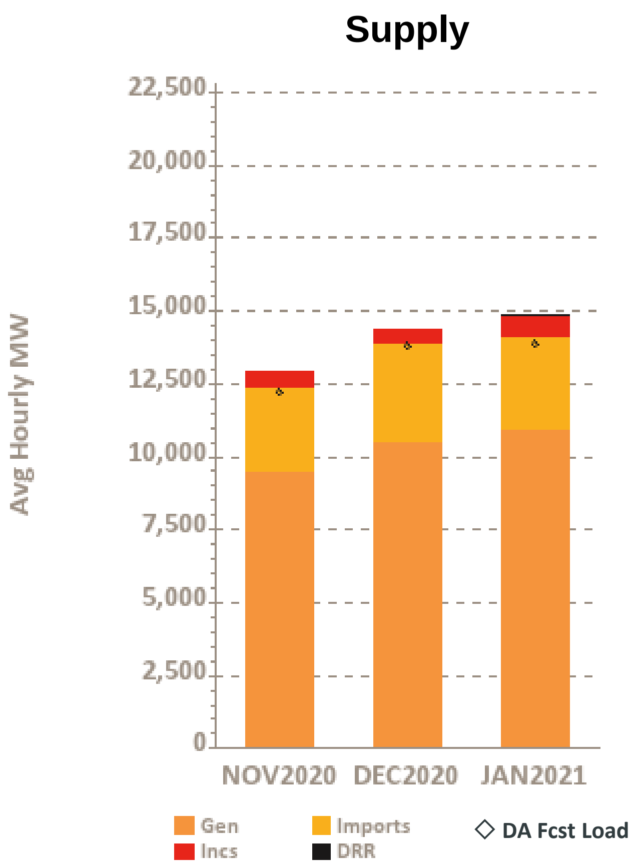
RT LMPs Average by Zone & Hub, January 2021

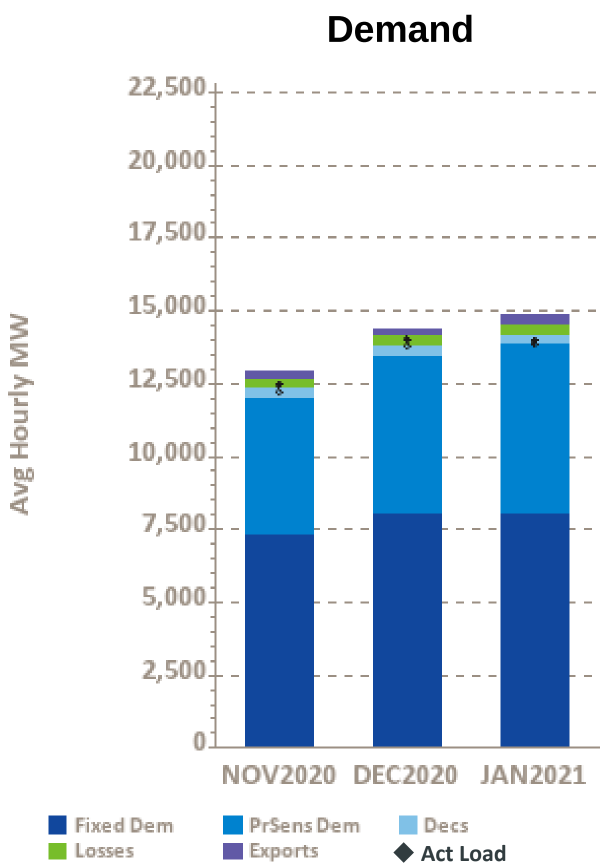


Definitions

Day-Ahead Concept	Definition
Day-Ahead Load Obligation **(DALO)**	The sum of day-ahead cleared load (including asset load, pump load, exports, and virtual purchases and excluding modeled transmission losses)
Day-Ahead Cleared Physical Energy	The sum of day-ahead cleared generation and cleared net imports

Components of Cleared DA Supply and Demand – Last Three Months

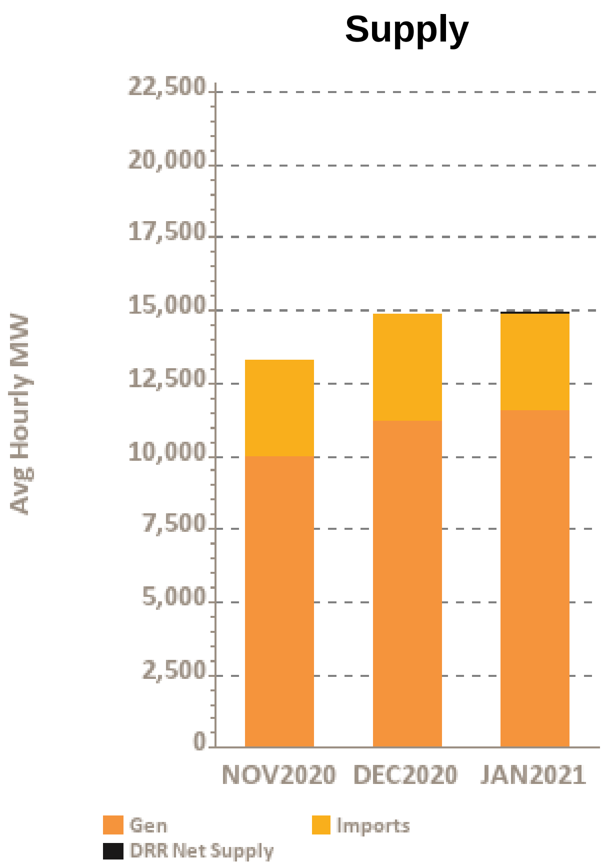


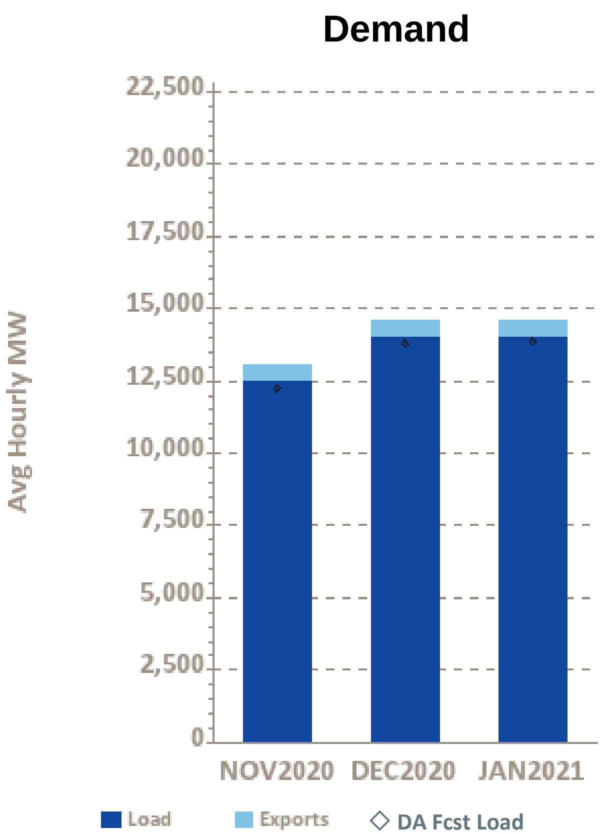


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

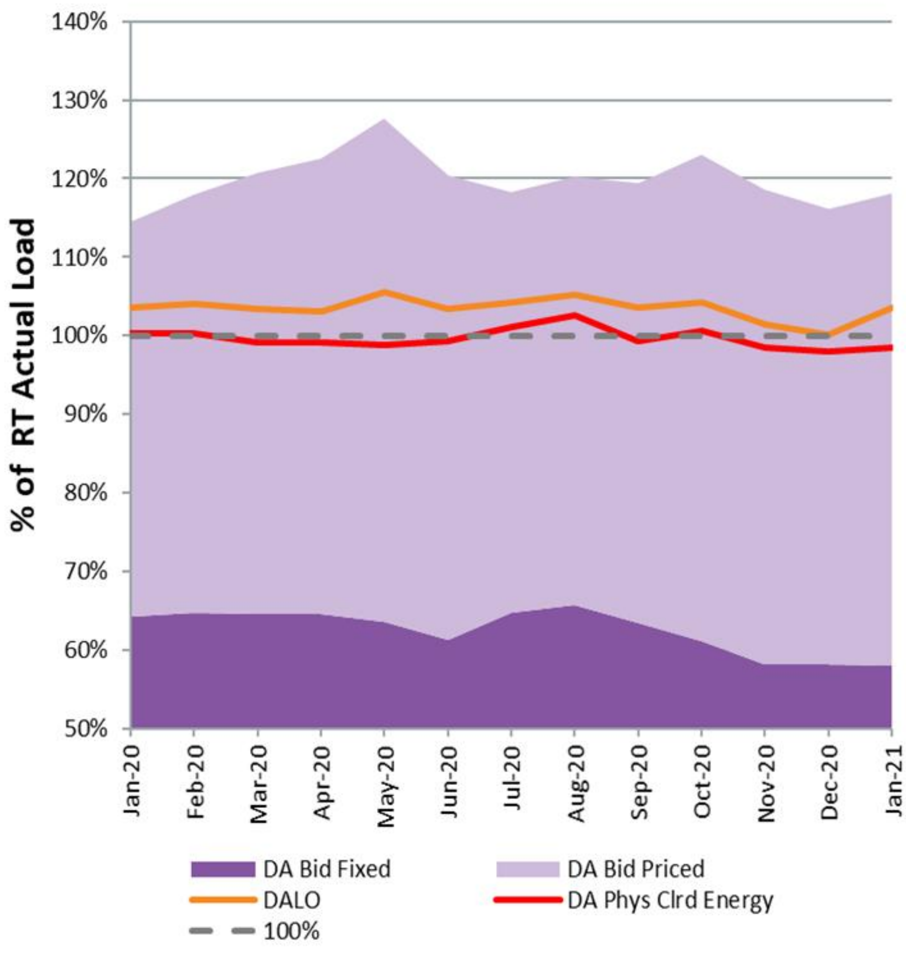
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

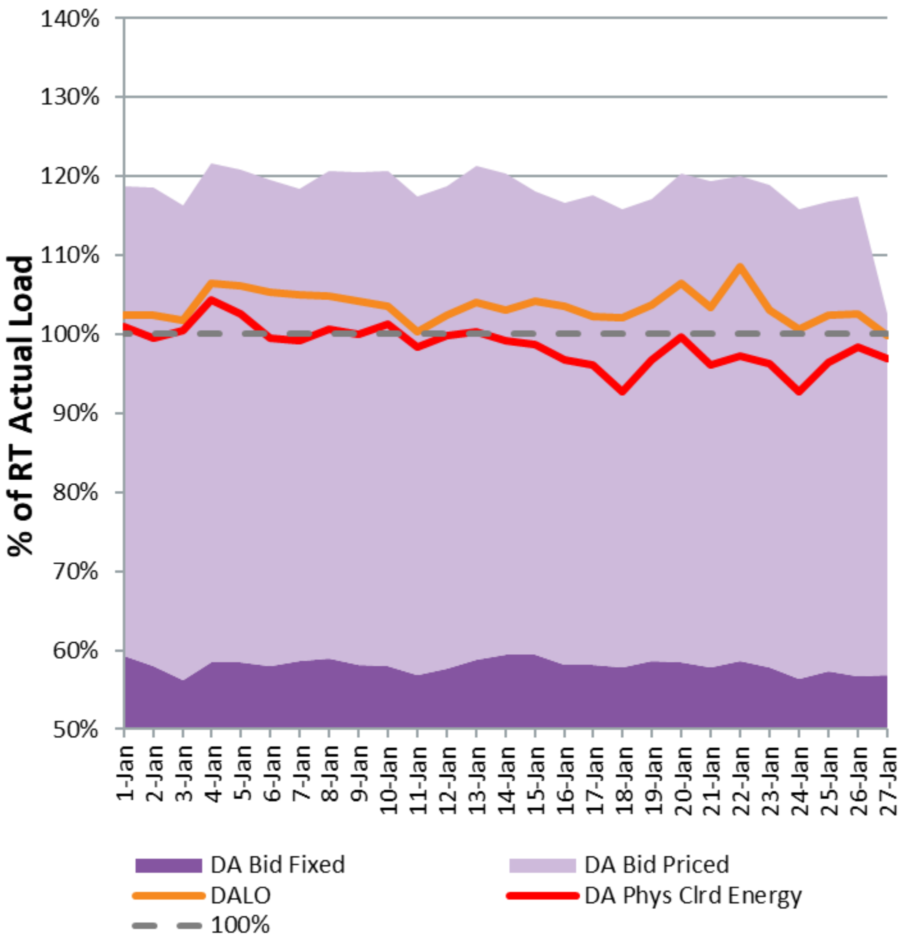
Components of RT Supply and Demand – Last Three Months





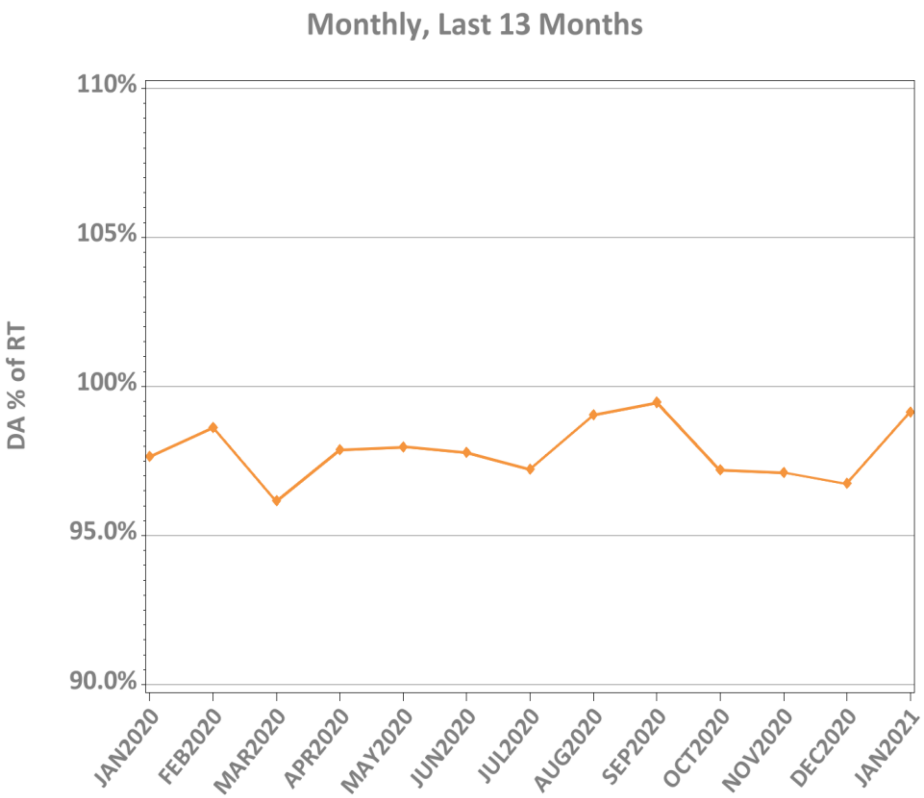
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

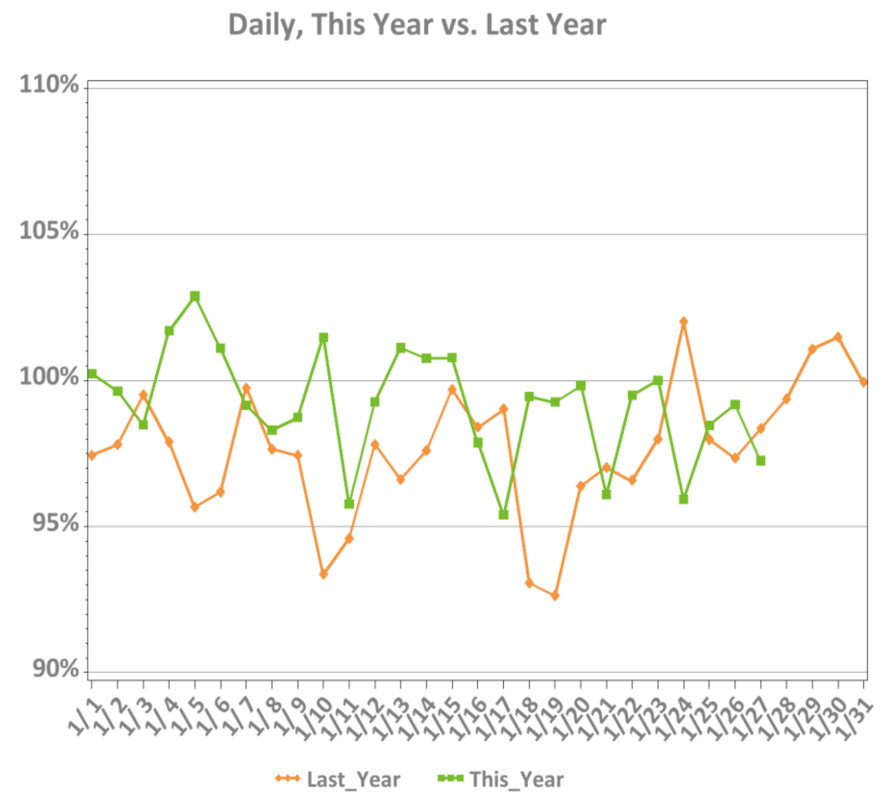




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

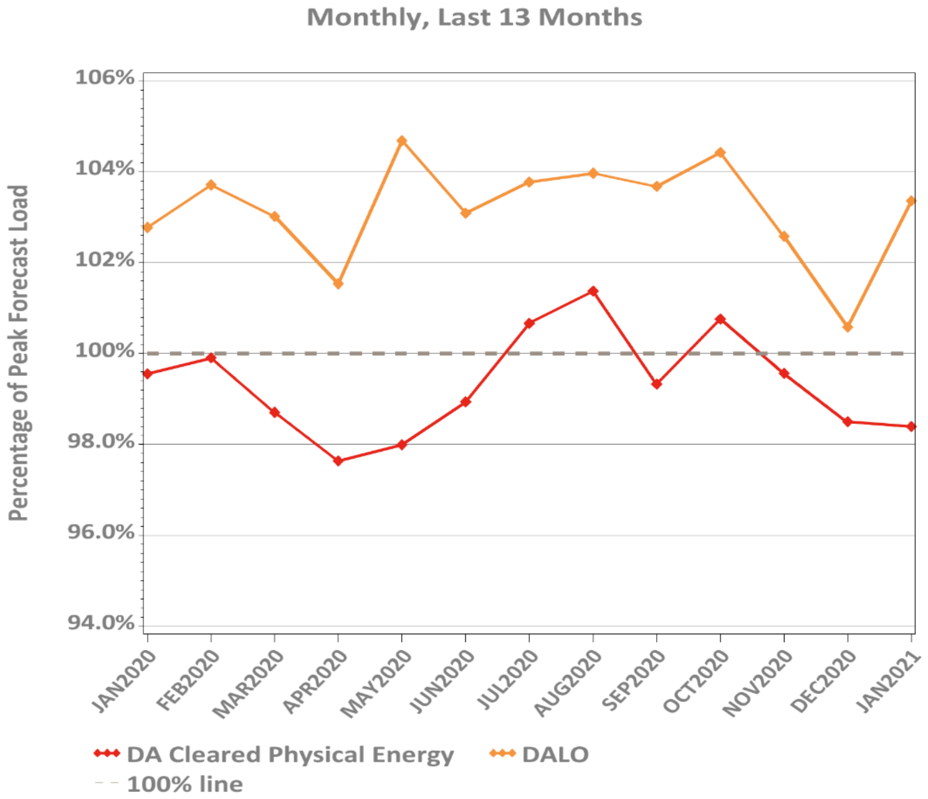
DA vs. RT Load Obligation: December, This Year vs. Last Year

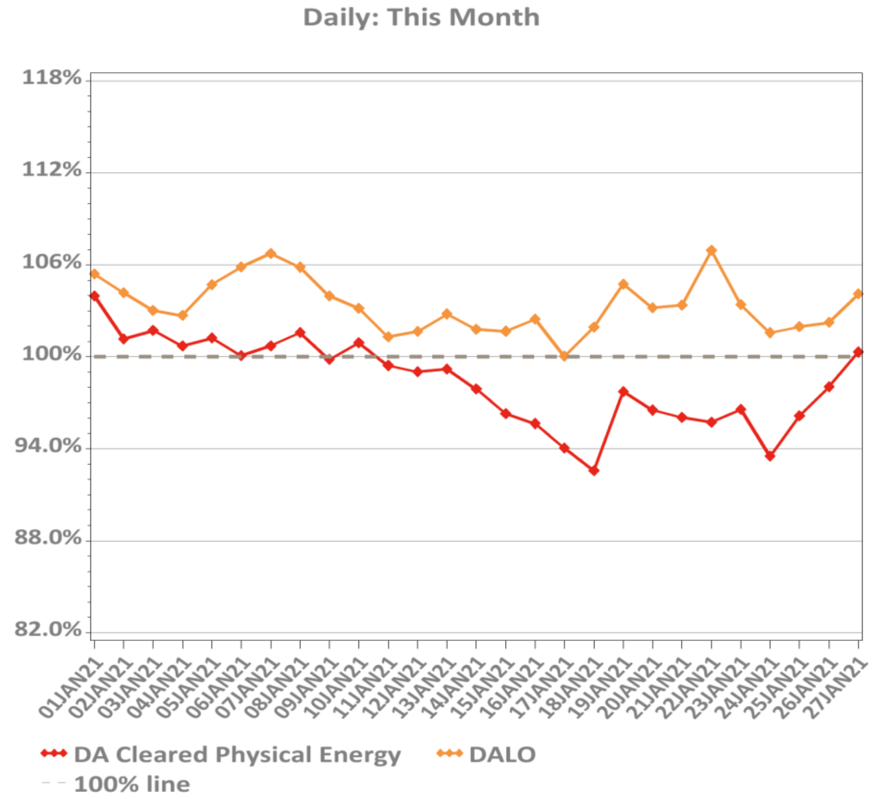




*Hourly average values

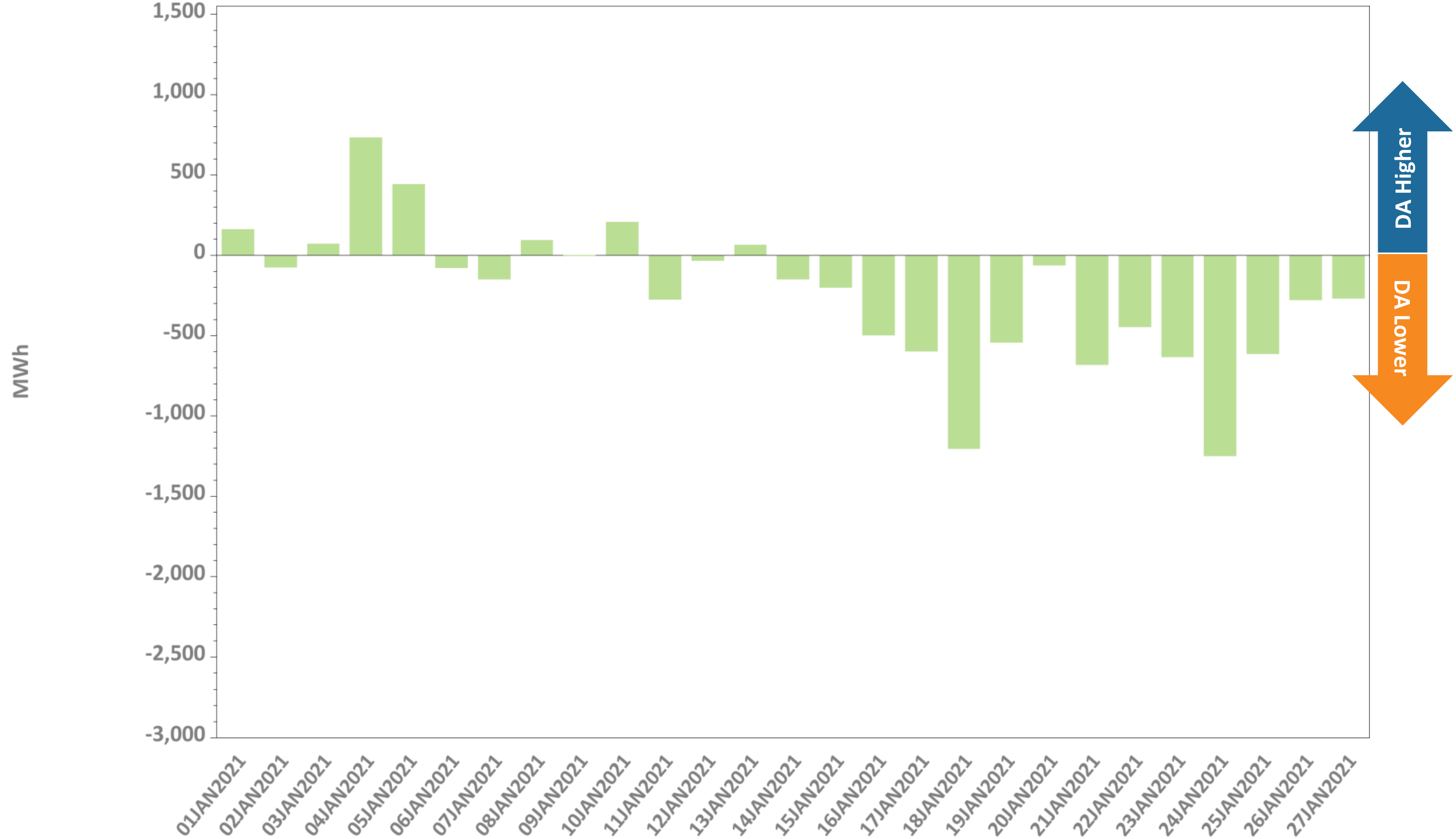
DA Volumes as % of Forecast in Peak Hour





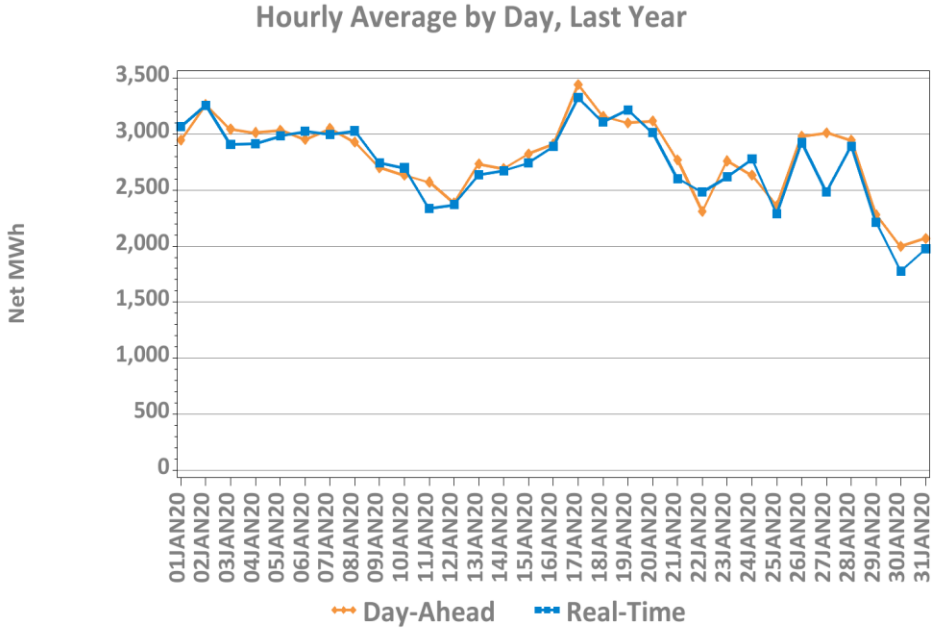
Note: There were three instances of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during January.

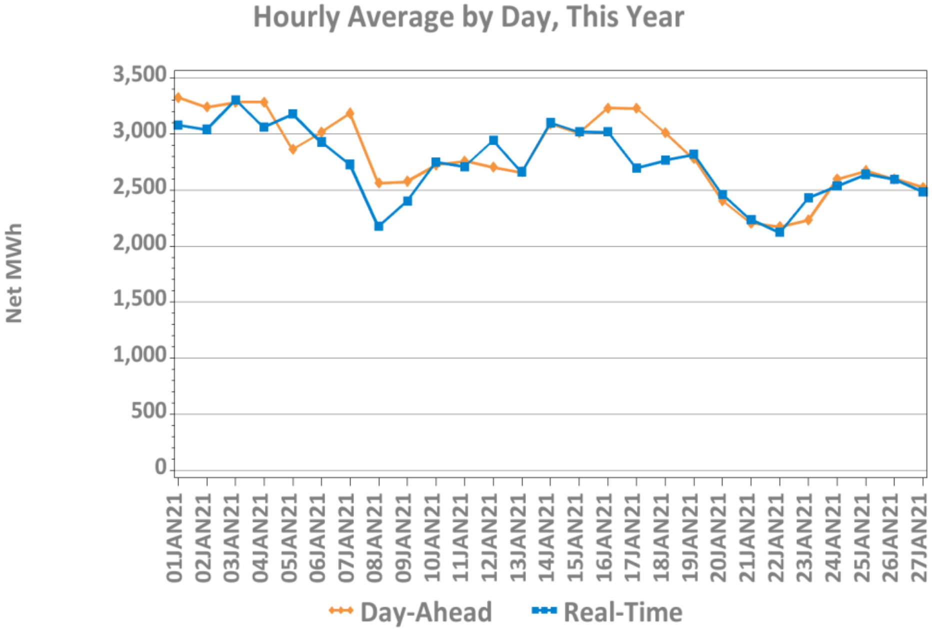
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



***Negative values indicate DA Cleared Physical Energy value below its RT counterpart. Forecast peak hour reflected.**

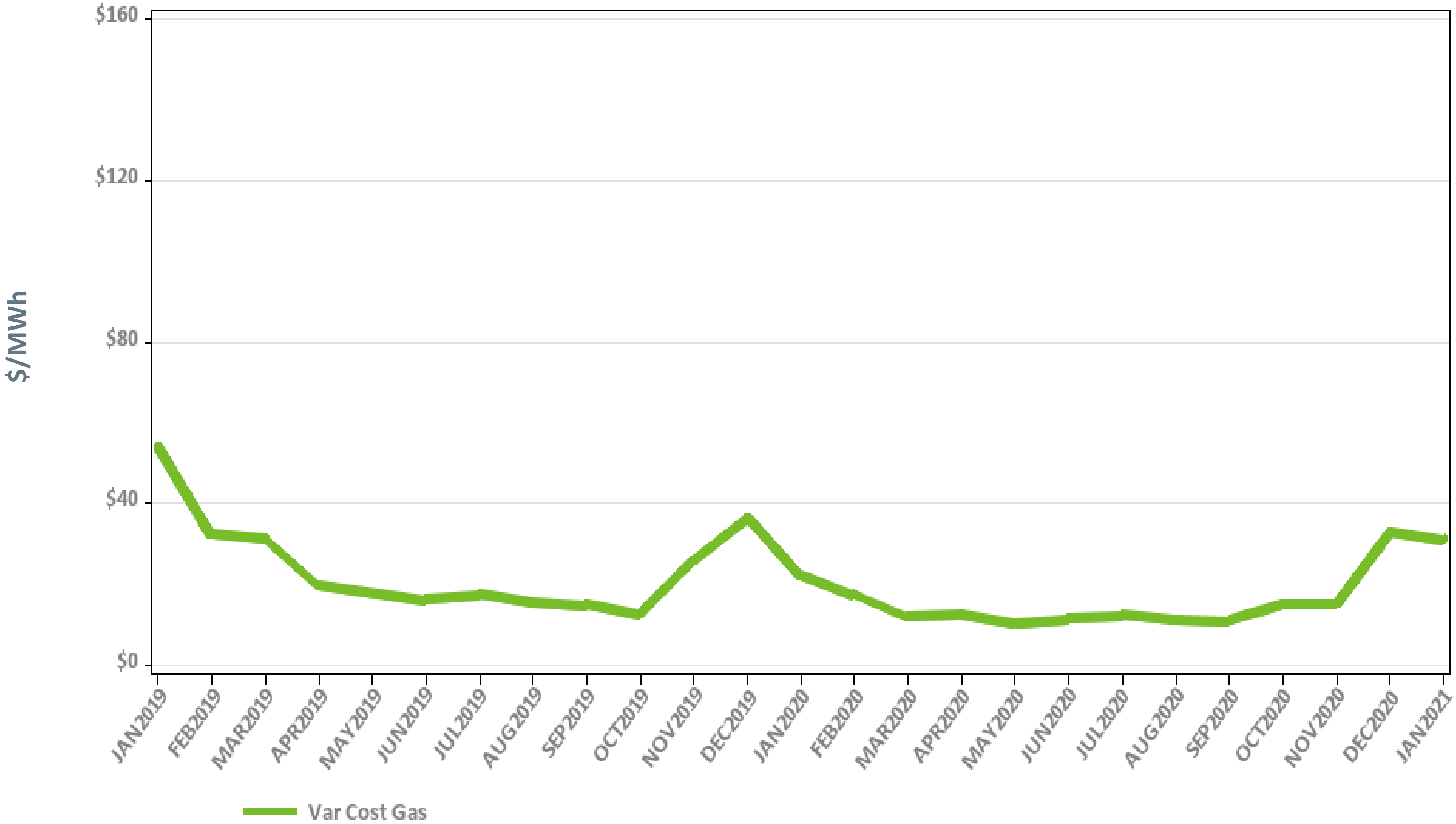
DA vs. RT Net Interchange
January 2020 vs. January 2021





Net Interchange is the sum of daily imports minus the sum of daily exports
Positive values are net imports

Variable Production Cost of Natural Gas: Monthly

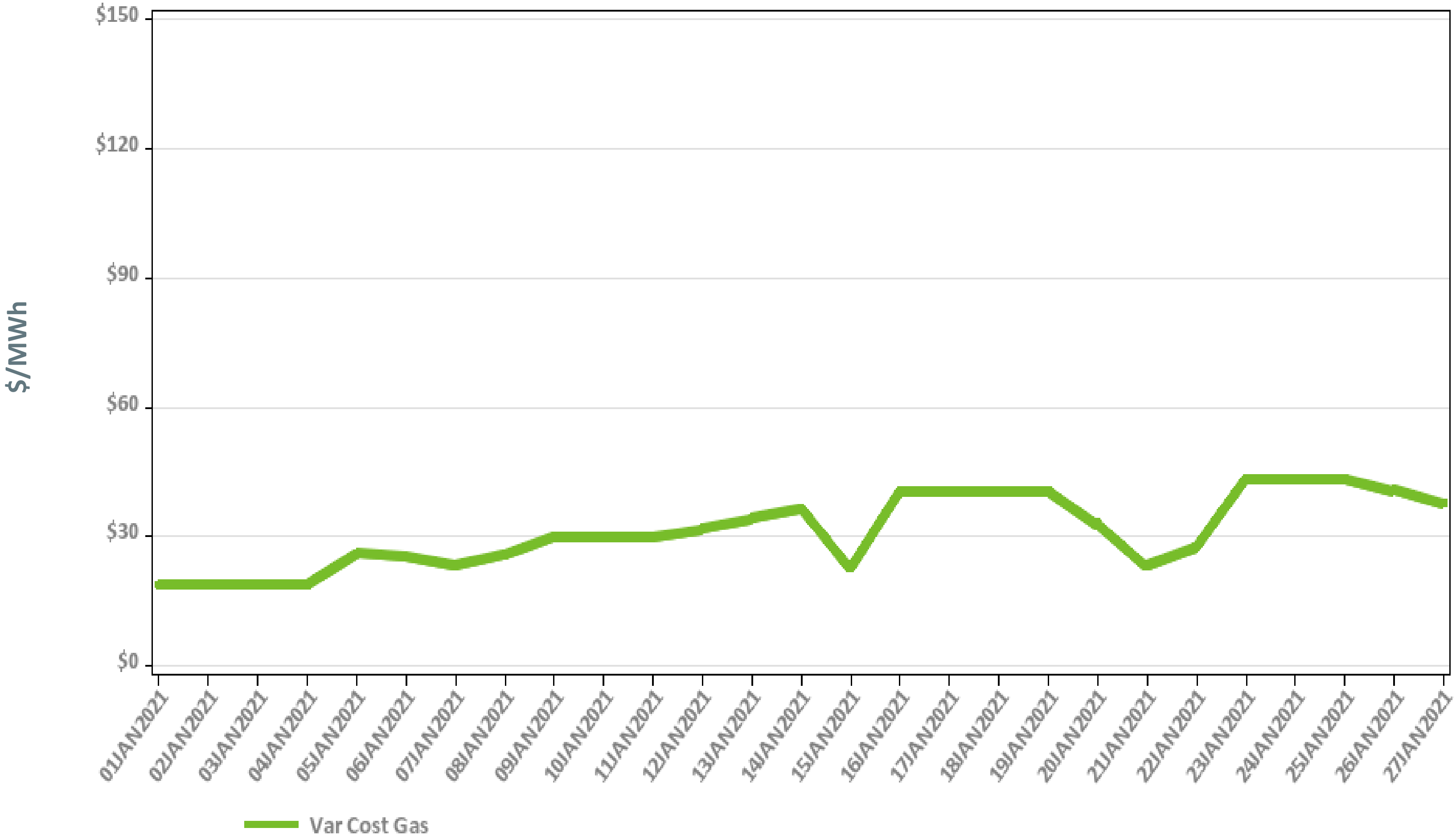


Underlying natural gas data furnished by:

ICE Global markets in clear view

Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Variable Production Cost of Natural Gas: Daily



Underlying natural gas data furnished by:

ICE Global markets in clear view

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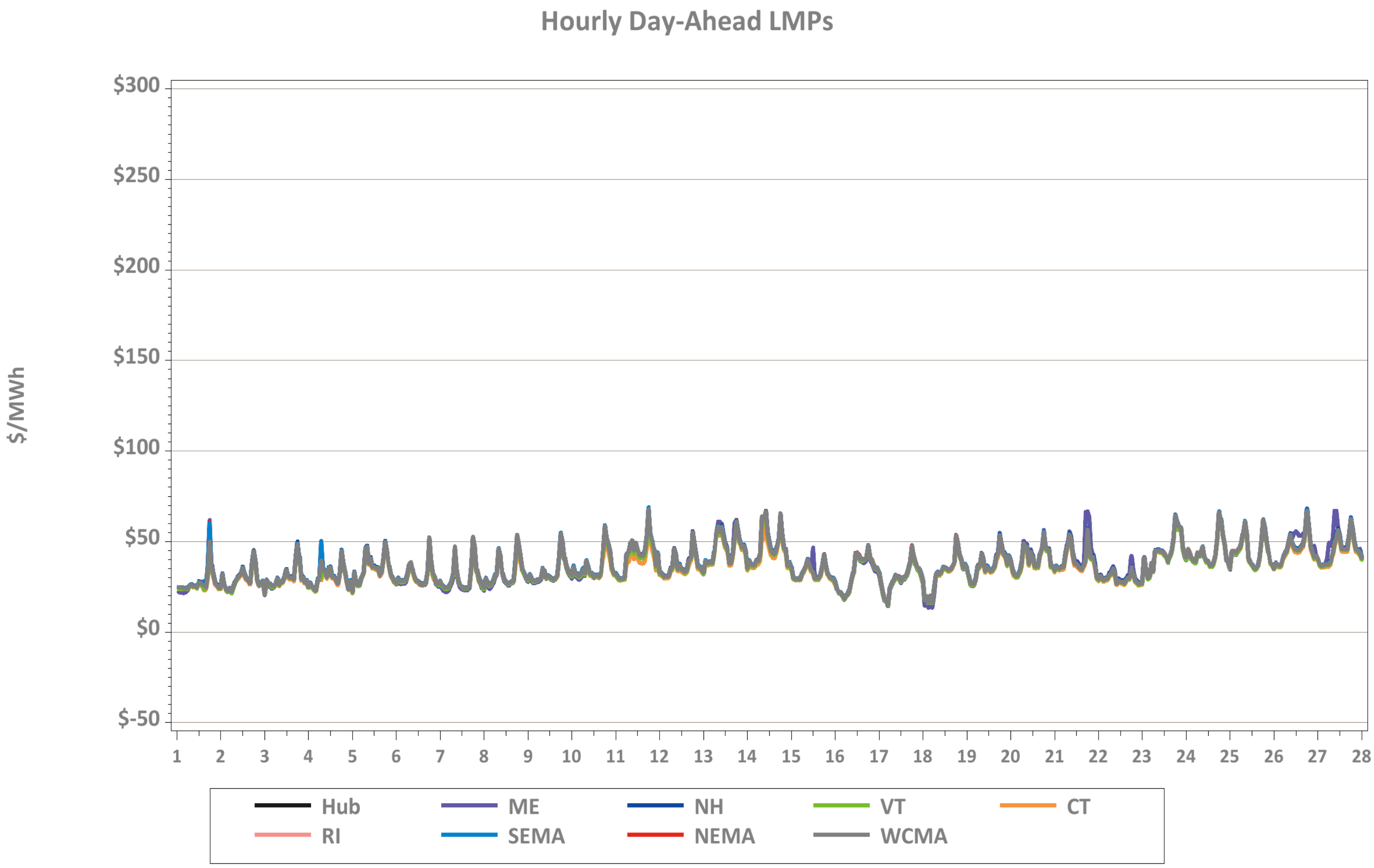
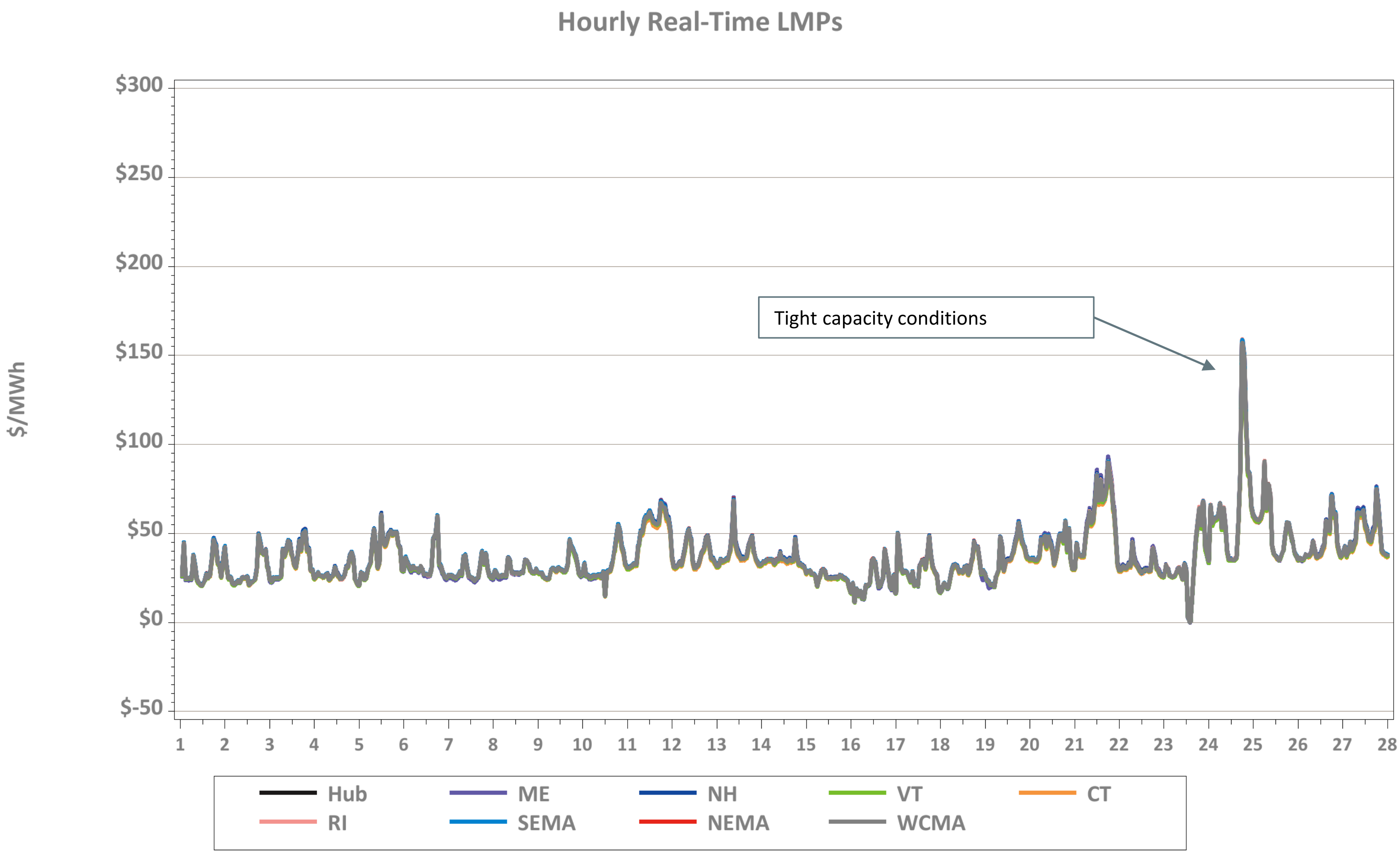
Hourly DA LMPs, January 1-27, 2021

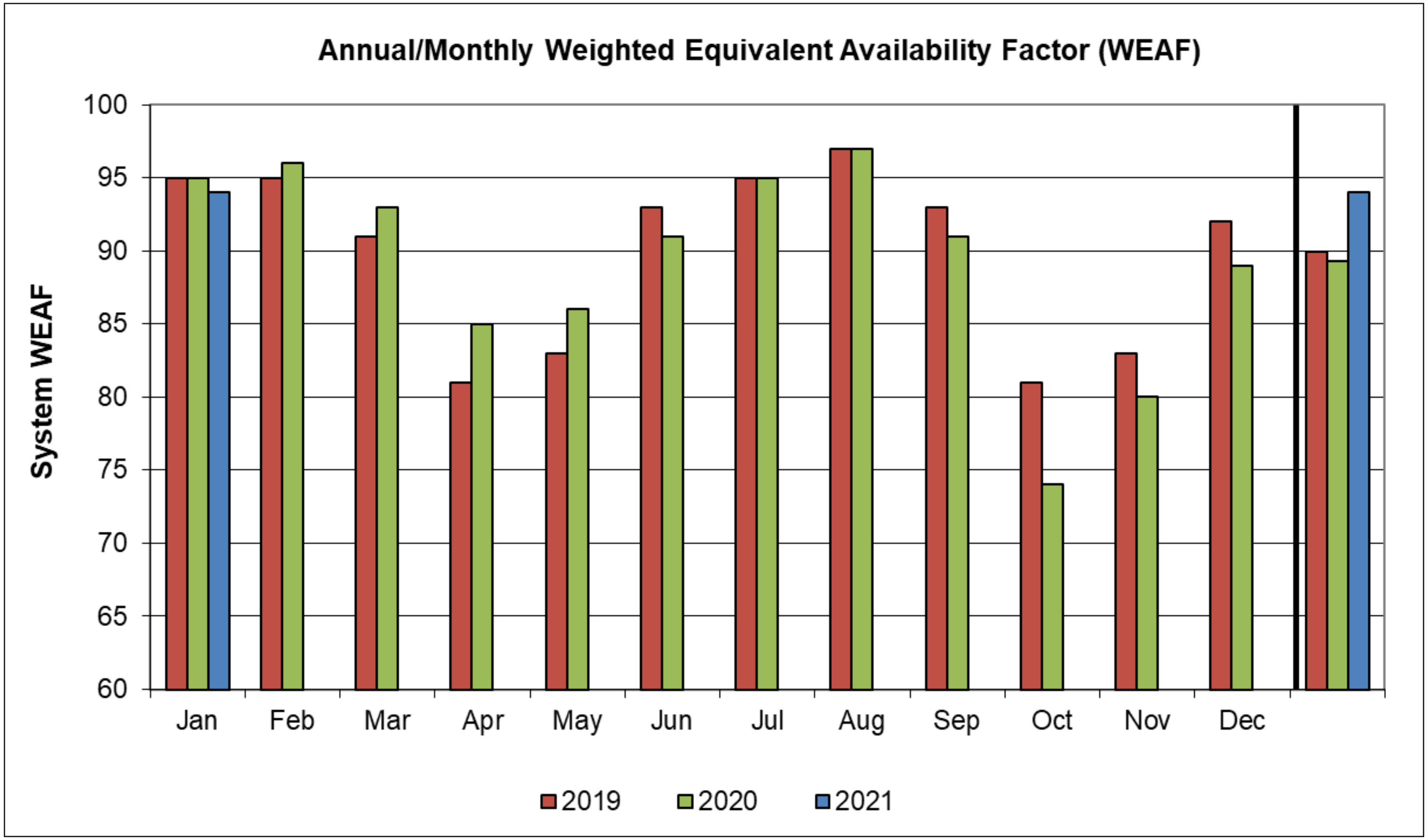


Hourly RT LMPs, January 1-27, 2021



- No Minimum Generation Emergencies were declared during January.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2021	94												94
2020	95	96	93	85	86	91	95	97	91	74	80	89	89
2019	95	95	91	81	83	93	95	97	93	81	83	92	90

Data as of 1/28/2021

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for February 2021

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	79.2	142.0	0.0	221.2
NH	36.5	131.3	0.0	167.7
VT	39.5	135.5	0.0	175.0
CT	107.2	100.8	571.4	779.4
RI	33.9	263.5	0.0	297.4
SEMA	40.2	415.2	0.0	455.3
WCMA	66.5	440.9	26.0	533.4
NEMA	58.4	764.7	0.0	823.1
Total	**461.3**	**2,393.8**	**597.4**	**3,452.5**

*** Active Demand Capacity Resources**
NOTE: CSO values include T&D loss factor (8%).

NEW GENERATION

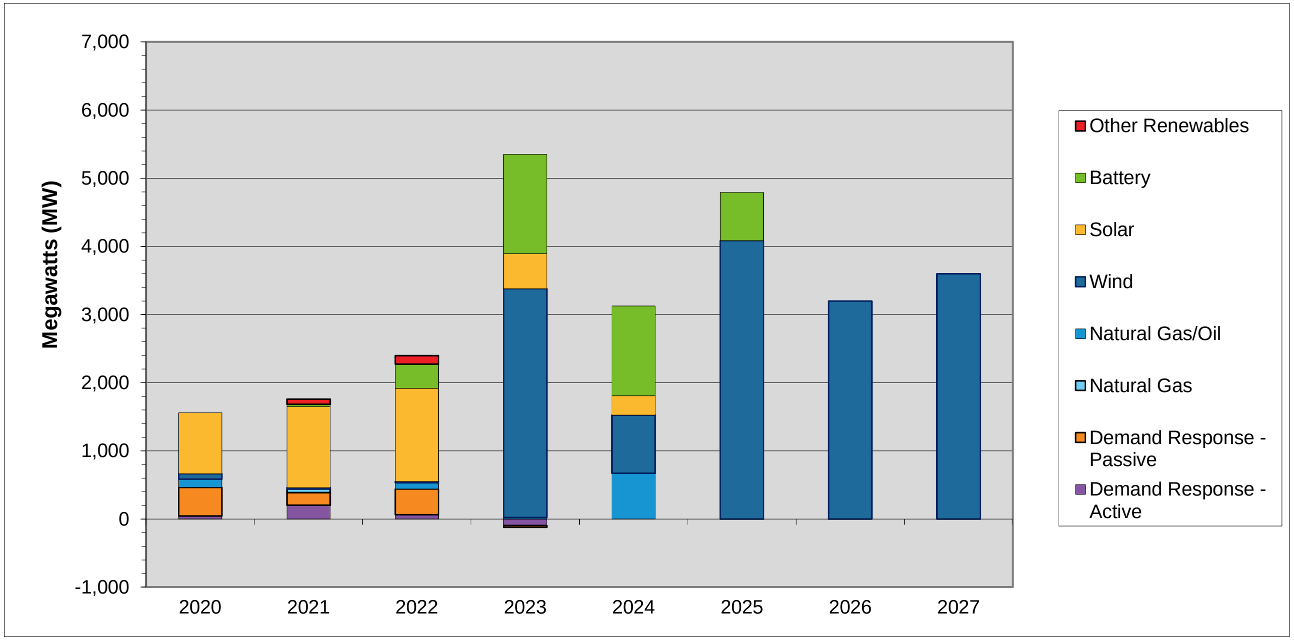
New Generation Update

Based on Queue as of 2/1/21

- Three new projects totaling 364 MW applied for interconnection study since the last update
  - They consist of two new battery storage projects and one PV project, with in-service dates in 2022 and 2023
- One project went commercial and five were withdrawn, resulting in a net increase in new generation projects of 199 MW
- In total, 258 generation projects are currently being tracked by the ISO, totaling approximately 24,200 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



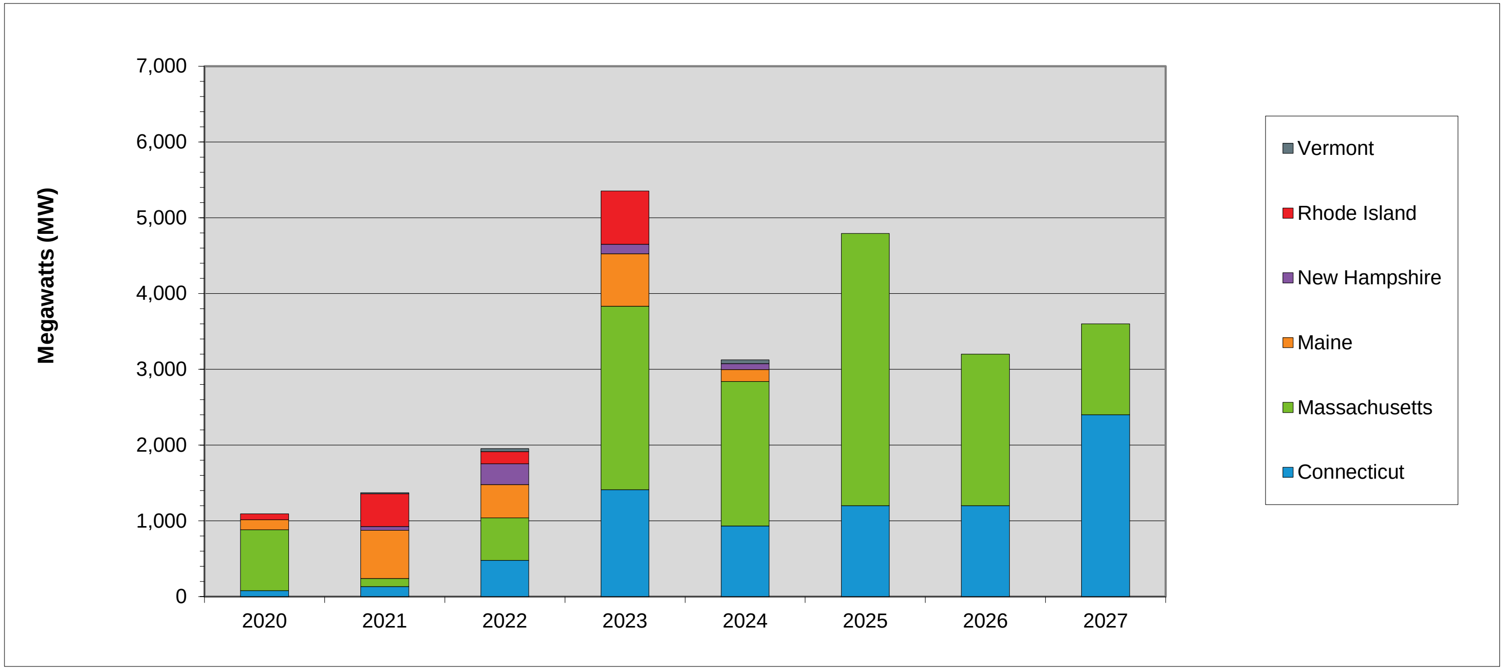
	2020	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Other Renewables	0	76	122	0	0	0	0	0	198	0.8
Battery	0	34	358	1,459	1,316	704	0	0	3,871	15.1
Solar[2]	894	1,189	1,365	516	285	0	0	0	4,249	16.6
Wind	78	19	20	3,355	852	4,087	3,200	3,600	15,211	59.3
Natural Gas/Oil[3]	121	0	89	23	672	0	0	0	905	3.5
Natural Gas	0	53	0	0	0	0	0	0	53	0.2
Demand Response - Passive	422	184	380	-28	0	0	0	0	958	3.7
Demand Response - Active	42	204	62	-94	0	0	0	0	214	0.8
Totals	**1,558**	**1,759**	**2,396**	**5,231**	**3,125**	**4,791**	**3,200**	**3,600**	**25,660**	**100.0**

[1] Sum may not equal 100% due to rounding
[2] This category includes both solar-only, and co-located solar and battery projects
[3] The projects in this category are dual fuel, with either gas or oil as the primary fuel

- 2020 values include the 274 MW of generation that went commercial in 2020
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2020	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Vermont	0	15	40	0	50	0	0	0	105	0.4
Rhode Island	78	433	160	704	0	0	0	0	1,375	5.6
New Hampshire	0	50	276	126	80	0	0	0	532	2.2
Maine	133	635	440	691	156	0	0	0	2,055	8.4
Massachusetts	802	105	560	2,420	1,907	3,591	2,000	1,200	12,585	51.4
Connecticut	80	133	478	1,412	932	1,200	1,200	2,400	7,835	32.0
Totals	**1,093**	**1,371**	**1,954**	**5,353**	**3,125**	**4,791**	**3,200**	**3,600**	**24,487**	**100.0**

[1] Sum may not equal 100% due to rounding

- 2020 values include the 274 MW of generation that went commercial in 2020

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	1	8	1	8	0	0
Battery Storage	21	3,871	0	0	21	3,871
Fuel Cell	4	54	1	10	3	44
Hydro	3	99	2	71	1	28
Natural Gas	5	53	0	0	5	53
Natural Gas/Oil	7	860	1	14	6	846
Nuclear	1	37	0	0	1	37
Solar	194	4,098	10	158	184	3,940
Wind	22	15,133	1	15	21	15,118
Total	258	24,213	16	276	242	23,937

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel
- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	8	132	3	23	5	109
Intermediate	9	822	1	14	8	808
Peaker	219	8,126	11	224	208	7,902
Wind Turbine	22	15,133	1	15	21	15,118
Total	258	24,213	16	276	242	23,937

- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type and Fuel Type

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	1	8	1	8	0	0	0	0	0	0
Battery Storage	21	3,871	0	0	0	0	21	3,871	0	0
Fuel Cell	4	54	4	54	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	5	53	0	0	4	47	1	6	0	0
Natural Gas/Oil	7	860	0	0	5	775	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	194	4,098	0	0	0	0	194	4,098	0	0
Wind	22	15,133	0	0	0	0	0	0	22	15,133
Total	258	24,213	8	132	9	822	219	8,126	22	15,133

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 11

Resource Type	Resource Type		FCA	ARA 1		ARA 2		ARA 3	
			CSO	CSO	Change	CSO	Change	CSO	Change
			MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*		419.928	441.221	21.293	594.551	153.33	584.35	-10.201
	Passive Demand		2,791.02	2,835.354	44.334	2,883.767	48.413	2,964.695	80.928
Demand Total			**3,210.95**	**3,276.575**	**65.625**	**3,478.318**	**201.743**	**3,549.045**	**70.727**
Generator		*Non-Intermittent*	30,494.80	30,064.23	-430.569	30,159.891	95.661	2,9678.995	-480.896
		Intermittent	894.217	823.796	-70.421	809.571	-14.225	689.524	-120.047
Generator Total			**31,389.02**	**30,888.027**	**-500.993**	**30,969.462**	**81.435**	**30,368.519**	**-600.943**
Import Total			**1,235.40**	**1,622.037**	**386.637**	**1,609.844**	**-12.193**	**1,124.6**	**-485.244**
Grand Total*			**35,835.37**	**35,786.64**	**-48.731**	**36,057.624**	**270.984**	**35,042.164**	**-1015.46**
Net ICR (NICR)			**34,075**	**33,660**	**-415**	**33,520**	**-140**	**32,205**	**-1,315**

* Grand Total reflects both CSO Grand Total and the net total of the Change Column.

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 12

Resource Type	Resource Type					ARA 2		ARA 3	
			CSO	CSO	Change	CSO	Change	CSO	Change
			MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*		624.445	659.137	34.692	603.776	-55.361		
	Passive Demand		2,975.36	3,045.073	69.713	31,23.232	78.159		
Demand Total			**3,599.81**	**3,704.21**	**104.4**	**37,27.008**	**22.798**		
Generator		*Non-Intermittent*	29,130.75	29,244.404	113.654	28,620.245	-624.159		
		Intermittent	880.317	806.609	-73.708	660.932	-145.677		
Generator Total			**30,011.07**	**30,051.013**	**39.943**	**29,281.177**	**-769.836**		
Import Total			**1,217**	**1,305.487**	**88.487**	**1,307.587**	**2.10**		
Grand Total*			**34,827.88**	**35,060.710**	**232.83**	**34,315.772**	**-744.94**		
Net ICR (NICR)			**33,725**	**33,550**	**-175**	**32,320**	**-230**		

* Grand Total reflects both CSO Grand Total and the net total of the Change Column

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 13

Resource Type	Resource Type		FCA	ARA 1		ARA 2		ARA 3	
			CSO	CSO	Change	CSO	Change	CSO	Change
			MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*		685.554	683.116	-2.438				
	Passive Demand		3,354.69	3,407.507	52.817				
Demand Total			**4,040.244**	**4,090.623**	**50.38**				
Generator		*Non-Intermittent*	28,586.498	27,868.341	-718.157				
		Intermittent	1,024.792	901.672	-123.12				
Generator Total			**2,9611.29**	**28,770.013**	**-841.28**				
Import Total			**1,187.69**	**1,292.41**	**104.72**				
Grand Total*			**34,839.224**	**34,153.046**	**-686.18**				
Net ICR (NICR)			**33,750**	**32,465**	**-1,285**				

* Grand Total reflects both CSO Grand Total and the net total of the Change Column

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 14

Resource Type	Resource Type		FCA	ARA 1		ARA 2		ARA 3	
			CSO	CSO	Change	CSO	Change	CSO	Change
			MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*		592.043						
	Passive Demand		3,327.071						
Demand Total			**3,919.114**						
Generator		*Non-Intermittent*	27,816.902						
		Intermittent	1,160.916						
Generator Total			**28,977.818**						
Import Total			**1,058.72**						
Grand Total*			**33,955.652**						
Net ICR (NICR)			**32,490**						

* Grand Total reflects both CSO Grand Total and the net total of the Change Column

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	**Grand Total**
2019-20	Active	357.221	20.304	**377.525**
	Passive	2,018.20	350.43	**2,368.63**
	Grand Total	2375.422	370.734	**2746.156**
2020-21	Active	334.634	85.294	**419.928**
	Passive	2,236.73	554.292	**2,791.02**
	Grand Total	2571.361	639.586	**3210.947**
2021-22	Active	480.941	143.504	**624.445**
	Passive	2,604.79	370.568	**2,975.36**
	Grand Total	3085.734	514.072	**3599.806**
2022-23	Active	598.376	87.178	**685.554**
	Passive	2,788.33	566.363	**3,354.69**
	Grand Total	3386.703	653.541	**4040.244**
2023-24	Active	560.55	31.493	**592.043**
	Passive	3,035.51	291.565	**3,327.07**
	Grand Total	3596.056	323.058	**3919.114**

RELIABILITY COSTS – NET COMMITMENT PERIOD COMPENSATION (NCPC) OPERATING COSTS

What are Daily NCPC Payments?

- Payments made to resources whose commitment and dispatch by ISO-NE resulted in a shortfall between the resource's offered value in the Energy and Regulation Markets and the revenue earned from output during the day
- Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area
- NCPC payments are intended to make a resource that follows the ISO's operating instructions "no worse off" financially than the best alternative generation schedule

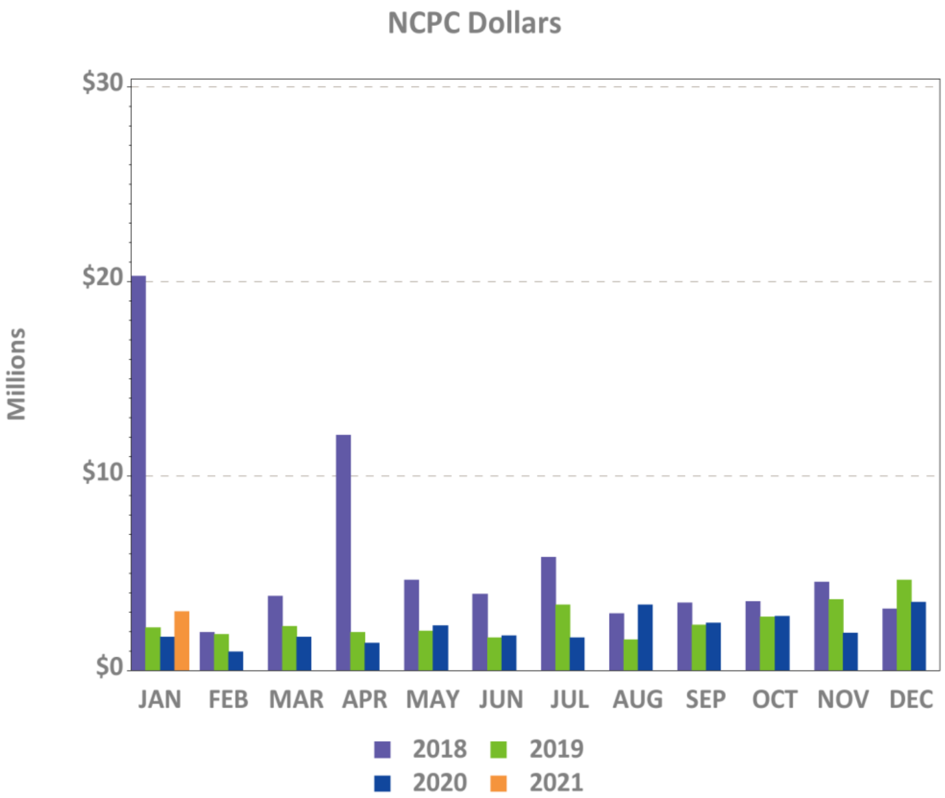
Definitions

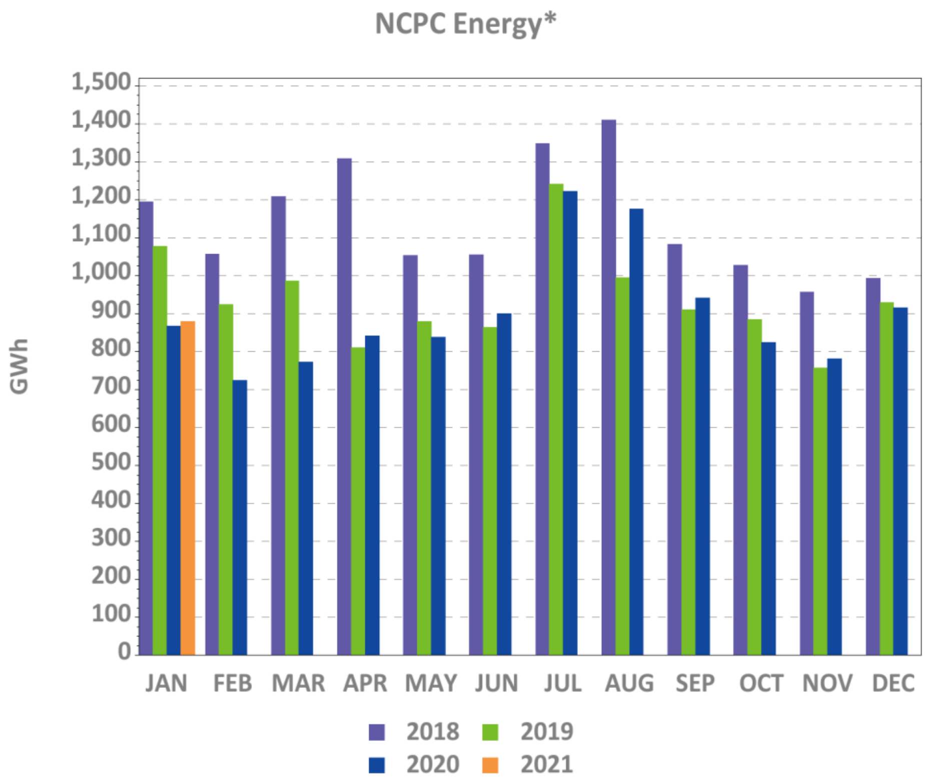
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2nd Contingency (2ndC) protocols, and are also known as Local Second Contingency Protection Resources (LSCPR)
Voltage NCPC Payments	Reliability costs paid to resources operated by ISO-NE to provide voltage support or control in specific locations
Distribution NCPC Payments	Reliability costs paid to units dispatched at the request of local transmission providers for purpose of managing constraints on the low voltage (distribution) system. These requirements are not modeled in the DA Market software
OATT	Open Access Transmission Tariff

Charge Allocation Key

Allocation Category	Market / OATT	Allocation
System 1st Contingency	Market	DA 1st C (excluding at external nodes) is allocated to system DALO. RT 1st C (at all locations) is allocated to System 'Daily Deviations'. Daily Deviations = sum of(generator deviations, load deviations, generation obligation deviations at external nodes, increment offer deviations)
External DA 1st Contingency	Market	DA 1st C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved
Zonal 2nd Contingency	Market	DA and RT 2nd C NCPC are allocated to load obligation in the Reliability Region (zone) served
System Low Voltage	OATT	(Low) Voltage Support NCPC is allocated to system Regional Network Load and Open Access Same-Time Information Service (OASIS) reservations
Zonal High Voltage	OATT	High Voltage Control NCPC is allocated to zonal Regional Network Load
Distribution - PTO	OATT	Distribution NCPC is allocated to the specific Participant Transmission Owner (PTO) requesting the service
System – Other	Market	Includes GPA, Economic Generator/DARD Posturing, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost NCPC (allocated to RTLO); and Min Generation Emergency NCPC (allocated to RTGO).

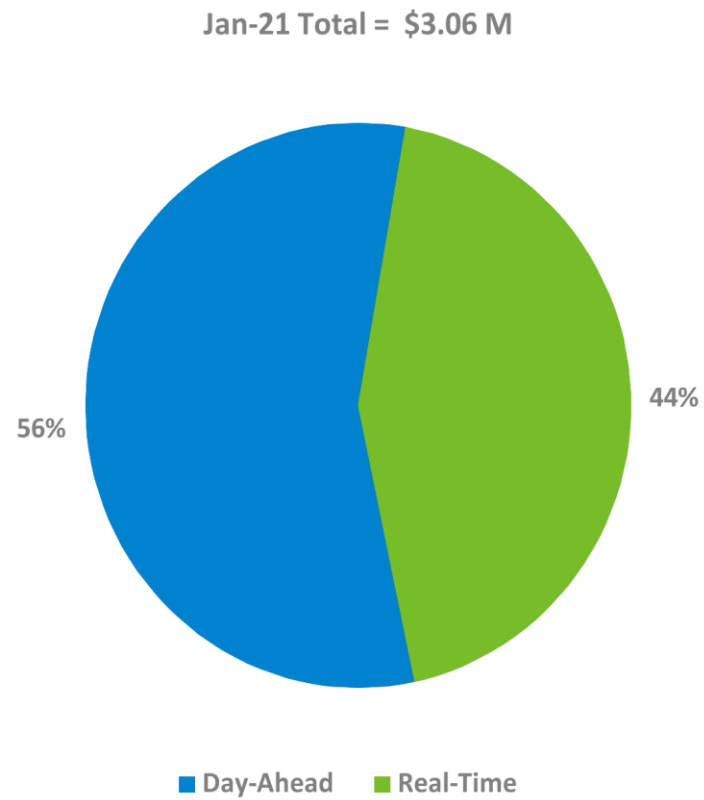
Year-Over-Year Total NCPC Dollars and Energy

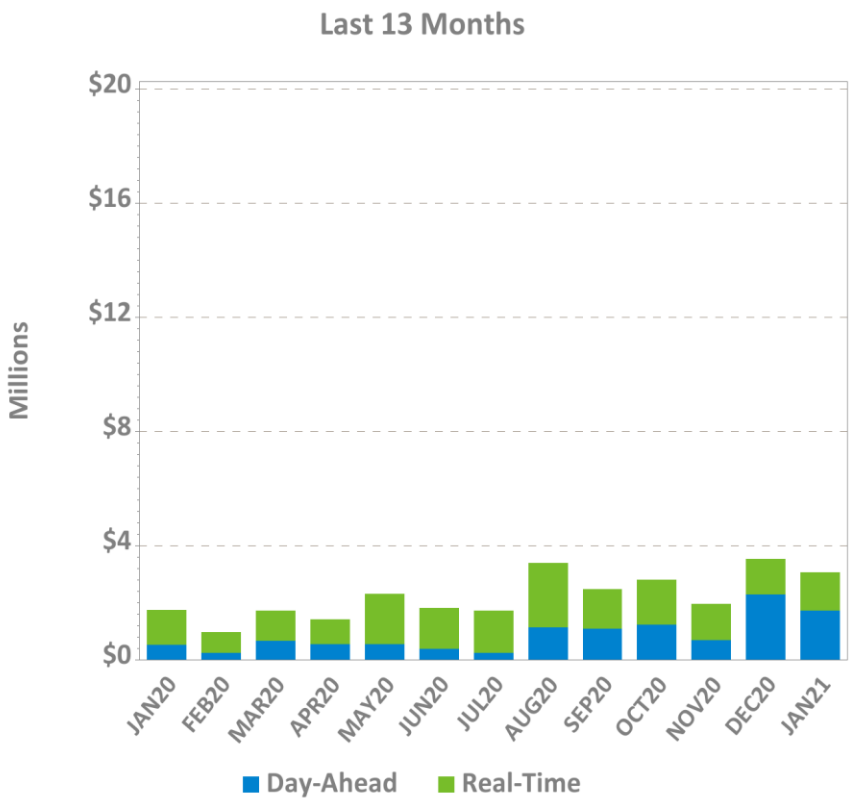




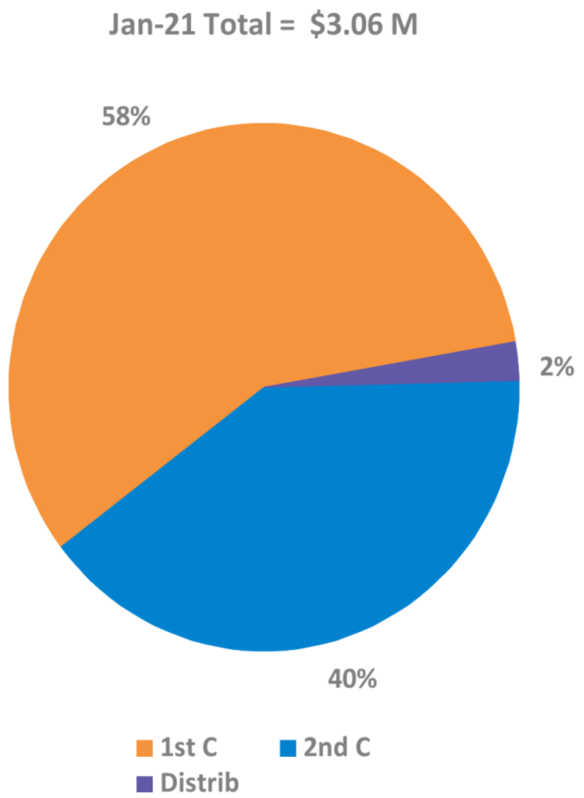
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.

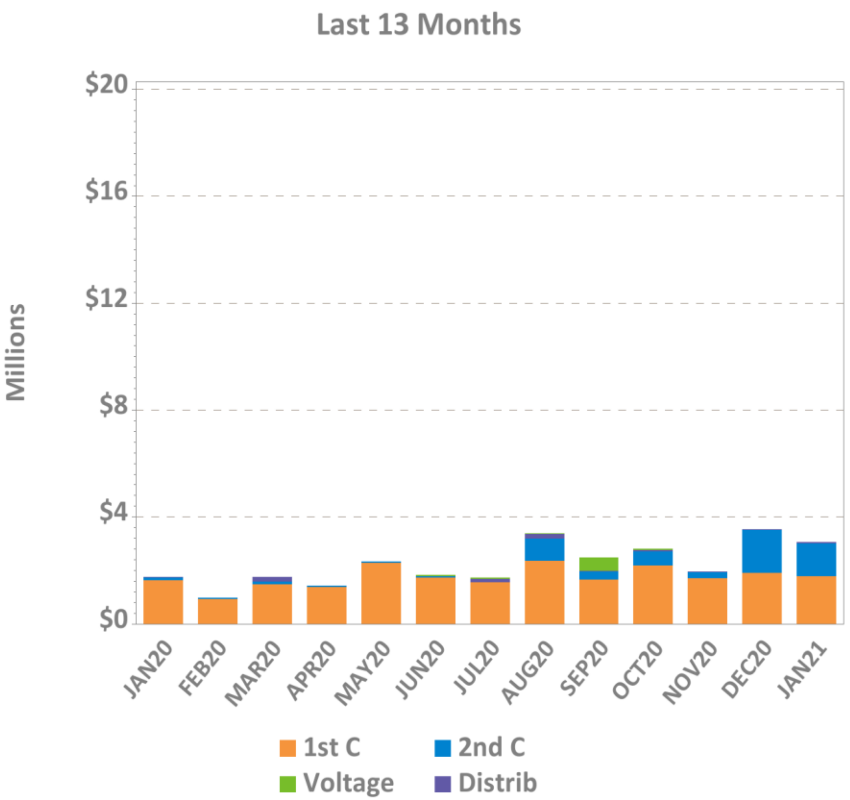
DA and RT NCPC Charges





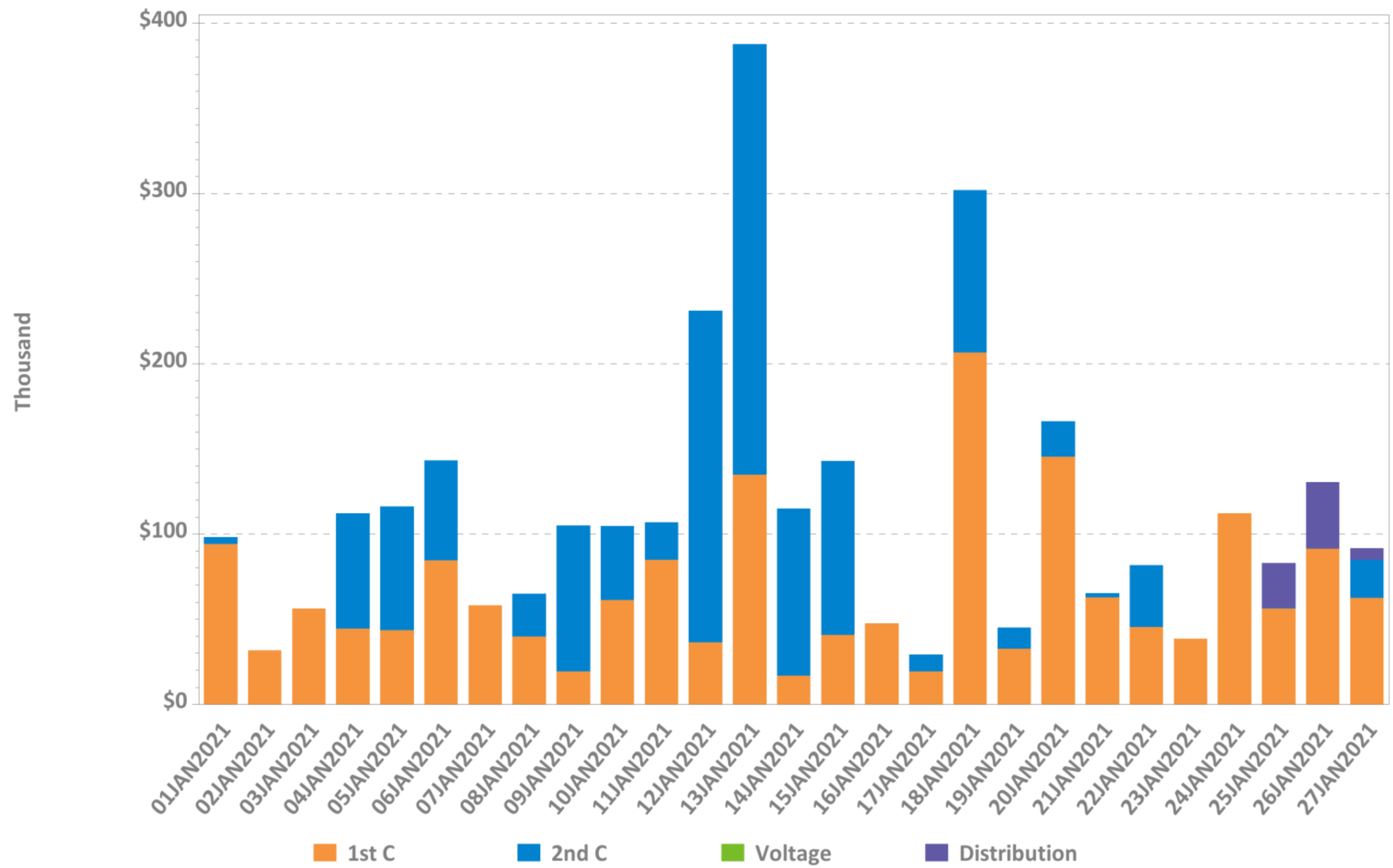
NCPC Charges by Type



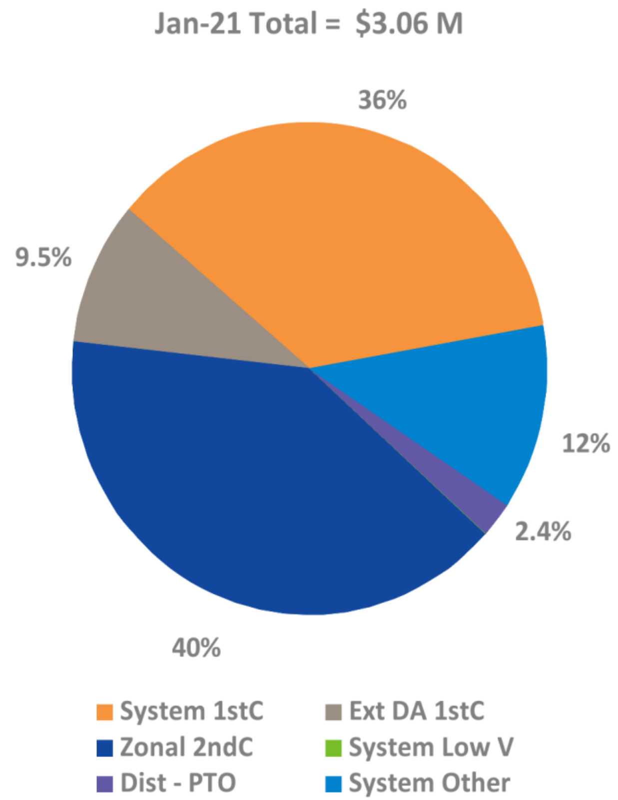


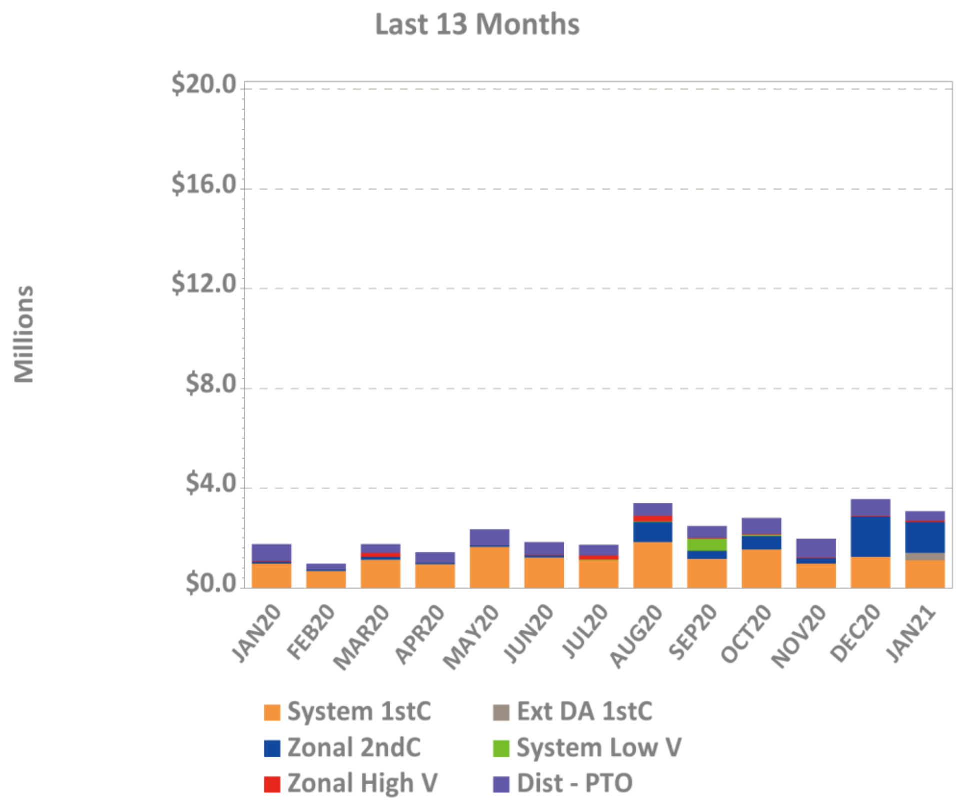
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



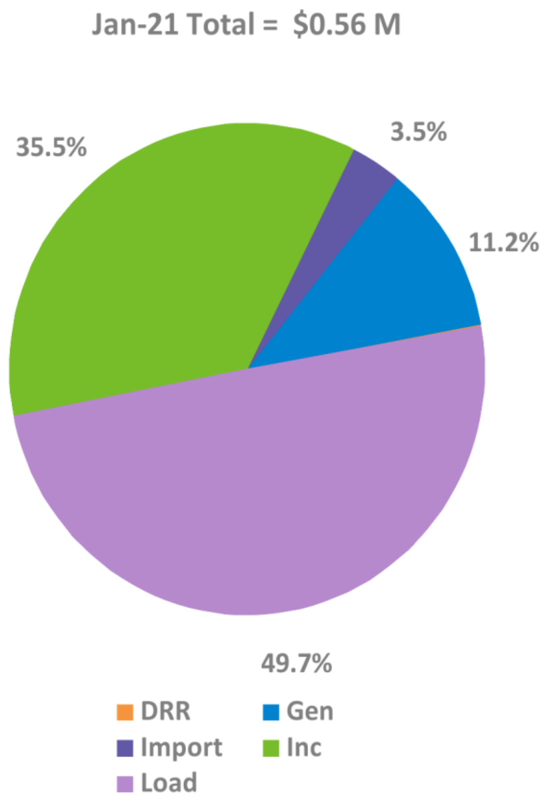
NCPC Charges by Allocation

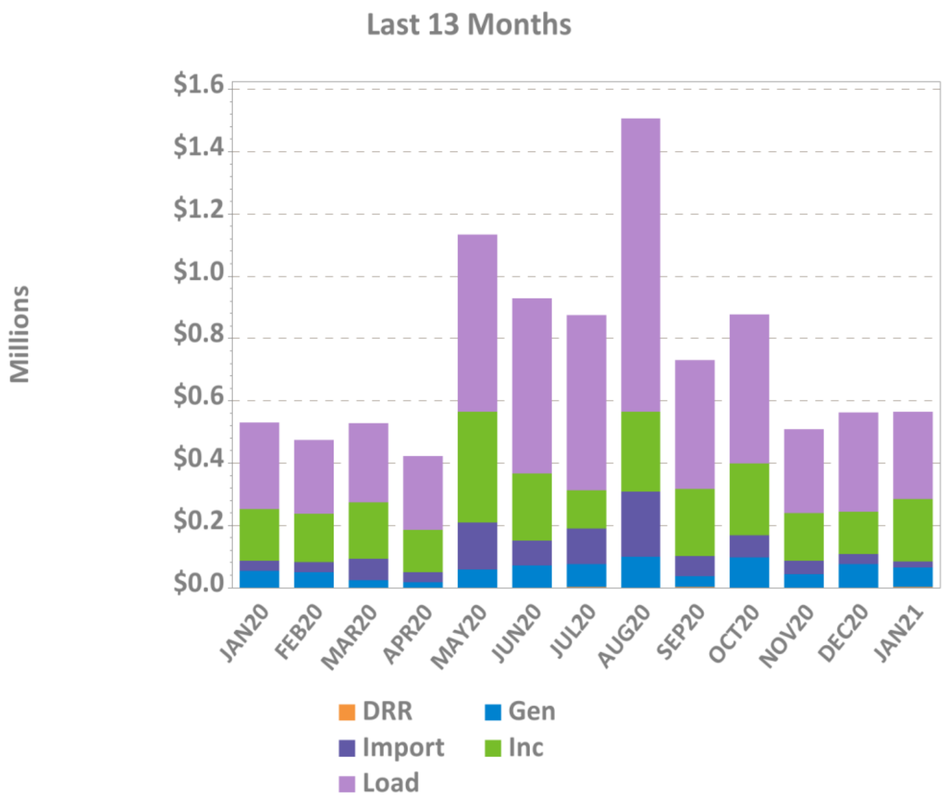




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

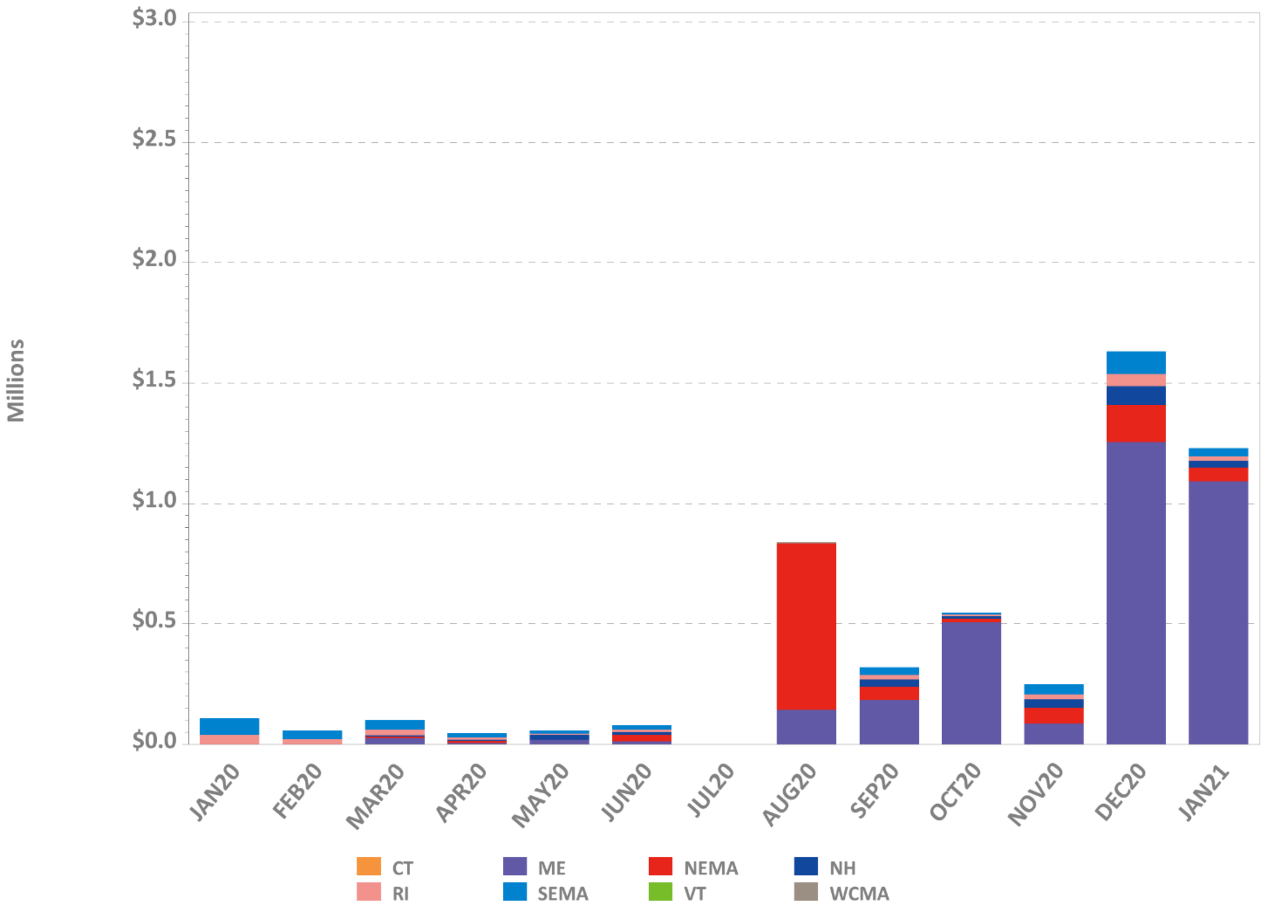
RT First Contingency Charges by Deviation Type





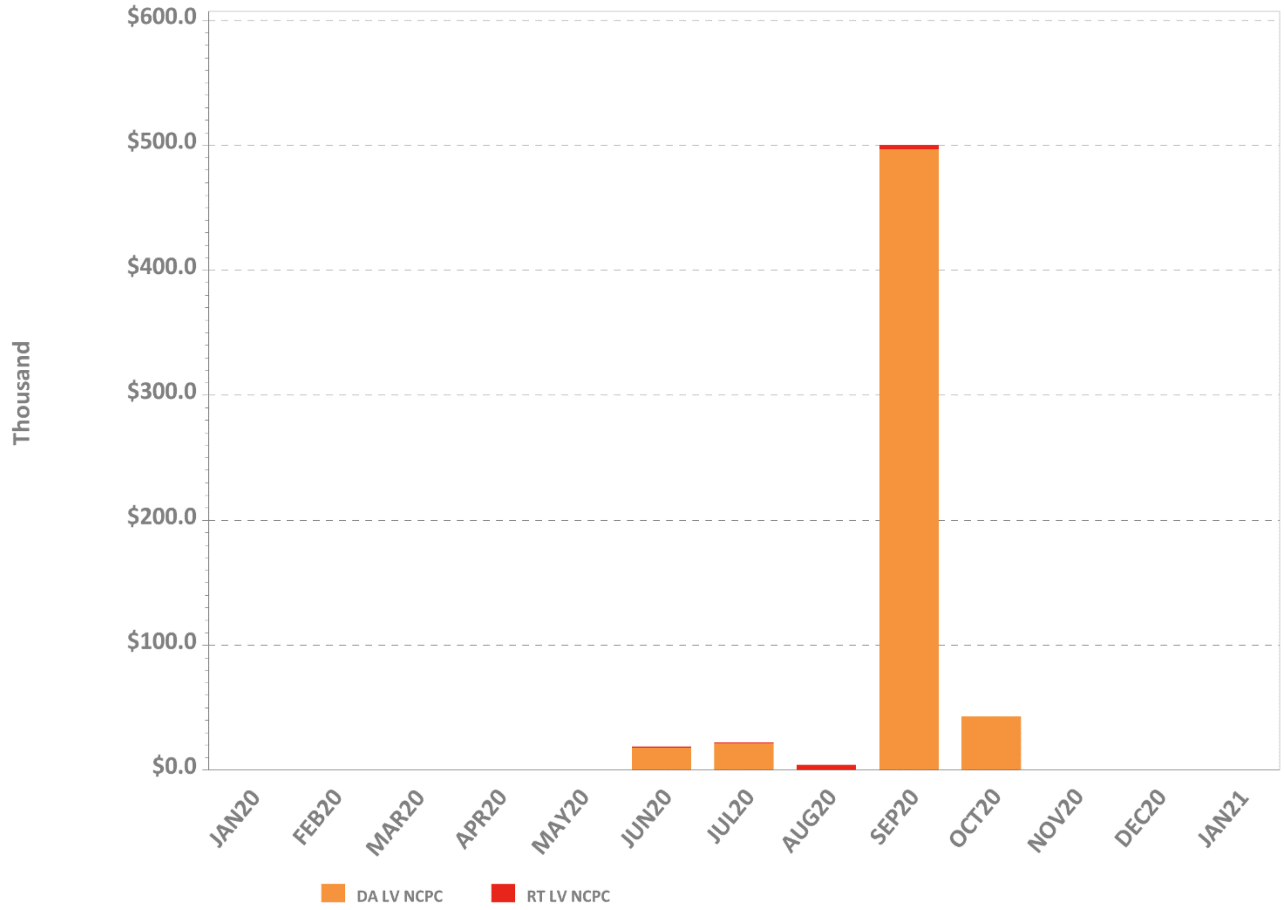
DRR – Demand Response Resource deviations
Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations

LSCPR Charges by Reliability Region

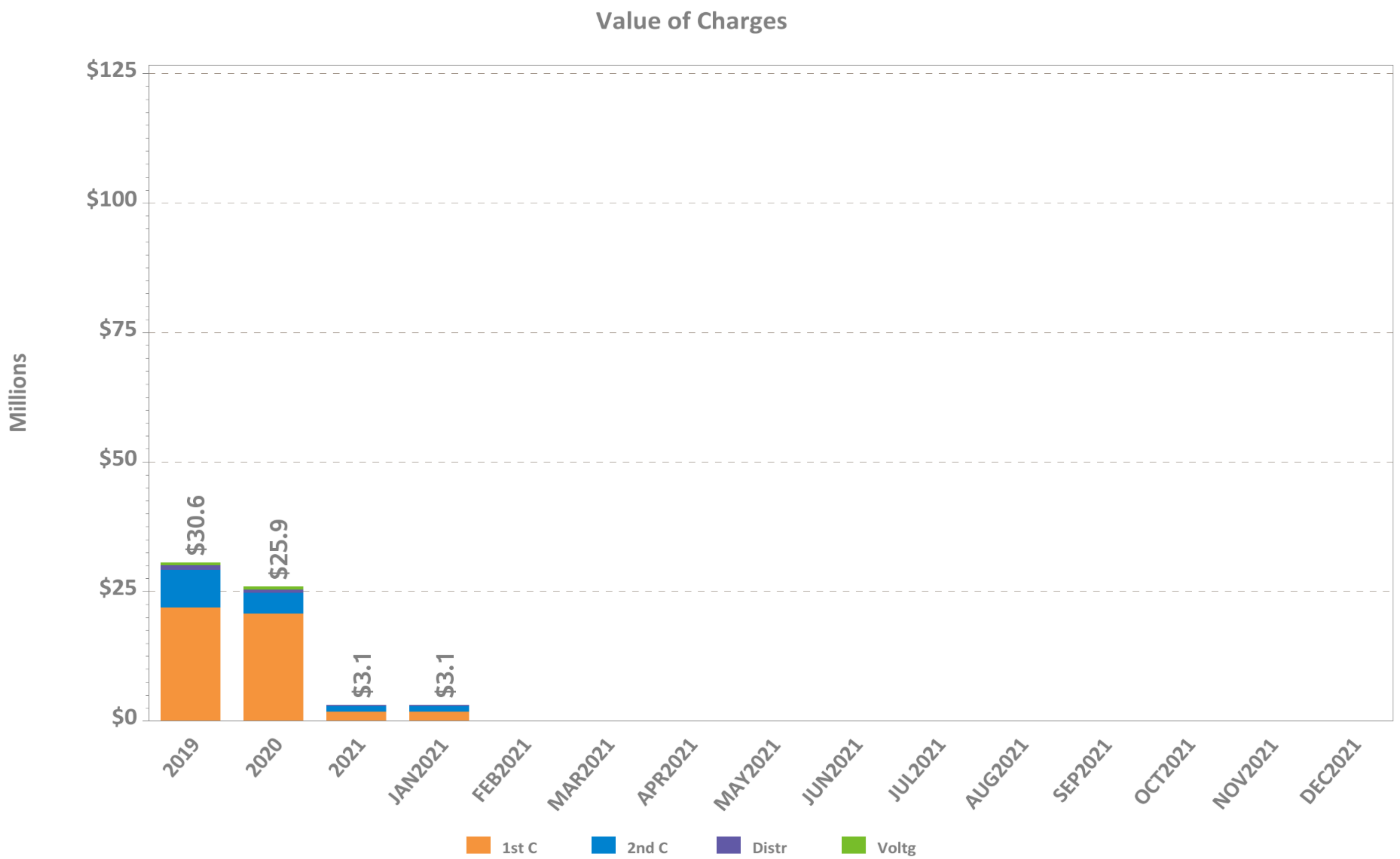


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region

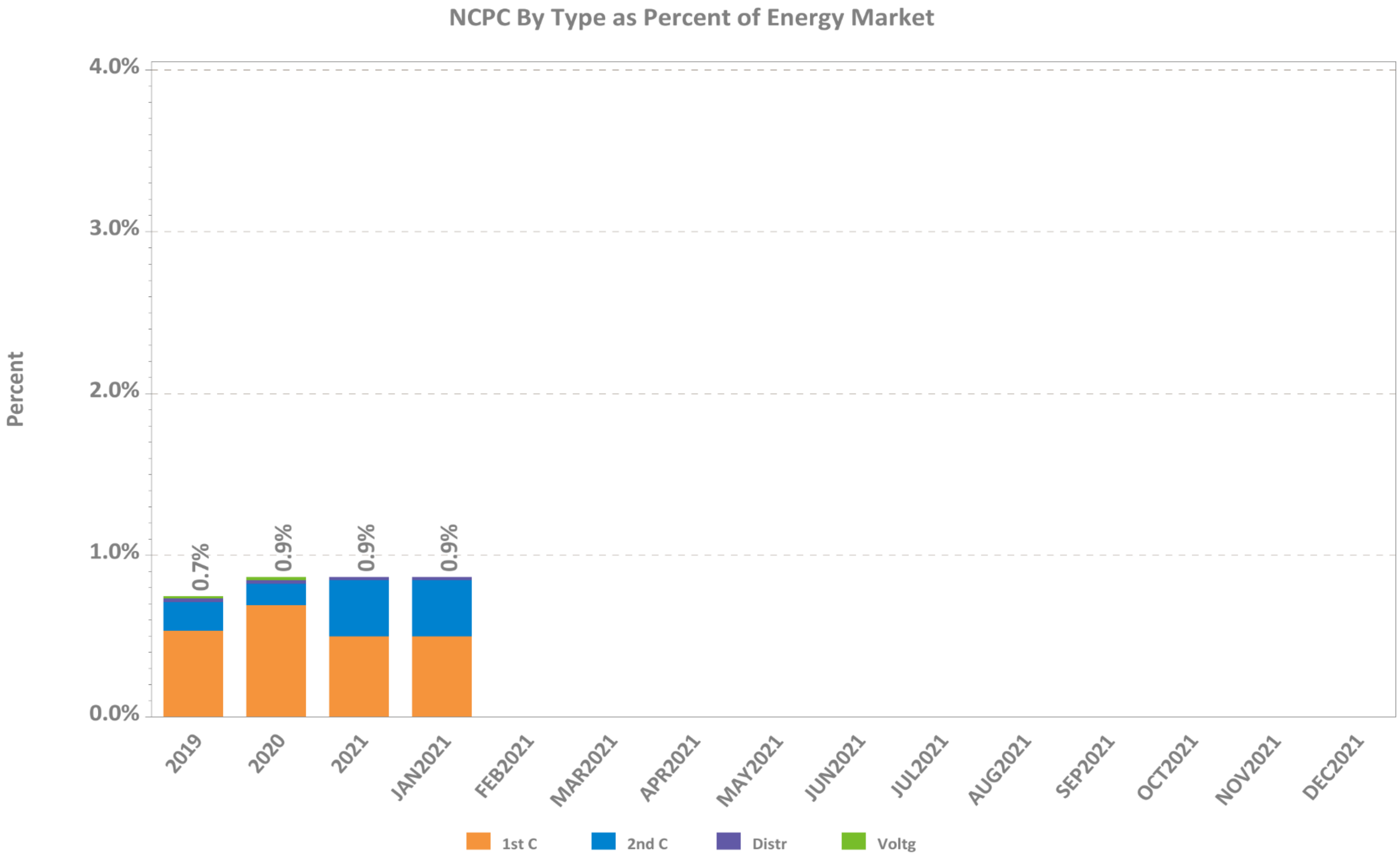
NCPC Charges for Voltage Support and High Voltage Control



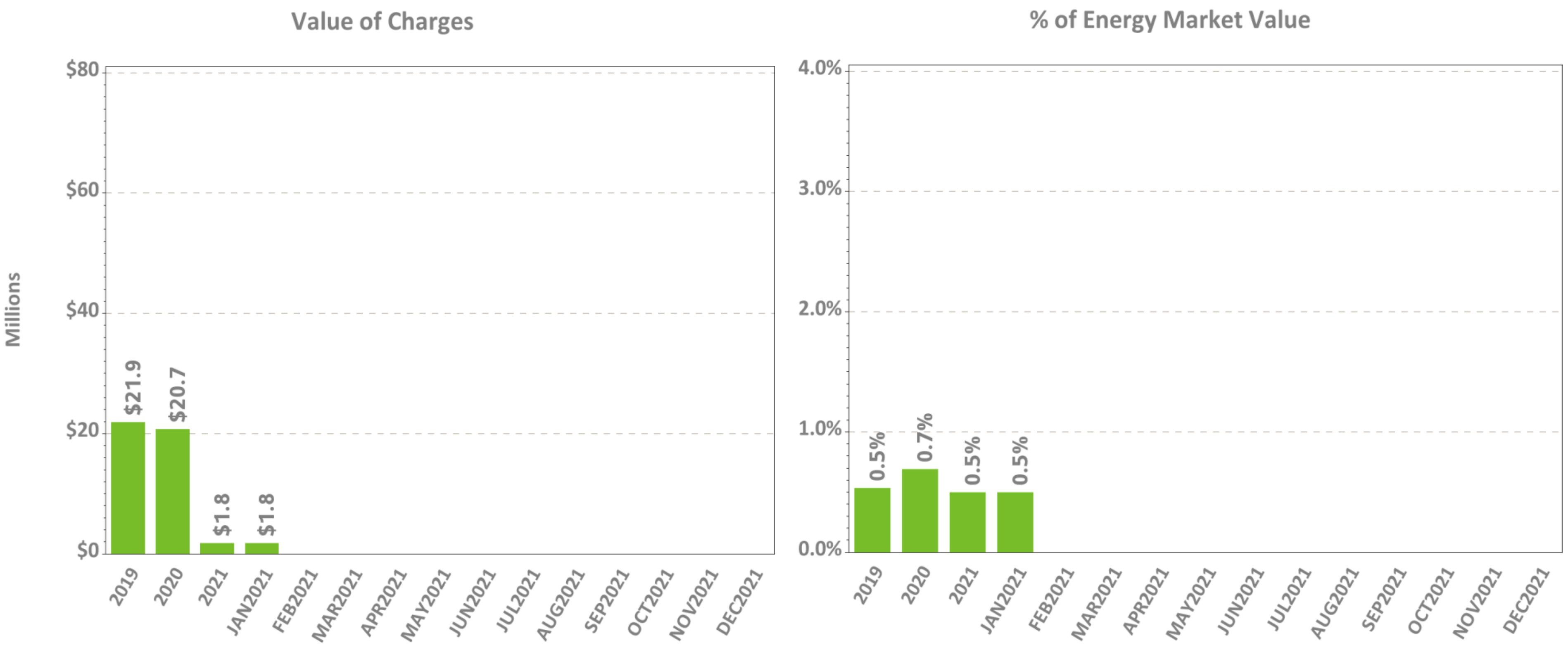
NCPC Charges by Type



NCPC Charges as Percent of Energy Market

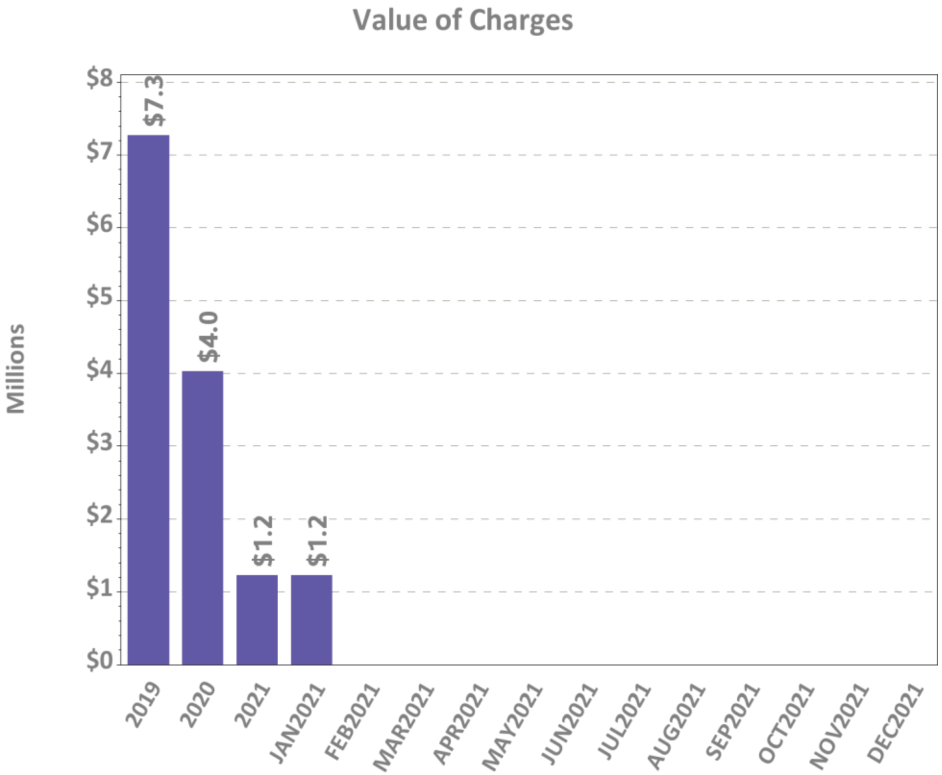


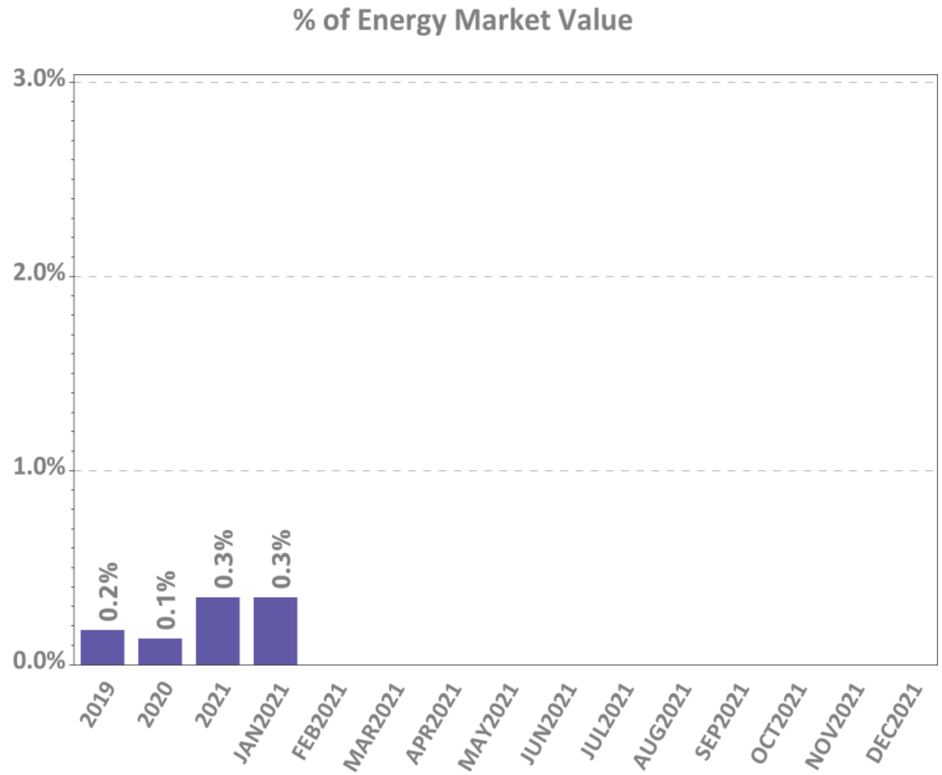
First Contingency NCPC Charges



Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

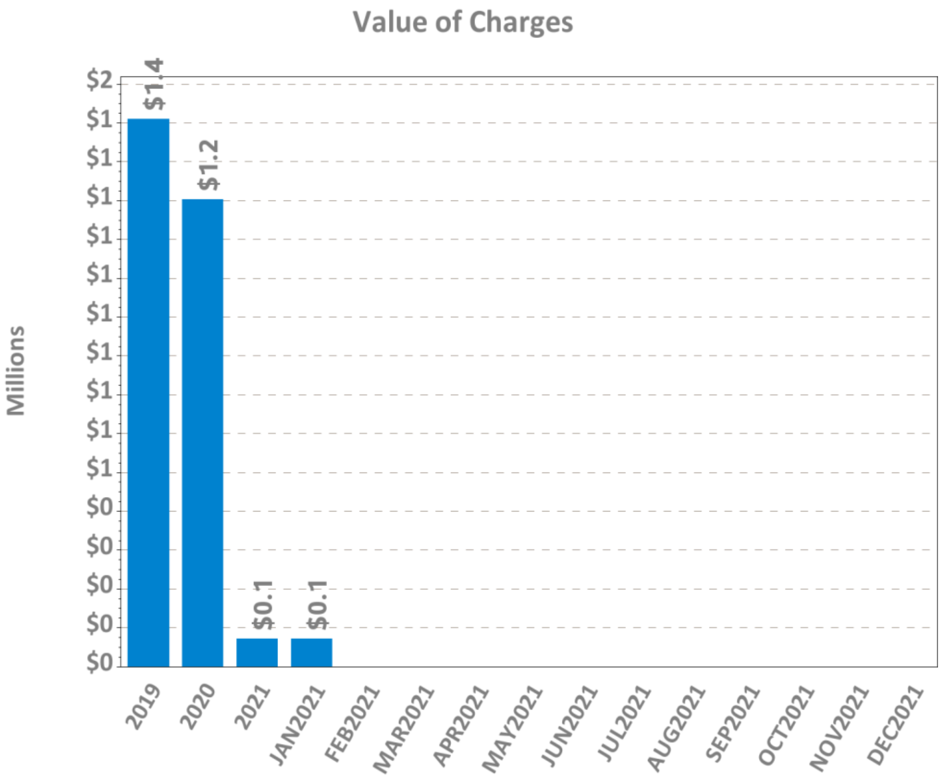
Second Contingency NCPC Charges

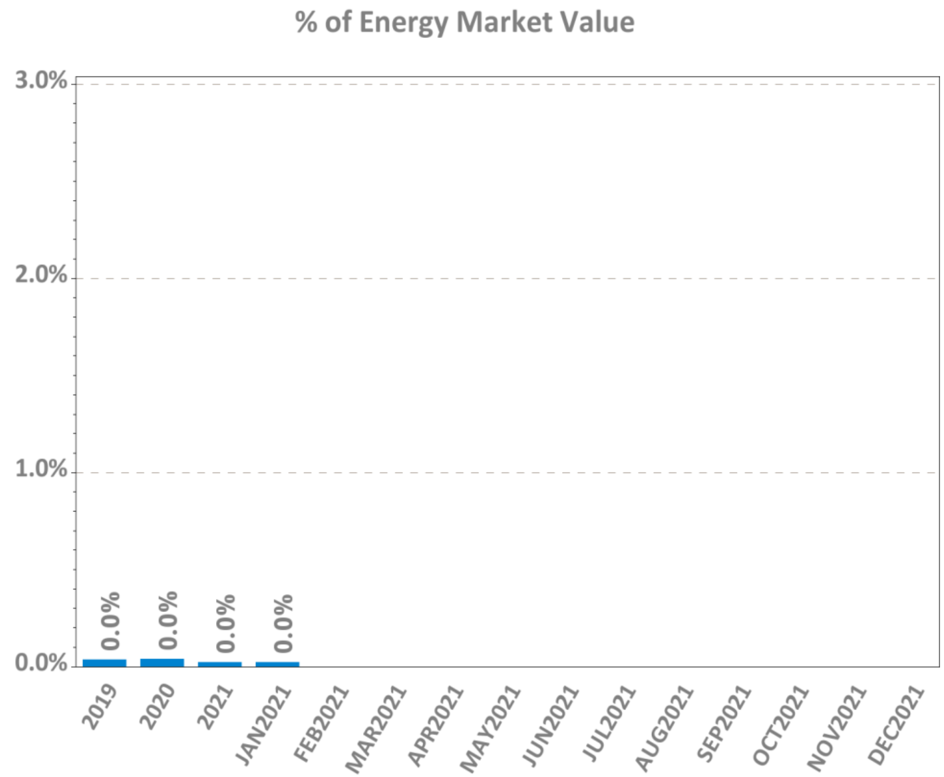




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

DA vs. RT Pricing

The following slides outline:

- This month vs. prior year's average LMPs and fuel costs
- Reserve Market results
- DA cleared load vs. RT load
- Zonal and total incs and decs
- Self-schedules
- DA vs. RT net interchange

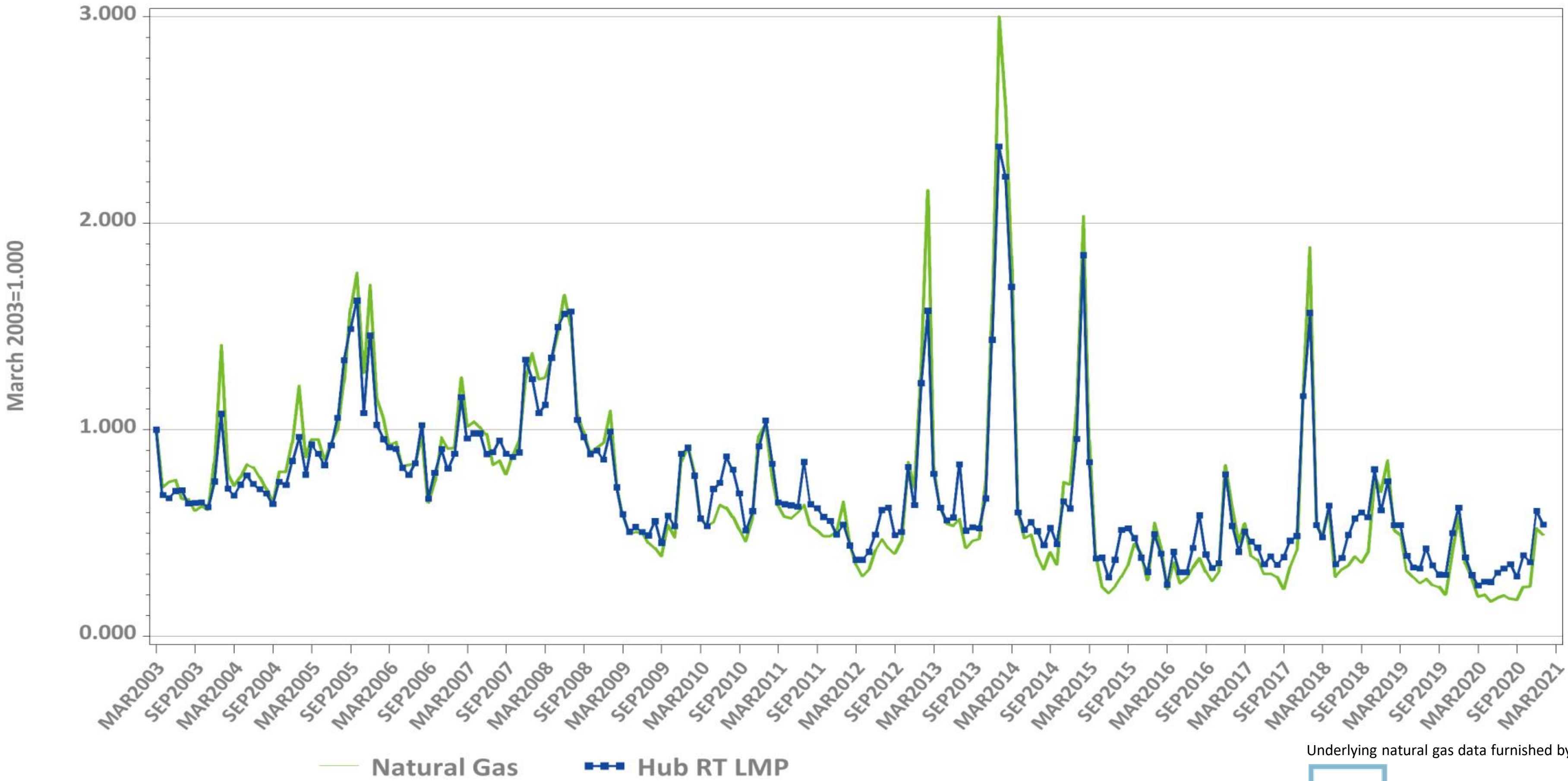
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2019	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$31.54	$30.72	$30.76	$31.20	$30.67	$31.19	$31.51	$31.24	$31.22
Real-Time	$30.92	$30.26	$30.12	$30.70	$30.05	$30.61	$30.80	$30.68	$30.67
RT Delta %	-2.0%	-1.5%	-2.1%	-1.6%	-2.0%	-1.9%	-2.2%	-1.8%	-1.8%
Year 2020	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$24.32	$23.20	$24.06	$24.28	$23.49	$24.15	$24.43	$23.98	$24.02
Real-Time	$24.26	$23.46	$24.05	$24.24	$23.58	$24.12	$24.38	$24.00	$24.04
RT Delta %	-0.3%	1.1%	0.0%	-0.1%	0.4%	-0.2%	-0.2%	0.1%	0.1%

January-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$24.32	$23.20	$24.06	$24.28	$23.49	$24.15	$24.43	$23.98	$24.02
Real-Time	$24.26	$23.46	$24.05	$24.24	$23.58	$24.12	$24.38	$24.00	$24.04
RT Delta %	-0.3%	1.1%	0.0%	-0.1%	0.4%	-0.2%	-0.2%	0.1%	0.1%
January-21	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$37.02	$35.44	$36.87	$37.06	$36.11	$36.75	$37.03	$36.80	$36.78
Real-Time	$37.39	$36.15	$37.10	$37.41	$36.51	$37.12	$37.32	$37.12	$37.16
RT Delta %	1.0%	2.0%	0.6%	0.9%	1.1%	1.0%	0.8%	0.9%	1.0%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	52.2%	52.7%	53.3%	52.7%	53.7%	52.1%	51.6%	53.5%	53.2%
Yr over Yr RT	54.1%	54.1%	54.3%	54.3%	54.9%	53.9%	53.0%	54.6%	54.6%

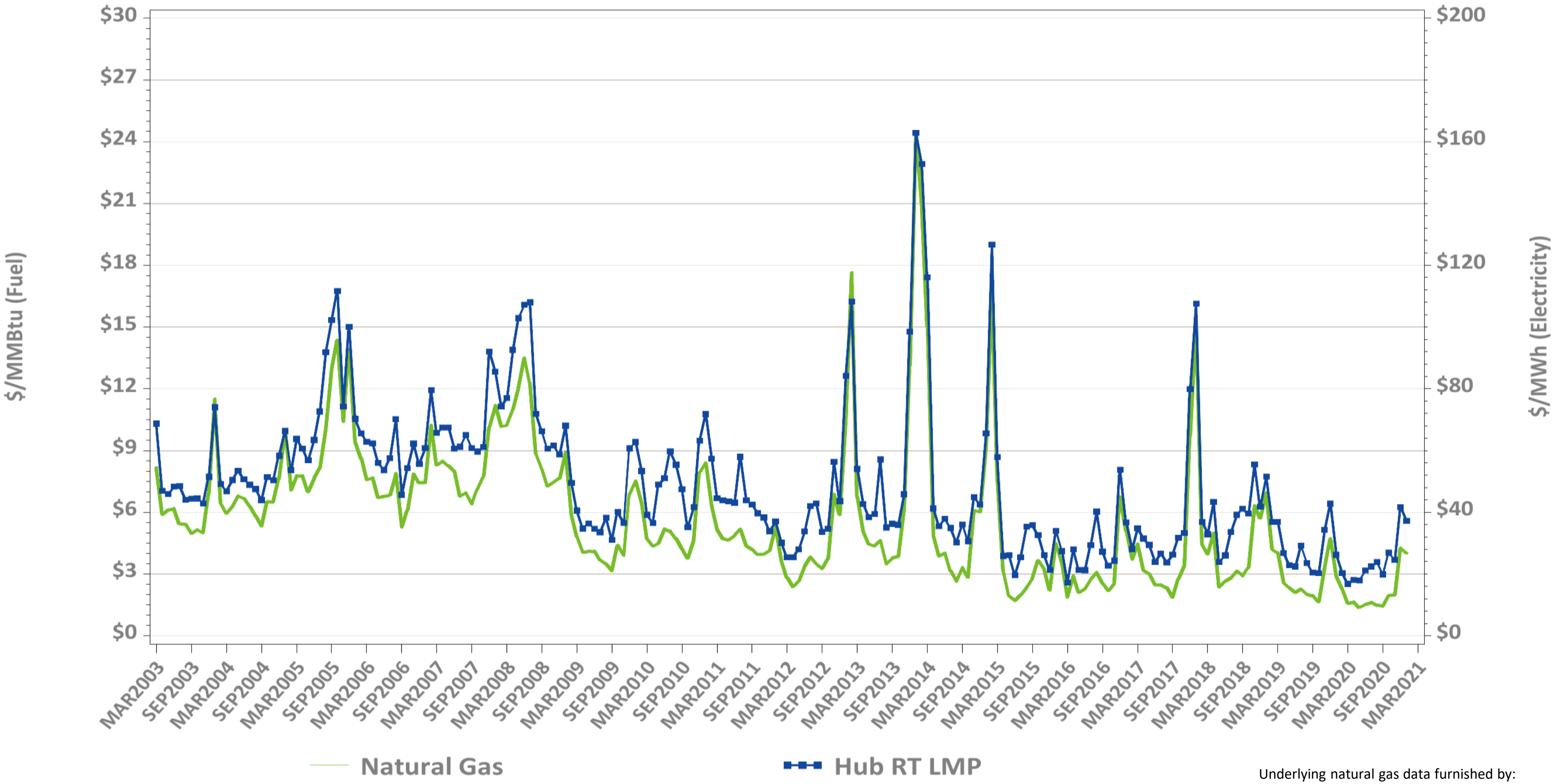
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

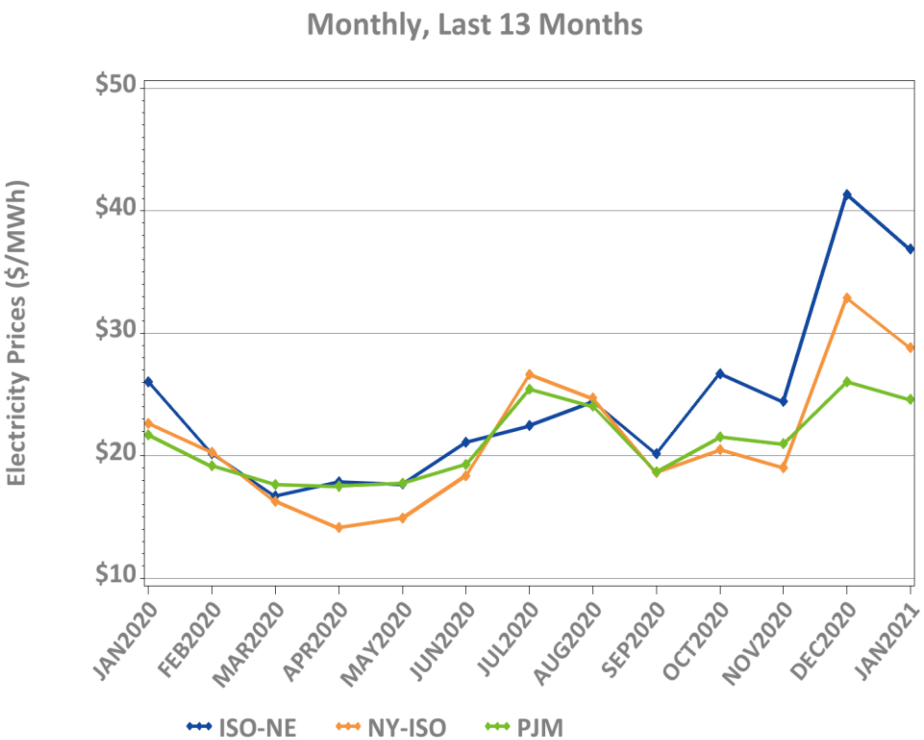
Monthly Average Fuel Price and RT Hub LMP



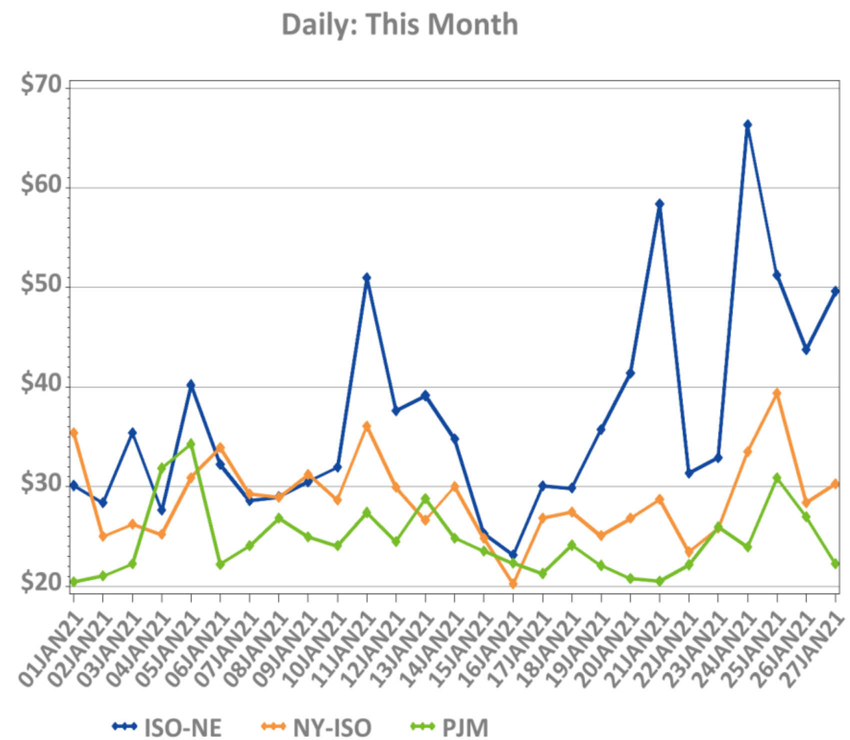
Underlying natural gas data furnished by:

ICE Global markets in clear view

New England, NY, and PJM Hourly Average Real Time Prices by Month

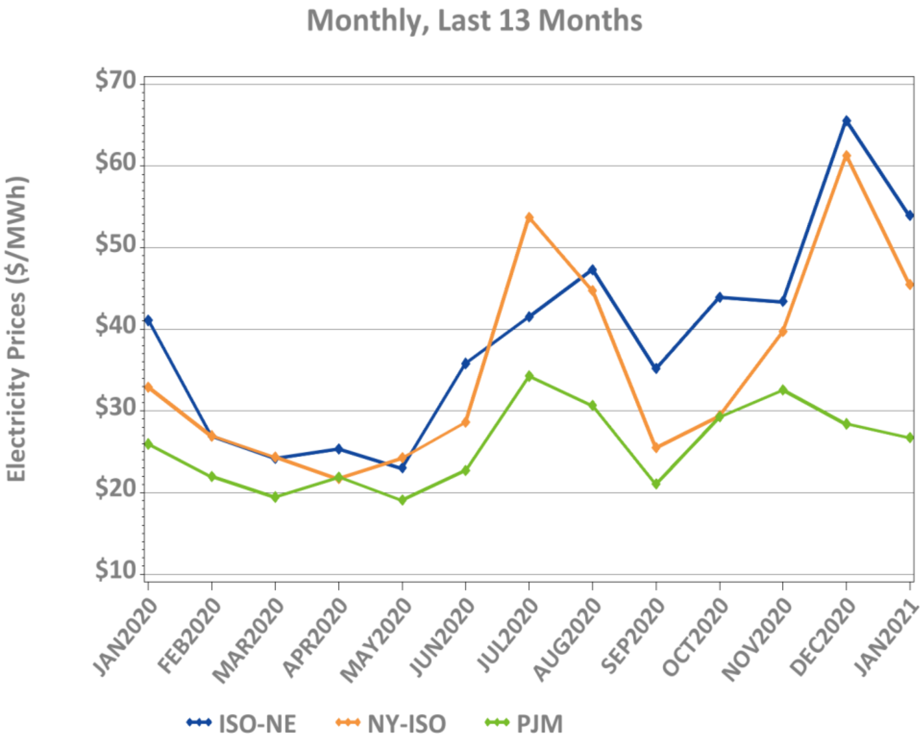


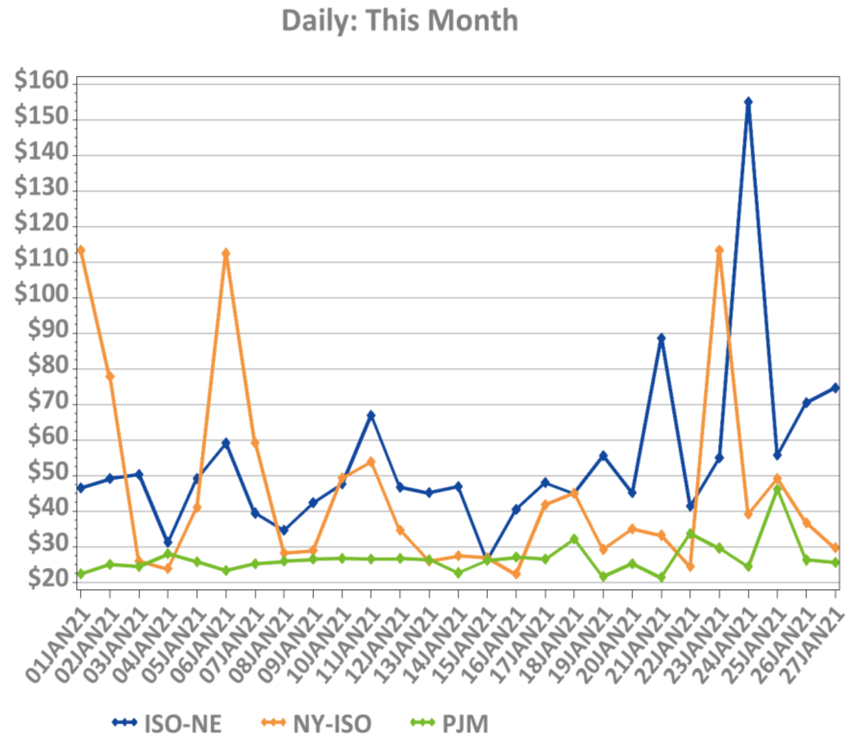
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

New England, NY, and PJM Average Peak Hour Real Time Prices





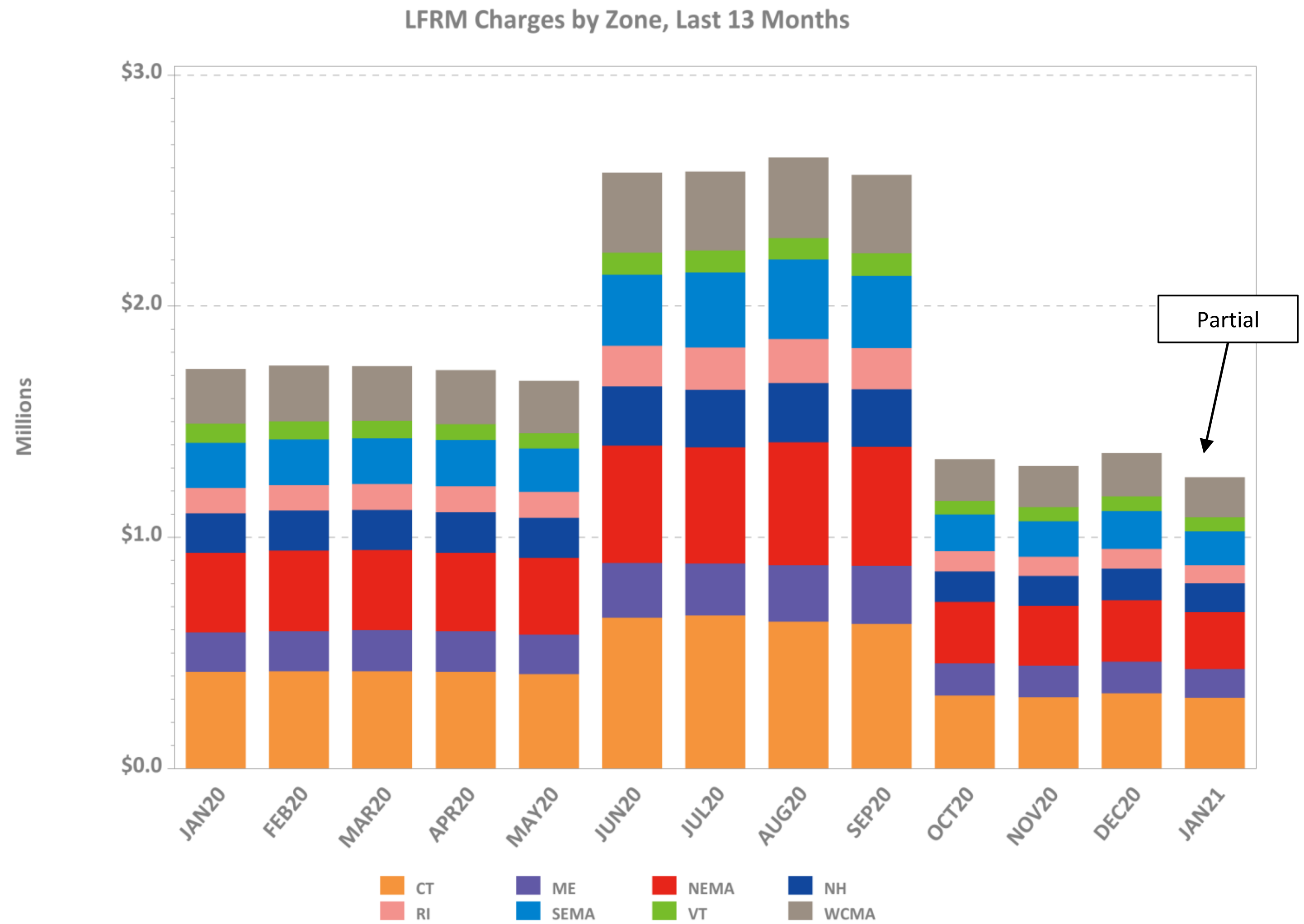
***Forecasted New England daily peak hours reflected**

Reserve Market Results – January 2021

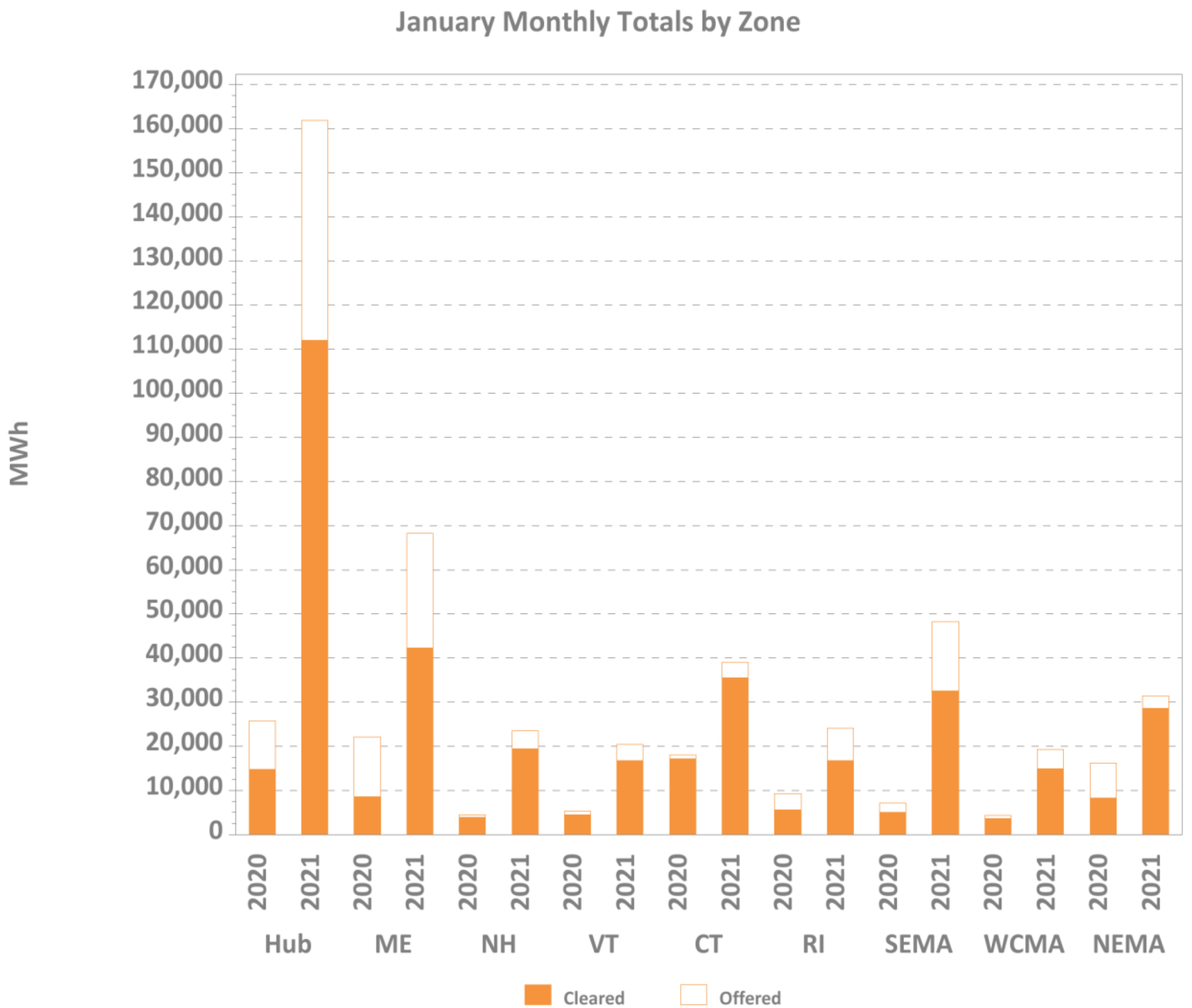
- Maximum potential Forward Reserve Market payments of $1.3M were reduced by credit reductions of $9K, failure-to-reserve penalties of $13K and no failure-to-activate penalties, resulting in a net payout of $1.3M or 98% of maximum
  - Rest of System: $0.98M/1M (99%)
  - Southwest Connecticut: $0.04M/0.04M (100%)
  - Connecticut: $0.24M/0.25M (97%)
  - $795K total
- $500K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $500K in Real-Time Reserve payments
  - Rest of System: 183 hours, $330K
  - Southwest Connecticut: 183 hours, $94K
  - Connecticut: 183 hours, $22K
  - NEMA: 183 hours, $54K

Note: "Failure to reserve" results in both credit reductions and penalties in the Locational Forward Reserve Market. While this summary reports performance by location, there were no locational requirements in effect for the current Forward Reserve auction period.

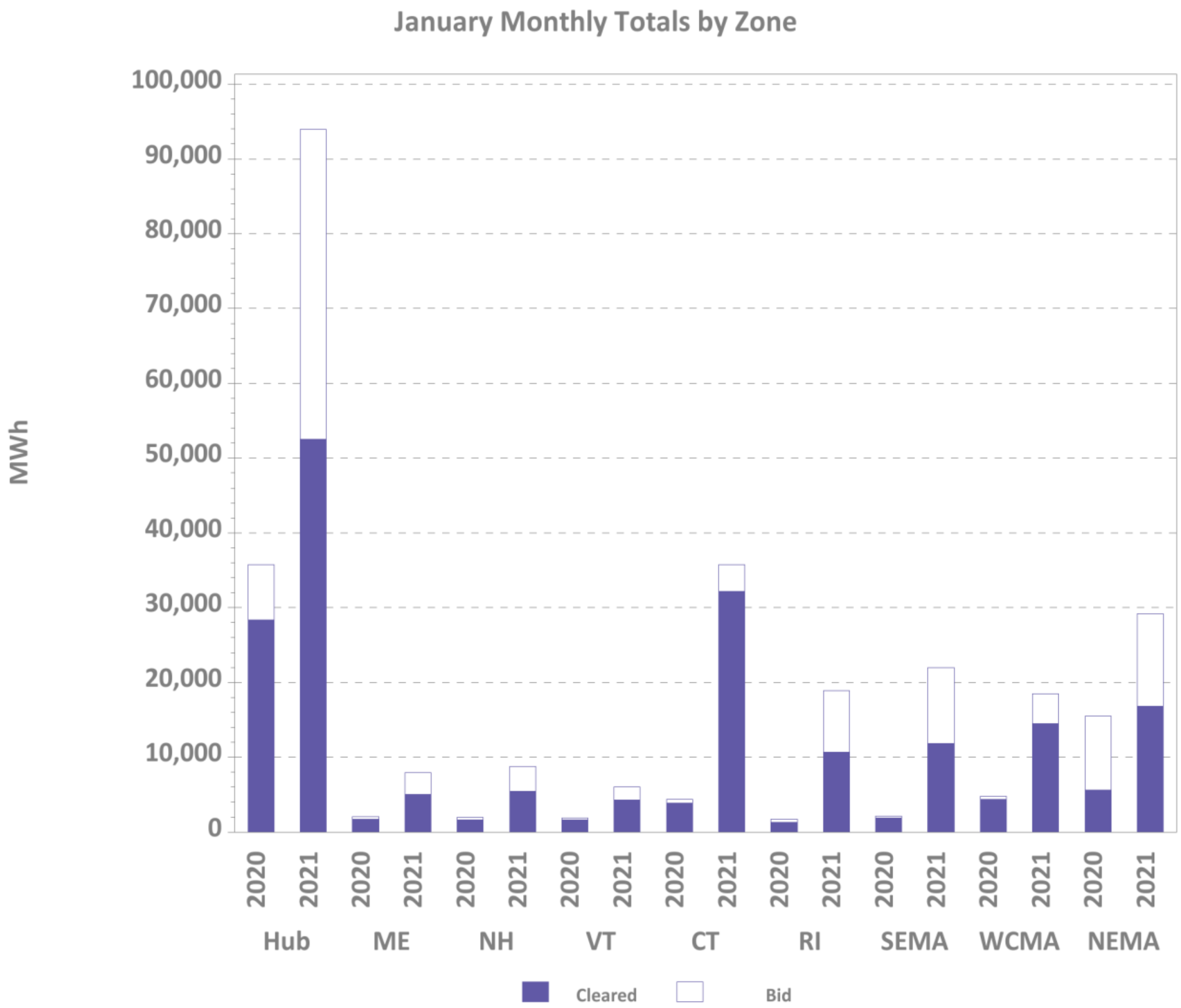
LFRM Charges to Load by Load Zone ($)



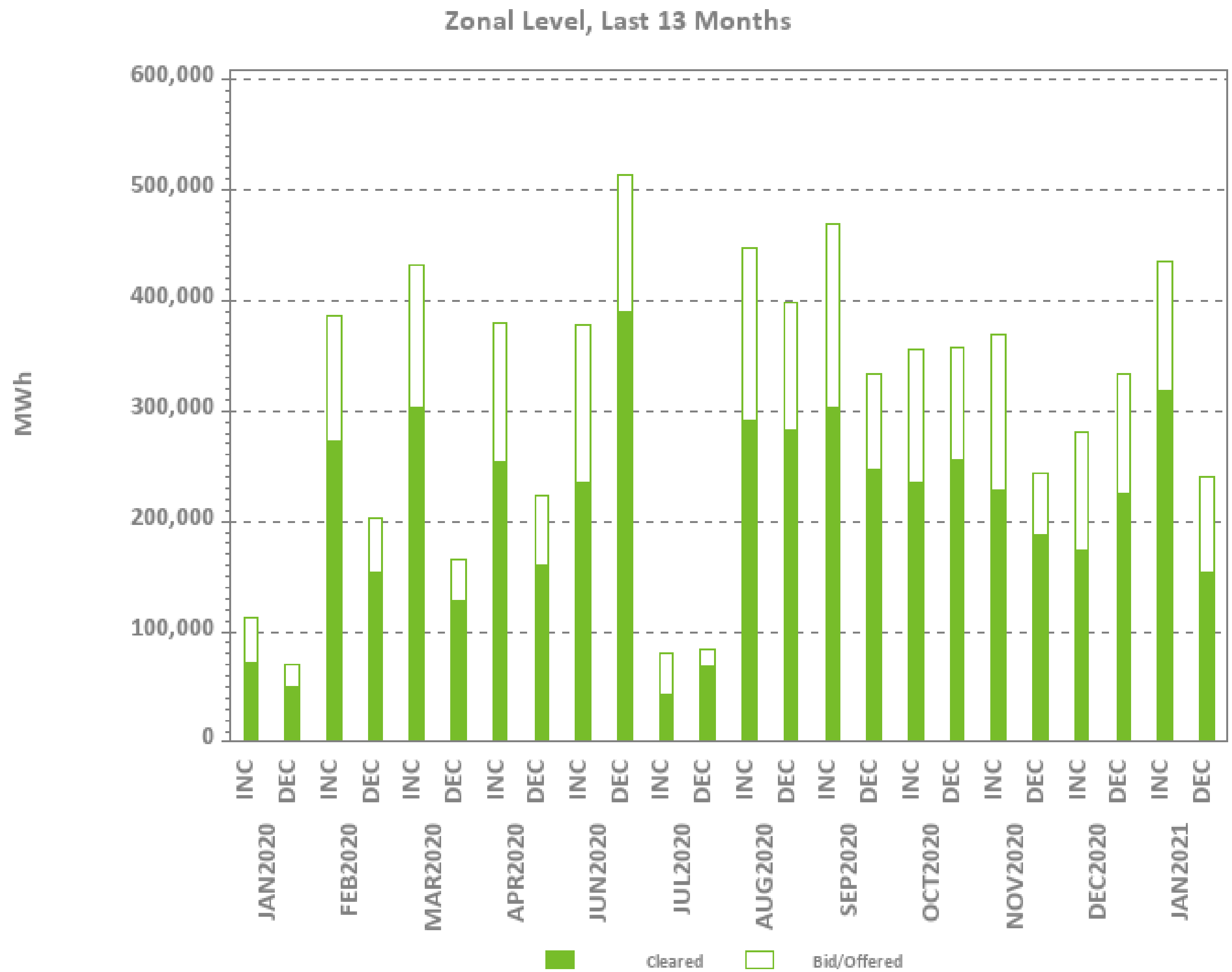
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

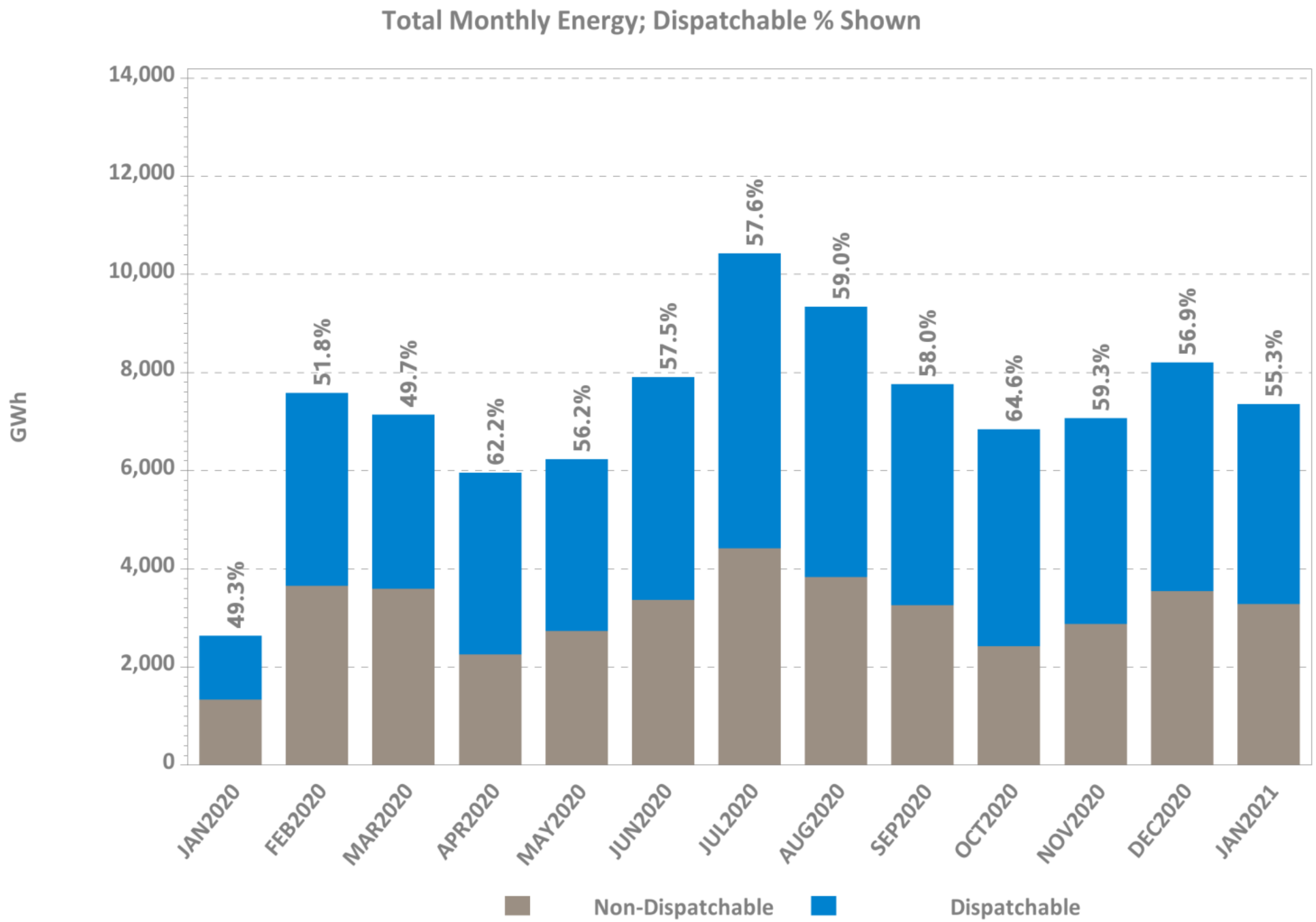


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



* **Dispatchable MWh here are defined to be all generation output that is not self-committed ('must run') by the customer.**

REGIONAL SYSTEM PLAN (RSP)

Regional System Plan (RSP)

- 2021 is an RSP publication year (RSP21)
- Goal is to improve value and usability of the RSP report
  - The ISO received valuable stakeholder feedback as part of the spring 2020 survey
- Target is for RSP21 to be 50% shorter in length than RSP19
  - Static information found in the RSP to be moved to the ISO-NE website
  - Dynamic information found in the RSP to be included in the report but at a high level
- ISO will improve the reporting of information related to the New England regional system planning process with:
  - Better utilization of the ISO-NE website
  - More frequent reporting
  - Tables/graphics in a format that is easily downloadable
- RSP21 Public Meeting date is set for October 6
  - Venue and format have yet to be decided

Planning Advisory Committee (PAC)

- February 17 PAC Meeting Agenda Topics*
  - Lower Maine 2030 Needs Assessment Results
  - Upper Maine 2029 Preliminary Preferred Solution
  - New Hampshire 2029 Preliminary Preferred Solution for Western & Central NH
  - Looking Forward: Dynamic Reactive Device Technologies
  - Boston 2028 RFP and Order 1000 Lessons Learned Update
  - 2020 Economic Study Sensitivities Presentation
  - Stochastic Time Series Modeling for ISO-NE: Results and Next Steps
  - Ludlow BPS and Asset Condition Project
  - Eddy (NH) Control House Replacement
  - Branford (CT) Bus Replacement

* Agenda topics are subject to change. Visit https://www.iso-ne.com/committees/planning/planning-advisory for the latest PAC agendas.

Transmission Planning for the Clean-Energy Transition

- On 9/24/20 the ISO initiated discussions with the PAC about proposed refinements to study assumptions that better reflect long-term trends, such as increased amounts of distributed-energy resources (primarily solar PV), offshore wind generation, and battery energy storage
- A follow-up presentation at the 11/19/20 PAC meeting outlined a proposal for a pilot study, with the following goals:
  - Explore transmission reliability concerns that may result from various system conditions possible by 2030
  - Quantify trade-offs necessary between transmission system reliability/flexibility and transmission investment cost
  - Inform future discussions on transmission planning study assumptions
- An overview of the system conditions and dispatch assumptions for the pilot study was discussed at the 12/16/20 and 1/21/21 PAC meetings
- Study work is in progress, with results expected in Q2

Economic Studies

- 2020 Economic Study Request
  - Study proponent is National Grid
  - Preliminary production cost results were shared at the November 19, 2020 PAC meeting, and additional scenarios/sensitivities will be presented in February
  - Ancillary Services is ongoing
  - The goal is to complete all study work by Q2 2021
    - Study results expected to influence the NEPOOL Future Grid study
- 2021 Economic Study requests are due April 1
  - Submitted in accordance with Attachment K, Section 4.1(b) of the Tariff
  - Memo to PAC to be issued in mid-February outlining the process and related deadlines

Future Grid Reliability Study (FGRS)

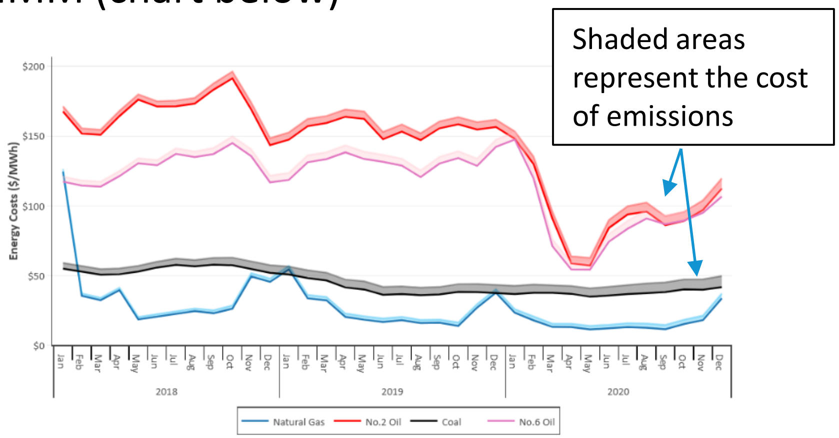
- Phase 1
  - Studies include: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - On December 29, 2020, NEPOOL formally asked ISO-NE if the ISO had the capability to undertake the study work described as “Phase 1”
    - The ISO agreed to perform this study work at the joint MC/RC meeting held on January 19
  - Framework Document and supporting assumptions table have been developed by stakeholders that describe the 24 study scenarios and objectives
  - The ISO is working on model development by reviewing assumptions with NEPOOL study proponents
  - Production Cost Simulations likely to commence in the April timeframe
  - Phase 1 work is likely to be classified as the 2021 Economic Study
- Phase 2
  - Studies include: Revenue Sufficiency Analysis and Transmission Security
  - Studies likely to be performed by a consultant
  - Embellishment of the study scope continues at the MC/RC

Environmental Matters – 2020 Emissions

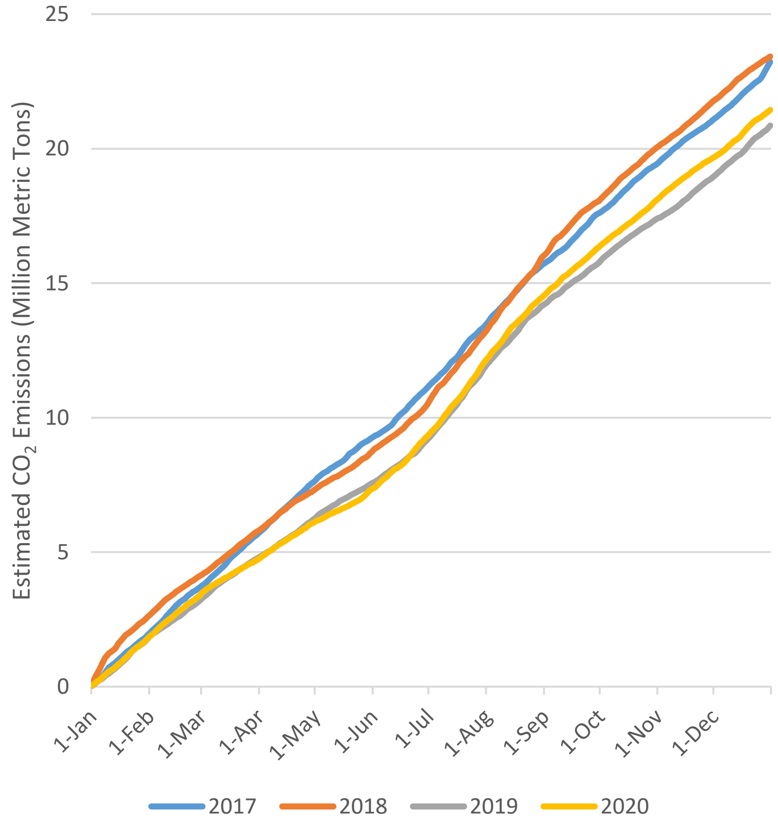
Increased Over 2019 Despite Pandemic

2020 Emissions Below Cap, January 2021 Emissions Typical

- 2020 CO_2 system emissions estimated at 21.44 million metric tons (MMT)
- 2019 CO_2 system emissions were 20.85 MMT
- Environmental compliance costs (mainly CO_2 allowance costs) have minor impact on economic merit order according to IMM (chart below)



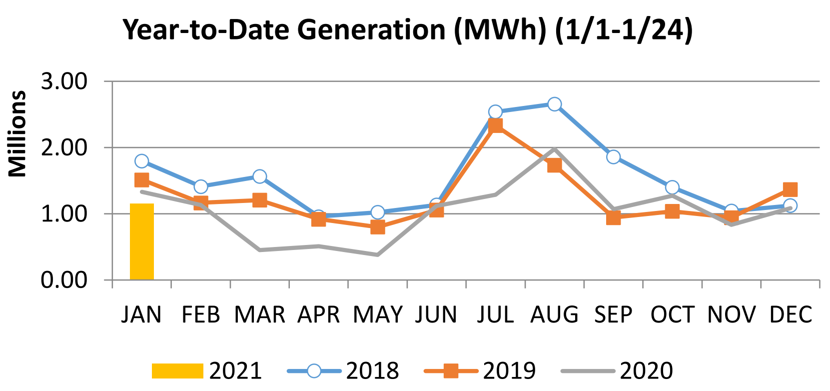
Cumulative Daily Estimated System CO_2 Emissions (MMT)



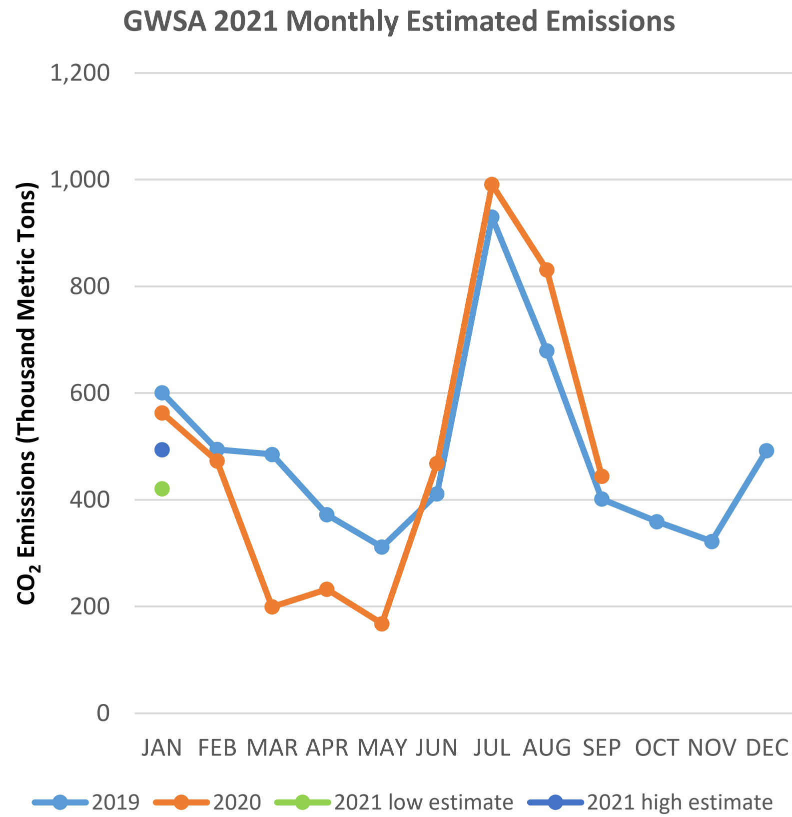
Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2020 CO_2 Emissions Below Cap January 2021 Emissions Typical

- 2020 CO_2 emissions estimated between 5.1 – 6.1 MMT
  - 2020 cap was 8.5 MMT
- January 2021 emissions estimated between 415,000 and 487,000 metric tons, similar to past Januarys
  - 2021 cap is 8.23 MMT



2019-2021 Estimated Monthly Emissions (Thousand Metric tons)



GWSA - Global Warming Solutions Act

RSP Project Stage Descriptions

Stage	Description
1	Planning and Preparation of Project Configuration
2	Pre-construction (e.g., material ordering, project scheduling)
3	Construction in Progress
4	In Service

Note: The listings in this section focus on major transmission line construction and rebuilding.

Southwest Connecticut (SWCT) Projects

Status as of 1/26/2021

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Add a 25.2 MVAR capacitor bank at the Oxford substation	Mar-16	4
Add 2 x 25 MVAR capacitor banks at the Ansonia substation	Oct-18	4
Close the normally open 115 kV 2T circuit breaker at Baldwin substation	Sep-17	4
Reconductor the 115 kV line between Bunker Hill and Baldwin Junction (1575)	Dec-16	4
Expand Pootatuck (formerly known as Shelton) substation to 4-breaker ring bus configuration and add a 30 MVAR capacitor bank at Pootatuck	Jul-18	4
Loop the 1570 line in and out the Pootatuck substation	Jul-18	4
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	4

Southwest Connecticut Projects, cont.

Status as of 1/26/2021

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	4
Add a new 115 kV line from Plumtree to Brookfield Junction	Jun-18	4
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Nov-20	4
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Apr-17	4
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	May-18	4
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	May-18	4
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Jun-18	4
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	May-18	4

Southwest Connecticut Projects, cont.

Status as of 1/26/2021

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Relocate the existing 37.8 MVAR capacitor bank from 115 kV B bus to 115 kV A bus at the Plumtree substation	Apr-17	4
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	May-16	4
Terminal equipment upgrade at the Newtown substation (1876)	Dec-15	4
Rebuild the 115 kV line from Wilton to Norwalk (1682) and upgrade Wilton substation terminal equipment	Jun-17	4
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Dec-19	4
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-19	4

Southwest Connecticut Projects, cont.

Status as of 1/26/2021

Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Add 2 x 20 MVAR capacitor banks at the Hawthorne substation	Mar-16	4
Upgrade the 115 kV bus at the Baird substation	Mar-18	4
Upgrade the 115 kV bus system and 11 disconnect switches at the Pequonnock substation	Dec-14	4
Add a 345 kV breaker in series with the existing 11T breaker at the East Devon substation	Dec-15	4
Rebuild the 115 kV lines from Baird to Congress (8809A / 8909B)	Dec-18	4
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Feb-21	3

Southwest Connecticut Projects, cont.

Status as of 1/26/2021

Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Remove the Sackett phase shifter	Mar-17	4
Install a 7.5 ohm series reactor on 1610 line at the Mix Avenue substation	Dec-16	4
Add 2 x 20 MVAR capacitor banks at the Mix Avenue substation	Dec-16	4
Upgrade the 1630 line relay at North Haven and Wallingford 1630 terminal equipment	Jan-17	4
Rebuild the 115 kV lines from Devon Tie to Milvon (88005A / 89005B)	Nov-16	4
Replace two 115 kV circuit breakers at Mill River	Dec-14	4

Greater Boston Projects

Status as of 1/26/2021

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn*	May-22	3*
Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-19	4

* Substation portion of the project is a Present Stage status 4

Greater Boston Projects, cont.

Status as of 1/26/2021

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Separate X-24 and E-157W DCT	Dec-18	4
Separate Q-169 and F-158N DCT	Dec-15	4
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
Install a new 115 kV line from Sudbury to Hudson	Dec-23	2

Greater Boston Projects, cont.

Status as of 1/26/2021

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
Install a 345 kV breaker in series with breaker 104 at Woburn	May-17	4
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
Install a 115 kV breaker on the East bus at K Street	Jun-16	4
Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	May-21	3*
Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	May-21	3

*Mystic to Chelsea line portion of the project is a present stage 4 as of October 2020.

Greater Boston Projects, cont.

Status as of 1/26/2021

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	May-22	3
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	May-19	4
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 1/26/2021

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	Dec-17	4
Install a 200 MVAR STATCOM at Coopers Mills	Nov-18	4
Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	4
Install a 345 kV 160 MVAR shunt reactor at K Street	Dec-19	4
Install a 115 kV breaker in series with the 5 breaker at Framingham	Apr-17	4
Install a 115 kV breaker in series with the 29 breaker at K Street	Apr-17	4

SEMA/RI Reliability Projects

Status as of 1/26/2021

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Upgrade	Expected/ Actual In-Service	Present Stage
Construct a new 115 kV GIS switching station (Grand Army) which includes remote terminal station work at Brayton Point and Somerset substations, and the looping in of the E-183E, F-184, X3, and W4 lines	Oct-20	4
Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Oct-20	4
Install upgrades at Brayton Point substation which include a new 115 kV breaker, new 345/115 kV transformer, and upgrades to E183E, F184 station equipment	Oct-20	4
Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	4
Separate the X3/W4 DCT and reconductor the X3 and W4 lines between Somerset and Grand Army substations; reconfigure Y2 and Z1 lines	Nov-19	4

SEMA/RI Reliability Projects, cont.

Status as of 1/26/2021

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Upgrade	Expected/ Actual In-Service	Present Stage
Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Dec-21	3
Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	May-25	2
Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Jun-23	2
Extend the Line 114 from the Dartmouth town line (Eversource-NGRID border) to Bell Rock substation	Dec-23	2
Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

*Cancelled per ISO-NE PAC presentation on August 27, 2020

SEMA/RI Reliability Projects, cont.

Status as of 1/26/2021

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Upgrade	Expected/ Actual In-Service	Present Stage
Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	Dec-23	1
Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	3
Retire the Barnstable SPS	Dec-21	3
Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-23	1
Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-22	1
Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-23	1

SEMA/RI Reliability Projects, cont.

Status as of 1/26/2021

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Upgrade	Expected/ Actual In-Service	Present Stage
Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	3
Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Jan-23	1
Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Aug-20	4

* Does not include the reconductoring work over the Cape Cod canal

** Cancelled per ISO-NE PAC presentation on August 27, 2020

SEMA/RI Reliability Projects, cont.

Status as of 1/26/2021

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Upgrade	Expected/ Actual In-Service	Present Stage
Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
Reconductor the J16S line	Jun-22	2
Replace the Kent County 345/115 kV transformer	Mar-22	2
West Medway 345 kV circuit breaker upgrades	Dec-21	3
Medway 115 kV circuit breaker replacements	Nov-20	4

Eastern CT Reliability Projects

Status as of 1/26/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

Upgrade	Expected/ Actual In-Service	Present Stage
Reconductor the L190-4 and L190-5 line sections	Dec-26	1
Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Mar-23	2
Upgrade Card 115 kV to BPS standards	Mar-23	2
Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	2
Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	1
Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Dec-21	1

Eastern CT Reliability Projects, cont.

Status as of 1/26/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

Upgrade	Expected/ Actual In-Service	Present Stage
Re-terminate the 100 Line at Montville station and associated work. Energize the 100 Line at 115 kV	Dec-23	1
Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Dec-22	1
Add one 115 kV circuit breaker and re-terminate the 400-1 line section into Tunnel substation. Energize 400 Line at 115 kV	Dec-23	1
Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Dec-21	3
Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Dec-21	1
Install a 25.2 MVAR 115 kV capacitor and one capacitor breaker at Killingly	Mar-22	2

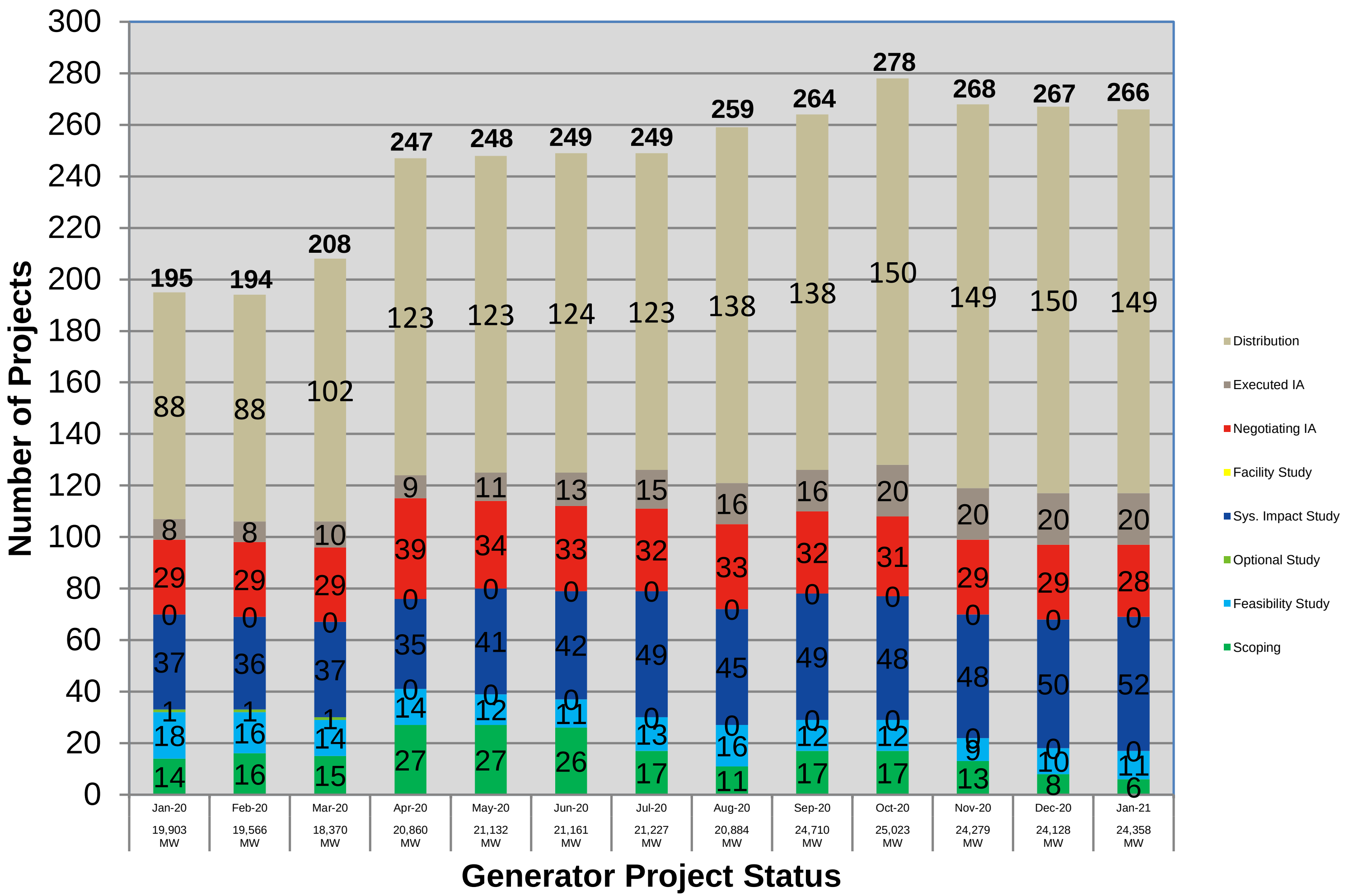
Eastern CT Reliability Projects, cont.

Status as of 1/26/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

Upgrade	Expected/ Actual In-Service	Present Stage
Install one 345 kV series breaker with the Montville 1T	June-22	2
Install a 50 MVAR synchronous condenser with two 115 kV breakers at Shunock	Dec-24	1
Install a 1% series reactor with bypass switch at Mystic, CT on the 1465 Line	Dec-22	1
Convert the 400-2 Line Section to 115 kV (Border Bus to Buddington), convert Buddington to 115 kV	Dec-23	1

Status of Tariff Studies



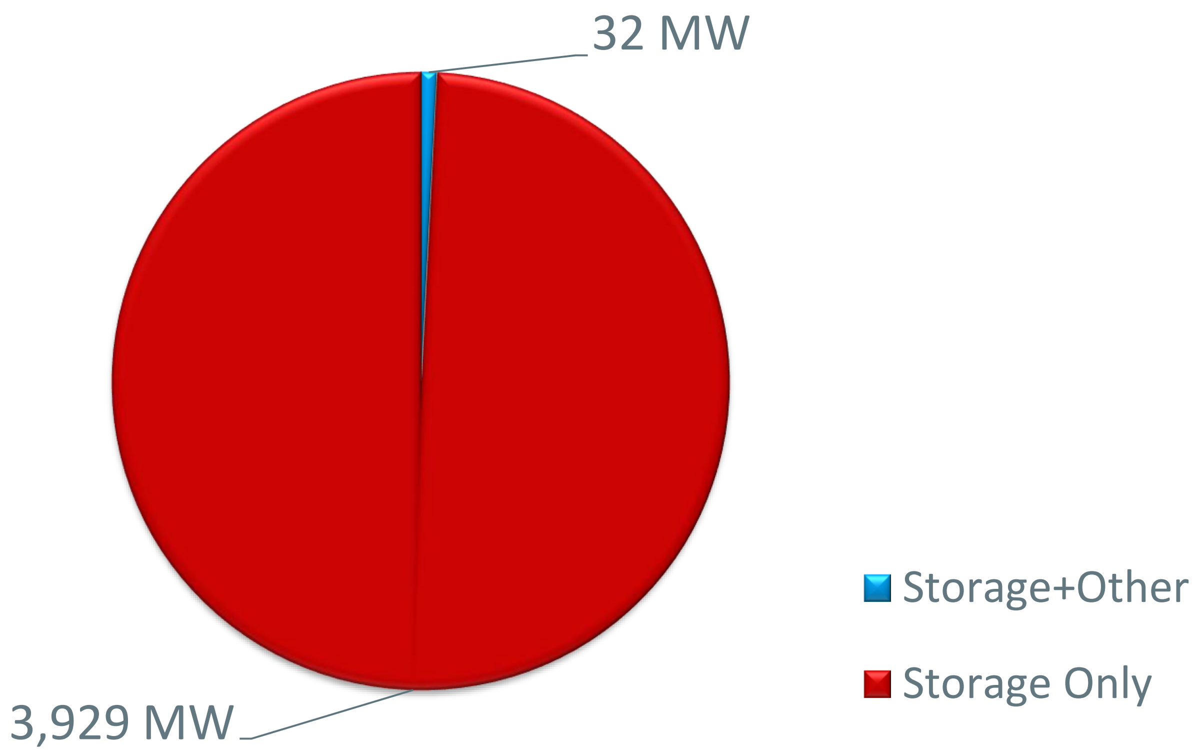
Note: January 2021 is based on partial data.

As of January 2021, there are 0 ETU's in Scoping, 0 in FS, 3 in SIS, 0 in OIS, 0 in FAC, 0 Negotiating IA, and 2 with Executed IA.

https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of January 26, 2021)

Storage Projects are proposed as stand-alone storage or as co-located with wind or solar projects



OPERABLE CAPACITY ANALYSIS

Winter 2021 Analysis

Winter 2021 Operable Capacity Analysis

50/50 Load Forecast (Reference)	February - 2021[2] CSO (MW)	February - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,435	33,677
Active Demand Capacity Resource (+) [5]	427	400
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,142	1,142
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	684	945
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	3,100	3,100
Generation at Risk Due to Gas Supply (-) [3]	2,335	2,666
Net Capacity (NET OPCAP SUPPLY MW)	25,904	28,527
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,622	19,622
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,927	21,927
Operable Capacity Margin	3,977	6,600

[1]Operable Capacity is based on data as of **January 26, 2021** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **January 26, 2021.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **February 13, 2021.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW).

[4] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Winter 2021 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	February - 2021[2] CSO (MW)	February - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,435	33,677
Active Demand Capacity Resource (+) [5]	427	400
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,142	1,142
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	684	945
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	3,100	3,100
Generation at Risk Due to Gas Supply (-) [3]	3,425	3,911
Net Capacity (NET OPCAP SUPPLY MW)	24,814	27,282
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,247	20,247
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,552	22,552
Operable Capacity Margin	2,262	4,730

[1] Operable Capacity is based on data as of **January 26, 2021** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **January 26, 2021.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **February 13, 2021.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW).

[4] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Winter 2021 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

January 29, 2021 - 50-50 FORECAST using CSO

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, August, and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]
2/6/2021	30435	427	1142	19	303	295	3100	2351	25974	19652	2305	21957	4017
2/13/2021	**30435**	**427**	**1142**	**19**	**684**	**0**	**3100**	**2335**	**25904**	**19622**	**2305**	**21927**	**3977**
2/20/2021	30435	427	1142	19	737	0	3100	1868	26318	19346	2305	21651	4667
2/27/2021	30505	505	1025	19	1193	0	2200	1557	27104	18308	2305	20613	6491
3/6/2021	30505	505	1025	19	1858	0	2200	1245	26751	17941	2305	20246	6505
3/13/2021	30505	505	1025	19	1828	250	2200	373	27403	17736	2305	20041	7362
3/20/2021	30505	505	1025	19	1692	1558	2200	0	26604	17352	2305	19657	6947
3/27/2021	30461	537	1025	19	727	299	2700	0	28316	16759	2305	19064	9252

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,125 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Winter 2021 Operable Capacity Analysis
90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

January 29, 2021 - 90-10 FORECAST using CSO

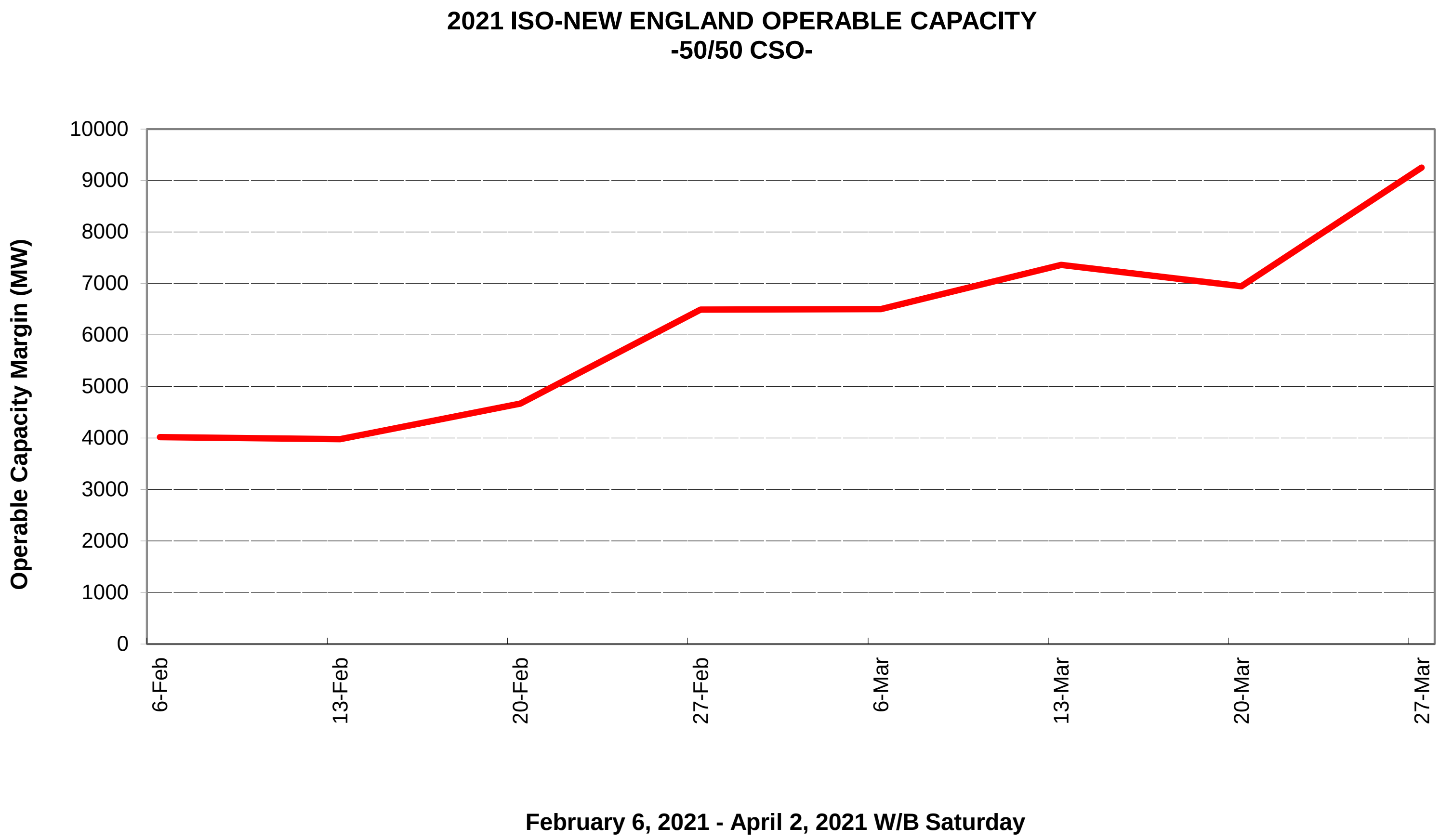
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, August, and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
2/6/2021	30435	427	1142	19	303	295	3100	3441	24884	20278	2305	22583	2301
2/13/2021	**30435**	**427**	**1142**	**19**	**684**	**0**	**3100**	**3425**	**24814**	**20247**	**2305**	**22552**	**2262**
2/20/2021	30435	427	1142	19	737	0	3100	2802	25384	19963	2305	22268	3116
2/27/2021	30505	505	1025	19	1193	0	2200	2335	26326	18897	2305	21202	5124
3/6/2021	30505	505	1025	19	1858	0	2200	2179	25817	18520	2305	20825	4992
3/13/2021	30505	505	1025	19	1828	250	2200	1307	26469	18309	2305	20614	5855
3/20/2021	30505	505	1025	19	1692	1558	2200	0	26604	17915	2305	20220	6384
3/27/2021	30461	537	1025	19	727	299	2700	324	27992	17305	2305	19610	8382

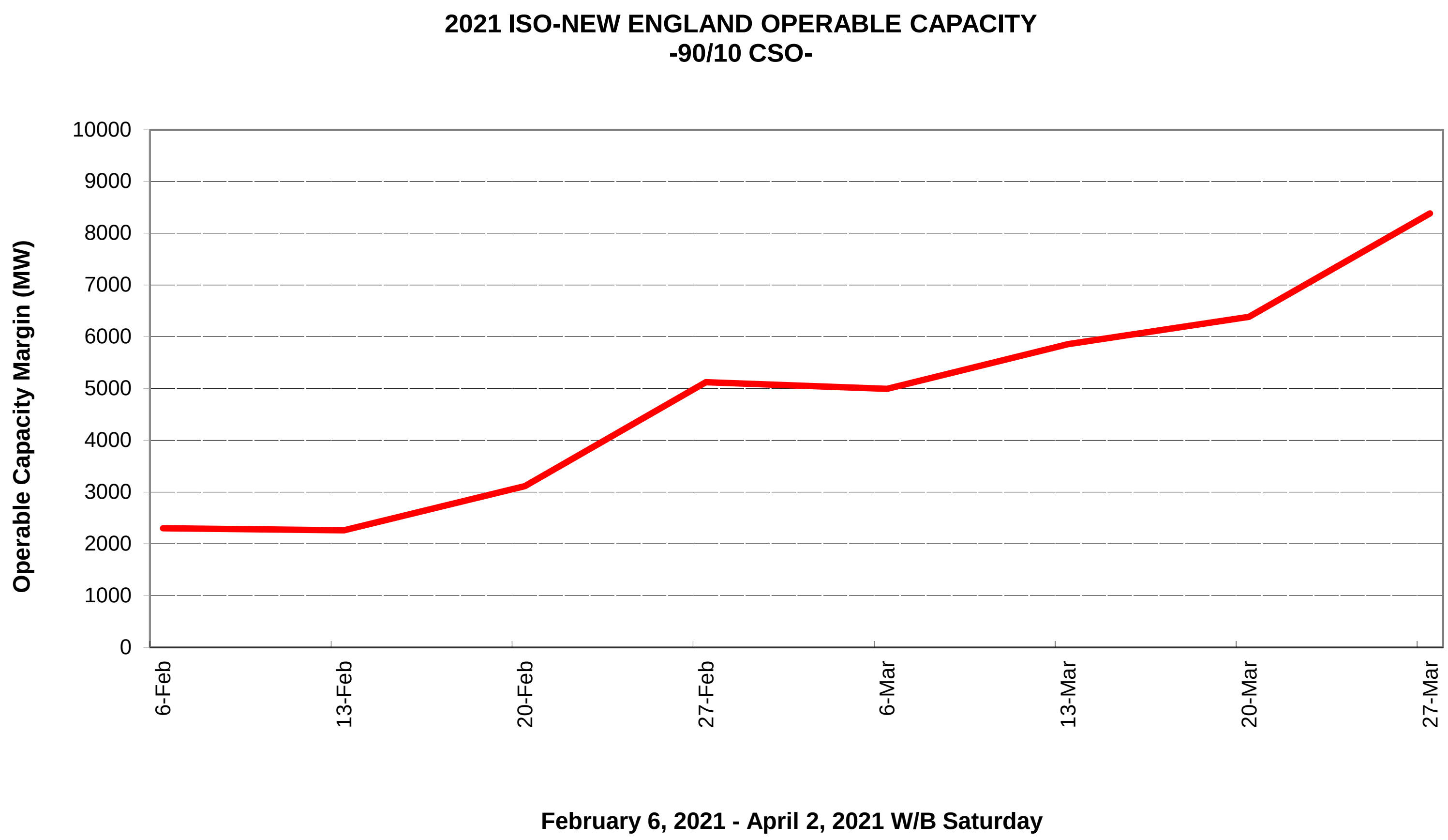
1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 27,084 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

***Highlighted week is based on the week determined by the 50/50 Load Forecast Reference week**

Winter 2021 Operable Capacity Analysis
50/50 Forecast (Reference)



Winter 2021 Operable Capacity Analysis
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Preliminary Spring 2021 Analysis

Preliminary Spring 2021 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2021[2] CSO (MW)	May - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,461	33,677
Active Demand Capacity Resource (+) [5]	537	436
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,025	1,025
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	2,649	2,918
Gas Generator Outages MW (-)	2,433	2,710
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,560	26,129
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,118	18,118
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,423	20,423
Operable Capacity Margin	3,137	5,706

[1]Operable Capacity is based on data as of **January 26, 2021** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **January 26, 2021.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 8, 2021.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW).

[4] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Preliminary Spring 2021 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	May - 2021[2] CSO (MW)	May - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,461	33,677
Active Demand Capacity Resource (+) [5]	537	436
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,025	1,025
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	2,649	2,918
Gas Generator Outages MW (-)	2,433	2,710
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,560	26,129
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,612	19,612
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,917	21,917
Operable Capacity Margin	1,643	4,212

[1]Operable Capacity is based on data as of **January 26, 2021** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **January 26, 2021.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 8, 2021.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW).

[4] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Preliminary Spring 2021 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

January 29, 2021 - 50-50 FORECAST using CSO

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, August, and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
4/3/2021	30461	537	1025	19	3107	2189	2700	0	24046	16134	2305	18439	5607
4/10/2021	30461	537	1025	19	5274	2174	2700	0	21894	15870	2305	18175	3719
4/17/2021	30461	537	1025	19	5315	1375	2700	0	22652	15335	2305	17640	5012
4/24/2021	30461	537	1025	19	3516	1658	2700	0	24168	15057	2305	17362	6806
5/1/2021	30461	537	1025	19	3032	1983	3400	0	23627	15029	2305	17334	6293
5/8/2021	**30461**	**537**	**1025**	**19**	**2649**	**2433**	**3400**	**0**	**23560**	**18118**	**2305**	**20423**	**3137**
5/15/2021	30461	537	1025	19	1362	1812	3400	0	25468	19152	2305	21457	4011
5/22/2021	30461	537	1025	19	1176	1213	3400	0	26253	20113	2305	22418	3835

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,125 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Preliminary Spring 2021 Operable Capacity Analysis
90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

January 29, 2021 - 90-10 FORECAST using CSO

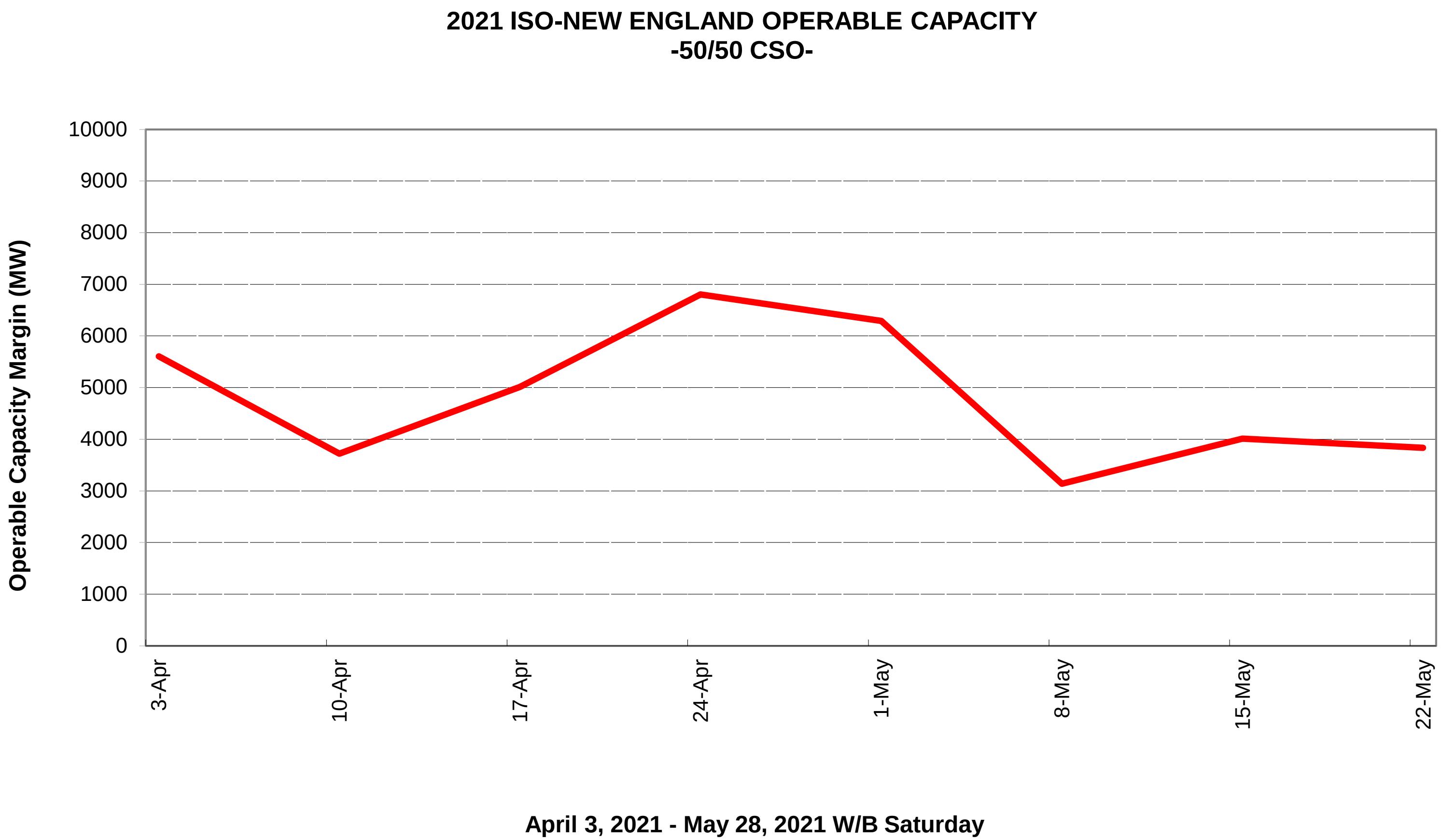
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, August, and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]
4/3/2021	30461	537	1025	19	3107	2189	2700	0	24046	16667	2305	18972	5074
4/10/2021	30461	537	1025	19	5274	2174	2700	0	21894	16395	2305	18700	3194
4/17/2021	30461	537	1025	19	5315	1375	2700	0	22652	15846	2305	18151	4501
4/24/2021	30461	537	1025	19	3516	1658	2700	0	24168	15560	2305	17865	6303
5/1/2021	30461	537	1025	19	3032	1983	3400	0	23627	15531	2305	17836	5791
5/8/2021	**30461**	**537**	**1025**	**19**	**2649**	**2433**	**3400**	**0**	**23560**	**19612**	**2305**	**21917**	**1643**
5/15/2021	30461	537	1025	19	1362	1812	3400	0	25468	20716	2305	23021	2447
5/22/2021	30461	537	1025	19	1176	1213	3400	0	26253	21741	2305	24046	2207

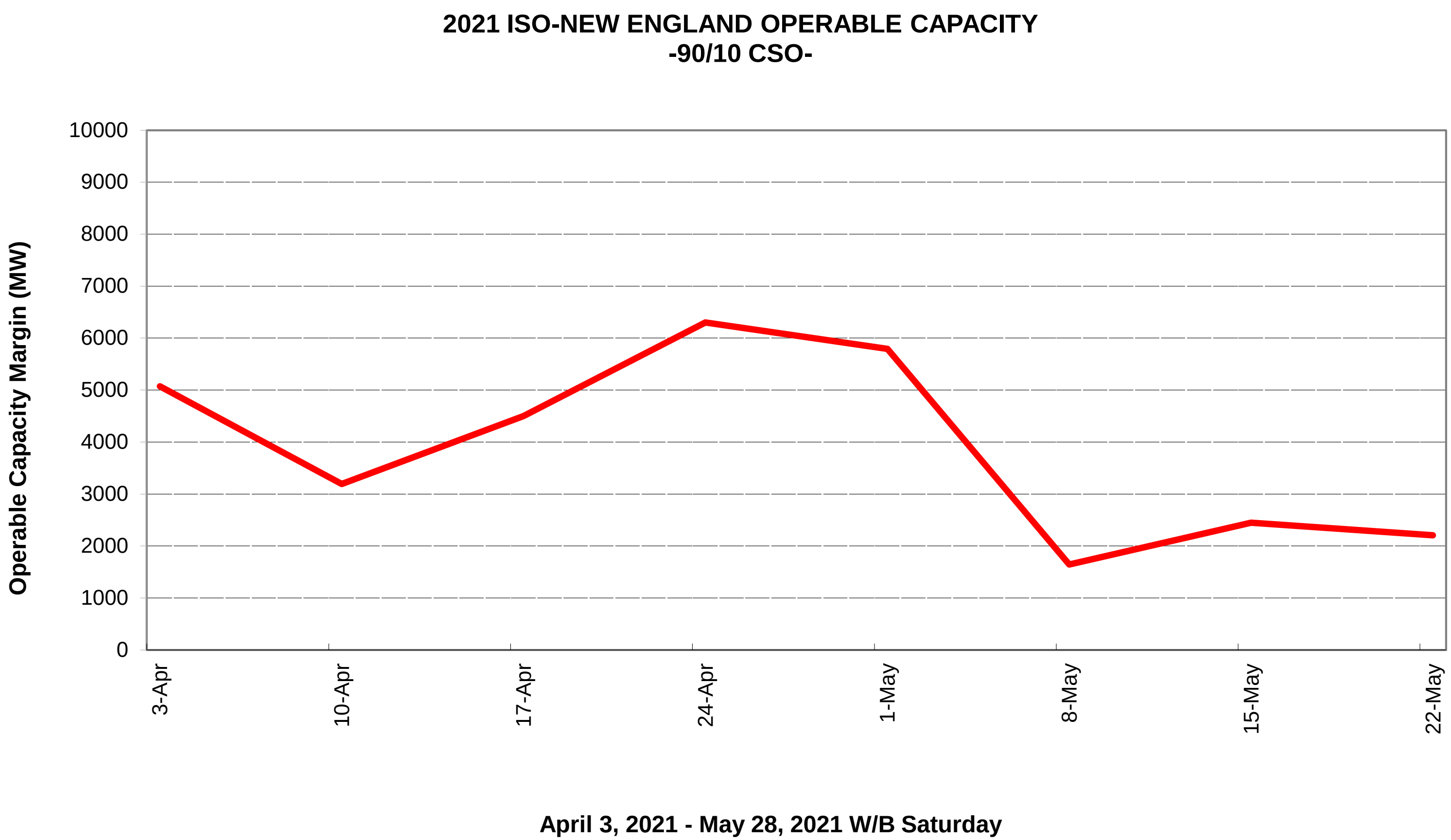
1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 27,084 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

***Highlighted week is based on the week determined by the 50/50 Load Forecast Reference week**

Preliminary Spring 2021 Operable Capacity Analysis
50/50 Forecast (Reference)



Preliminary Spring 2021 Operable Capacity Analysis
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify “Settlement Only” generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow the depletion of 30-minute reserve.	0 [1] 600
2	Declare Energy Emergency Alert (EEA) Level 1[4]	0
3	Voluntary Load Curtailment of Market Participants’ facilities.	40 [2]
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes	125 [3]

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are based on a 25,000 MW system load and verified by the most recent voltage reduction test.
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0
8	5% Voltage Reduction requiring 10 minutes or less	250 [3]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 [2]
11	Request State Governors to Reinforce Power Warning Appeals.	100 [2]
Total		**2,520**

NOTES:

1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are based on a 25,000 MW system load and verified by the most recent voltage reduction test.
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations