NEPOOL Participants Committee Report

December 2019

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EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy market value was $284M, up $82M from October 2019 and down $319M from November 2018
    - November 2019 natural gas prices over the period were double October 2019 average values
    - Average RT Hub Locational Marginal Prices ($35.52/MWh) over the period were 74% higher than October averages
    - Average November 2019 natural gas prices and RT Hub LMPs over the period were down 46% and 36%, respectively, from November 2018 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 99.6% during November, up from 98.8% during October*
    - The minimum value for the month was 95.7% on Friday, November 8th

Data is through November 25th unless otherwise indicated.

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

Underlying natural gas data furnished by:

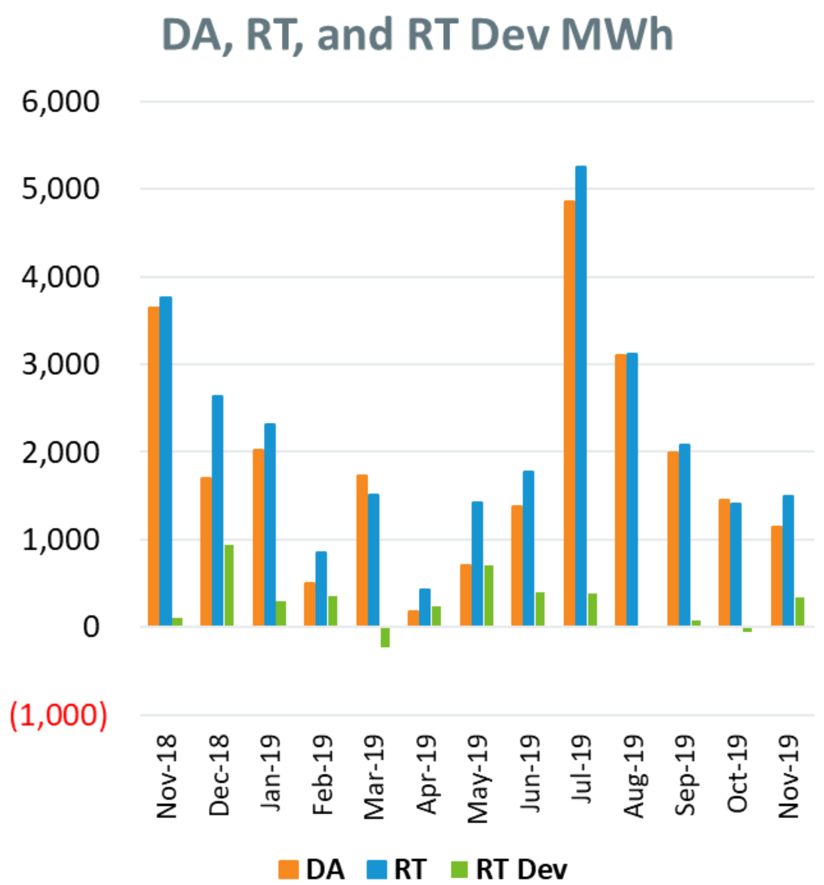
ice Global markets in clear view

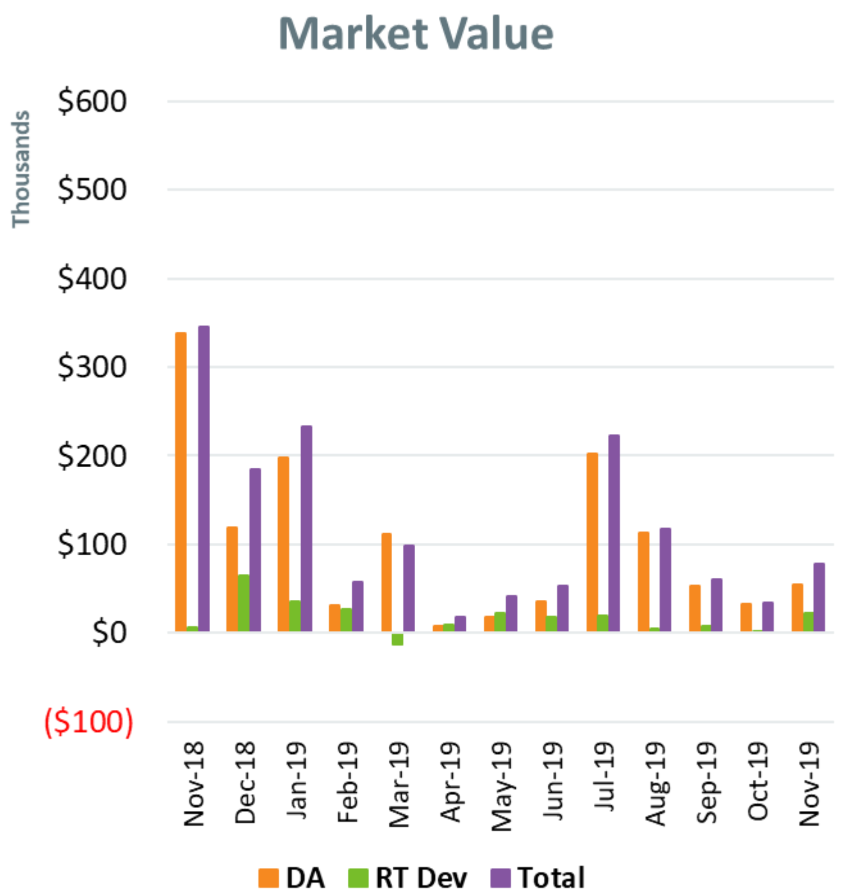
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - November NCPC payments totaled $3.3M over the period, up $0.6M from October 2019 and down $1.3M from November 2018
    - First Contingency* payments totaled $3.1M, up $1.6M from October
      - $2.9M paid to internal resources, up $1.4M from October
        - » $410K charged to DALO, $1.1M to RT Deviations, $1.6M to RTLO
      - $199K paid to resources at external locations, up $144K from October
        - » $2K charged to DALO at external locations, $198K to RT Deviations
    - Second Contingency payments totaled $103K, down $835K from October
    - Voltage payments totaled $138K, down $6K from October
    - NCPC payments over the period as percent of Energy Market value were 1.2%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $237K; Rapid Response Pricing (RRP) Opportunity Cost - $283K; Posturing - $172K; Generator Performance Auditing (GPA) - $874K**

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.

Highlights

- FERC filings pertaining to ICR and qualification were made on November 5
- The final version of RSP19 was approved by the ISO Board on October 31
- The ISO is developing forecasts of the anticipated energy and demand impacts of electrification of the transportation and heating sectors for incorporation in the 2020 CELT forecast
- NESCOE 2019 Economic Study request preliminary results to be shared at the December 19 PAC Meeting

Forward Capacity Market (FCM) Highlights

- CCP 10 (2019-2020)
  - Late, new resources (regardless of size) are being monitored closely
- CCP 11 (2020-2021)
  - There will be a qualification timeline change introduced for the third annual reconfiguration auction qualification process
    - Participant qualification materials (e.g., restoration plans) to be submitted closer to the auction, thereby reducing duplicate work by ISO staff and Participants; training held accordingly
  - Third and final annual reconfiguration auction to be held March 2-4, 2020 and results to be posted no later than April 1, 2020

CCP – Capacity Commitment Period

Forward Capacity Market (FCM) Highlights

- CCP 12 (2021-2022)
  - Second reconfiguration auction will be August 3-5, 2020 and results to be posted by September 2, 2020
- CCP 13 (2022-2023)
  - First reconfiguration auction will be June 1-3, 2020 and results to be posted by July 1, 2020
- CCP 14 (2023-2024)
  - New Capacity Resource Qualification is complete and QDNs were released on September 27
  - Existing Capacity Resource Qualification is complete
  - This will be the first FCA where nested capacity zones will be modeled
    - Tariff changes were filed with FERC on July 18 and FERC ruled on September 3 accepting the changes
    - Capacity Zones to be modeled include: Rest of Pool, Southeastern New England, Northern New England, and Maine (nested zone within Northern New England)

FCA – Forward Capacity Auction
QDN – Qualification Notification Determination

FCM Highlights, cont.

- CCP 14 (2023-2024), cont.
  - Both the ICR and Informational (qualification) FERC filings made on November 5
- CCP 15 (2024-2025)
  - The qualification process has started, and training materials are under development
  - Topology certifications were sent to the TOs on October 9
    - TOs to identify in-service dates for new transmission projects and revisions to previously certified projects; responses were due on October 25
    - Approved projects to be shared with the RC at their January 2020 meeting
  - Capacity zone development discussions started in November at the PAC
    - All subsequent reconfiguration auctions model the same zones as the FCA

ICR – Installed Capacity Requirement

Load Forecast

- The 2020 load forecast process has begun
  - Distributed Generation Forecast Working Group meeting will be held on December 5
  - Energy-Efficiency Forecast Working Group WebEx will be held on December 12
  - Load Forecast Committee meeting will be held on December 20
- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
- ISO is developing forecasts of the anticipated energy and demand impacts of electrification of the transportation and heating sectors for incorporation in the 2020 CELT forecast
  - Methodologies and supporting assumptions are being discussed as part of the annual Load Forecast Committee stakeholder process

FERC Order 1000

- Intraregional Planning
  - Qualified Transmission Project Sponsor (QTPS)
    - 22 companies have achieved QTPS status
    - 2 companies are currently moving through the QTPS application process
  - Based on the results of the Boston Needs Assessment to date, the ISO plans to release its first request for proposal (RFP) for a competitively developed transmission solution in late 2019 or early 2020
  - The ISO filed Tariff revisions on October 11 that propose enhancements to the competitive transmission process
  - Draft RFP templates were updated based on stakeholder feedback and were reposted for PAC comment on November 8
    - After any necessary updates are made, these templates will be used to create the Boston RFP

Highlights

- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning January 11, 2020.

DAY AHEAD MARKET BIDDING DEADLINE

On November 3, 2019 for Operating Day November 4, 2019

What was the issue?

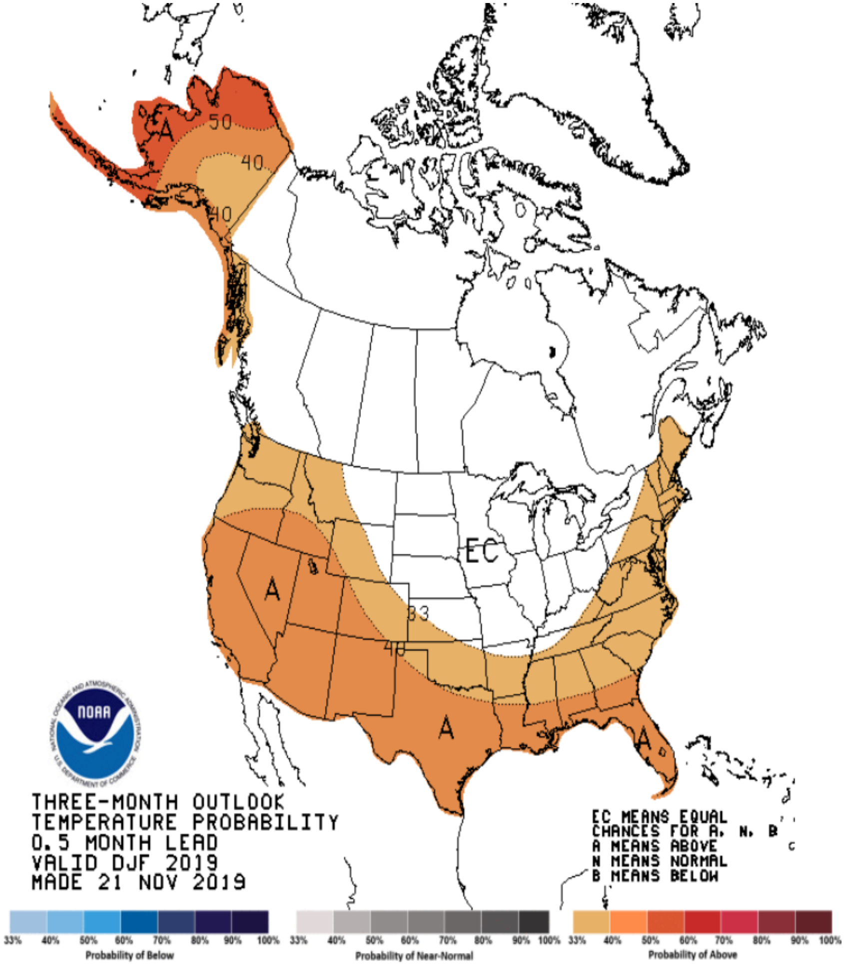
- On November 3rd, the submission window for external transactions closed at 9:00 AM instead of 10:00 AM
  - The ISO application that records external transactions had a software error related to Daylight Savings Time (DST) transition
  - This new application was recently placed in service (October 23)
  - A few participants could not enter or modify external transactions after 9:00 AM
  - eMarket application performed as expected for all other Supply Offers & Demand Bids (open until 10:00 AM)
  - The Day-ahead Market was cleared with the offers and bids as of 10:00 AM, per normal schedule

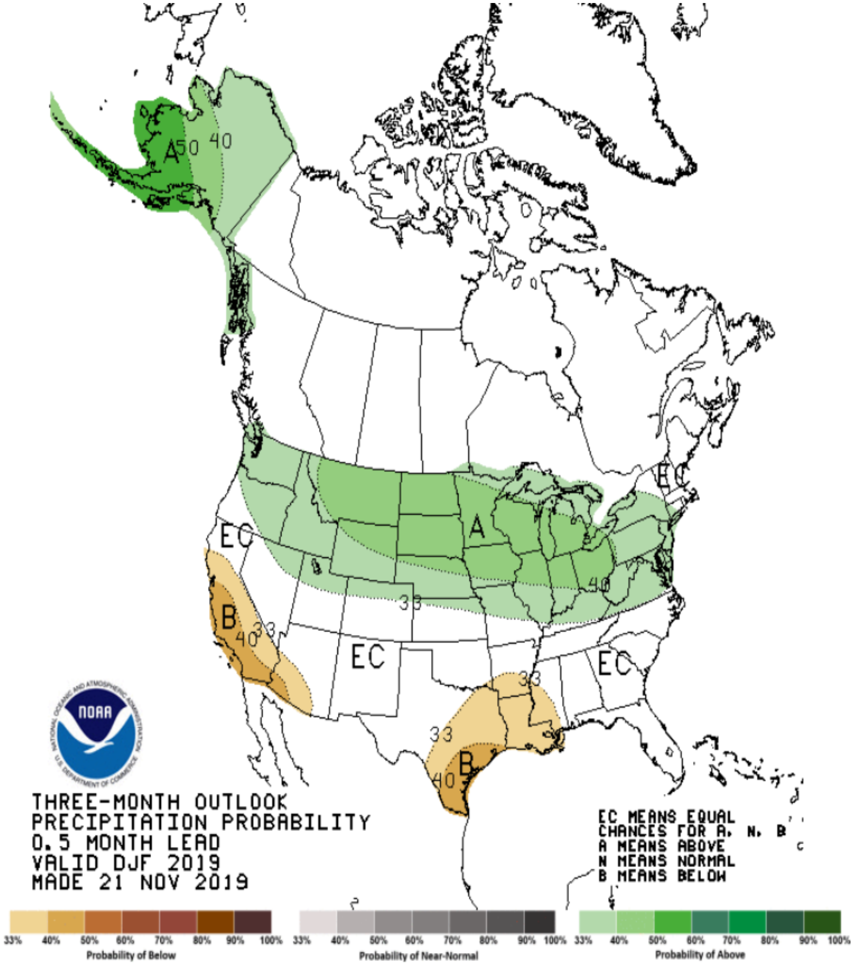
Improvements Underway

- Issue was promptly fixed (by early afternoon on Nov 3)
- Some internal process improvements have already been made
  - The ISO will further improve its software and business testing protocols
  - The ISO will further improve internal business communication protocols
- The ISO is evaluating improvements to communications protocol between ISO and Participants when reporting problems related to submitting market data
- The ISO is evaluating extending the Day-ahead Market submission window to 10:30 AM (from its current 10 AM deadline) and will confirm this decision by early 2020
  - This has been of interest to Participants and will also help alleviate the tight time constraints between the ISONE and NYISO Day-ahead Markets

WINTER READINESS 2019-2020

Winter Temperature & Precipitation Probability





Highlights

- Seasonal Outlook
  - The seasonal temperature outlook for the winter months of December-January-February indicate a 33% probability of above normal temperatures for all of New England
  - There is a 33 % probability of above normal precipitation for a portion of southwestern New England. An equal chance for above average or below average precipitation is forecasted across the remainder of New England.
- Capacity analysis for the 50/50 and the 90/10 load forecast indicates a surplus even after accounting for generation at risk due to gas supply
  - In case of extended periods of cold weather that impact fuel inventories, the capacity outlook and OP21 reporting will be adjusted accordingly

Winter Expectations 2019-2020

- Winter Demand Forecast
  - 50/50 winter peak demand forecast of 20,476 MW
  - 90/10 winter peak demand forecast of 21,173 MW
- Scheduled Generation and Transmission Outages
  - All transmission and generations outages have been coordinated to minimize adverse transmission or capacity conditions
- Transfer Capability
  - Transfer capability on the New York Northern AC ties will be increased from 1,400 to 1,500MW for the winter period to account for lower ambient air conditions

Winter Expectations 2019-2020, cont.

- Natural Gas Deliverability
  - ISO-NE will continue to monitor natural gas deliverability throughout the winter period
  - Participants should monitor status of fuel availability including interstate pipeline bulletins
  - Inspections continue on the Algonquin Pipeline System
    - The inspections have been generally positive so far
- Fuel and Emissions Availability
  - ISO-NE will continue to closely monitor fuel inventories and potential emissions restrictions of oil, coal, and natural-gas fired resources via weekly surveys and move to daily surveys if necessary.
  - Entering Winter 2018-2019 fuel oil tanks were approximately 50% full and ended the winter approximately 55% full
  - Entering Winter 2019-2020 fuel oil tanks are approximately 52% full.

Winter Preparations 2019-2020

- Winter Readiness Seminar
  - ISO-NE hosted a Generator Winter Readiness Seminar with Market Participants on November 1, 2019
- Winter Readiness Survey
  - ISO-NE distributed a Winter Generator Readiness Survey to all generating resources in the region on October 30, 2019 based upon recommendations from the 2019 FERC and NERC Staff Report
  - Survey was reviewed with the RC prior to implementation
- OP-21 Enhancements
  - Provides market participants with a weekly 21-day look ahead of forecasted system conditions, thus providing an opportunity for generators to take action in advance of an Energy Alert or Emergency
  - The process will move to daily updates when alert and/or emergency conditions are triggered

Coordination and Communication

ISO-NE continues to step up communications through:

- Regular conference calls with NPCC Reliability Coordinators
- Pre-winter conference calls with the Northeast Gas Association
  - Emphasize maintaining close coordination regarding outages
- Regular communications with gas pipelines
  - Information Policy changes were made to improve gas-electric coordination per FERC Order 787

Transmission & Distribution

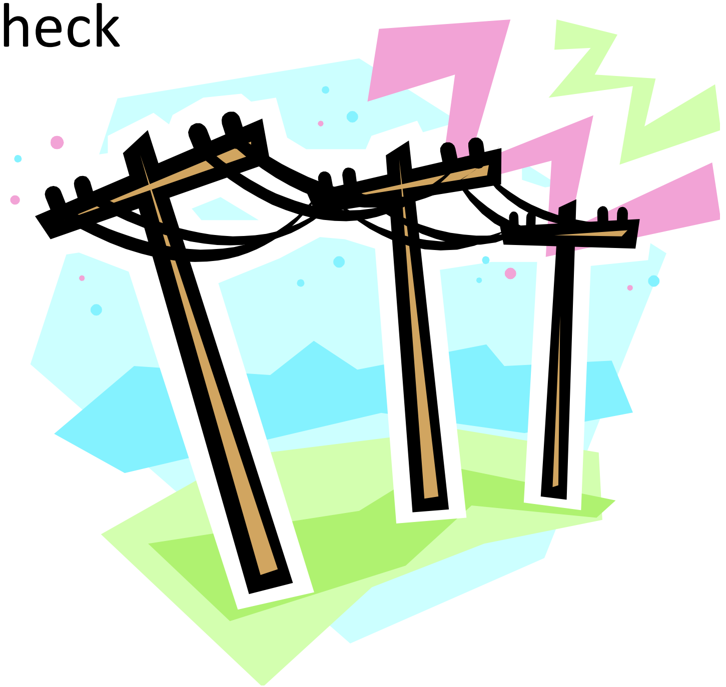
Load shed plans tested monthly and consider

- Electric generators
- Gas wellheads
- Gas pipeline compressors
- Gas gathering facility
- Other critical and essential loads

Actions & Plans

Seasonal Preparations

- Assess generator outages
- Gas pipeline communications
- Transmission system preparedness check
- Other Readiness Actions
  - Dual fuel testing
  - Blackstart resource testing
  - Calls to dual-fuel generators



SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (-1.9 °F) Max: 72°F, Min: 21°F Precipitation: 3.37" – Below Normal Normal: 3.99"	Hartford	Temperature: Below Normal (-2.2°F) Max: 74°F, Min: 15°F Precipitation: 2.18" - Below Normal Normal: 3.89"

Peak Load:	17,429 MW	Nov 13, 2019	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
None			

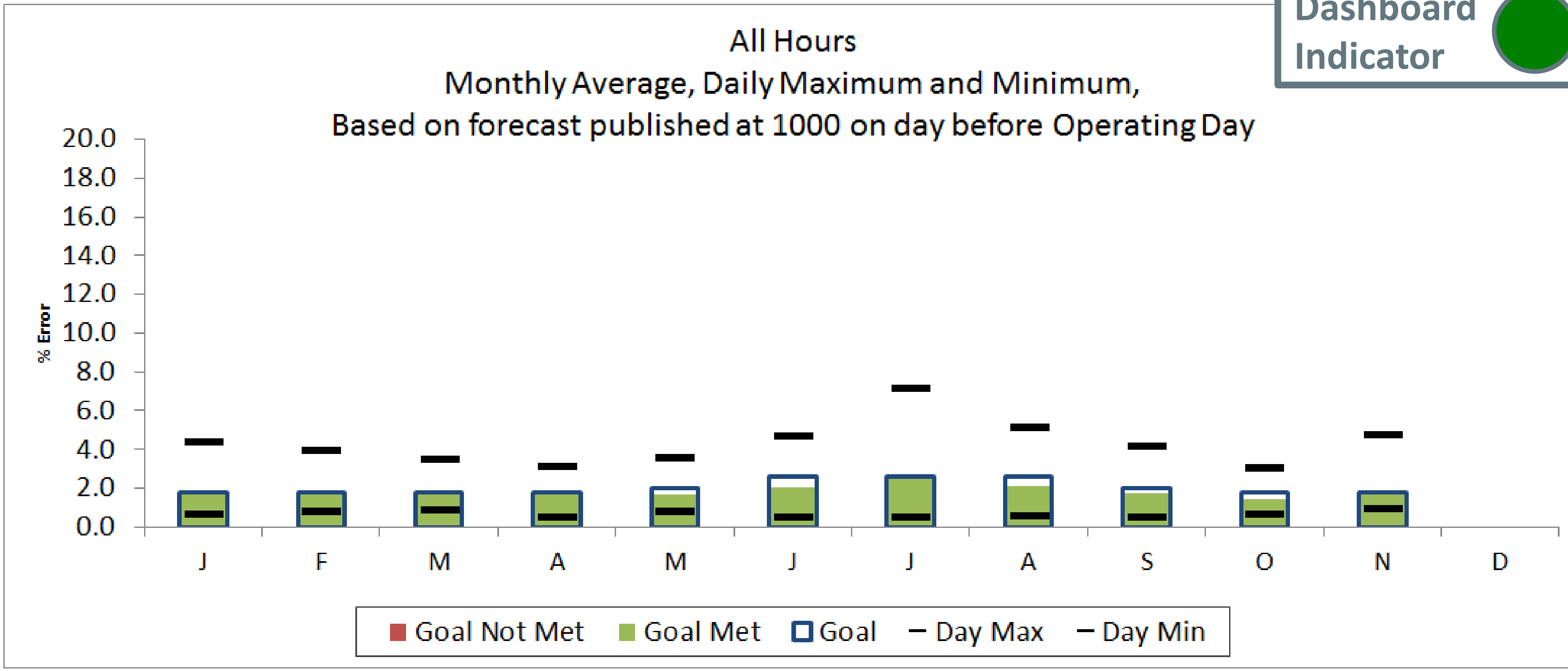
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
11/26/2019	ISO-NE	720

2019 System Operations - Load Forecast Accuracy

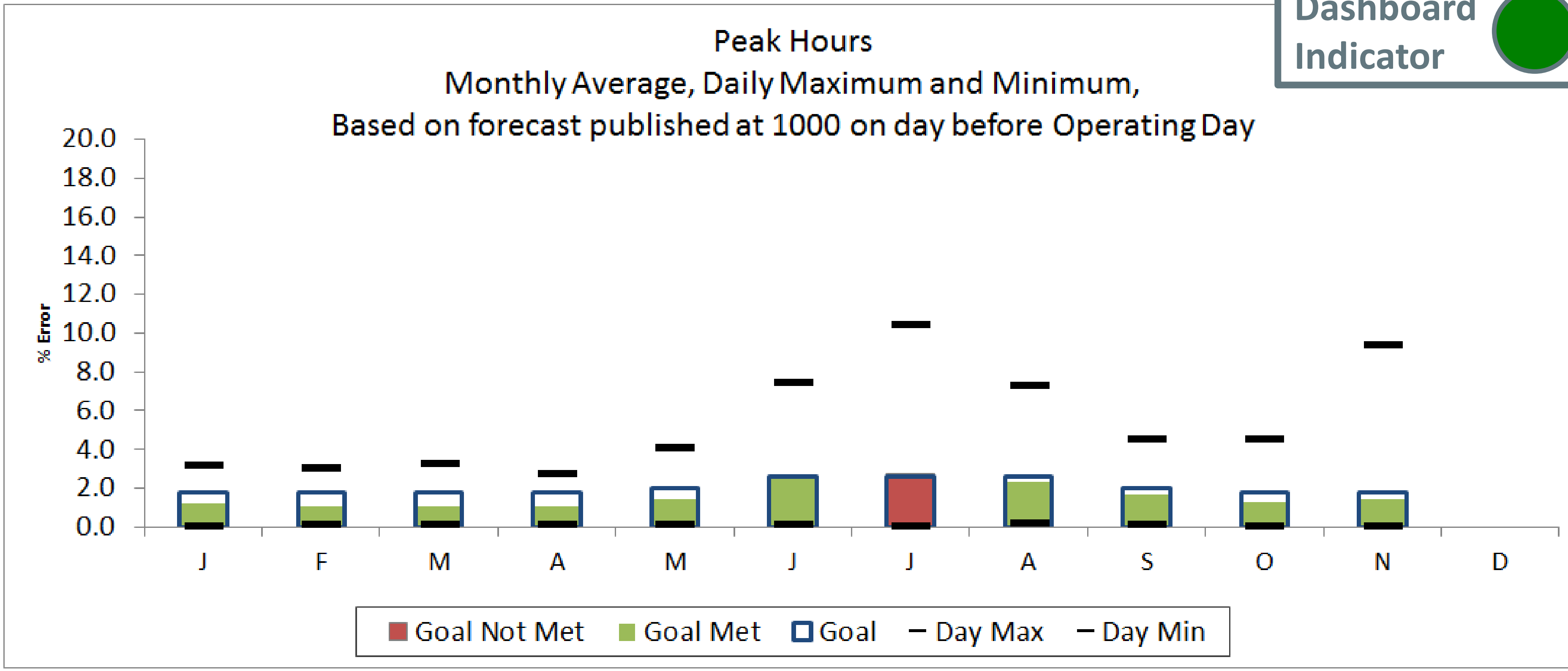
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.36	3.87	3.47	3.11	3.53	4.68	7.14	5.10	4.11	3.04	4.75		7.14
Day Min	0.60	0.77	0.81	0.49	0.79	0.49	0.44	0.57	0.48	0.63	0.91		0.44
MAPE	1.76	1.68	1.72	1.79	1.64	2.01	2.46	2.12	1.73	1.47	1.80		1.84
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80		

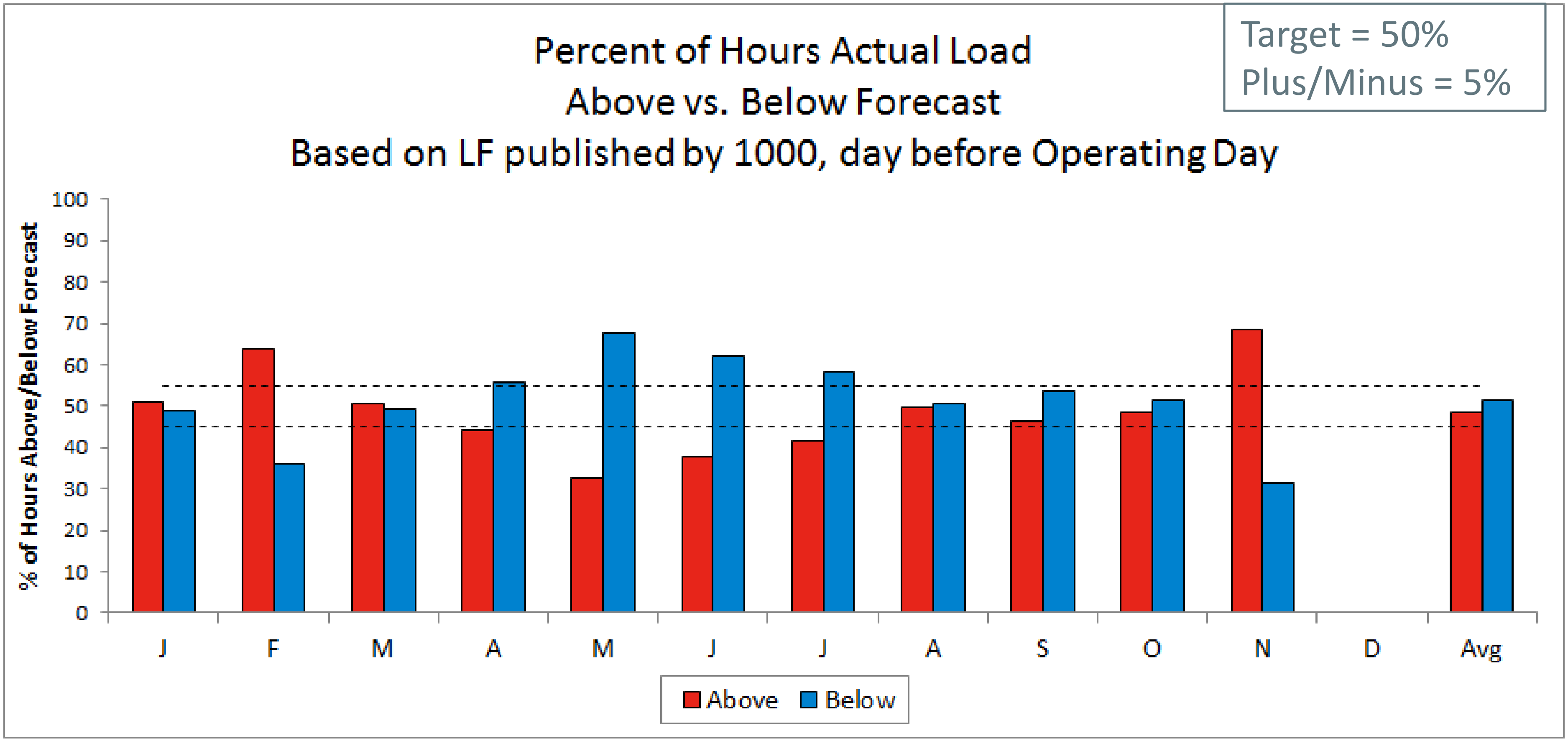
2019 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



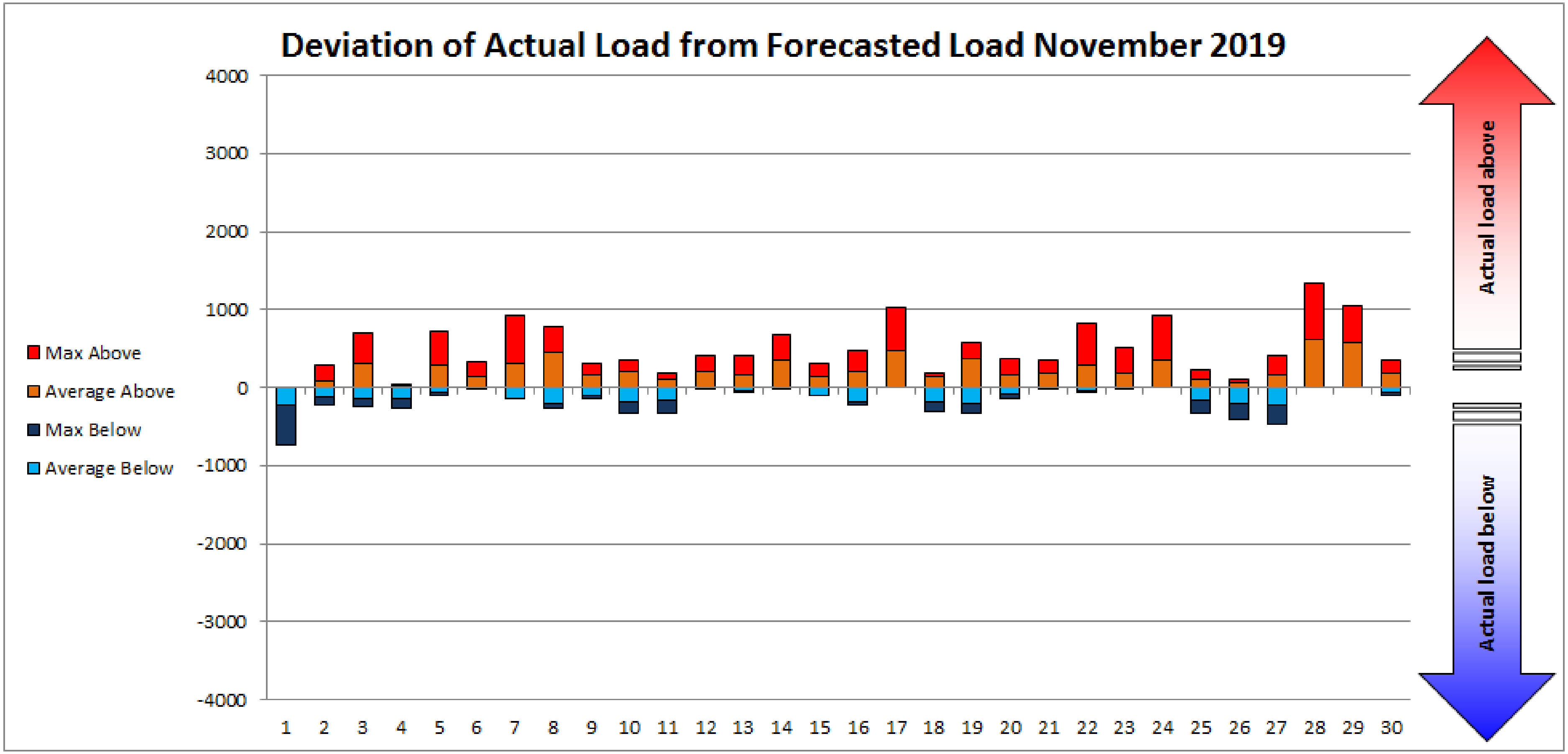
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.17	3.03	3.23	2.71	4.08	7.39	10.38	7.27	4.53	4.48	9.36		10.38
Day Min	0.02	0.06	0.06	0.12	0.07	0.07	0.01	0.16	0.07	0.01	0.01		0.01
MAPE	1.22	1.04	1.06	1.04	1.45	2.53	2.72	2.37	1.63	1.29	1.44		1.62
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80		

2019 System Operations - Load Forecast Accuracy cont.

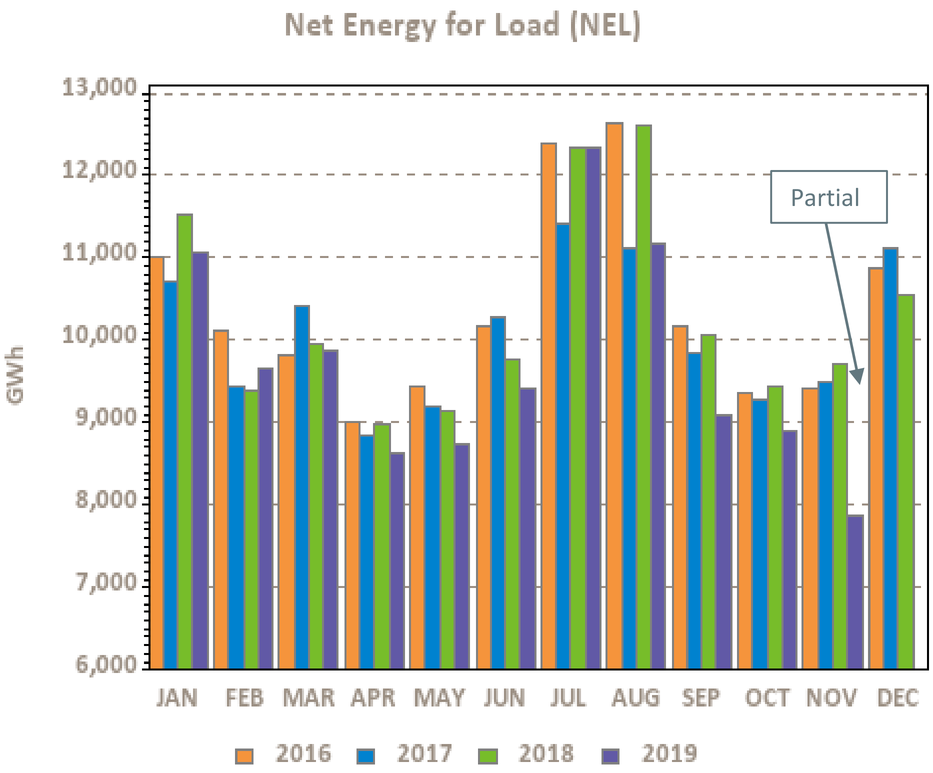


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	51.1	64	50.5	44.2	32.5	37.9	41.7	49.6	46.2	48.5	68.6		48
Below %	48.9	36	49.5	55.8	67.5	62.1	58.3	50.4	53.8	51.5	31.4		52
Avg Above	211.7	224.2	162.1	184.1	126.1	144.9	268.3	230.9	181.2	158.1	232.6		268
Avg Below	-183.0	-174.3	-192.4	-161.7	-179.6	-225.1	-350.1	-220.1	-157.5	-118.7	-101.3		-350
Avg All	30	88	-12	1	-79	-80	-108	8	13	20	134		0

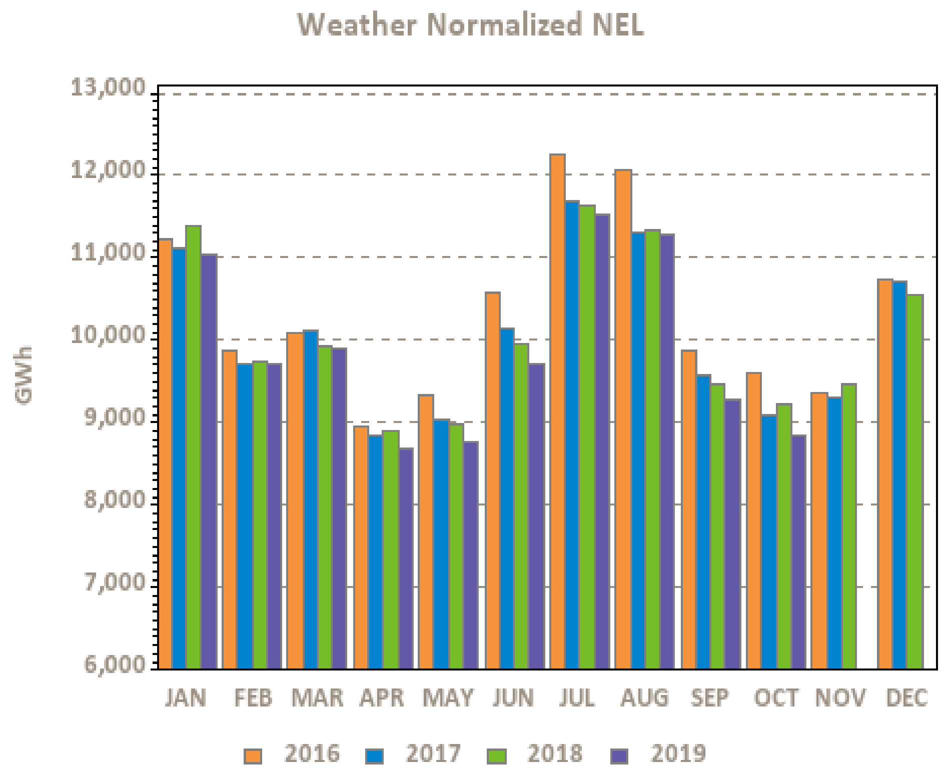
2019 System Operations - Load Forecast Accuracy cont.



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



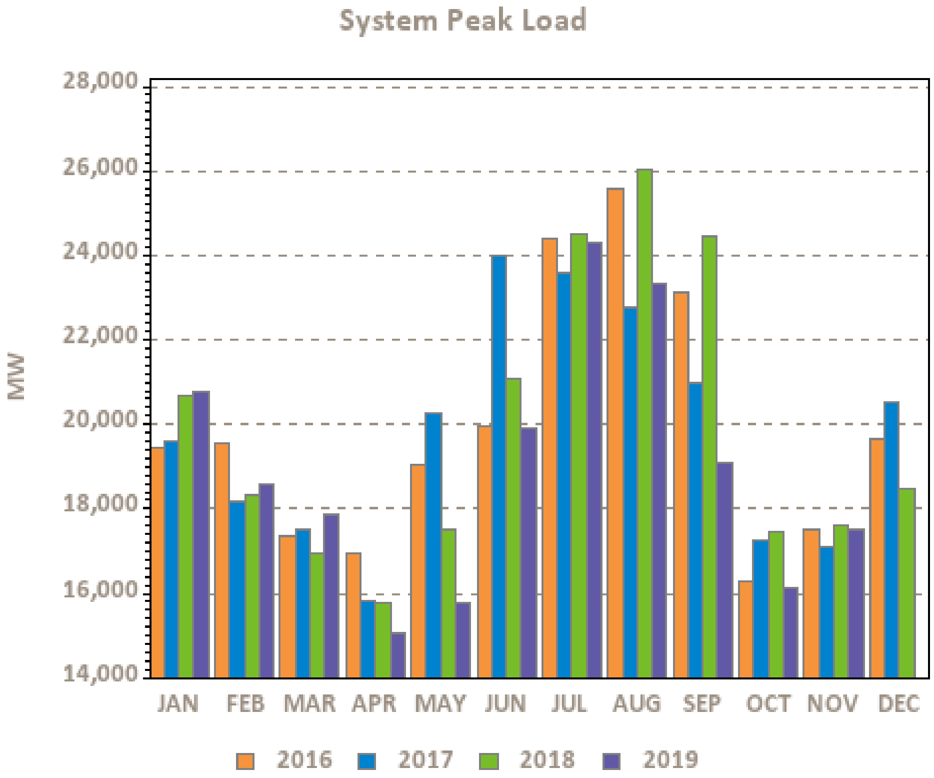
Ann Tot (TWh): 124.4 121.2 123.5 106.8



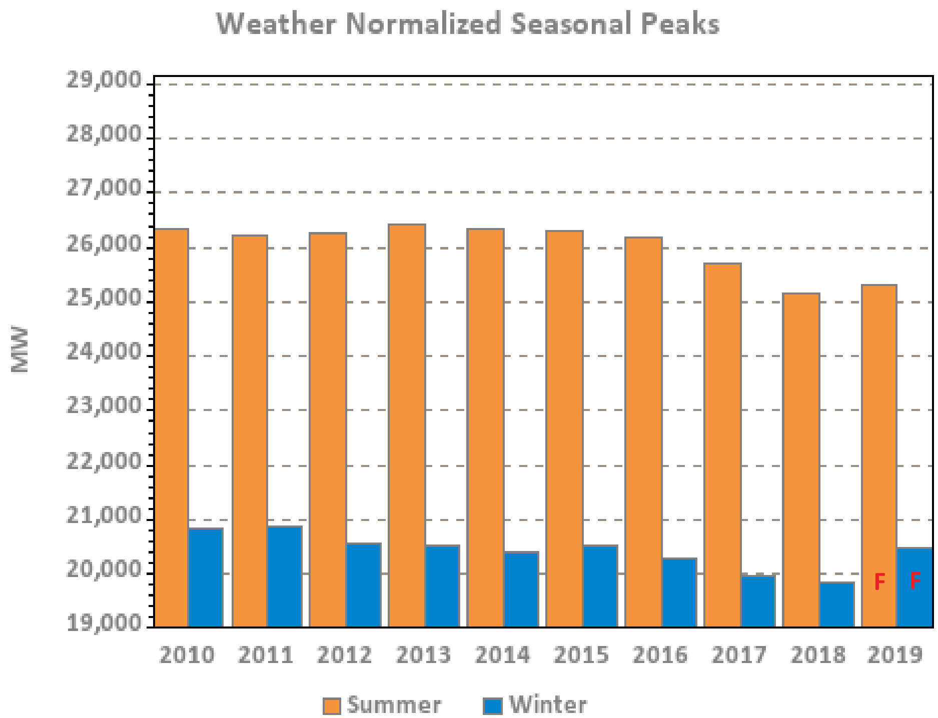
Ann Tot (TWh): 124.0 120.7 120.6 98.7

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

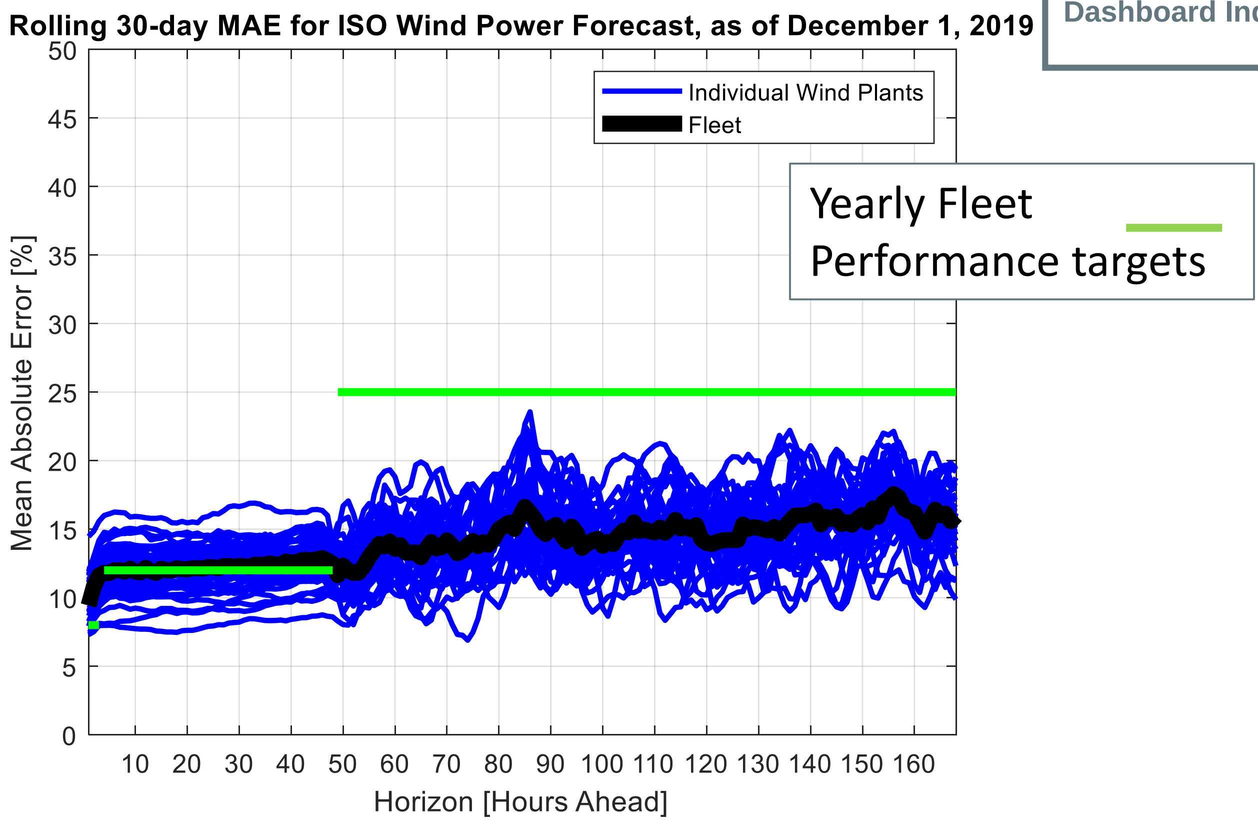


Winter beginning in year displayed

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

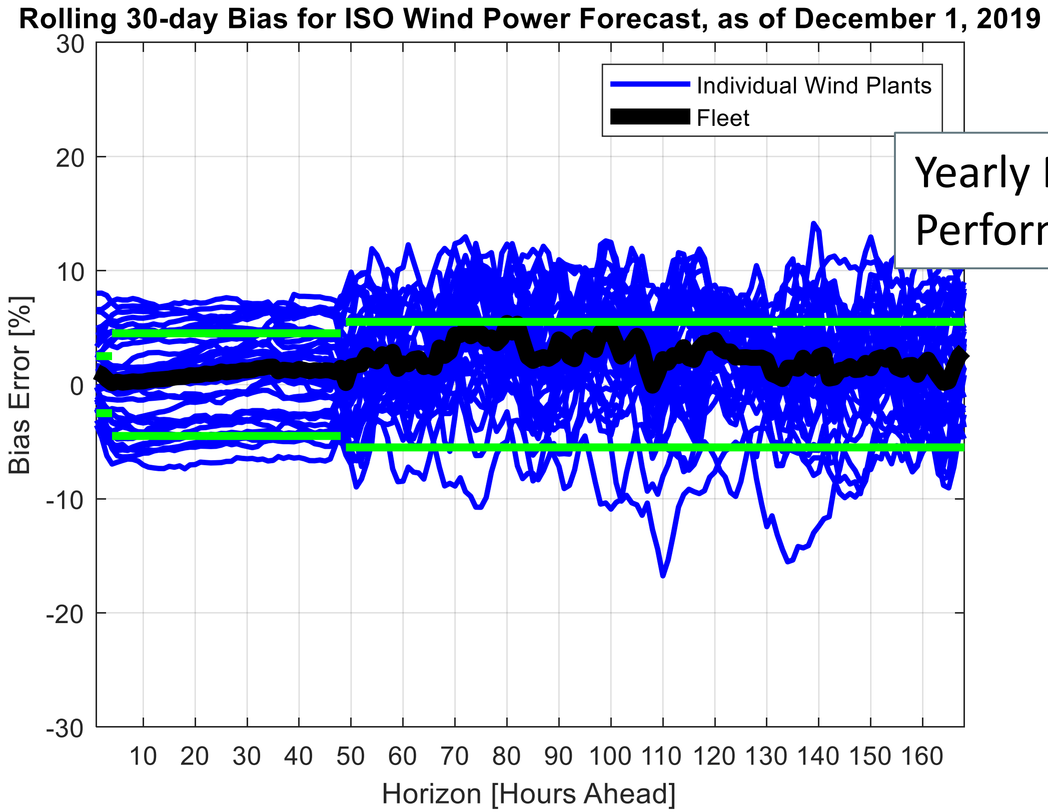
Dashboard Indicator



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. Monthly MAE is within the yearly performance targets for all hours except the 46 to 48 hour ahead timeframe..

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

Dashboard Indicator

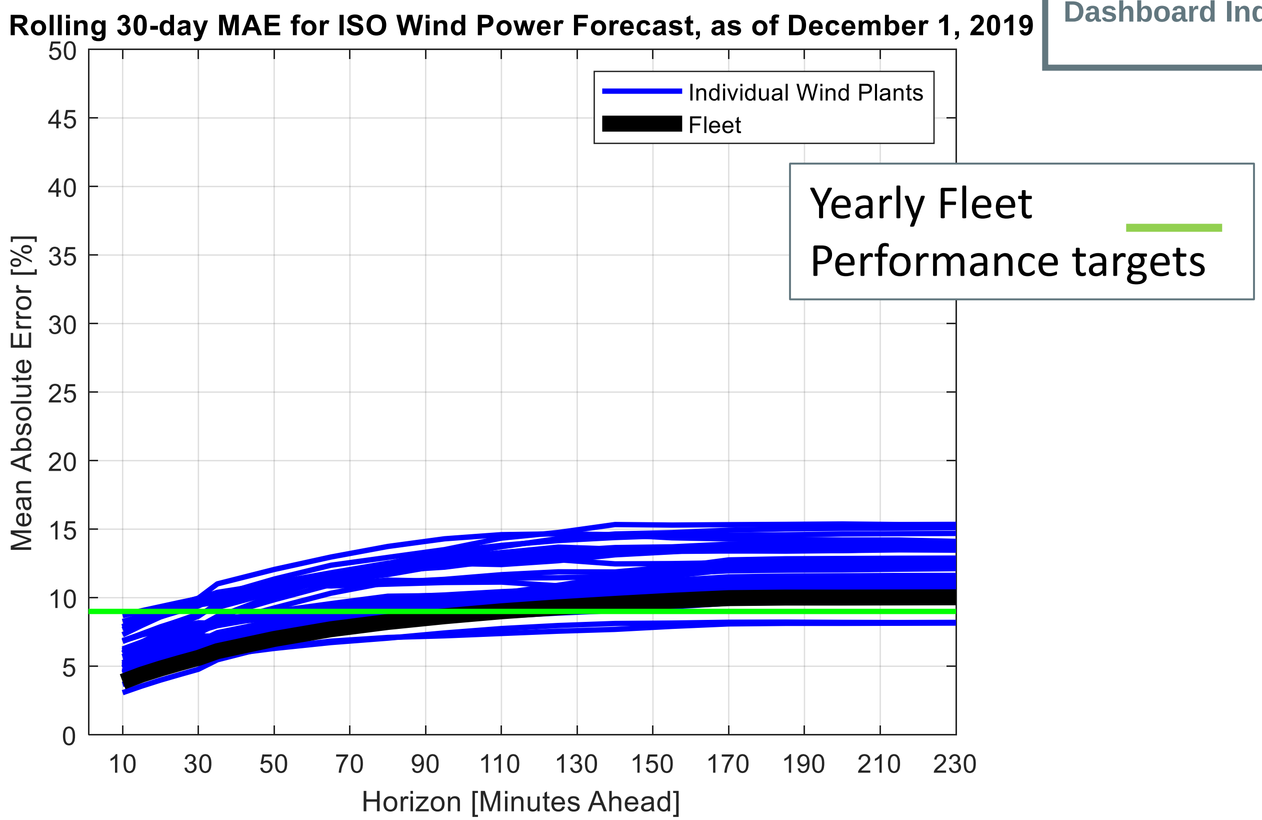


Yearly Fleet Performance targets

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 within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

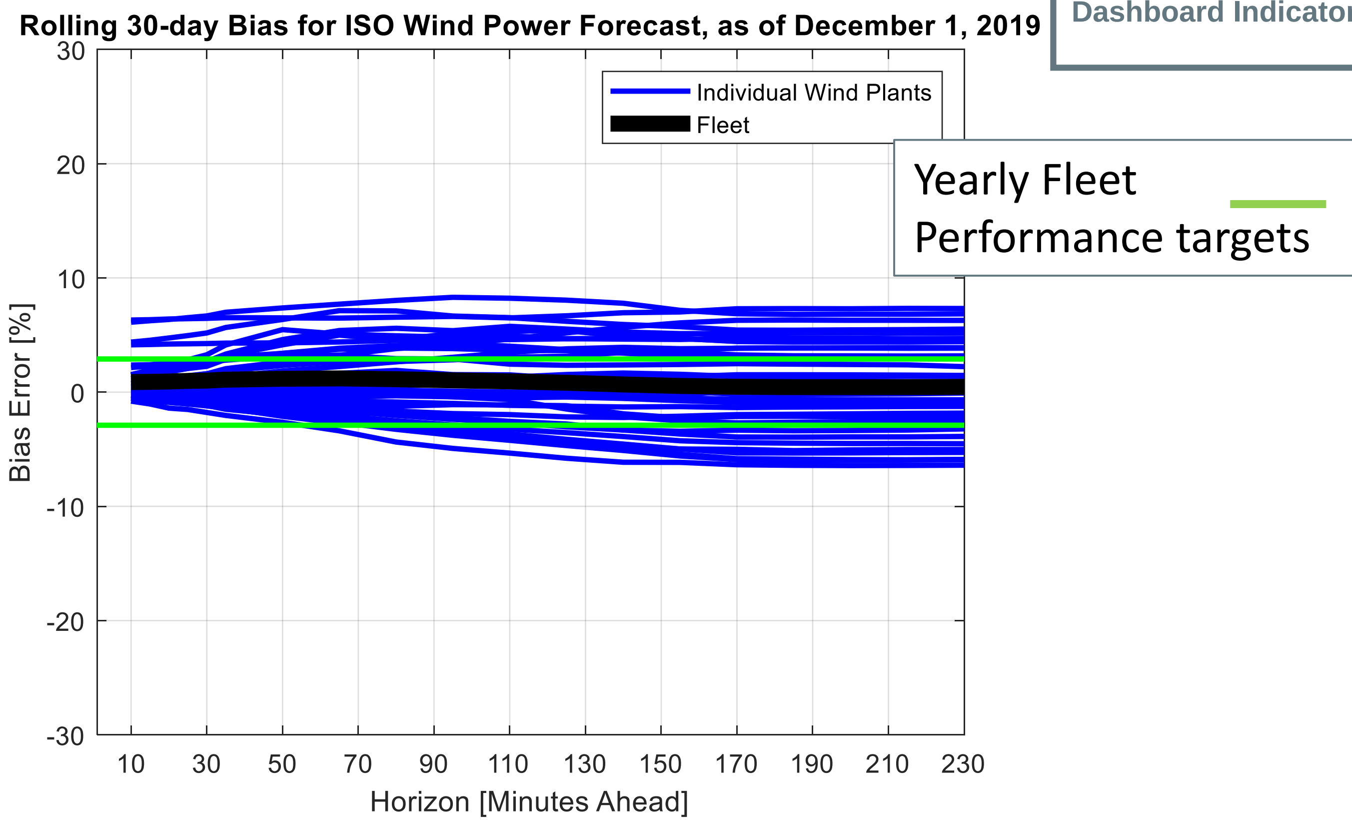
Dashboard Indicator



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. Monthly MAE is within the yearly performance targets up to 2 hours ahead.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator



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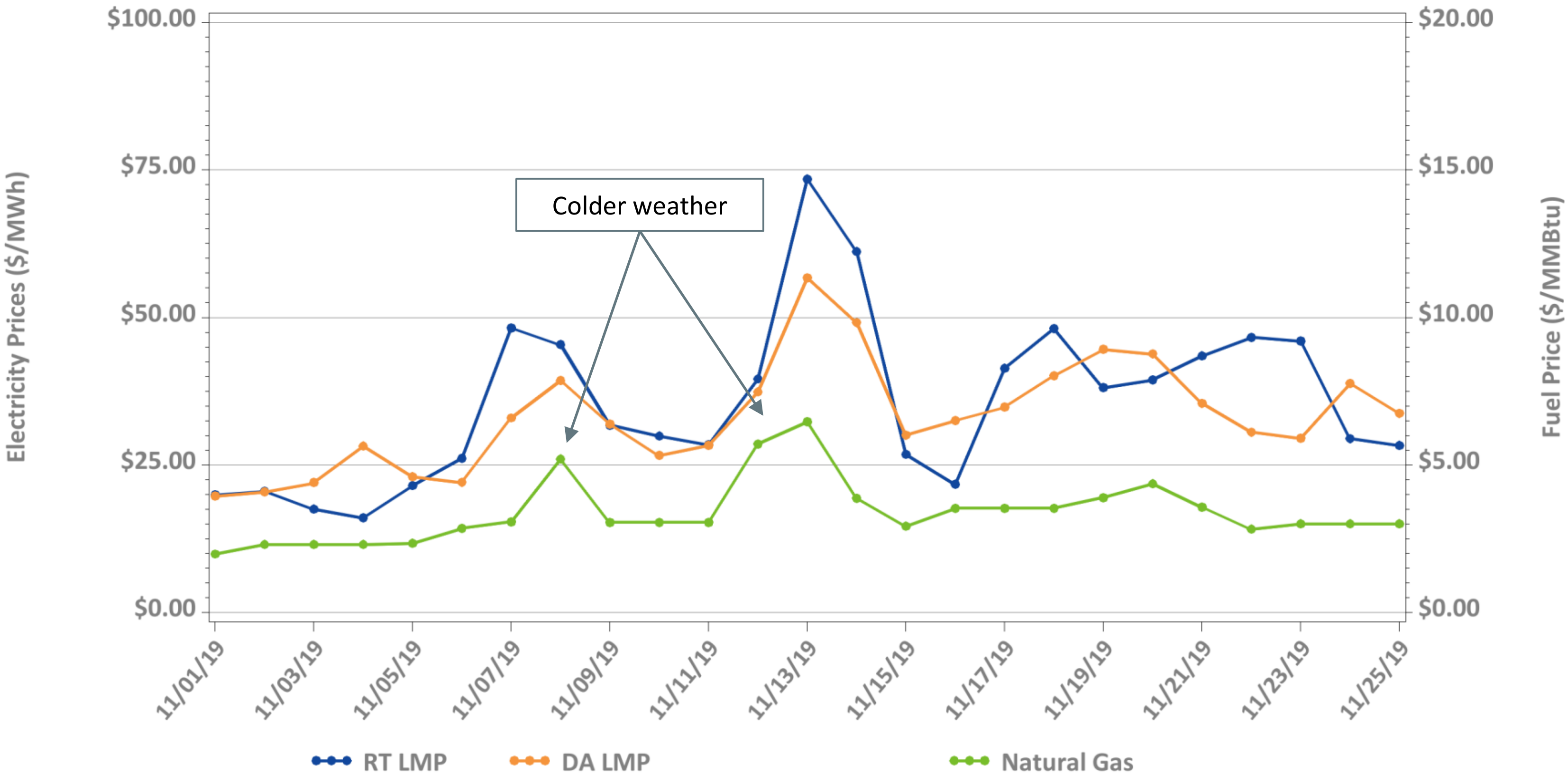
MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: November 1-25, 2019

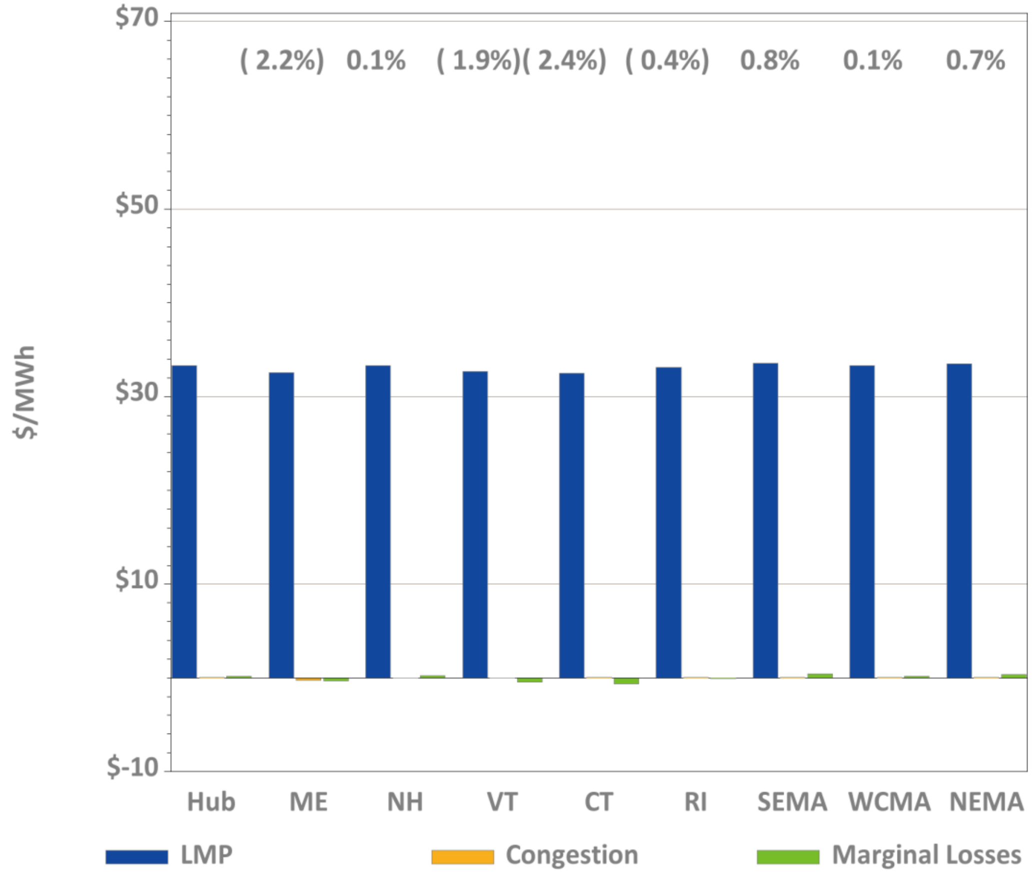


Underlying natural gas data furnished by:

ICE Global markets in clear view

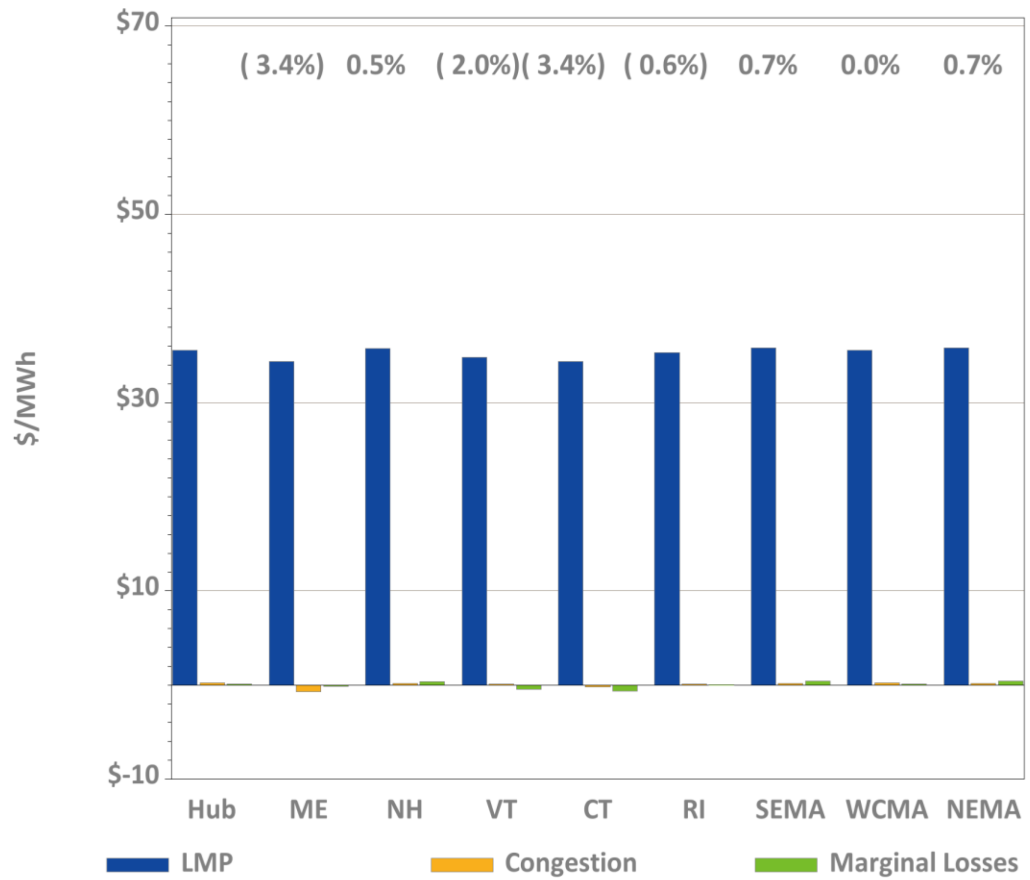
Average price difference over this period (DA-RT): $-2.28
Average price difference over this period ABS(DA-RT): $6.93
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 19%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, November 2019



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

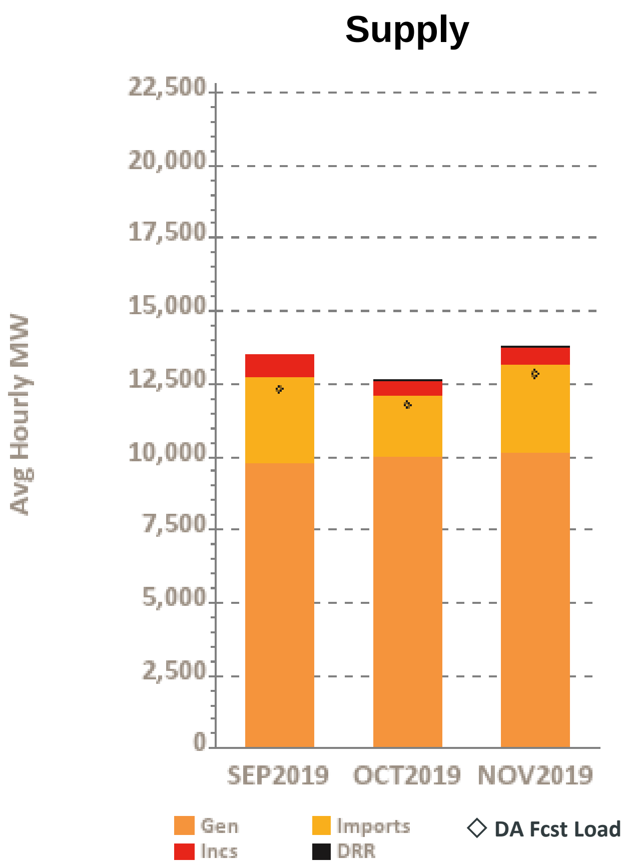
RT LMPs Average by Zone & Hub, November 2019

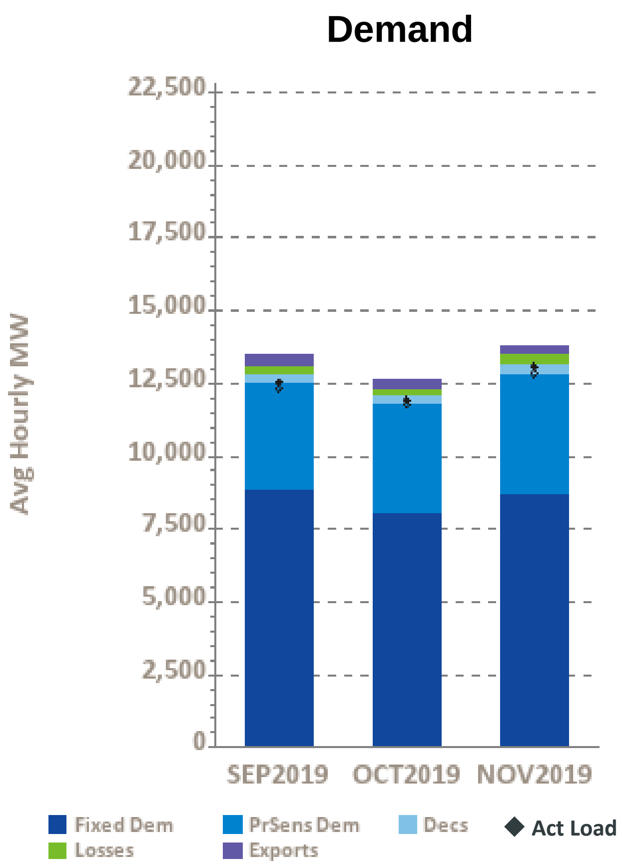


Definitions

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

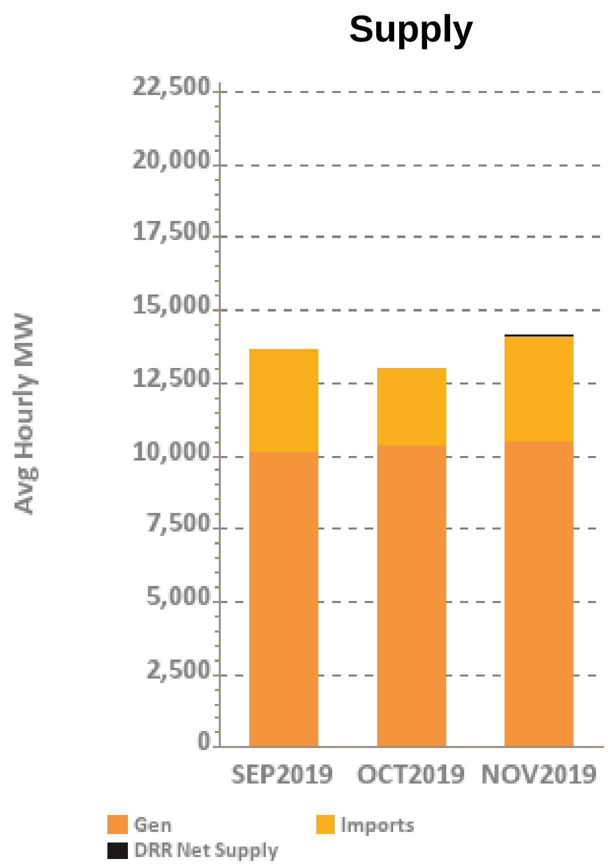


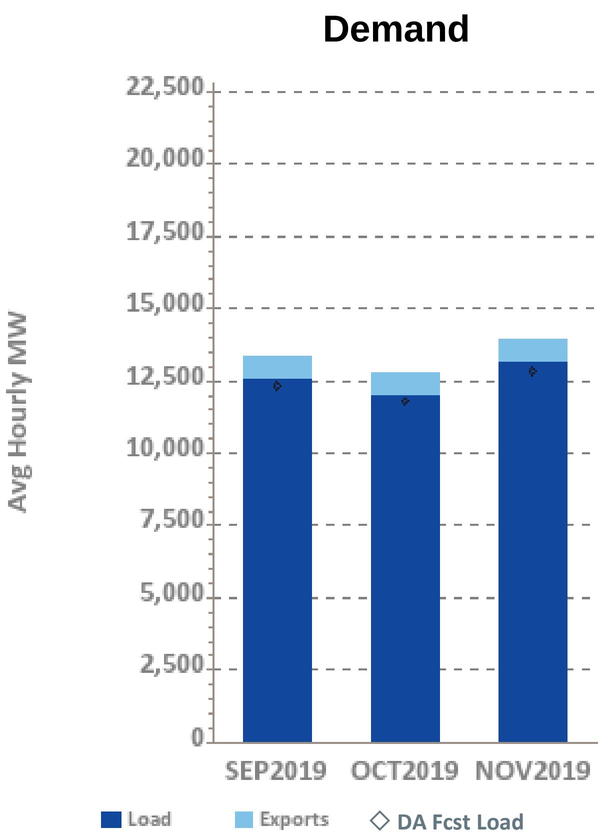


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

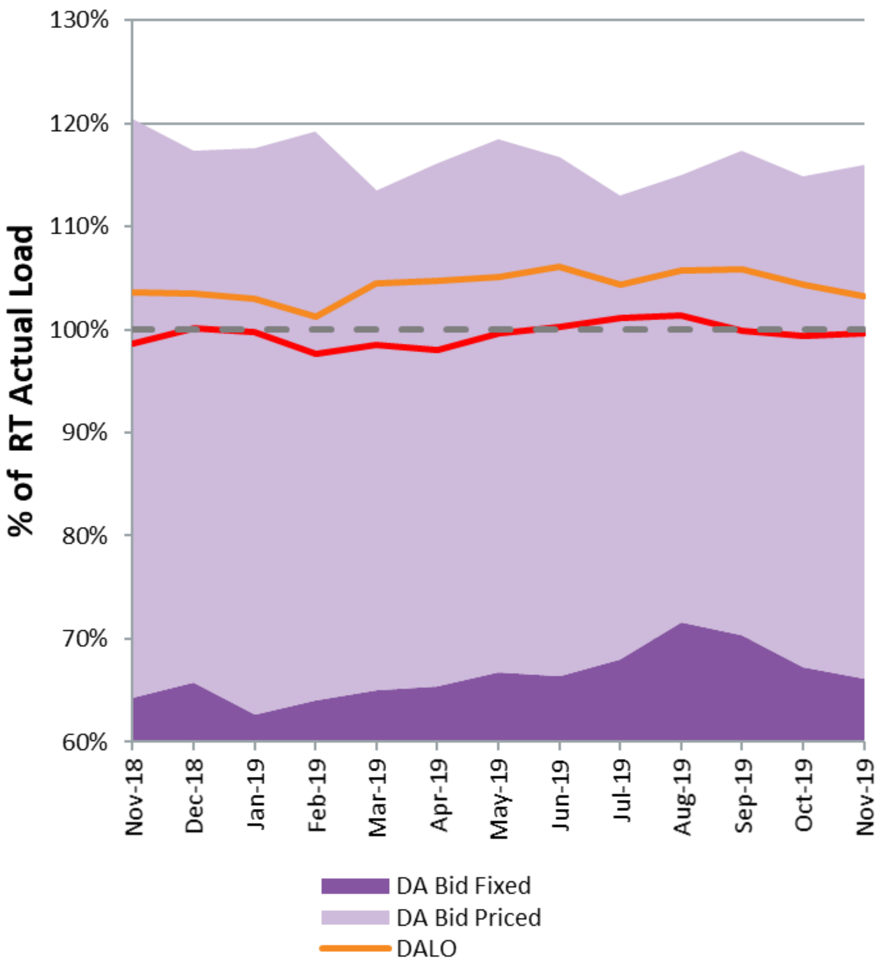
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

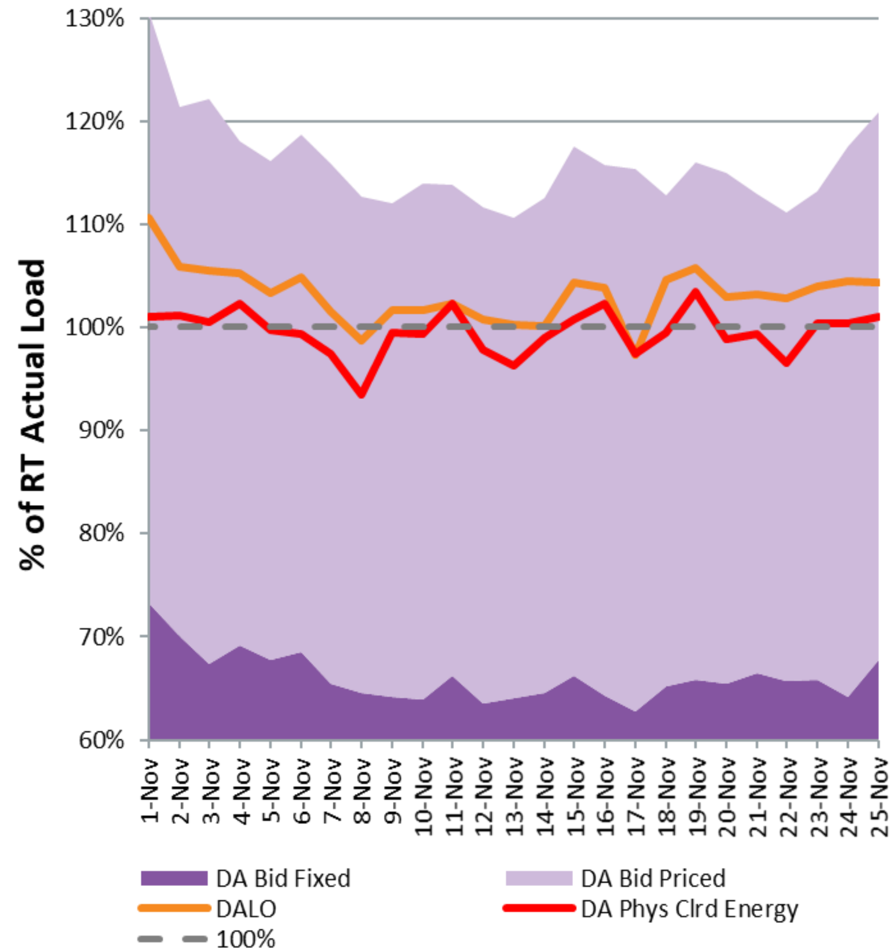
Components of RT Supply and Demand – Last Three Months





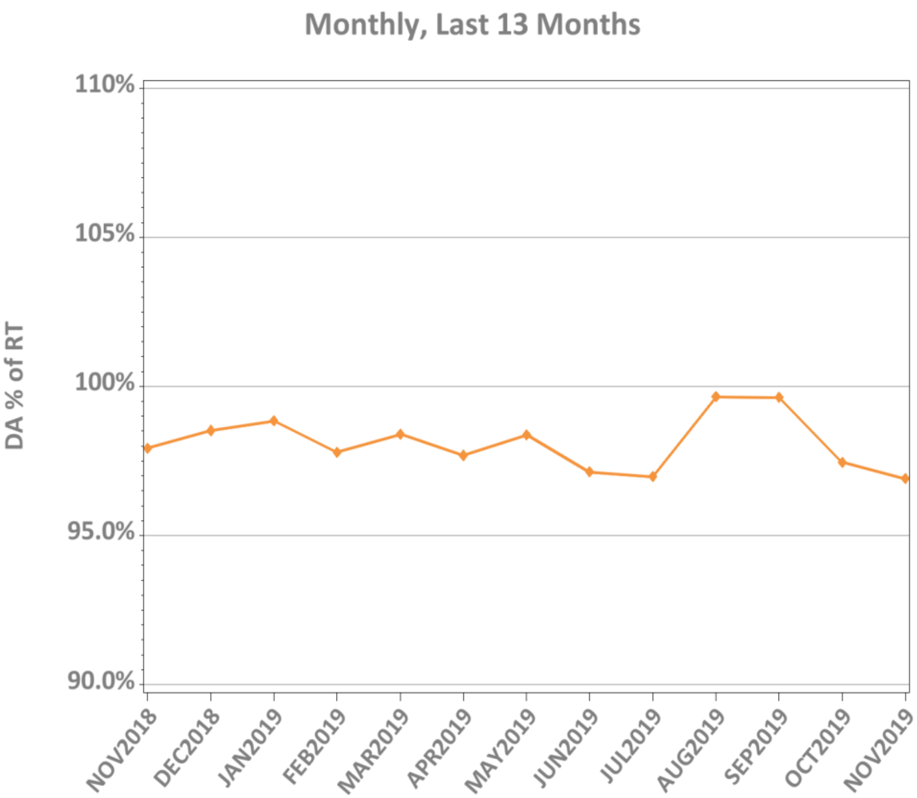
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

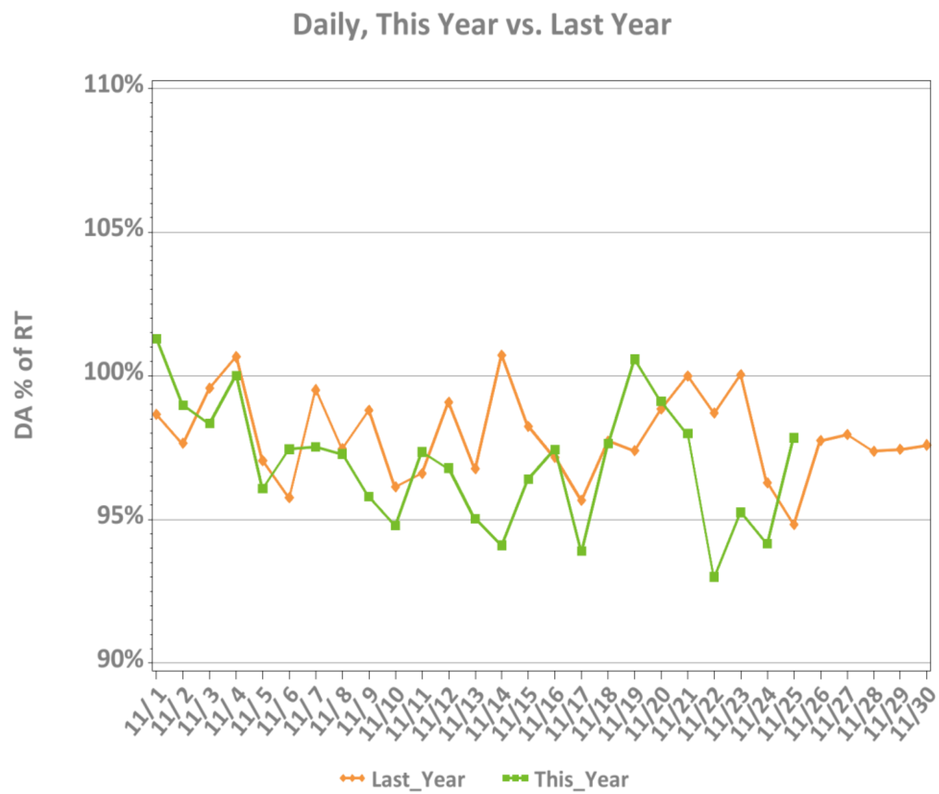




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load. DA Bid categories reflect internal load asset bidding behavior (Virtual demand and export bid behavior not reflected).

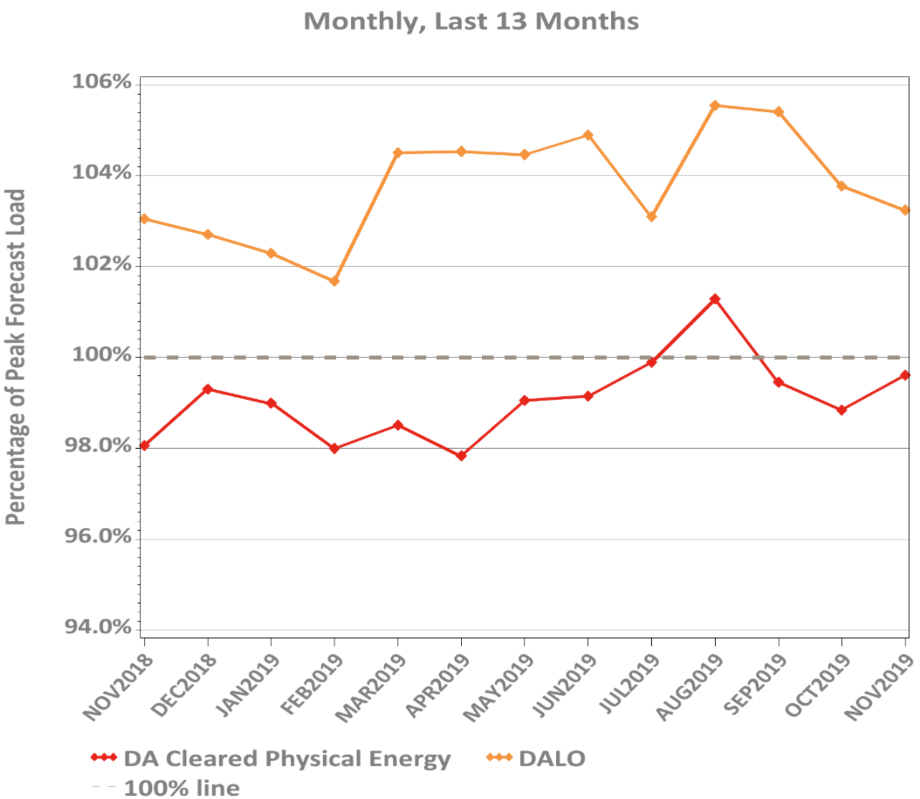
DA vs. RT Load Obligation: November, This Year vs. Last Year

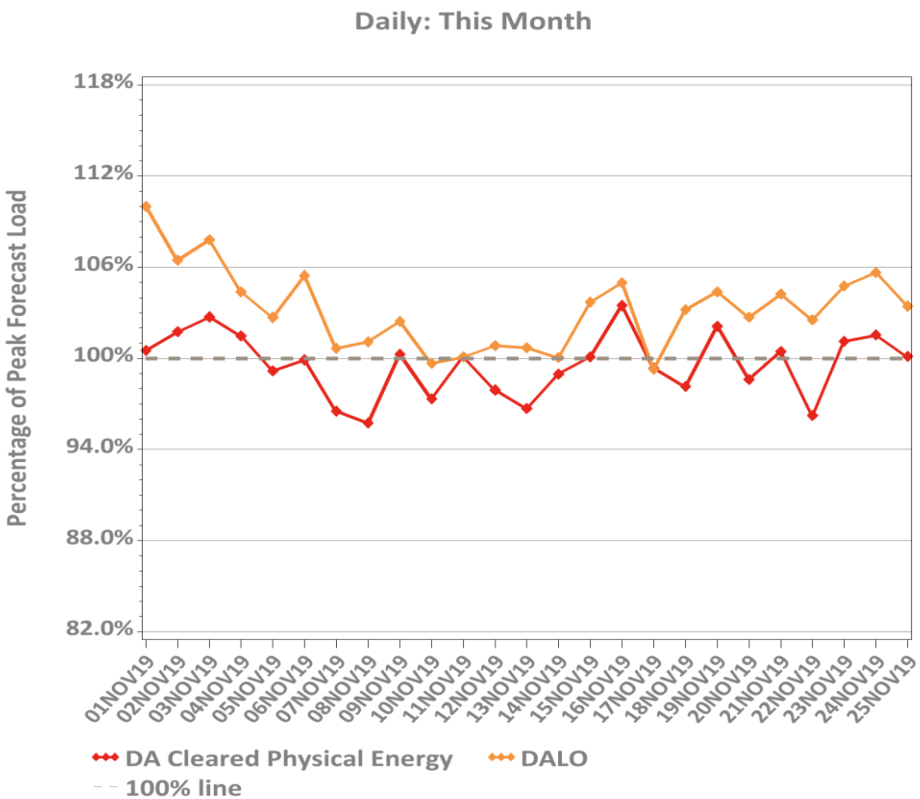




*Hourly average values

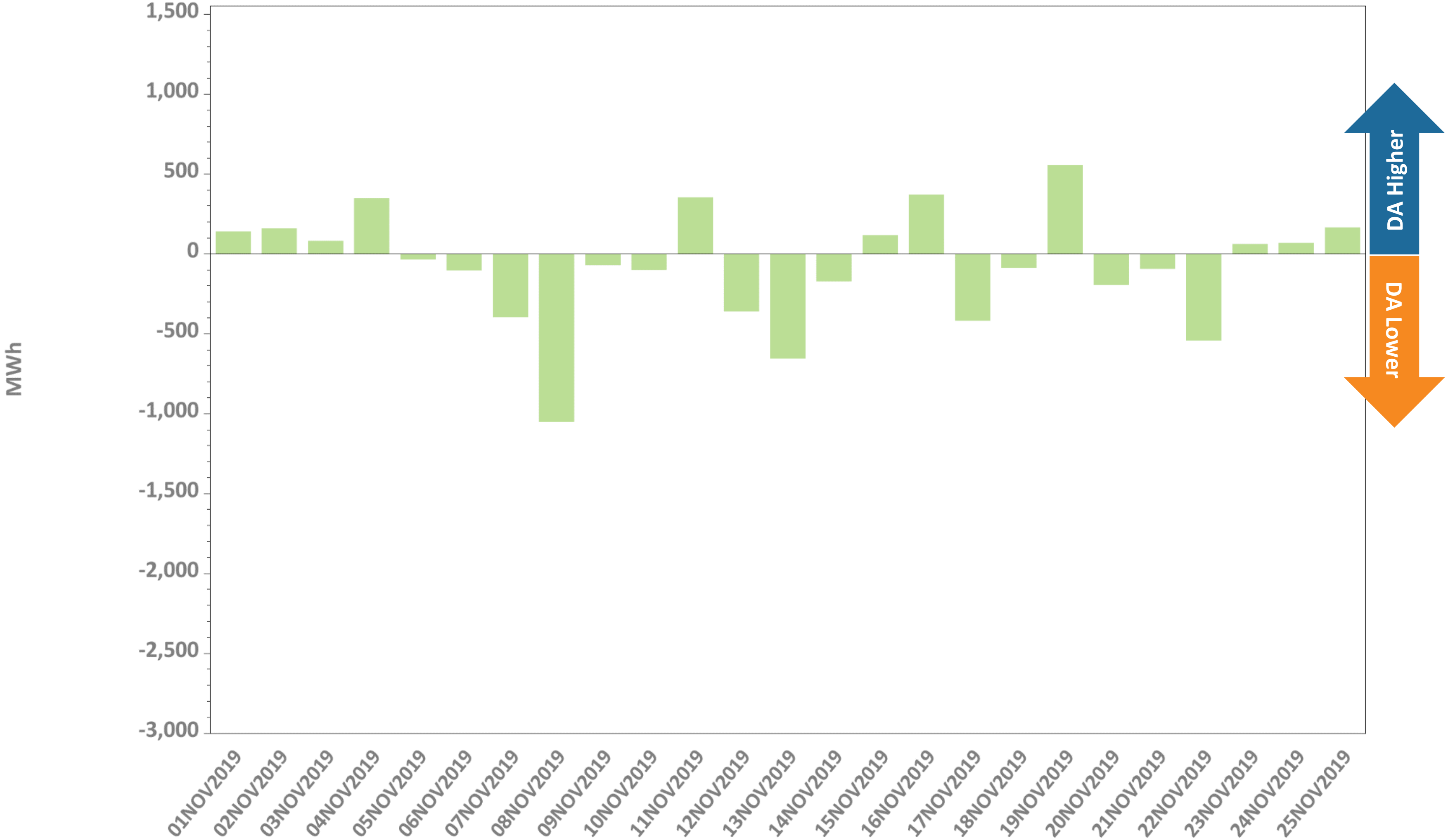
DA Volumes as % of Forecast in Peak Hour





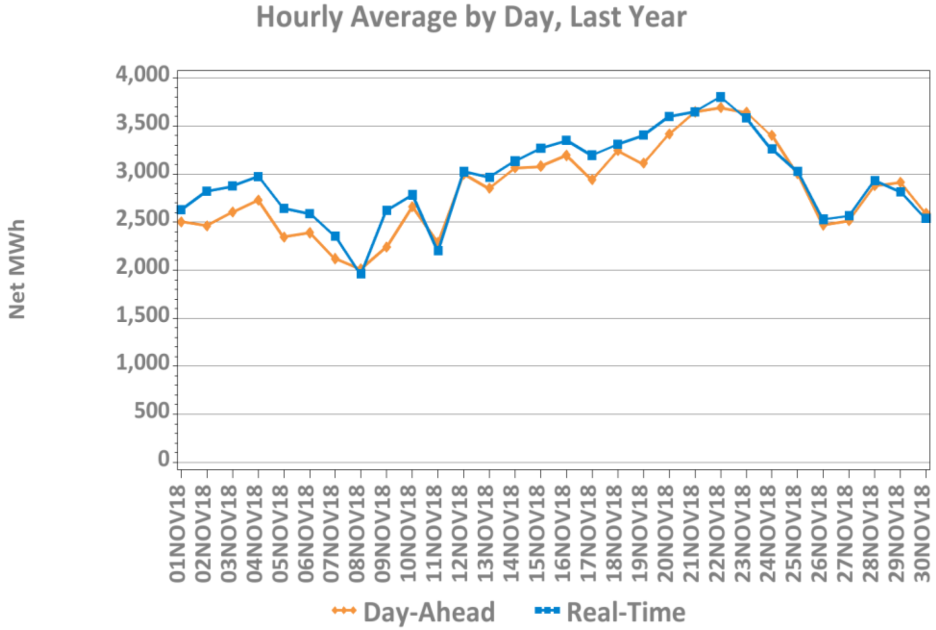
* There were *three* supplemental commitments required for system-level capacity during the Reserve Adequacy Assessment (RAA) during November.

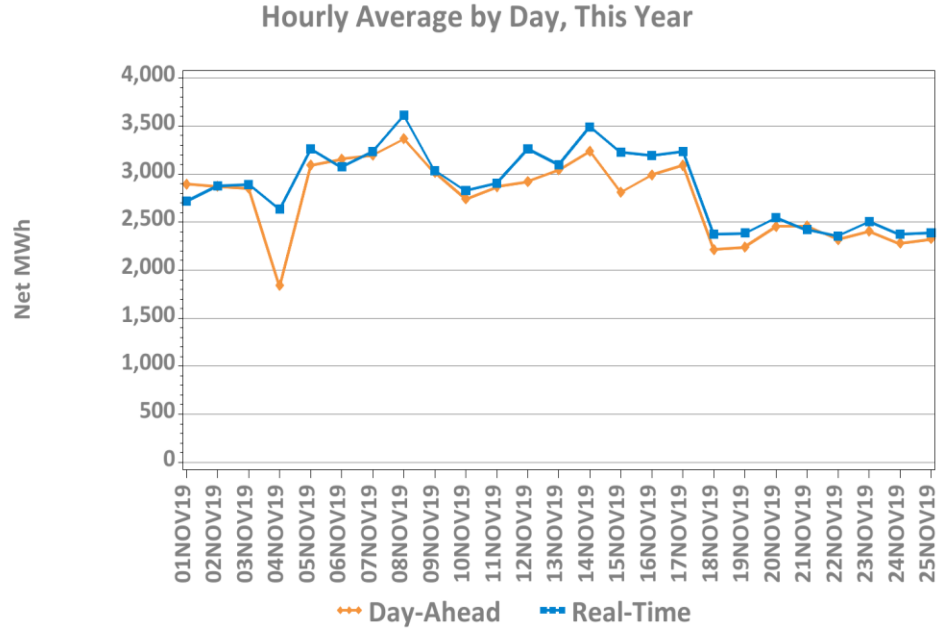
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

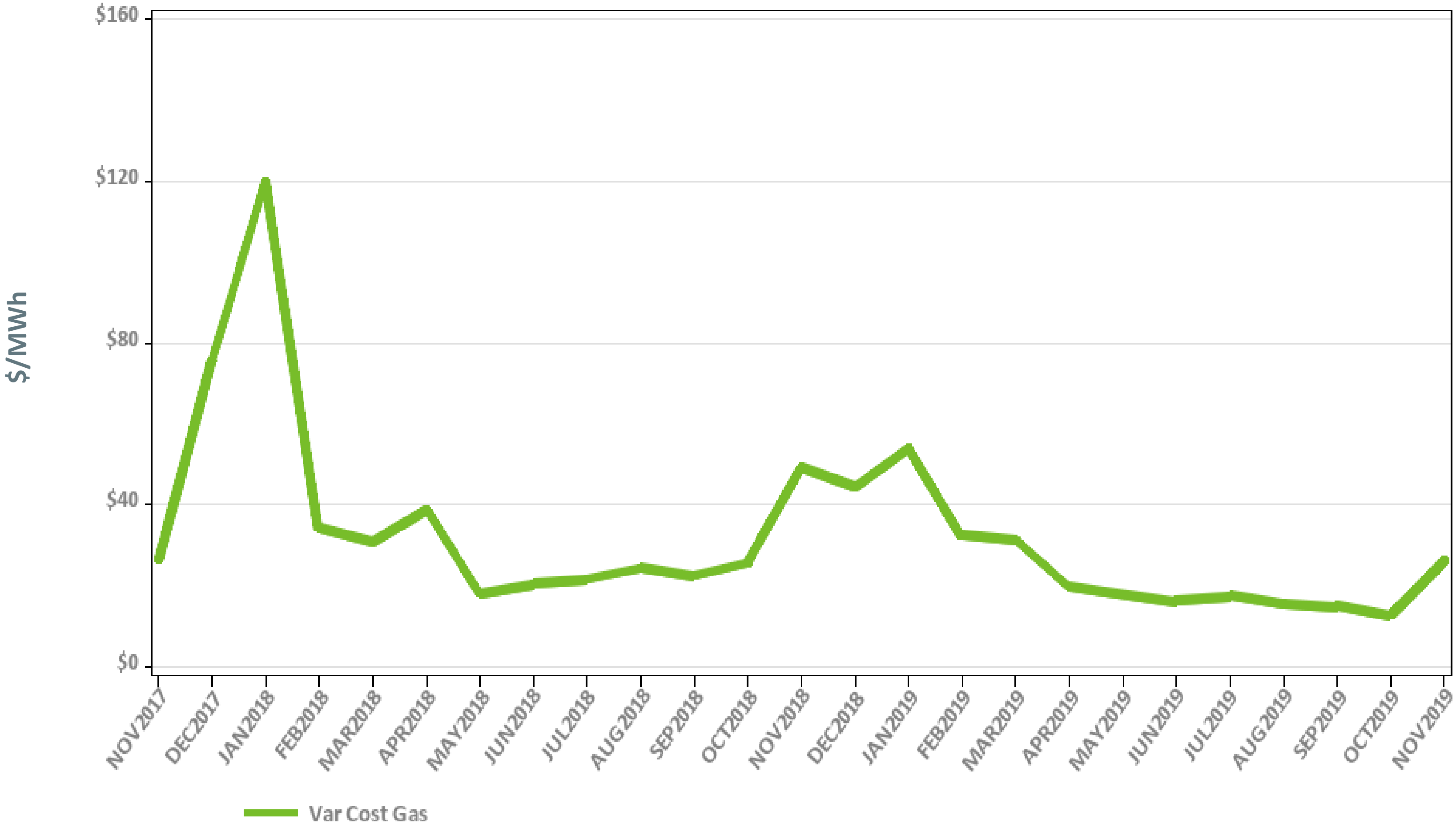
DA vs. RT Net Interchange November 2019 vs. November 2018





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

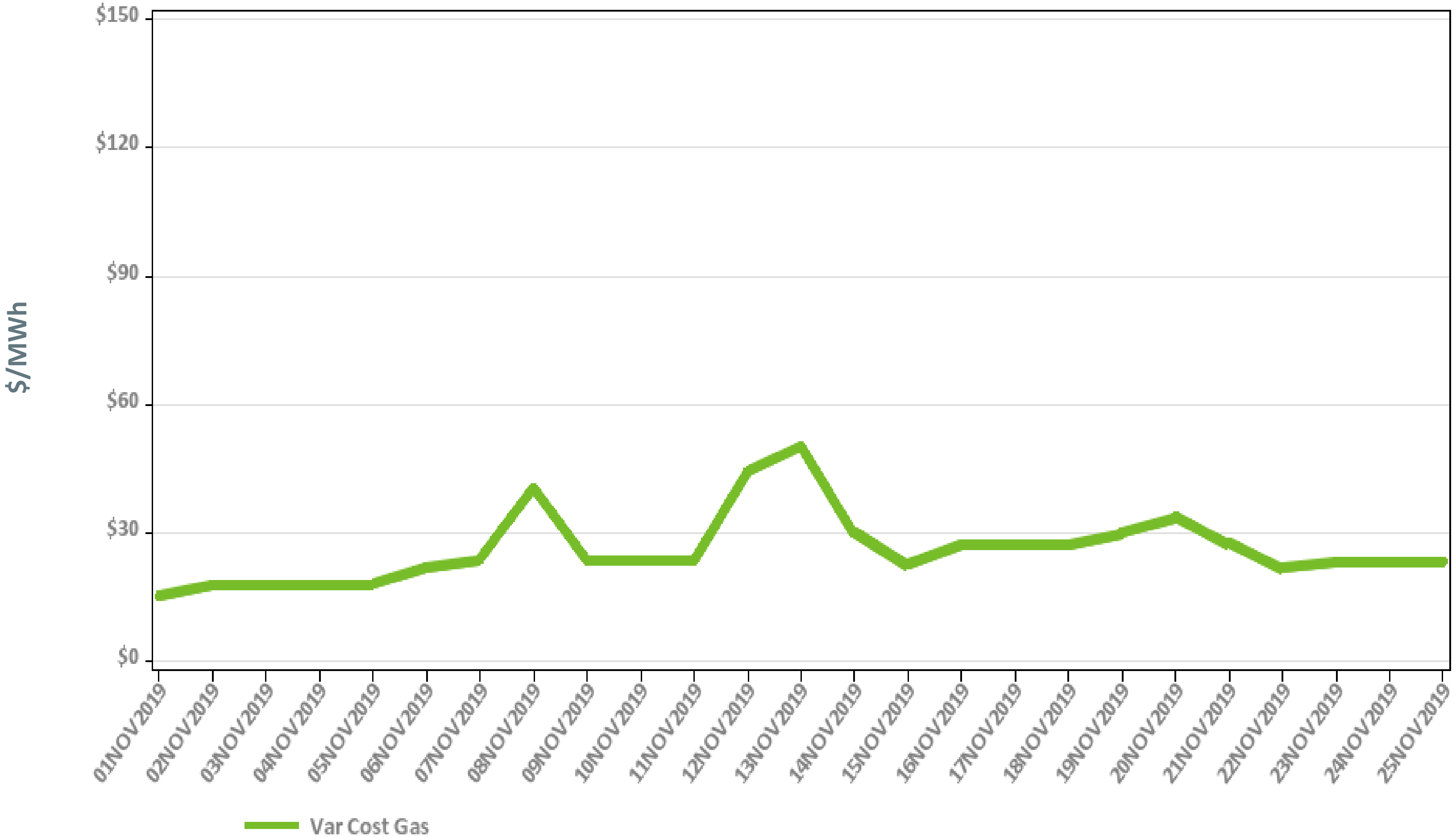


Underlying natural gas data furnished by:

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

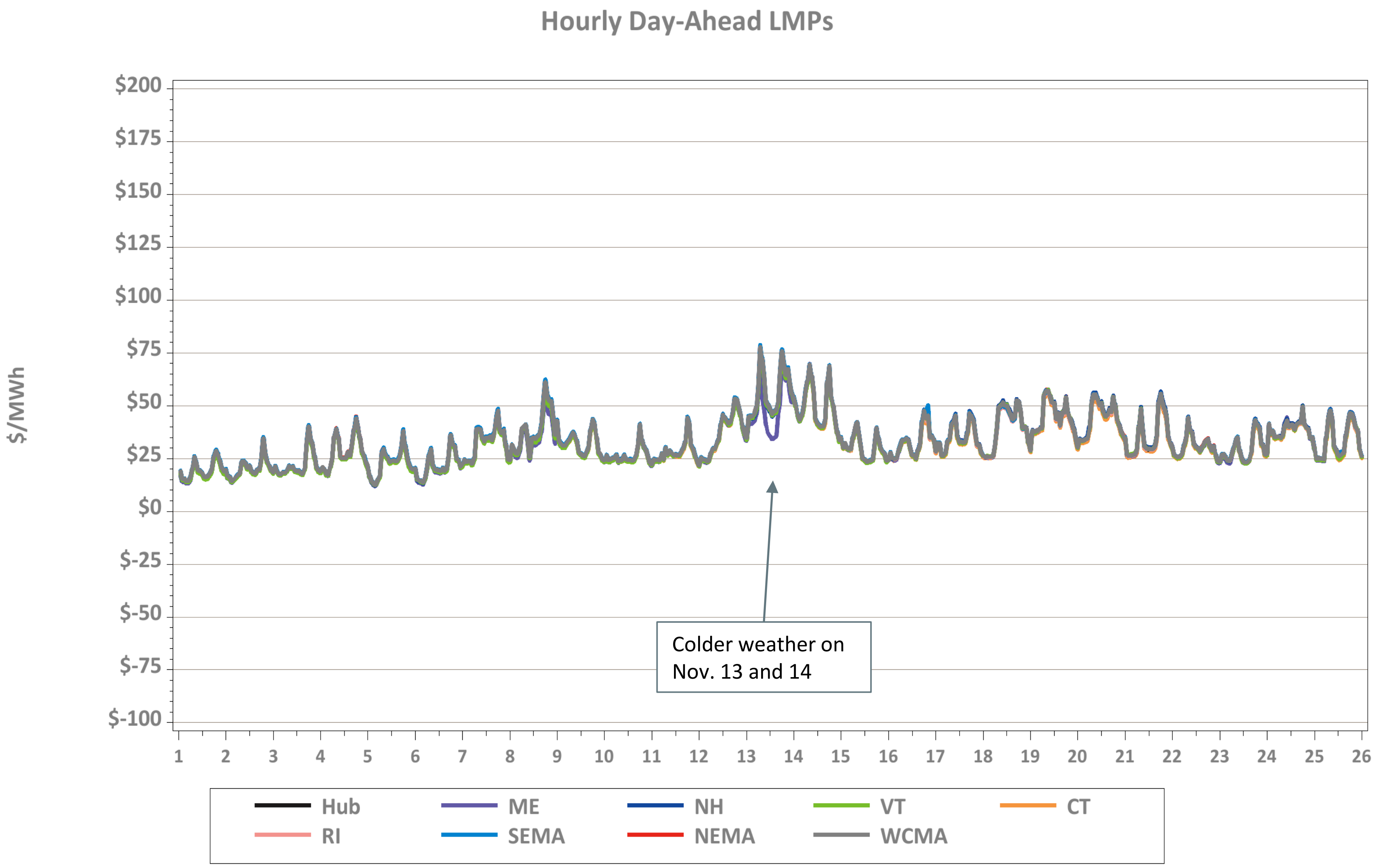


Underlying natural gas data furnished by:

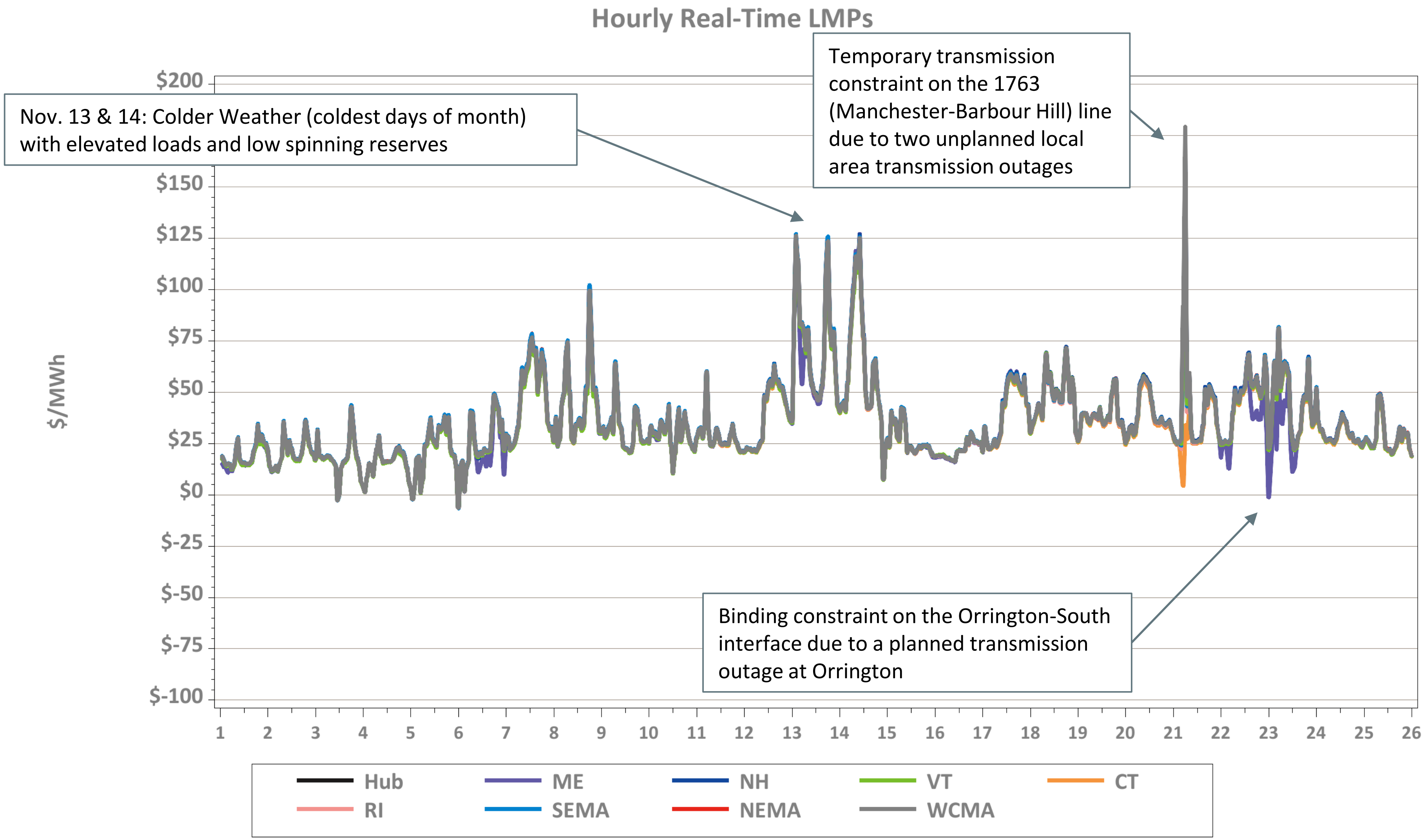
ice Global markets in clear view

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

Hourly DA LMPs, November 1-25, 2019

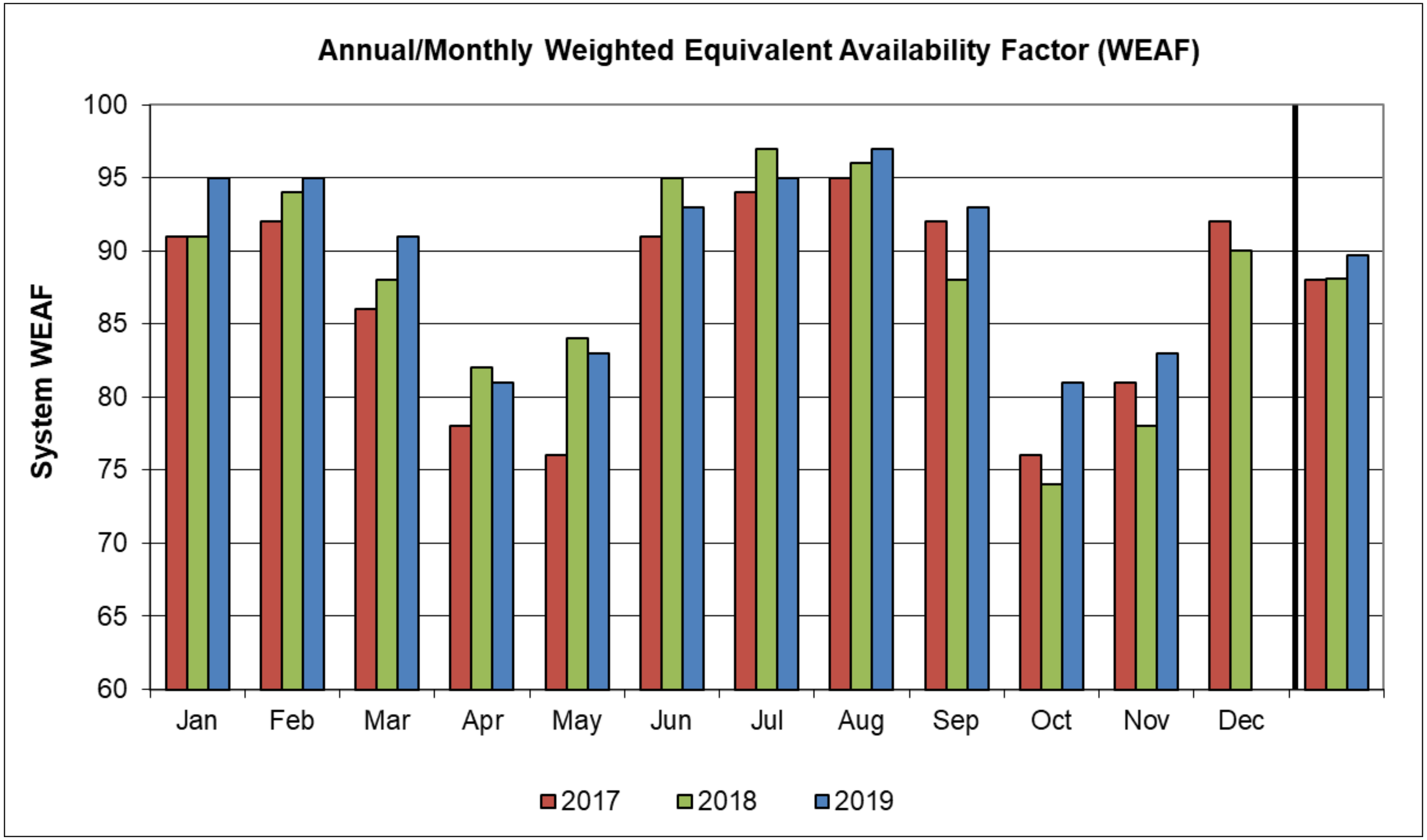


Hourly RT LMPs, November 1-25, 2019



- No Minimum Generation Emergencies were declared during November.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2019	95	95	91	81	83	93	95	97	93	81	83		90
2018	91	94	88	82	84	95	97	96	88	74	78	90	88
2017	91	92	86	78	76	91	94	95	92	76	81	92	88

Data as of 11/29/19

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for December 2019

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	111.9	168.0	0.0	279.9
NH	27.3	90.9	0.0	118.3
VT	29.2	142.9	0.0	172.1
CT	100.8	77.4	437.6	615.7
RI	30.0	227.4	0.0	257.5
SEMA	37.0	396.2	0.0	433.1
WCMA	61.5	430.0	33.9	525.4
NEMA	57.1	619.0	0.0	676.1
Total	**454.8**	**2,151.8**	**471.5**	**3,078.1**

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

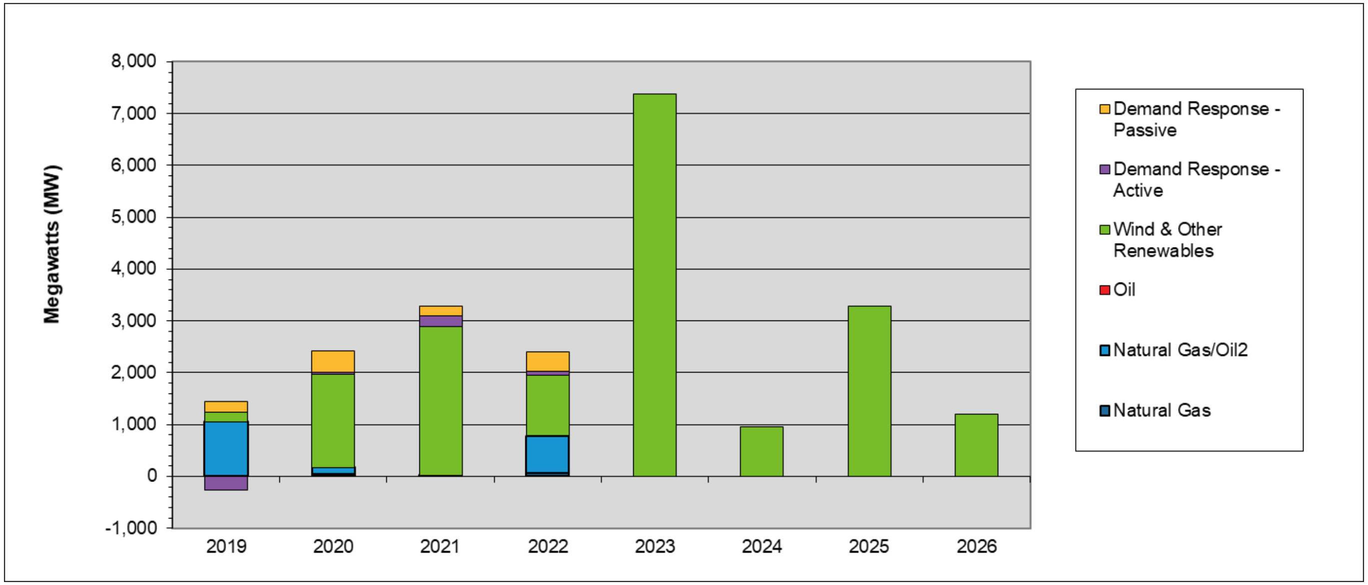
NEW GENERATION

New Generation Update

Based on Queue as of 12/2/19

- 3 projects totaling 98 MW applied for interconnection study since the last update
- 2 projects withdrew and none went commercial resulting in a net decrease in new generation projects of 952 MW
- In total, 178 generation projects are currently being tracked by the ISO, totaling approximately 19,732 MW

Actual and Projected Annual Capacity Additions
By Supply Fuel Type and Demand Resource Type



	2019	2020	2021	2022	2023	2024	2025	2026	Total MW	% of Total[1]
Demand Response - Passive	212	422	184	380	0	0	0	0	1,199	5.4
Demand Response - Active	-270	42	204	62	0	0	0	0	39	0.2
Wind & Other Renewables	187	1,792	2,870	1,175	7,371	960	3,276	1,200	18,831	85.2
Oil	0	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	1,052	121	0	711	0	0	0	0	1,884	8.5
Natural Gas	0	49	25	73	0	0	0	0	147	0.7
Totals	**1,182**	**2,427**	**3,283**	**2,401**	**7,371**	**960**	**3,276**	**1,200**	**22,100**	**100.0**

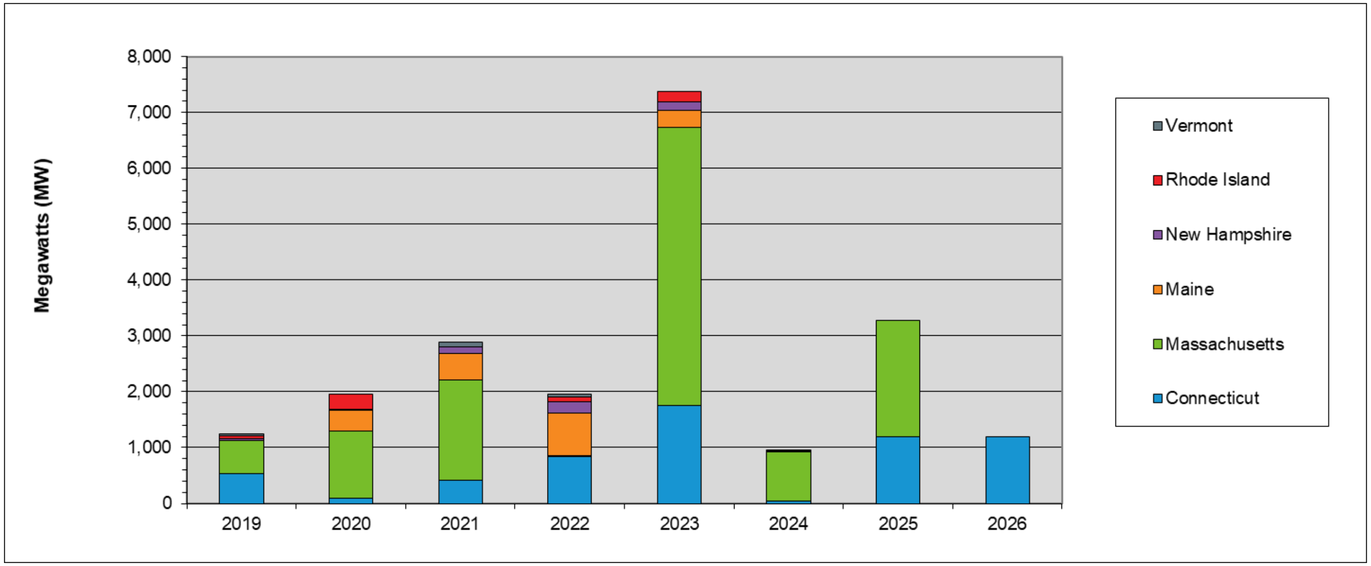
[1] Sum may not equal 100% due to rounding

[2] The projects in this category are dual fuel, with either gas or oil as the primary fuel

- DR reflects changes from the initial FCM Capacity Supply Obligations since 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2019	2020	2021	2022	2023	2024	2025	2026	Total MW	% of Total[1]
Vermont	33	0	85	60	0	0	0	0	178	0.9
Rhode Island	50	282	0	73	180	0	0	0	585	2.8
New Hampshire	28	10	118	210	150	20	0	0	536	2.6
Maine	0	378	480	755	301	20	0	0	1,934	9.3
Massachusetts	592	1,192	1,790	16	4,980	880	2,076	0	11,526	55.2
Connecticut	536	100	422	845	1,760	40	1,200	1,200	6,103	29.3
Totals	**1,239**	**1,962**	**2,895**	**1,959**	**7,371**	**960**	**3,276**	**1,200**	**20,862**	**100.0**

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

New Generation Projection

By Fuel Type

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/wood waste	1	37	0	0	1	37
Hydro	2	71	0	0	2	71
Landfill Gas	0	0	0	0	0	0
Natural Gas	6	210	0	0	6	210
Natural Gas/Oil	6	832	1	45	5	787
Oil	0	0	0	0	0	0
Solar	124	3,475	4	87	120	3,388
Wind	24	13,092	2	33	22	13,059
Battery storage	15	2,015	0	0	15	2,015
Total	178	19,732	7	165	171	19,567

- 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

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	6	167	0	0	6	167
Intermediate	2	116	0	0	2	116
Peaker	146	6,357	5	132	141	6,225
Wind Turbine	24	13,092	2	33	22	13,059
Total	178	19,732	7	165	171	19,567

- 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

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Fuel Type	**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	37	1	37	0	0	0	0	0	0
Hydro	2	71	1	5	0	0	1	66	0	0
Landfill Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas	6	210	3	88	2	116	1	6	0	0
Natural Gas/Oil	6	832	0	0	0	0	6	832	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	124	3,475	1	37	0	0	123	3,438	0	0
Wind	24	13,092	0	0	0	0	0	0	24	13,092
Battery storage	15	2,015	0	0	0	0	15	2,015	0	0
Total	178	19,732	6	167	2	116	146	6,357	24	13,092

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 10

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	377.525	367.227	-10.298	464.715	97.488	460.55	-4.165	459.928	-0.622	457.966	-1.962	493.5	35.534
	Passive Demand	2,368.631	2,366.783	-1.848	2,363.949	-2.834	2,363.789	-0.16	2,527.244	163.46	2,529.014	1.77	2594.08	65.066
Demand Total		**2,746.156**	**2,734.01**	**-12.146**	**2,828.664**	**94.654**	**2,824.339**	**-4.325**	**2,987.172**	**162.83**	**2,986.98**	**-0.192**	**3,087.58**	**100.6**
Generator	*Non-Intermittent*	30,520.433	30,462.67	-57.763	30,048.398	-414.272	30,103.684	55.286	30,093.142	-10.54	30,081.64	-11.502	30,146.76	65.115
	Intermittent	850.143	893.189	43.046	904.311	11.122	831.251	-73.06	798.958	-32.293	800.387	1.429	733.668	-66.719
Generator Total		**31,370.576**	**31,355.86**	**-14.716**	**30,952.709**	**-403.151**	**30,934.935**	**-17.774**	**30,892.1**	**-42.84**	**30,882.027**	**-10.073**	**30,880.42**	**-1.604**
Import Total		**1,449.8**	**1,449.8**	**0**	**1,451**	**1.2**	**1,451**	**0**	**1,451**	**0**	**1,459**	**8**	1,428	-31
**Grand Total		**35,566.532**	**35,539.668**	**-26.864**	**35,232.373**	**-307.295**	**35,210.274**	**-22.099**	**35,330.272**	**120.00**	**35,328.007**	**-2.265**	**35,396**	**67.996**
Net ICR (NICR)		**34,151**	**33,755**	**-396**	**33,755**	**0**	**33,407**	**-348**	**33,407**	**0**	**33,390**	**-17**	33,390	0

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** 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 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		
	Passive Demand	2,791.02	2,835.354	44.334	2,883.767	48.413		
Demand Total		**3,210.95**	**3,276.575**	**65.625**	**3,478.318**	**201.743**		
Generator	*Non-Intermittent*	30,494.80	30,064.23	-430.569	30,159.891	95.661		
	Intermittent	894.217	823.796	-70.421	809.571	-14.225		
Generator Total		**31,389.02**	**30,888.03**	**-500.993**	**30,969.462**	**81.432**		
Import Total		**1,235.40**	**1,622.037**	**386.637**	**1,609.844**	**-12.193**		
****Grand Total**		**35,835.37**	**35,786.64**	**-48.731**	**36,057.624**	**270.984**		
Net ICR (NICR)		**34,075**	**33,660**	**-415**	**33,520**	**-140**		

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** 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	FCA	ARA 1		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				
	Passive Demand	2,975.36	3,045.073	69.713				
Demand Total		**3,599.81**	**3,704.21**	**104.4**				
Generator	*Non-Intermittent*	29,130.75	29,244.404	113.654				
	Intermittent	880.317	806.609	-73.708				
Generator Total		**30,011.07**	**30,051.013**	**39.943**				
Import Total		**1,217**	**1,305.487**	**88.487**				
****Grand Total**		**34,827.88**	**35,060.710**	**232.83**				
Net ICR (NICR)		**33,725**	**33,550**	**-175**				

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** 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						
	Passive Demand		3,354.69						
Demand Total			**4,040.244**						
Generator		*Non-Intermittent*	28,586.498						
		Intermittent	1,024.792						
Generator Total			**2,9611.29**						
Import Total			**1,187.69**						
**Grand Total			**34,839.224**						
Net ICR (NICR)			**33,750**						

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** 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
2010-11	Active	1,246.40	603.675	1,850.07
	Passive	119.211	584.277	703.488
	Grand Total	1365.61	1187.952	2553.562
2011-12	Active	1,768.39	184.99	1,953.38
	Passive	719.98	263.25	983.23
	Grand Total	2488.372	448.24	2936.612
2012-13	Active	1,726.55	98.227	1,824.78
	Passive	861.602	211.261	1,072.86
	Grand Total	2588.15	309.488	2897.638
2013-14	Active	1,794.20	257.341	2,051.54
	Passive	1,040.11	257.793	1,297.91
	Grand Total	2834.308	515.134	3349.442
2014-15	Active	2,062.20	41.945	2,104.14
	Passive	1,264.64	221.072	1,485.71
	Grand Total	3326.837	263.017	3589.854
2015-16	Active	1,935.41	66.104	2,001.51
	Passive	1,395.89	247.449	1,643.33
	Grand Total	3331.291	313.553	3644.844
2016-17	Active	1,116.47	0.23	1,116.70
	Passive	1,386.56	244.775	1,631.34
	Grand Total	2503.028	245.005	2748.033
2017-18	Active	1,066.59	13.486	1,080.08
	Passive	1,619.15	341.37	1,960.52
	Grand Total	2685.74	354.856	3040.596
2018-19	Active	565.866	81.394	647.26
	Passive	1,870.55	285.602	2,156.15
	Grand Total	2436.415	366.996	2803.411
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

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

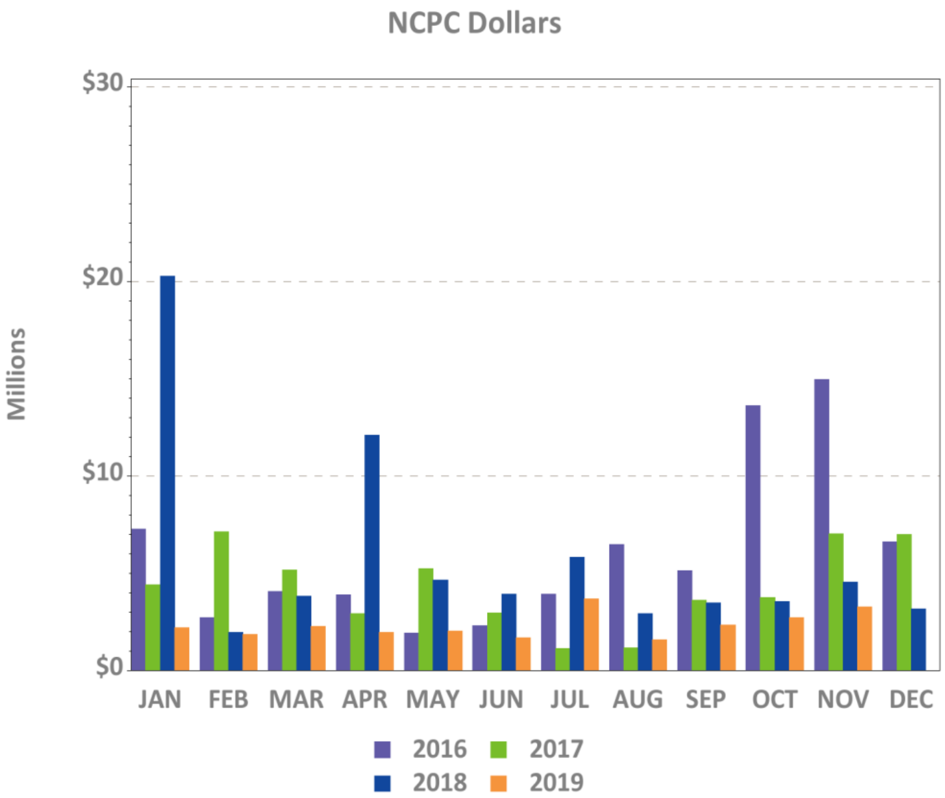
Definitions

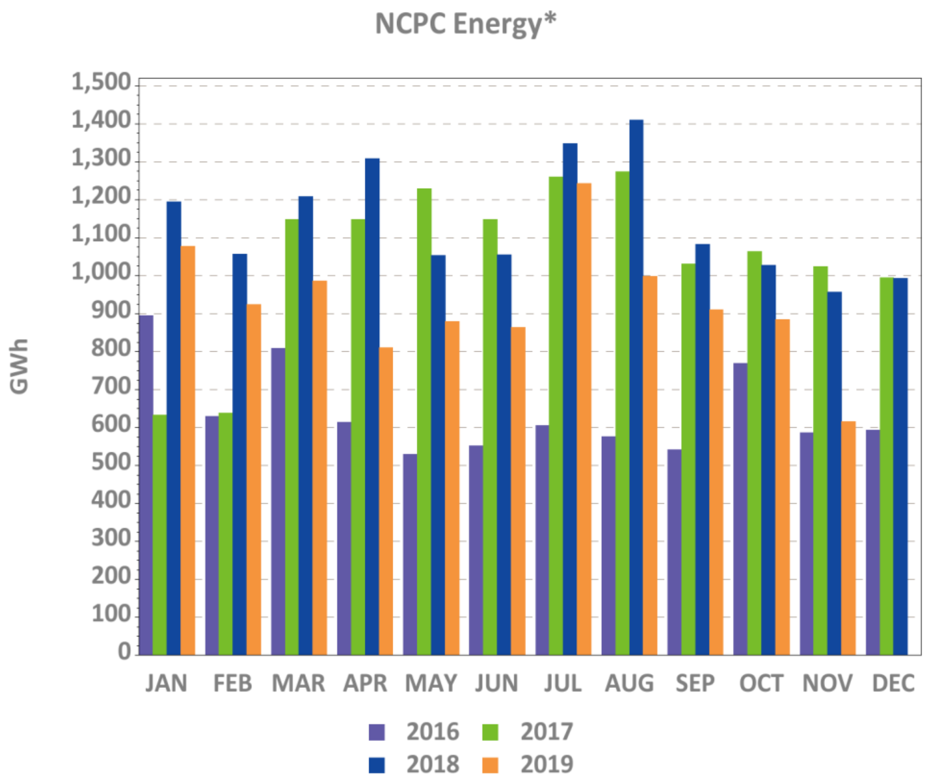
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing 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).

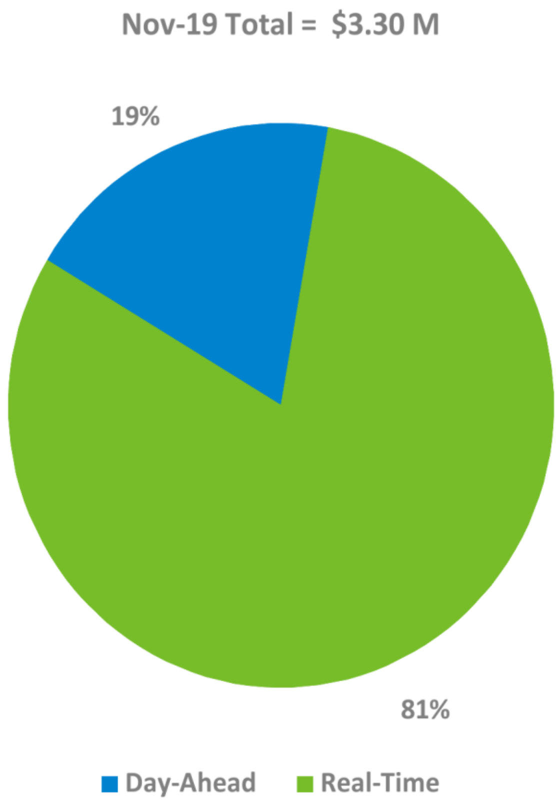
Year-Over-Year Total NCPC Dollars and Energy

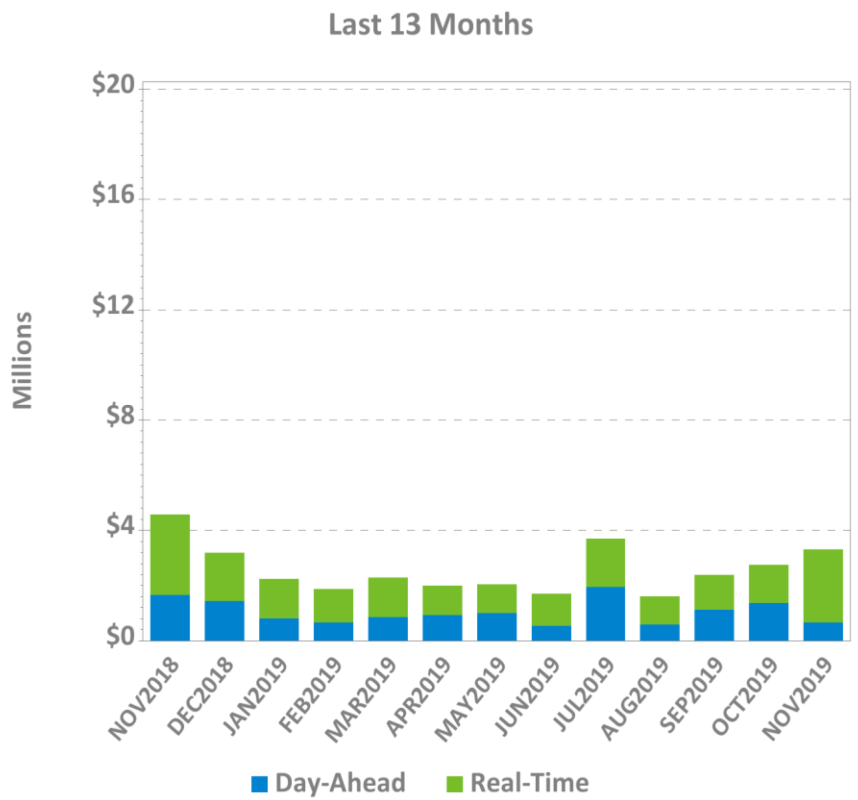




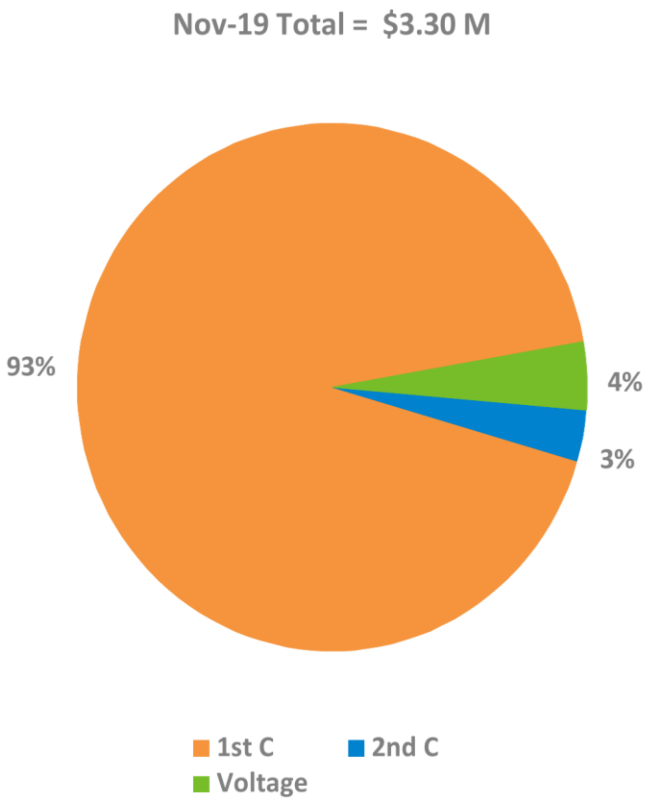
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

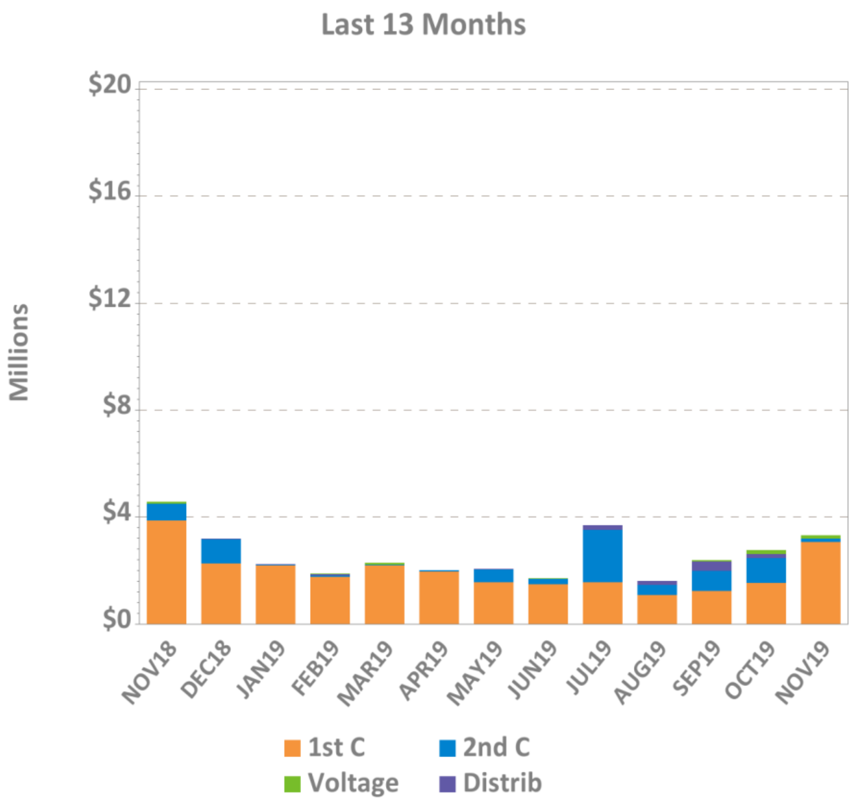
DA and RT NCPC Charges





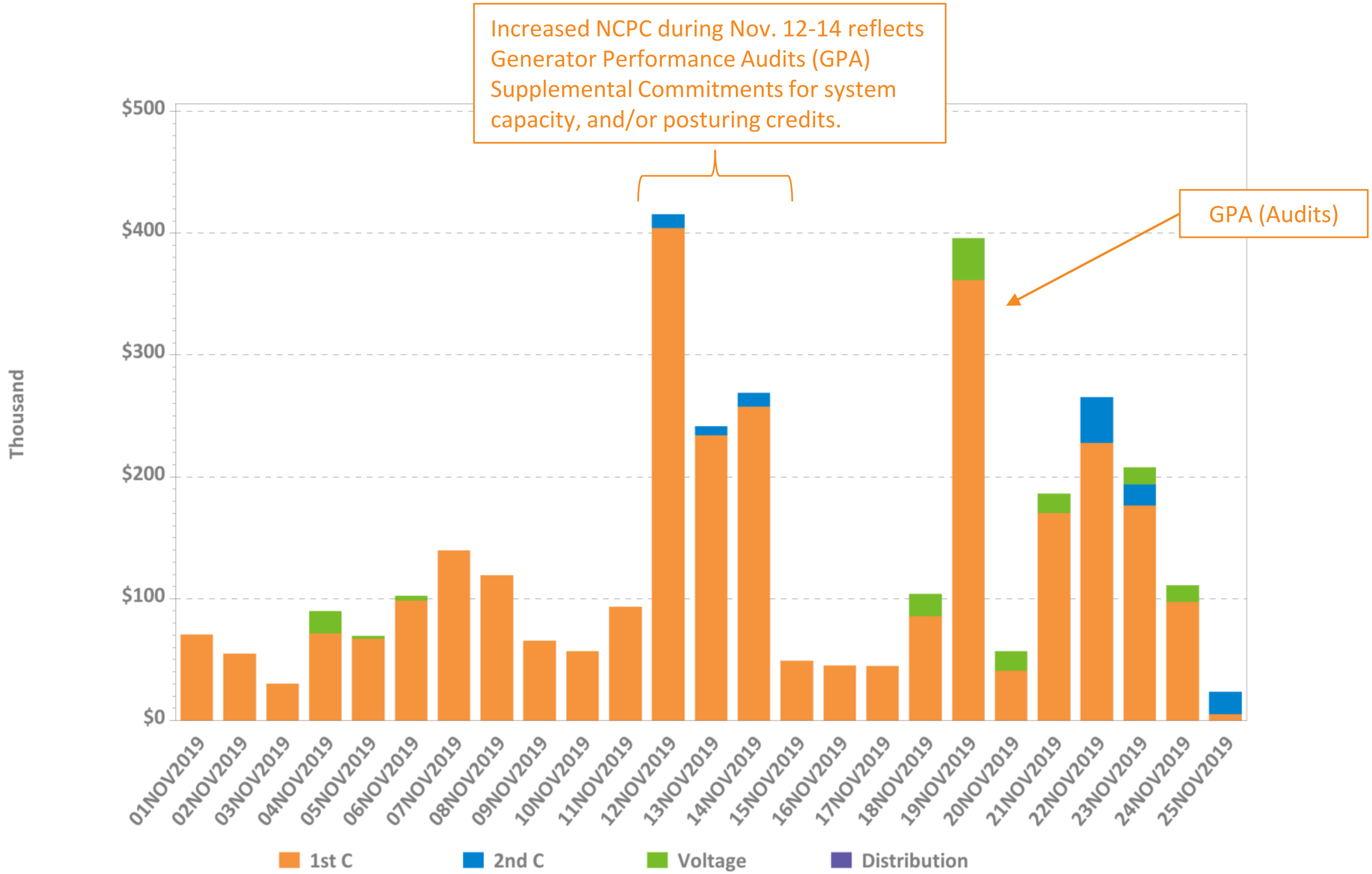
NCPC Charges by Type



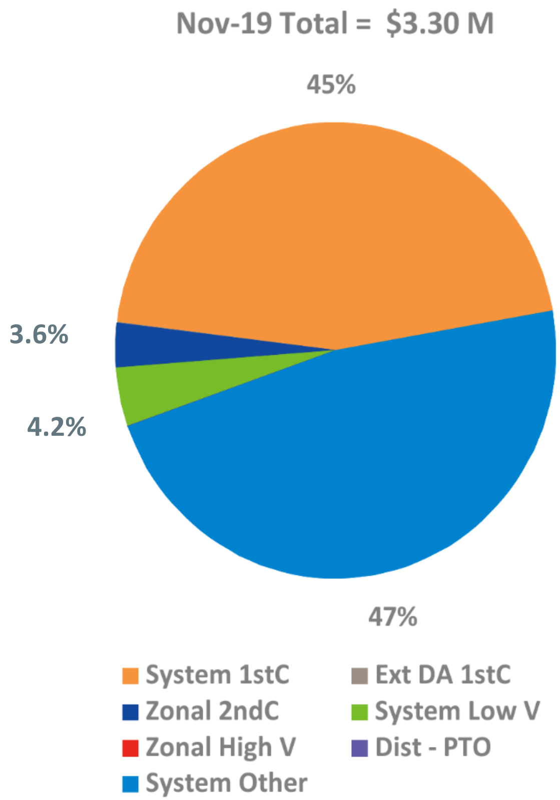


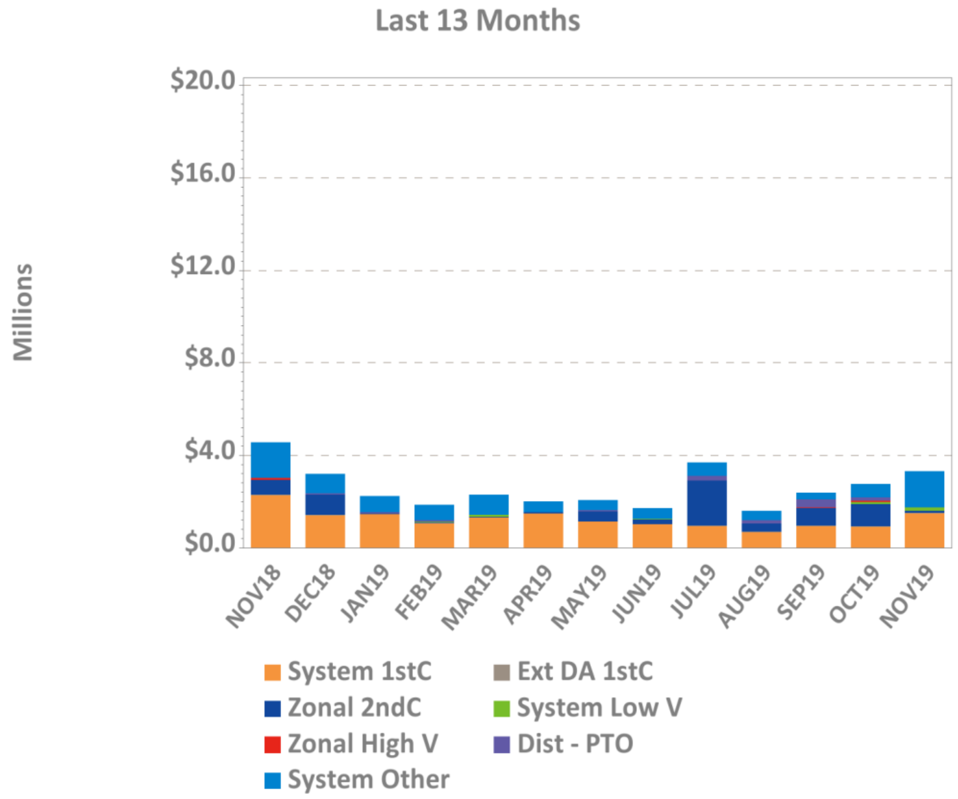
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



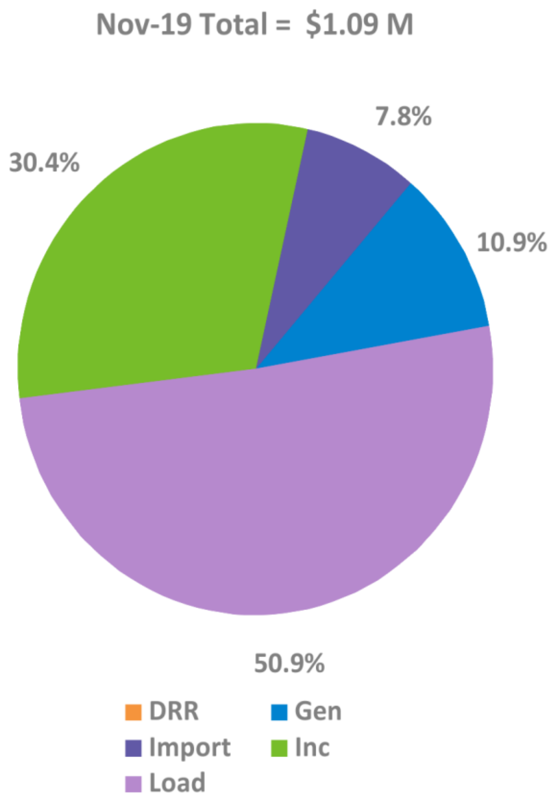
NCPC Charges by Allocation

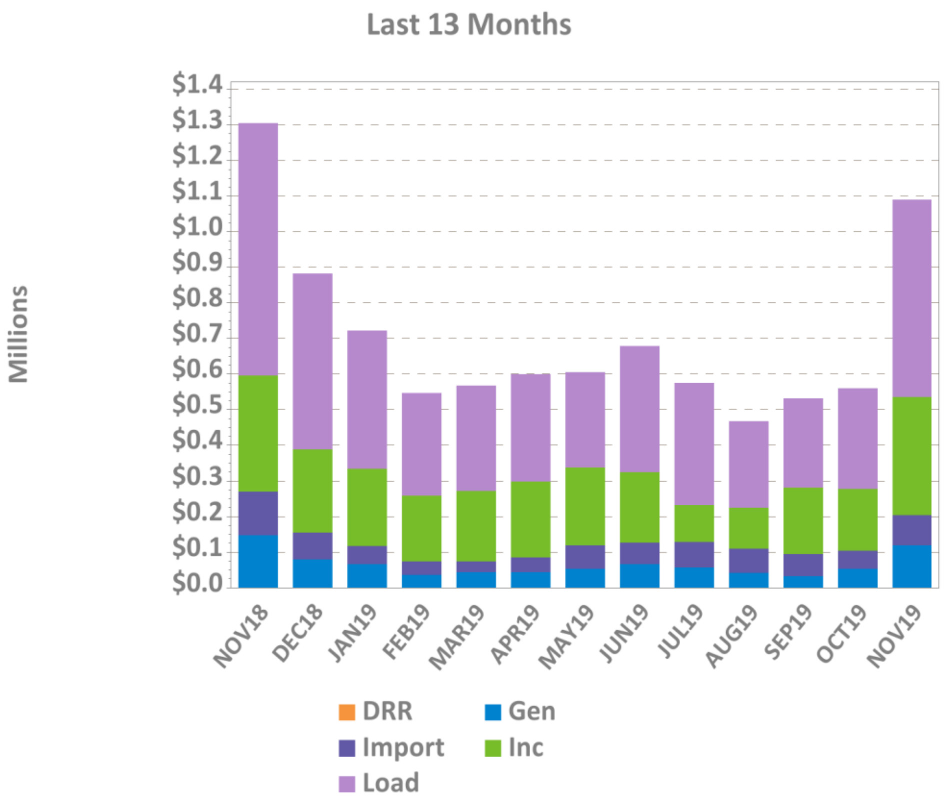




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

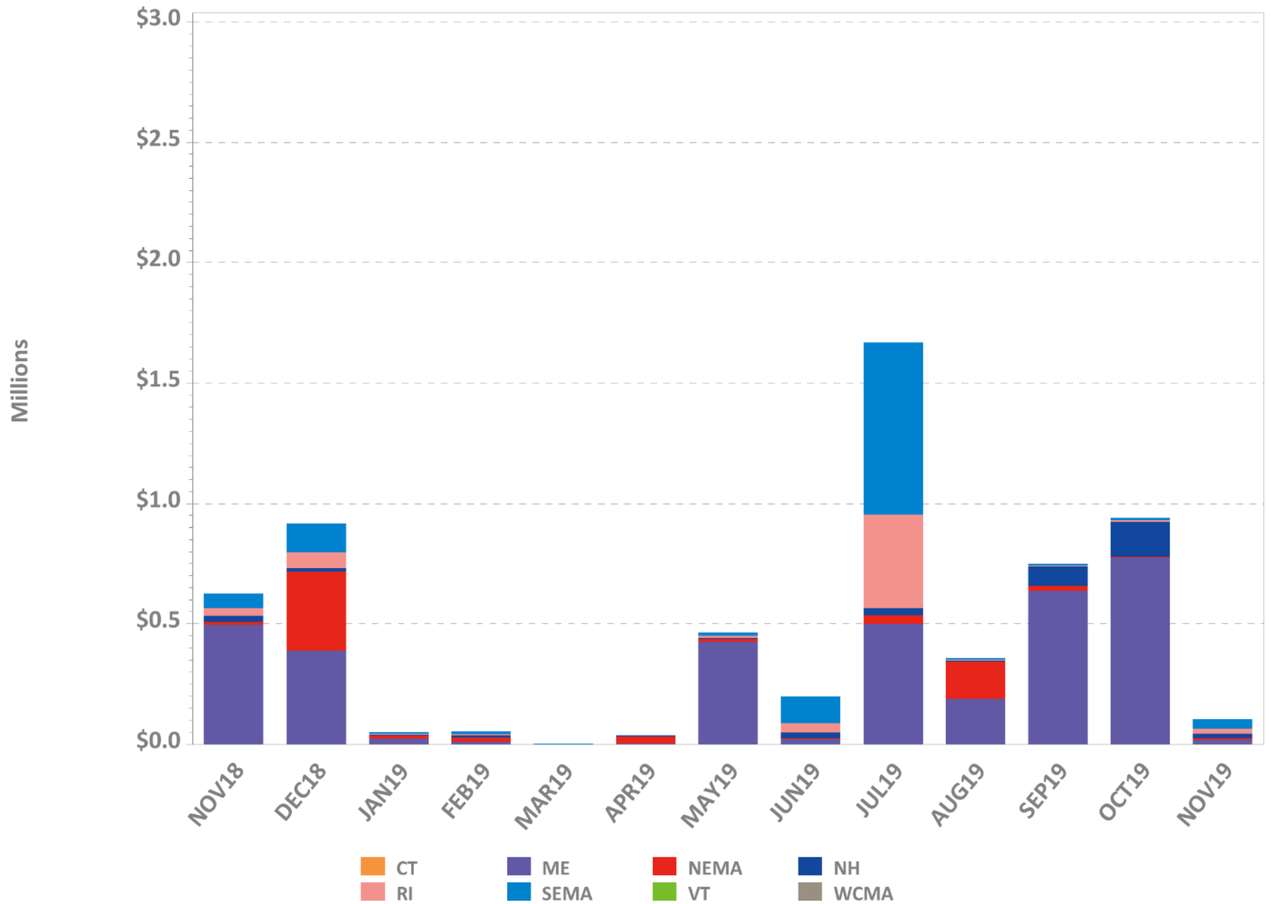
RT First Contingency Charges by Deviation Type





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

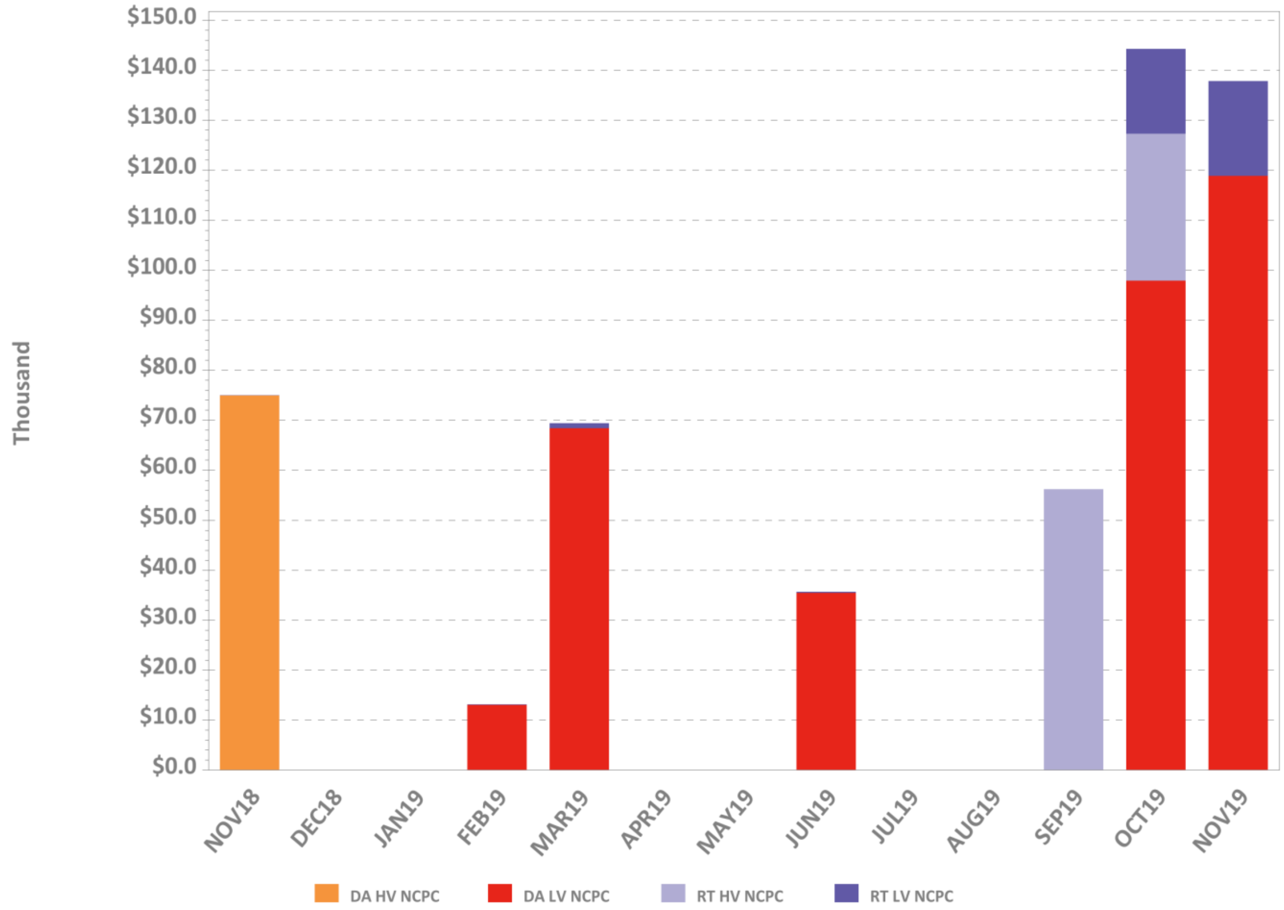
LSCPR Charges by Reliability Region



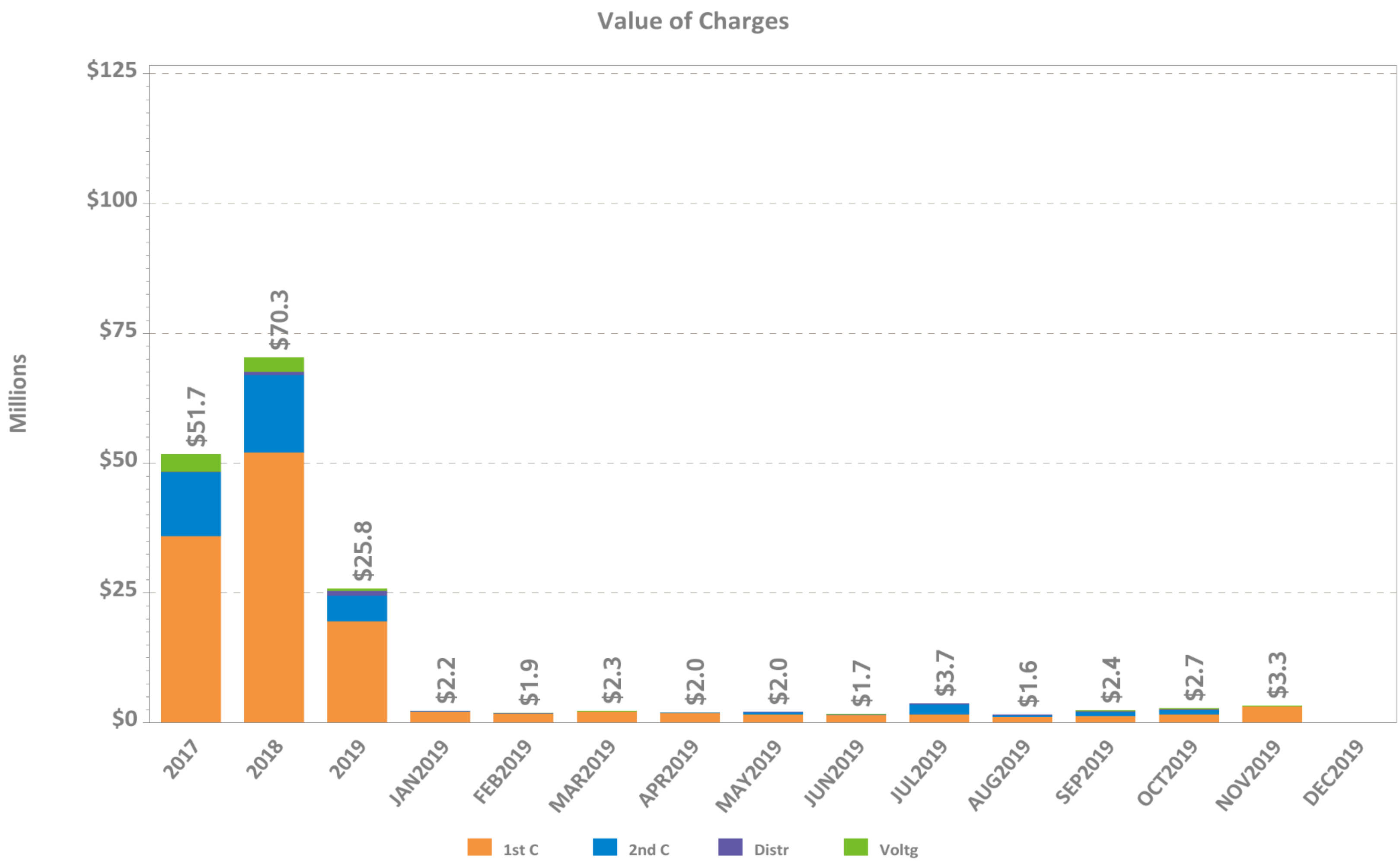
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region
EXT – External Locations

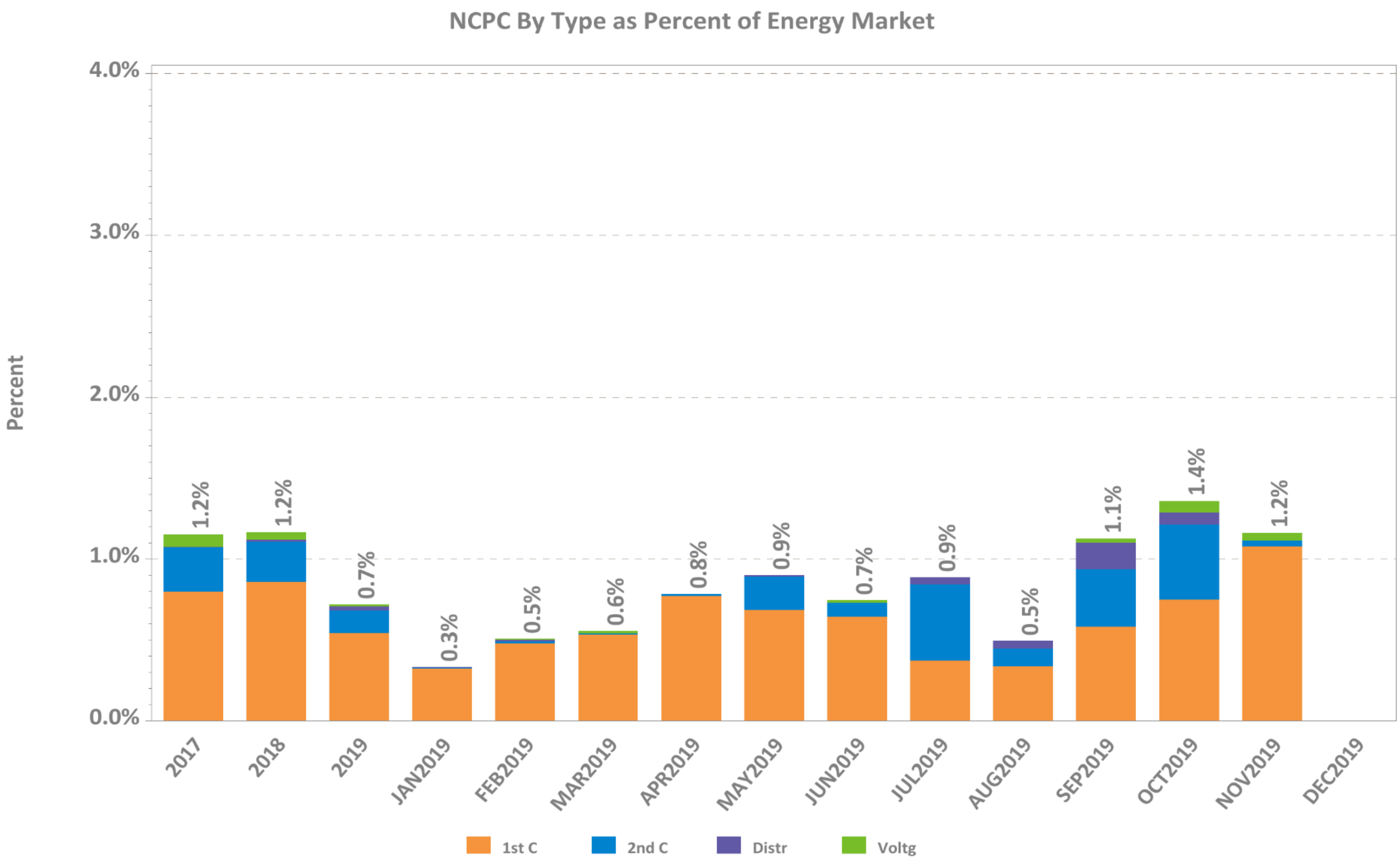
NCPC Charges for Voltage Support and High Voltage Control



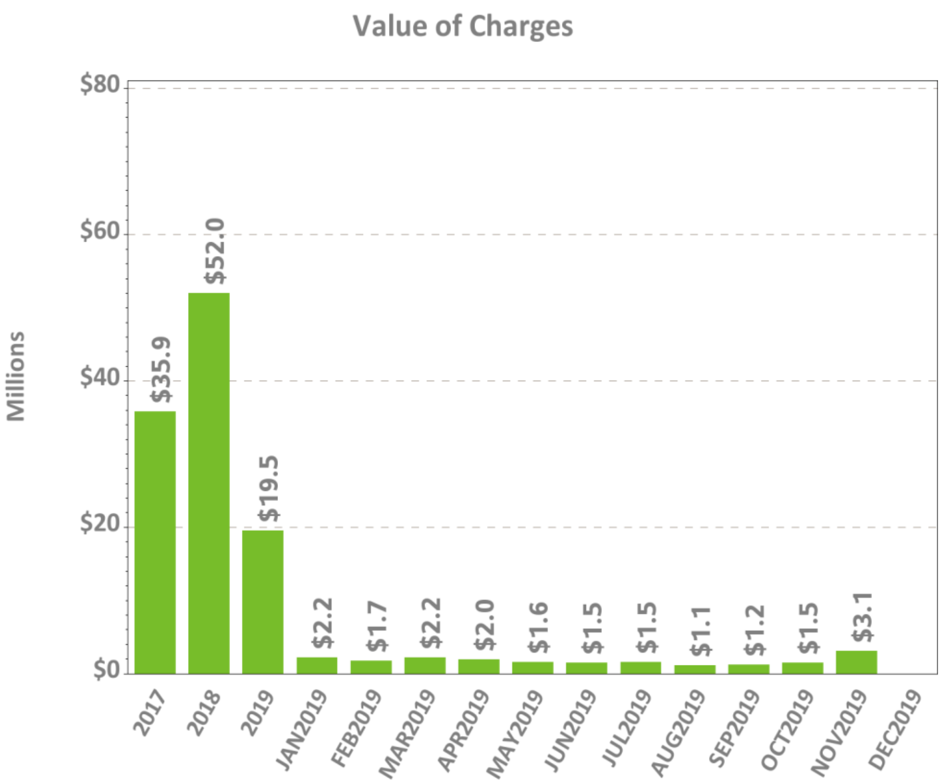
NCPC Charges by Type

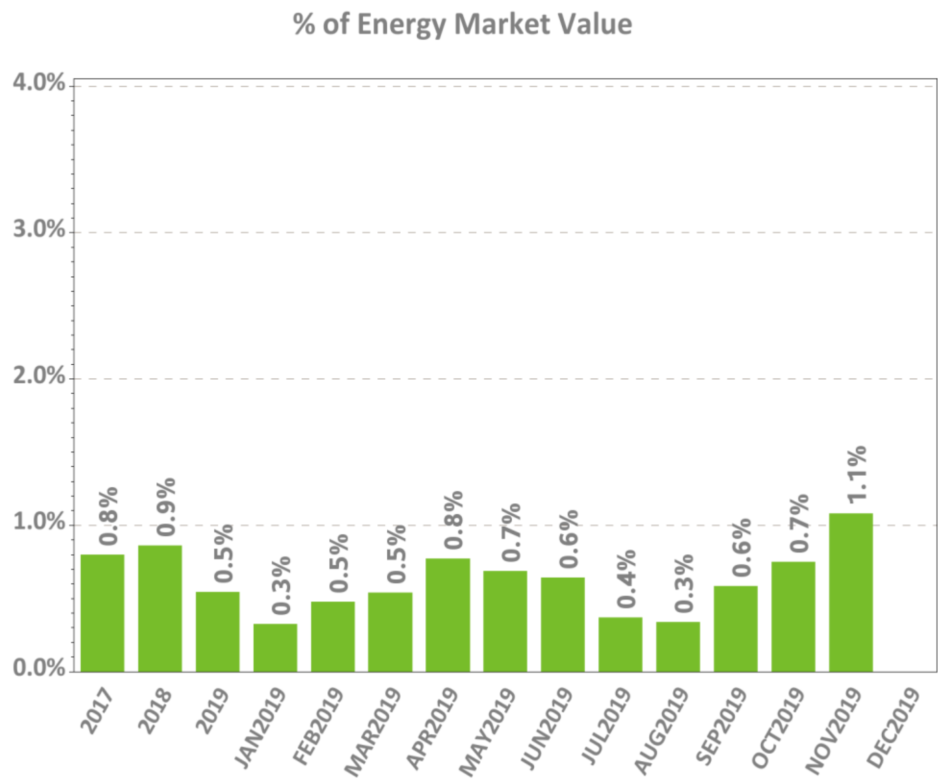


NCPC Charges as Percent of Energy Market



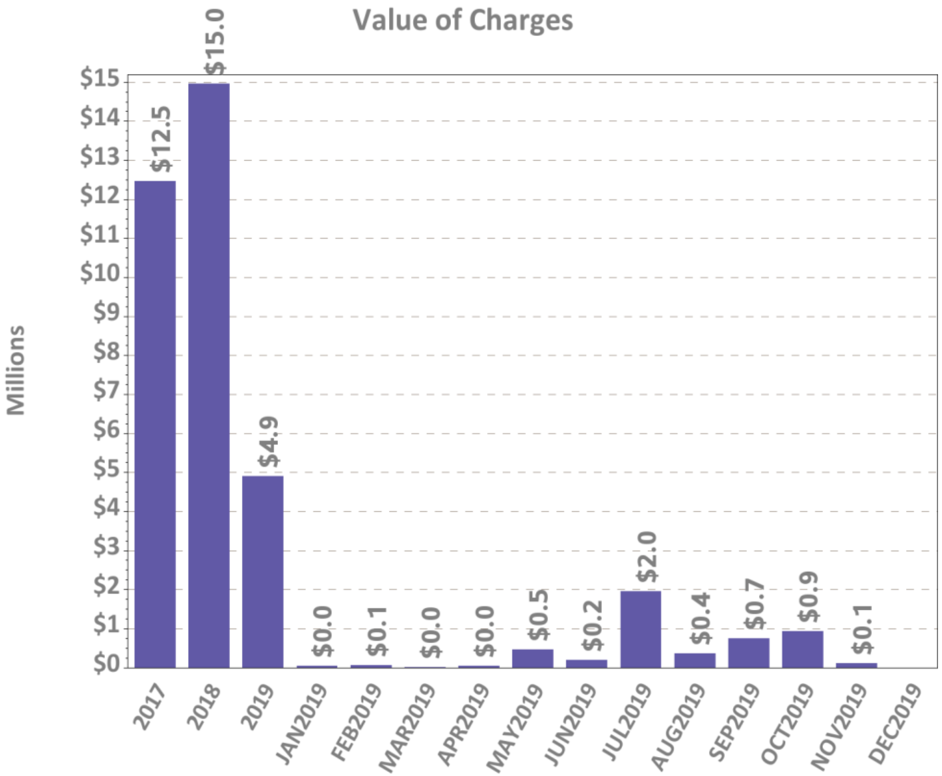
First Contingency NCPC Charges

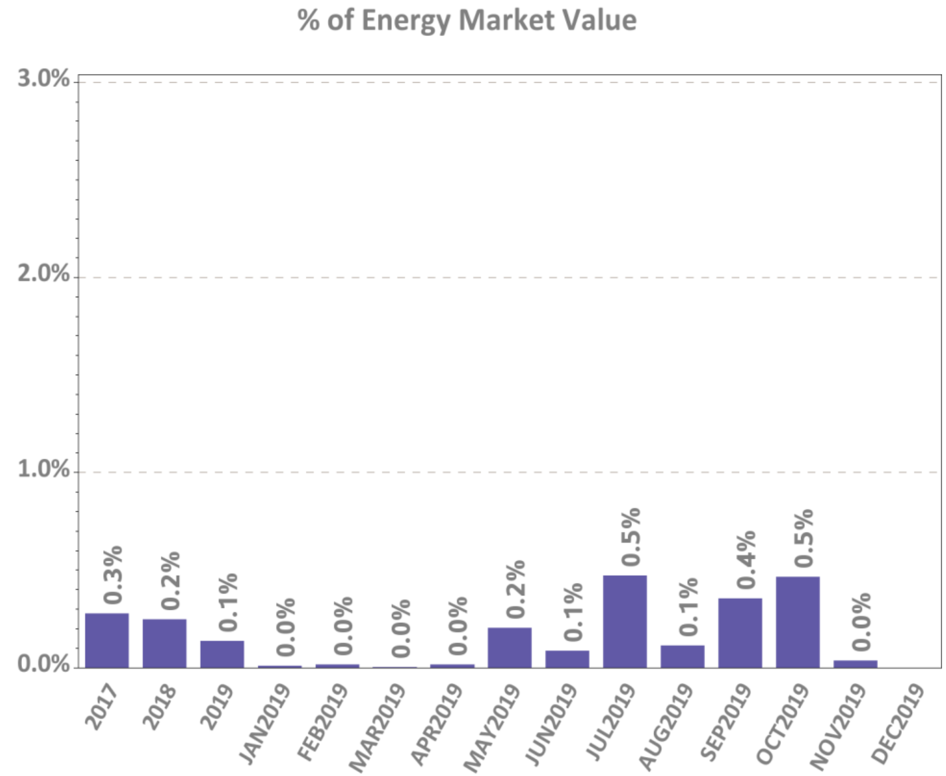




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

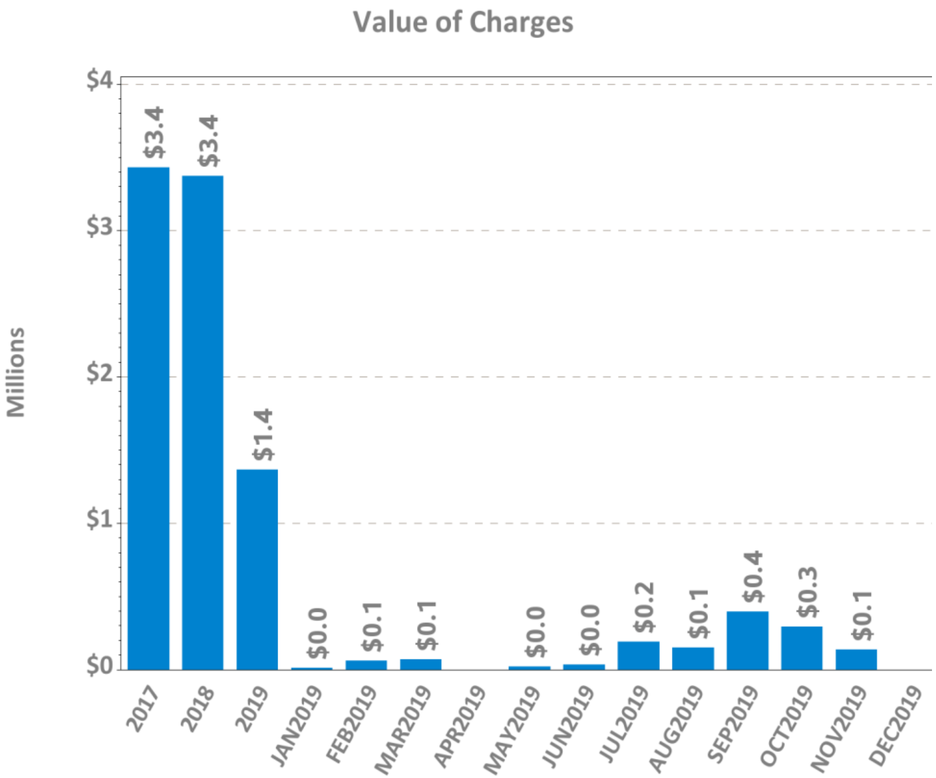
Second Contingency NCPC Charges

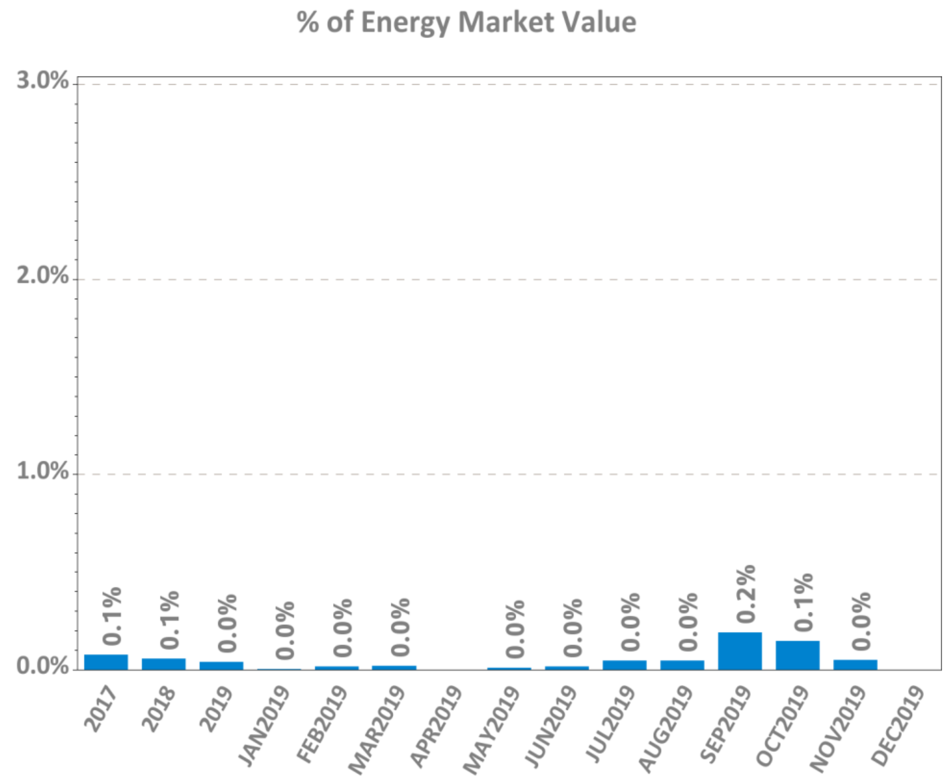




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

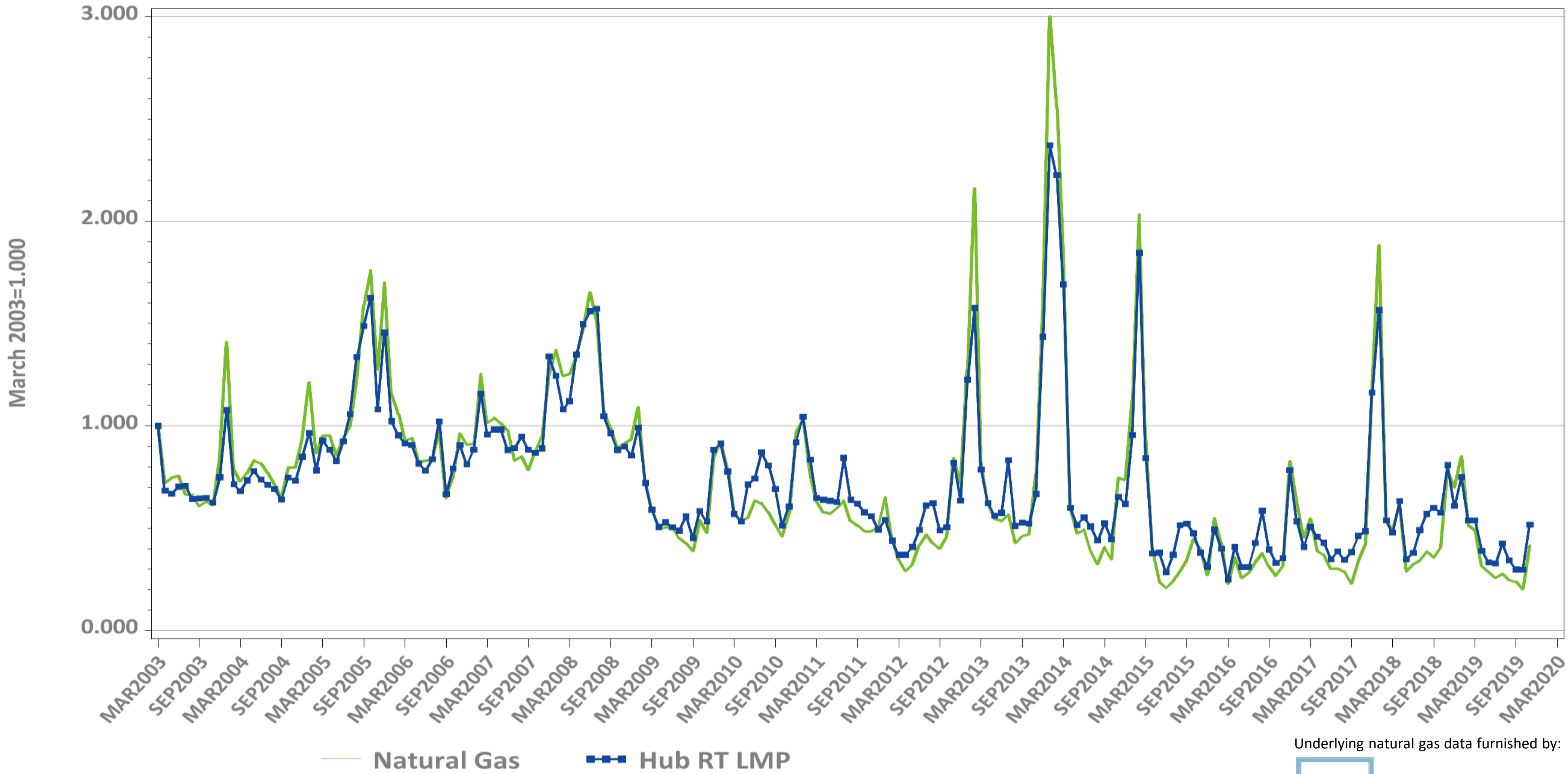
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2017	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$33.46	$33.35	$32.50	$33.13	$33.05	$33.13	$33.27	$33.43	$33.35
Real-Time	$34.76	$33.93	$31.39	$32.78	$33.02	$33.78	$33.98	$33.97	$33.94
RT Delta %	3.9%	1.7%	-3.4%	-1.0%	-0.1%	2.0%	2.1%	1.6%	1.7%
Year 2018	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$44.45	$43.60	$42.63	$44.04	$43.71	$44.11	$44.62	$44.19	$44.13
Real-Time	$43.87	$43.13	$41.03	$43.17	$42.83	$43.37	$43.68	$43.58	$43.54
RT Delta %	-1.3%	-1.1%	-3.8%	-2.0%	-2.0%	-1.7%	-2.1%	-1.4%	-1.3%

November-18	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$58.01	$56.08	$56.32	$57.59	$56.58	$57.10	$57.63	$57.46	$57.43
Real-Time	$56.51	$54.60	$52.18	$54.68	$54.14	$55.22	$55.72	$55.48	$55.49
RT Delta %	-2.6%	-2.6%	-7.3%	-5.0%	-4.3%	-3.3%	-3.3%	-3.4%	-3.4%
November-19	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$33.47	$32.45	$32.52	$33.29	$32.63	$33.12	$33.54	$33.28	$33.26
Real-Time	$35.76	$34.33	$34.32	$35.70	$34.80	$35.31	$35.76	$35.54	$35.52
RT Delta %	6.8%	5.8%	5.5%	7.3%	6.7%	6.6%	6.6%	6.8%	6.8%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-42.3%	-42.1%	-42.3%	-42.2%	-42.3%	-42.0%	-41.8%	-42.1%	-42.1%
Yr over Yr RT	-36.7%	-37.1%	-34.2%	-34.7%	-35.7%	-36.1%	-35.8%	-35.9%	-36.0%

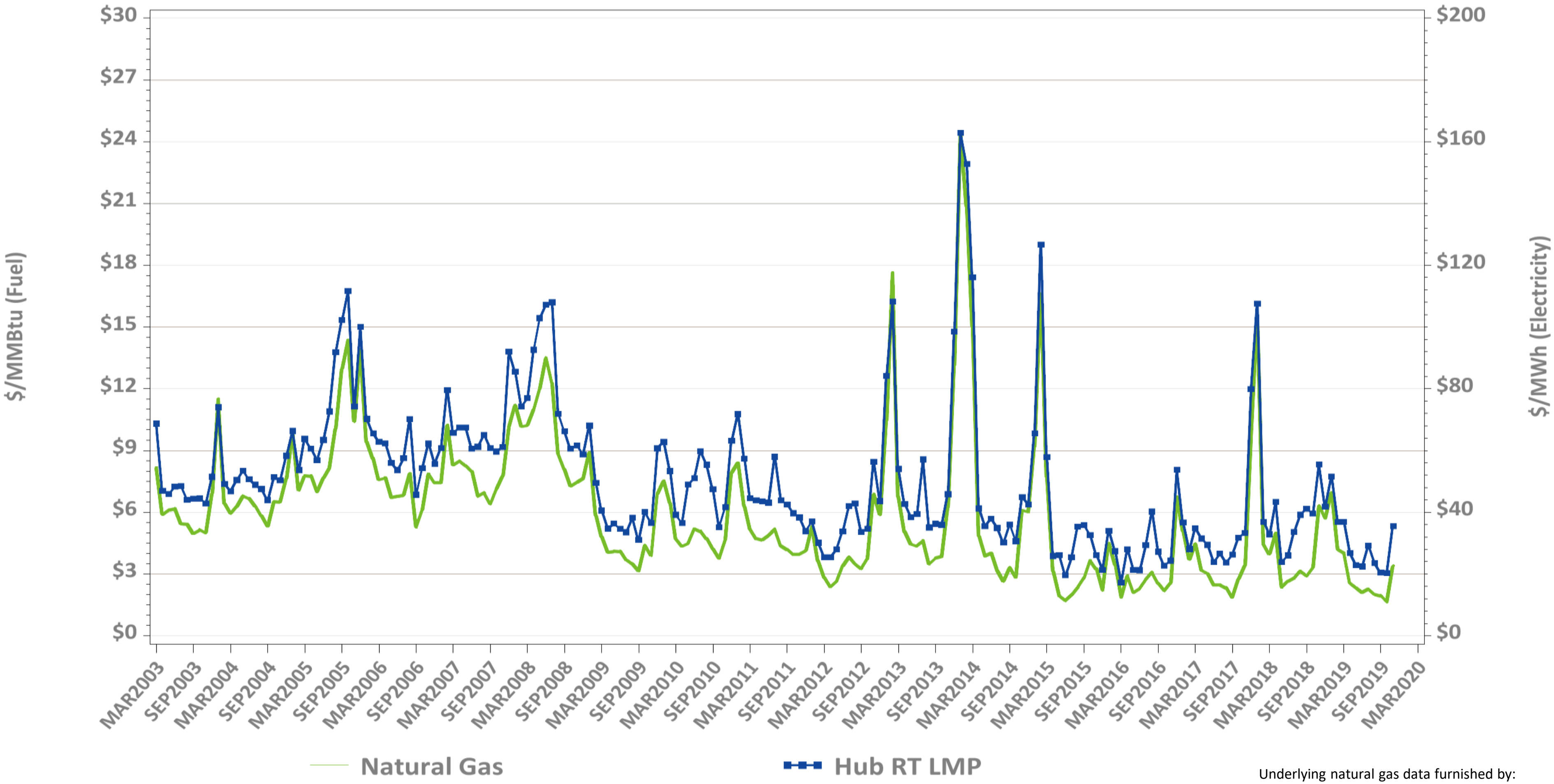
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

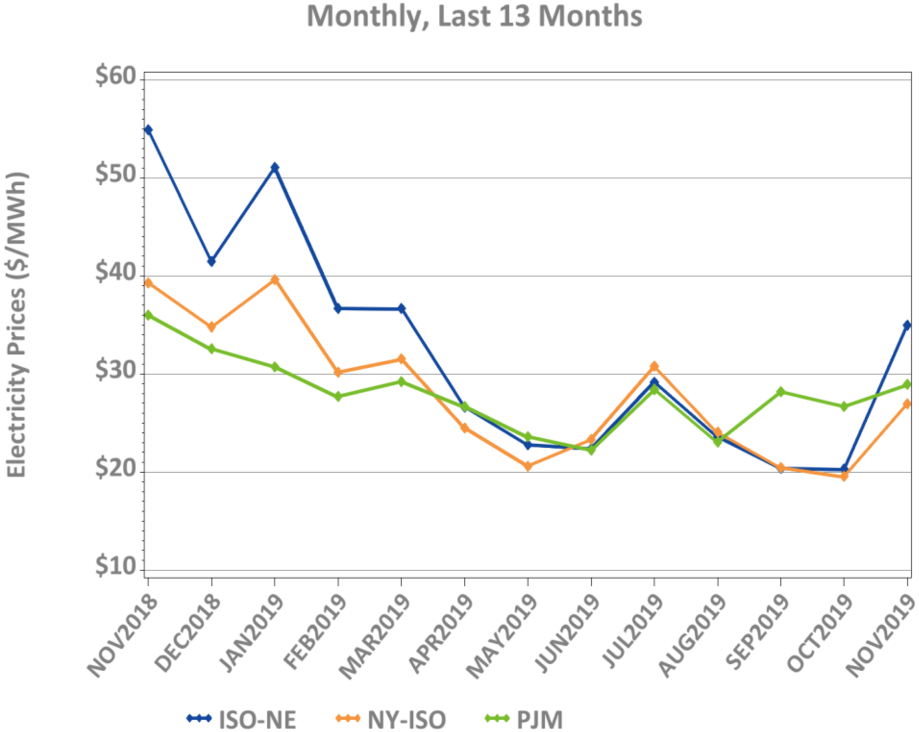
Monthly Average Fuel Price and RT Hub LMP



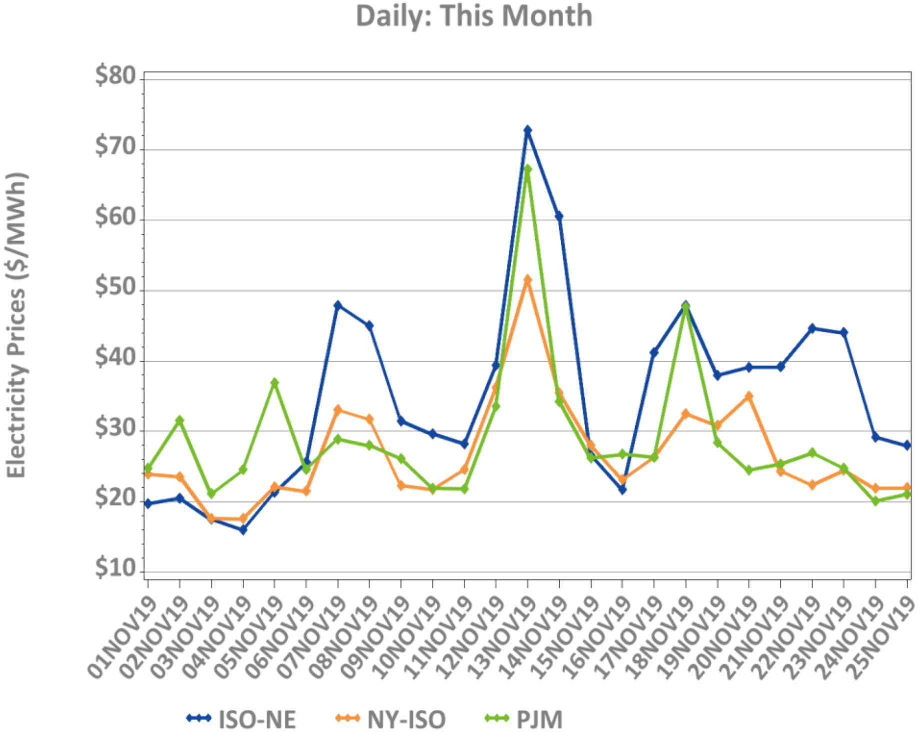
Underlying natural gas data furnished by:

ice Global markets in clear view

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

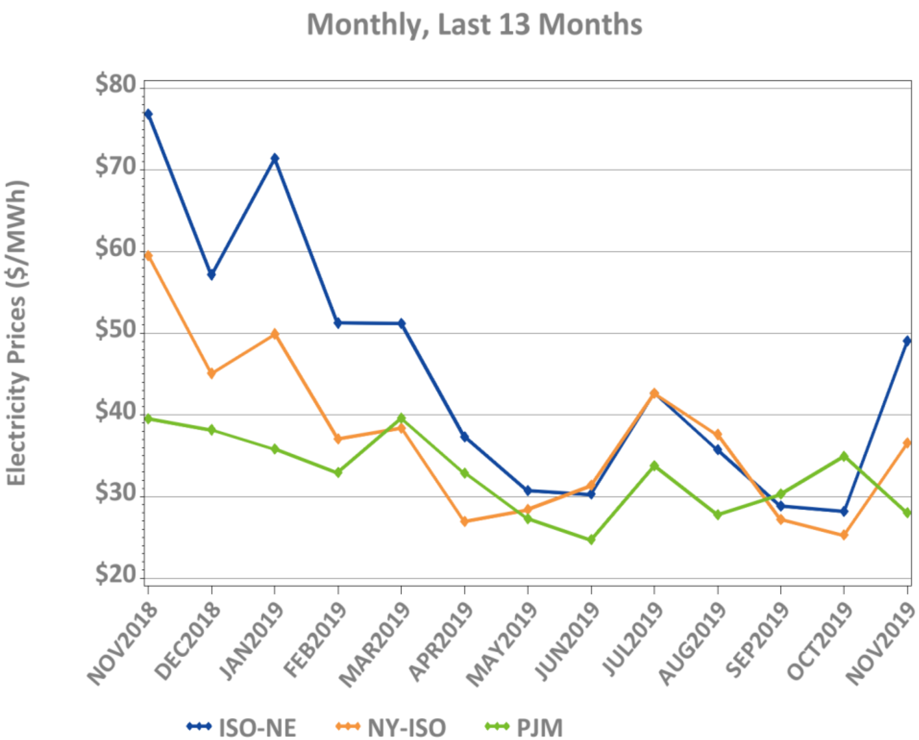


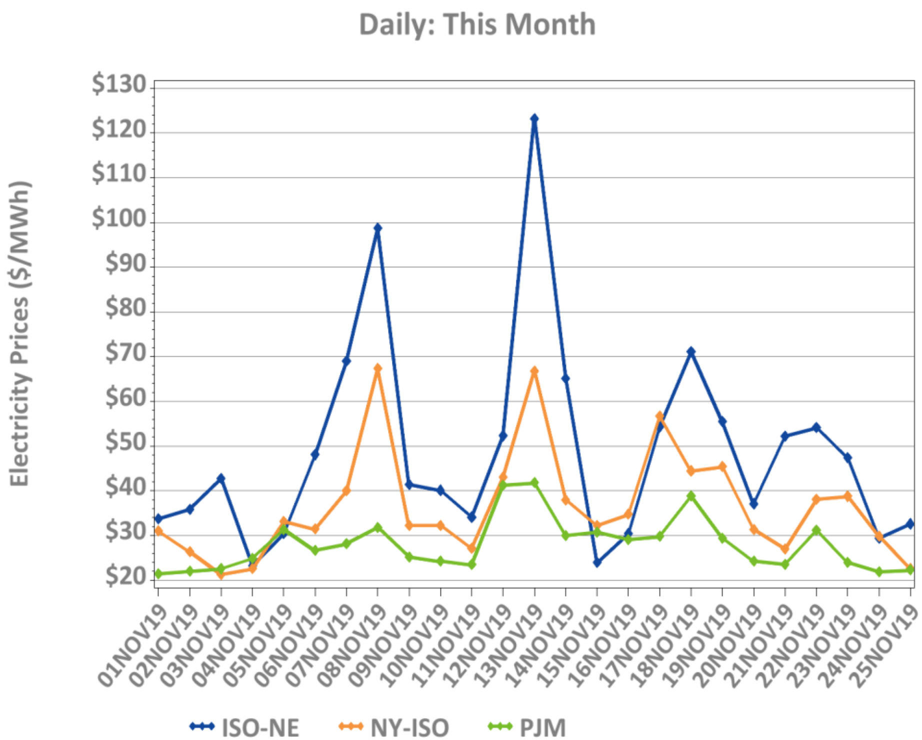
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





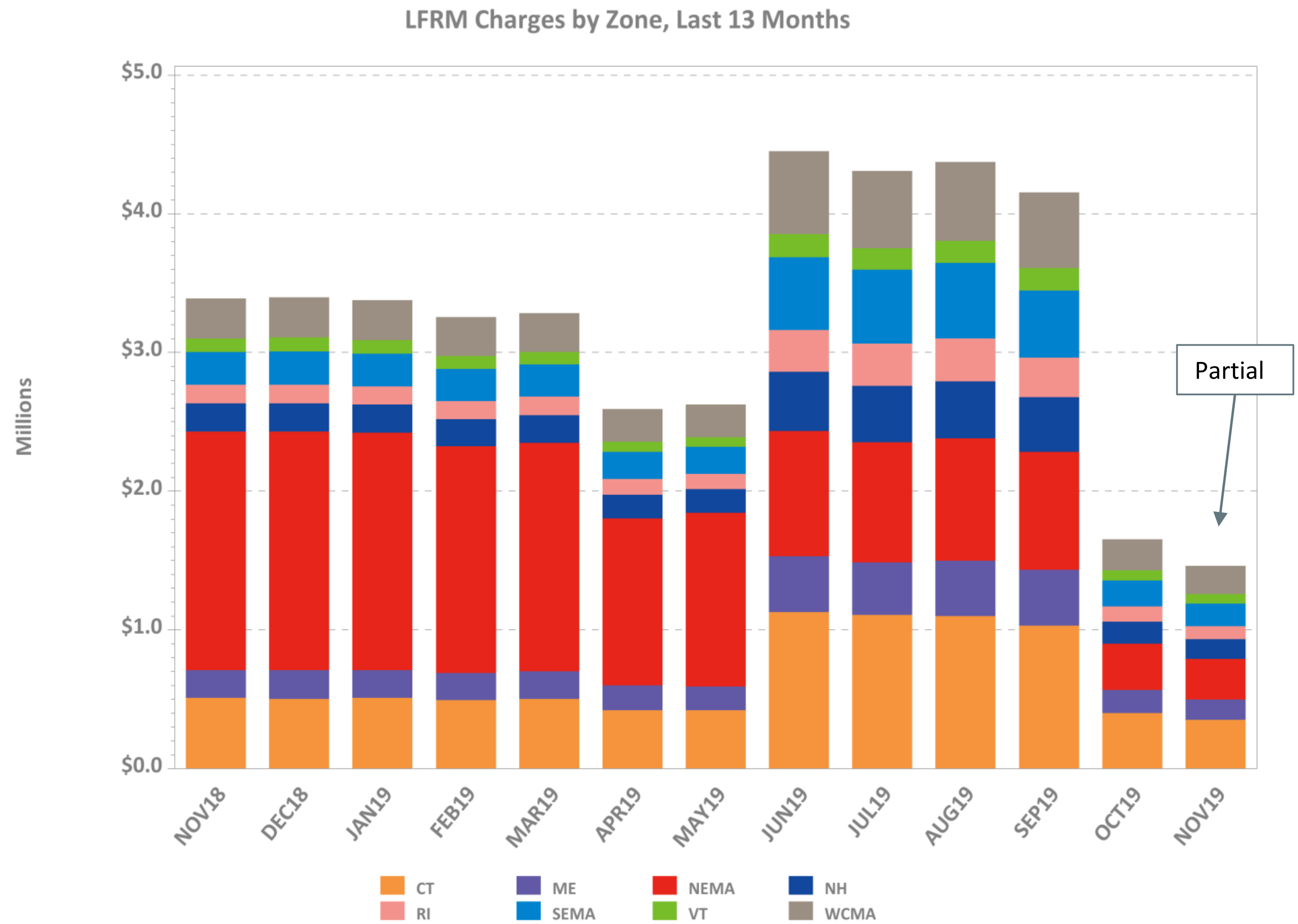
***Forecasted New England daily peak hours reflected**

Reserve Market Results – November 2019

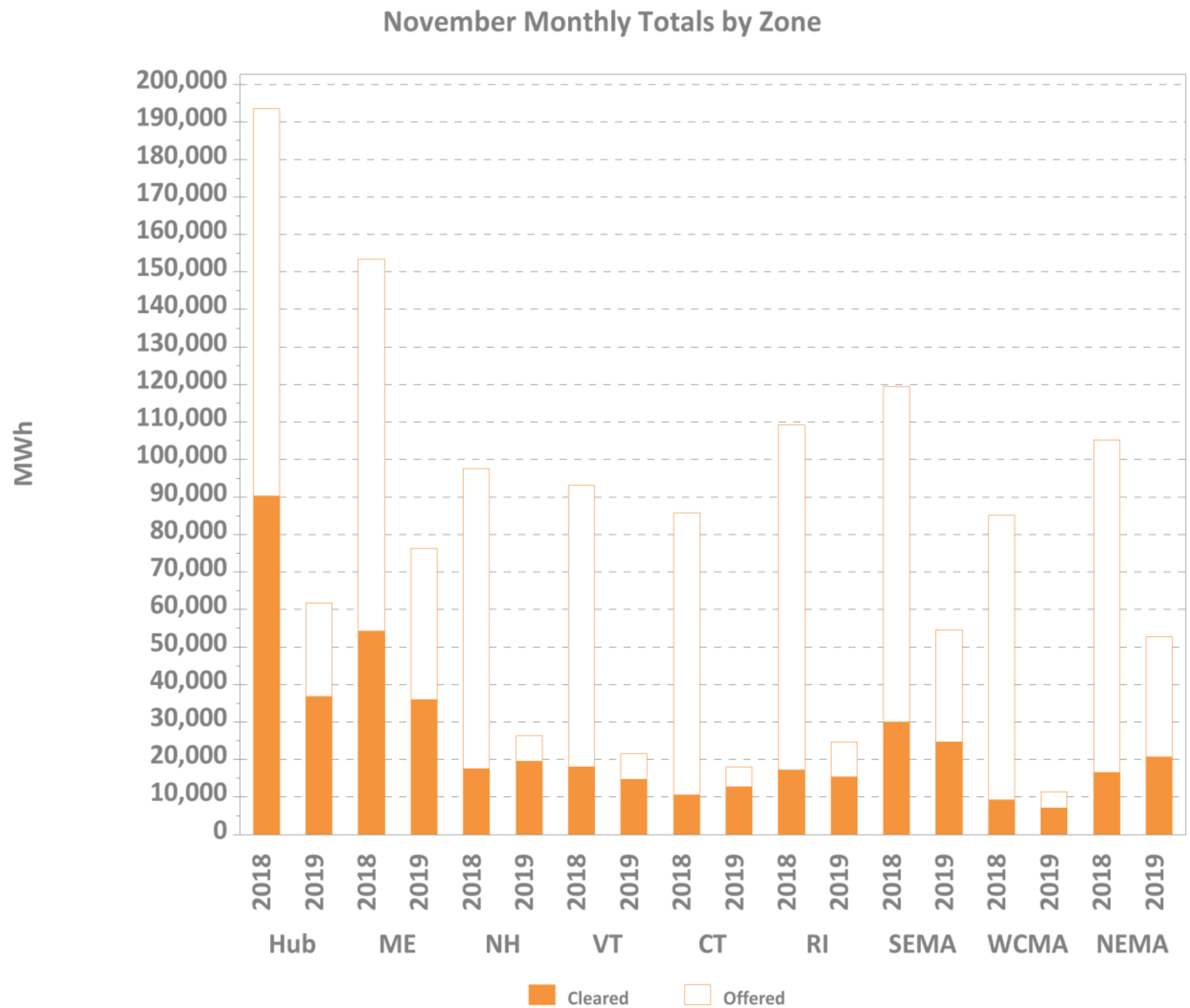
- Maximum potential Forward Reserve Market payments of $1.5M were reduced by credit reductions of $12K, failure-to-reserve penalties of $17K and no failure-to-activate penalties, resulting in a net payout of $1.5M or 98% of maximum
  - Rest of System: $1.11M/1.13M (98%)
  - Southwest Connecticut: $0.05M/0.05M (100%)
  - Connecticut: $0.3M/0.31M (99%)
- $821K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $821K in Real-Time Reserve payments
  - Rest of System: 232 hours, $573K
  - Southwest Connecticut: 232 hours, $140K
  - Connecticut: 232 hours, $69K
  - NEMA: 232 hours, $40K

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.

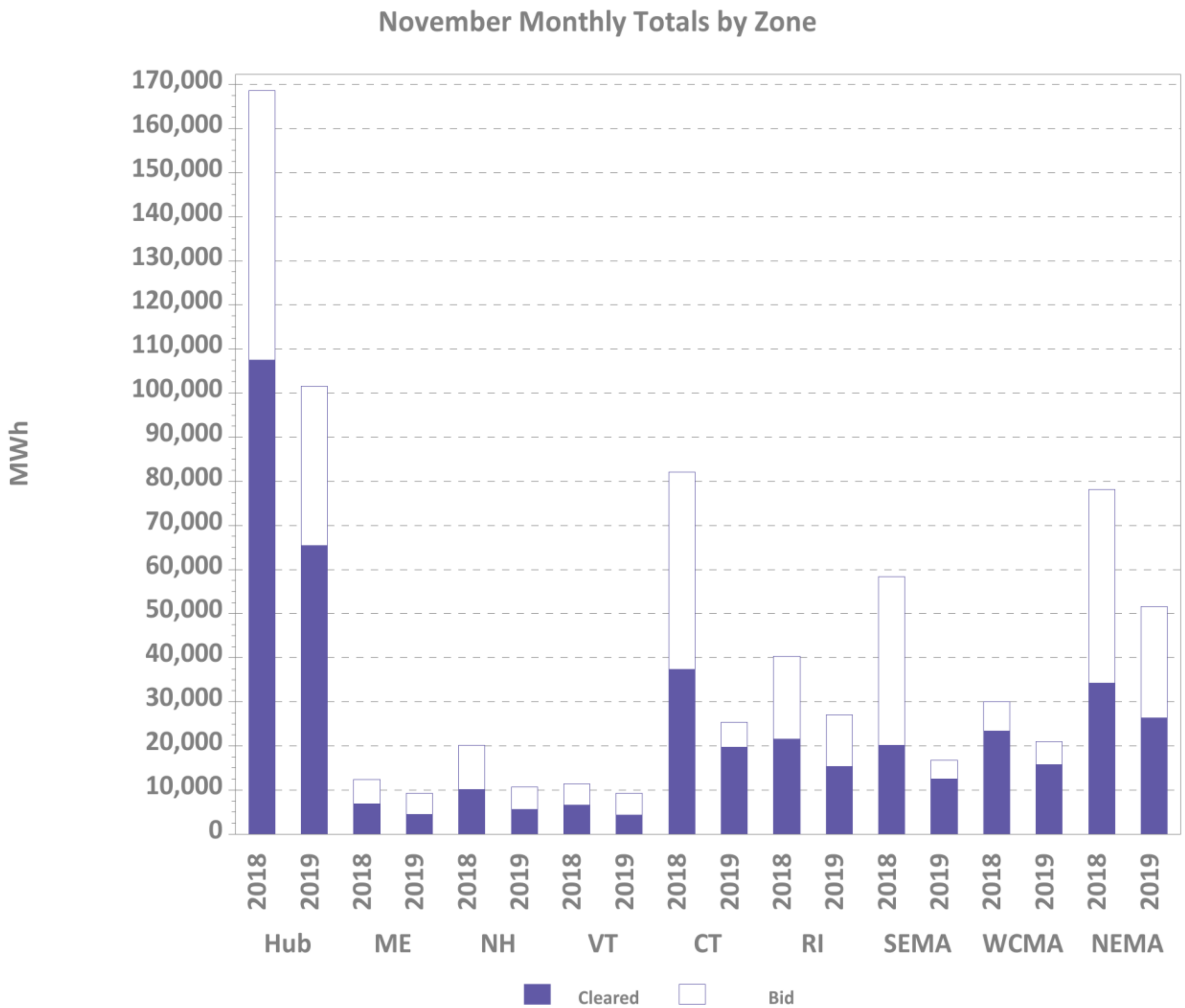
LFRM Charges to Load by Load Zone ($)



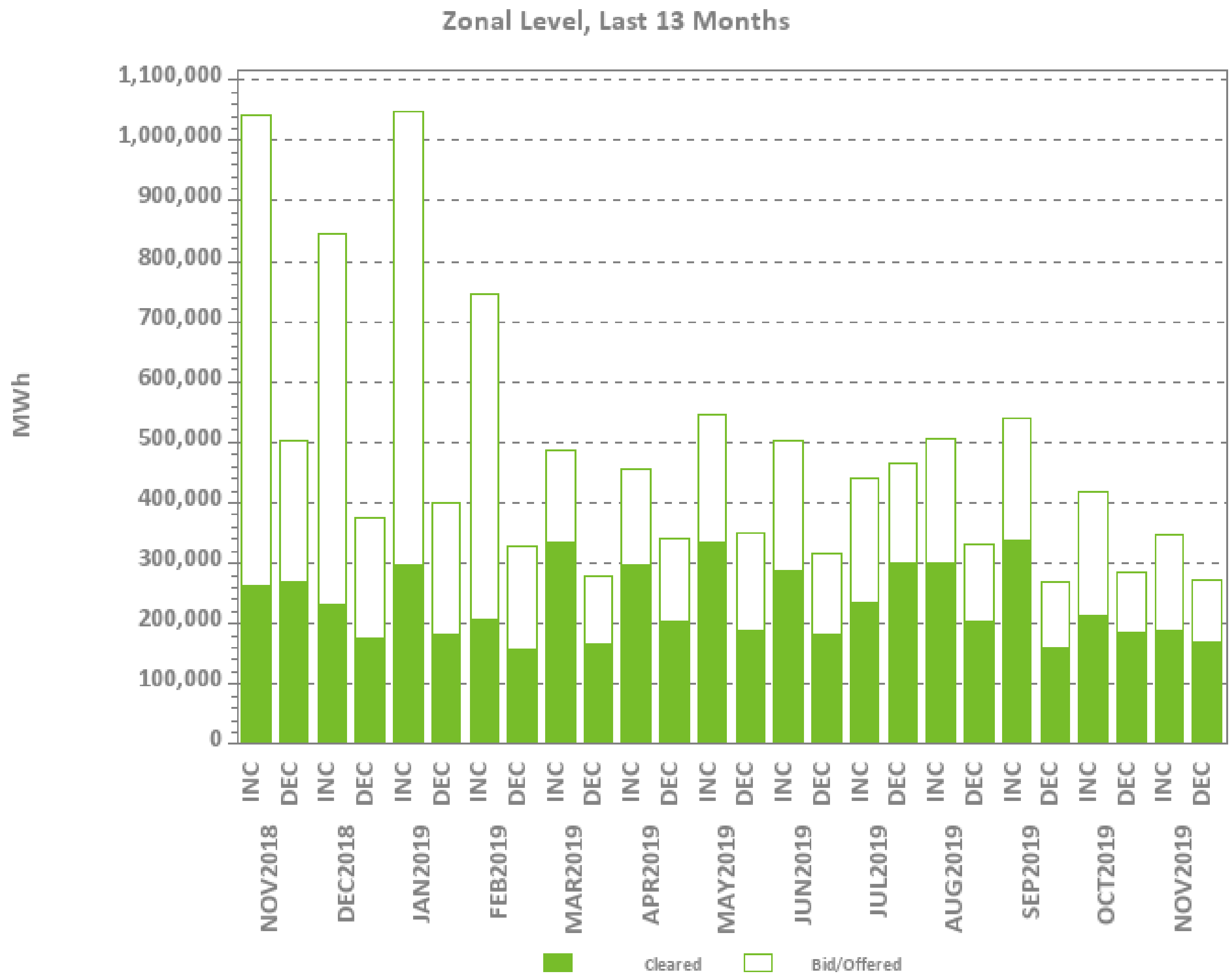
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

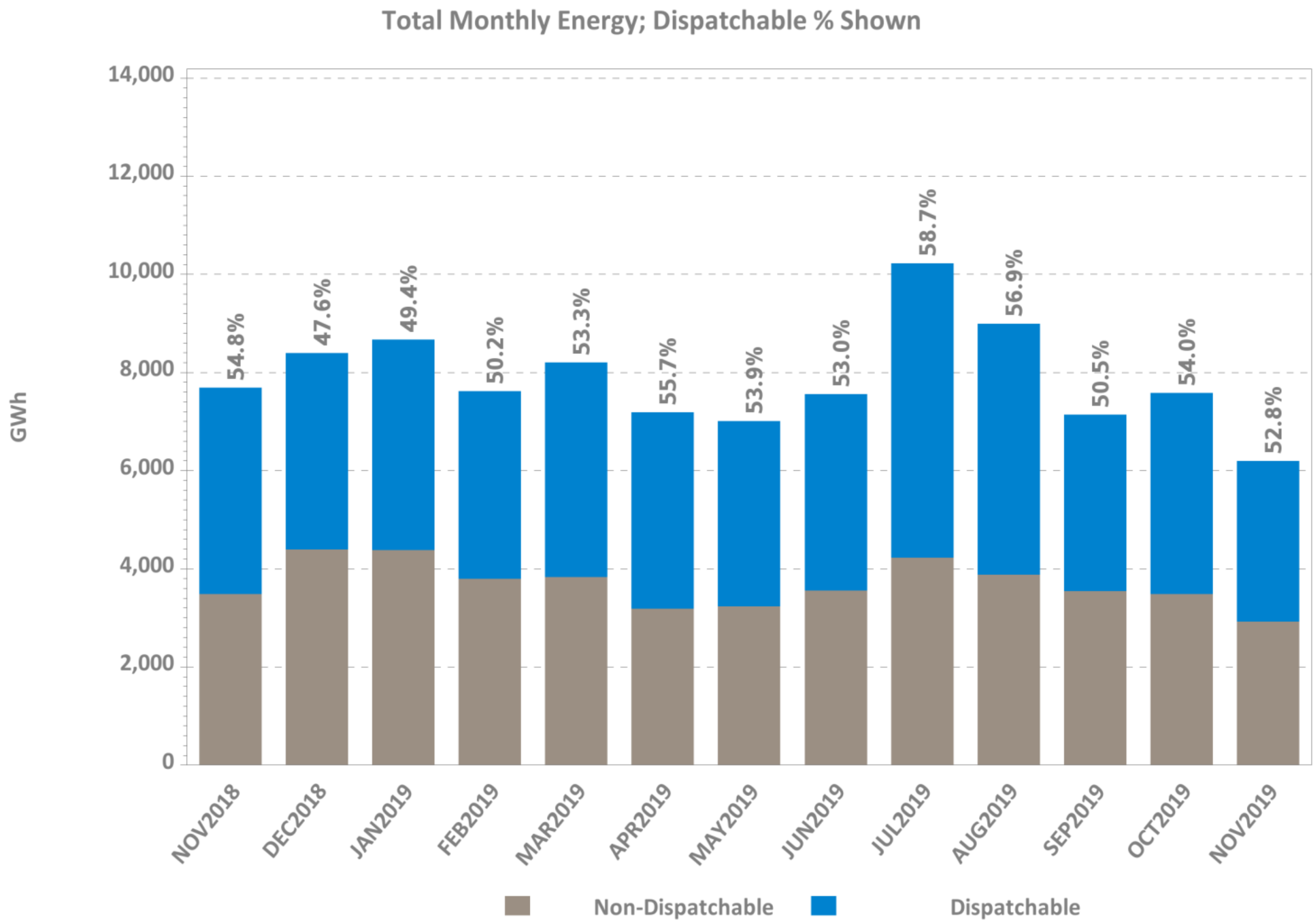


Total Increment Offers and Decrement Bids



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)

2019 Regional System Plan

- The final version of RSP19 was approved by the ISO Board and posted on the ISO website on October 31
  - The final version reflects minor revisions to the Public Meeting version

Interregional Planning Stakeholder Advisory Committee

- IPSAC webinar is scheduled for December 9 from 9:00am until noon with the following agenda:
  - Agenda and Administrative Items
  - Regional Planning Needs and Solutions - PJM/ISO-NE/NYISO
  - Interconnection Coordination - Interconnection Queue and Long-Term Firm Transmission Requests - NYISO/ISO-NE/PJM
  - Scope of NCSP19
  - Receive Stakeholder Input and Outline Next Steps
  - Adjourn
- Registration is required at:
  - https://www.pjm.com/committees-and-groups/stakeholder-meetings/ipsac-ny-ne.aspx

Planning Advisory Committee (PAC)

- December 19 PAC Meeting Agenda Topics*
  - 2019 Economic Study Request Preliminary Results - NESCOE
  - SEMA/RI 2029 Needs Assessment Update
  - Eversource 115 kV Wood Pole and Shield Wire Replacements 2020-2023
  - National Grid NPCC Directory 1 Project Updates

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

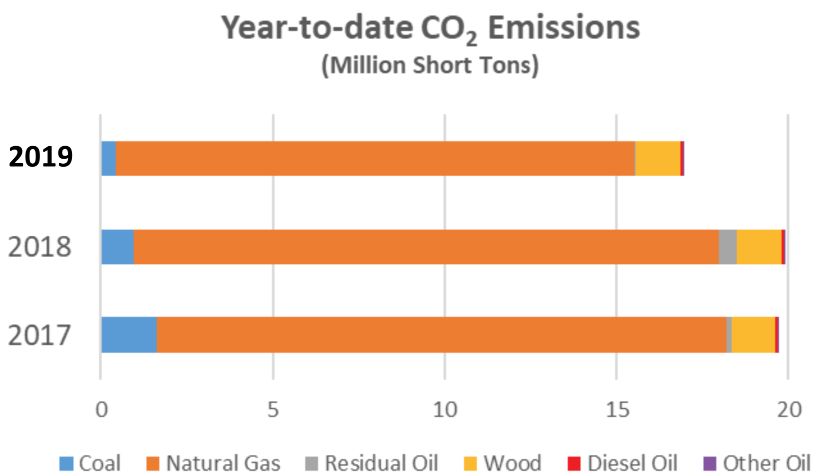
Economic Studies

- Economic study requests were submitted by Anbaric, NESCOE, and RENEW Northeast
- Detailed assumptions for each study request were discussed at the August 8 PAC meeting; status update was presented at the November 20 PAC meeting
- Preliminary results for the NESCOE study (up to 6,000 MW of offshore wind additions) will be presented at the December 19 PAC meeting
  - Preliminary results for Anbaric and RENEW Northeast studies will be presented to PAC in January
- The ISO will attempt to complete all analyses for all three requests by Q2 of 2020

Environmental Matters – Monthly System Emissions

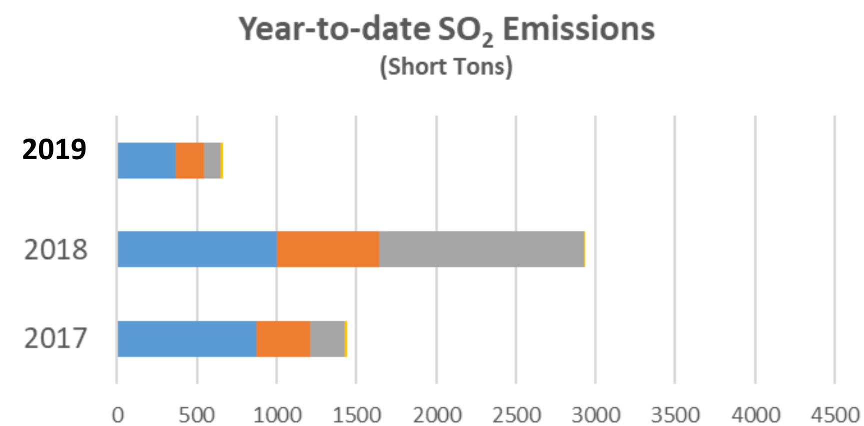
Reported by Fossil Generators directly to EPA on quarterly basis

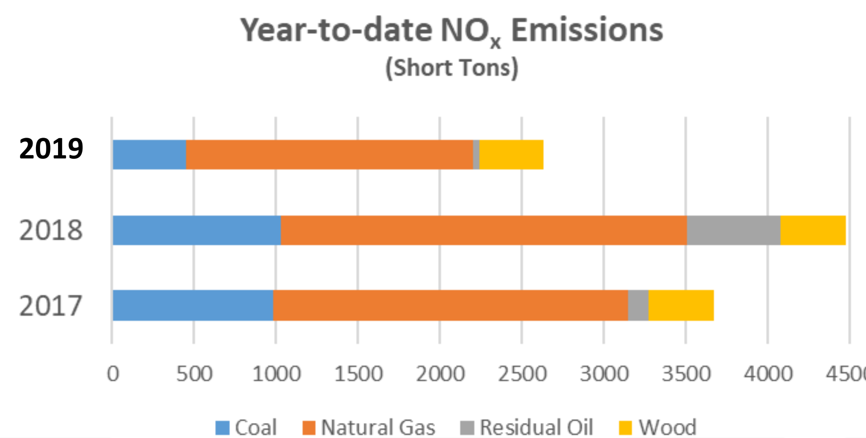
Regional 2019 CO_2 Emissions Trend Lower for Most Fuel Types



- Compared to 2017 & 2018, **2019** year-to-date CO_2 emissions from:
  - Coal & Oil generation fell > 50%
  - Natural gas generation fell 10%
  - Wood, refuse generation & CO_2 emissions were unchanged

Declines in Coal & Oil Generation Lower Other System Emissions





Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

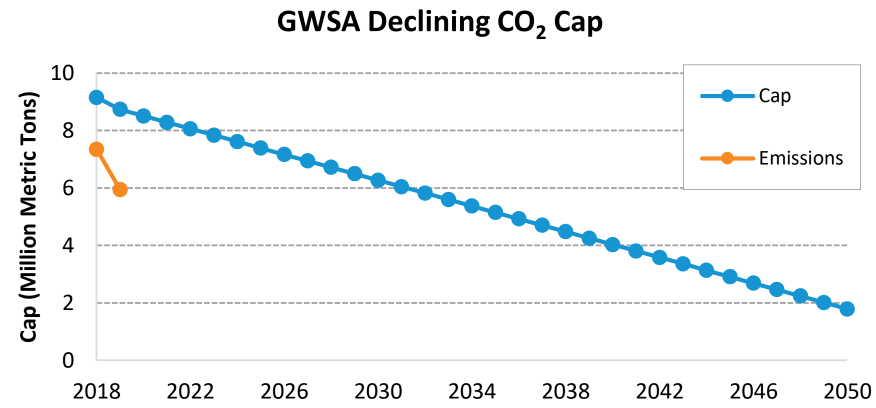
Year-to-Date CO_2 Emissions Well Below 2019 GWSA Cap

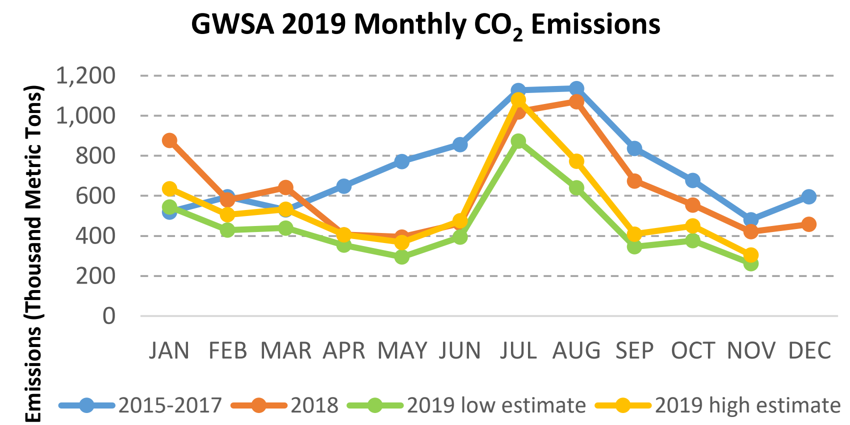
- 2019: **8.73** million metric ton (MMT) cap (25% auctioned, 75% allocated)
  - YTD 2019* emissions estimated between **4.9 MMT – 5.9 MMT**
  - No recent trading activity
- 2020: **8.50** MMT cap (50% auctioned, 50% allocated)
- December 2019 GWSA auction:
  - Limited demand expected for remaining 2019 allowances (1.9% of 2019 cap)
  - Robust demand expected for 2020 allowances (10% of 2020 cap)

* YTD 2019 estimated emissions through 11/21/19

GWSA - Global Warming Solutions Act

GWSA Annual Cap & Emissions Monthly 2019 CO_2 Emissions





November 2019 estimated emissions through 11/21/19

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.

New Hampshire/Vermont 10-Year Upgrades

Status as of 12/2/19

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual In-Service	Present Stage
Eagle Substation Add: 345/115 kV autotransformer	Dec-16	4
Littleton Substation Add: Second 230/115 kV autotransformer	Oct-14	4
New C-203 230 kV line tap to Littleton NH Substation	Nov-14	4
New 115 kV overhead line, Fitzwilliam-Monadnock	Feb-17	4
New 115 kV overhead line, Scobie Pond-Huse Road	Dec-15	4
New 115 kV overhead/submarine line, Madbury-Portsmouth	May-20	3
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 12/2/19

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual In-Service	Present Stage
Saco Valley Substation - Add two 25 MVAR dynamic reactive devices	Aug-16	4
Rebuild 115 kV line K165, W157 tap Eagle-Power Street	May-15	4
Rebuild 115 kV line H137, Merrimack-Garvins	Jun-13	4
Rebuild 115 kV line D118, Deerfield-Pine Hill	Nov-14	4
Oak Hill Substation - Loop in 115 kV line V182, Garvins-Webster	Dec-14	4
Uprate 115 kV line G146, Garvins-Deerfield	Mar-15	4
Uprate 115 kV line P145, Oak Hill-Merrimack	May-14	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 12/2/19

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual In-Service	Present Stage
Upgrade 115 kV line H141, Chester-Great Bay	Nov-14	4
Upgrade 115 kV line R193, Scobie Pond-Kingston Tap	Dec-14	4
Upgrade 115 kV line T198, Keene-Monadnock	Nov-13	4
Upgrade 345 kV line 326, Scobie Pond-NH/MA Border	Dec-13	4
Upgrade 115 kV line J114-2, Greggs - Rimmon	Dec-13	4
Upgrade 345 kV line 381, between MA/NH border and NH/VT border	Jun-13	4

Greater Hartford and Central Connecticut (GHCC) Projects*

Status as of 12/2/19

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected/ Actual In-Service	Present Stage
Add a 2nd 345/115 kV autotransformer at Haddam substation and reconfigure the 3-terminal 345 kV 348 line into two 2-terminal lines	Apr-17	4
Terminal equipment upgrades on the 345 kV line between Haddam Neck and Beseck (362)	Feb-17	4
Redesign the Green Hill 115 kV substation from a straight bus to a ring bus and add two 115 kV 25.2 MVAR capacitor banks	Jun-18	4
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-15	4
Separation of 115 kV double circuit towers corresponding to the Branford – Branford RR line (1537) and the Branford to North Haven (1655) line and adding a 115 kV breaker at Branford 115 kV substation	Mar-17	4
Increase the size of the existing 115 kV capacitor bank at Branford Substation from 37.8 to 50.4 MVAR	Jan-17	4
Separation of 115 kV double circuit towers corresponding to the Middletown – Pratt and Whitney line (1572) and the Middletown to Haddam (1620) line	Dec-16	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 12/2/19

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected/ Actual In-Service	Present Stage
Terminal equipment upgrades on the 115 kV line from Middletown to Dooley (1050)	Jun-15	4
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Jun-15	4
Add a 3.7 mile 115 kV hybrid overhead/underground line from Newington to Southwest Hartford and associated terminal equipment including a 1.4% series reactor	Jun-20	3
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Jun-18	4
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	May-17	4
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Nov-17	4
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Jun-20	3

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 12/2/19

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected/ Actual In-Service	Present Stage
Separation of 115 kV DCT corresponding to the Bloomfield to South Meadow (1779) line and the Bloomfield to North Bloomfield (1777) line and add a breaker at Bloomfield 115 kV substation	Dec-17	4
Separation of 115 kV DCT corresponding to the Bloomfield to North Bloomfield (1777) line and the North Bloomfield – Rood Avenue – Northwest Hartford (1751) line and add a breaker at North Bloomfield 115 kV substation	Dec-17	4
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Jun-20	3
Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with a 5% series reactors	Dec-18	4
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Jun-19	4
Add a 345 kV breaker in series with breaker 5T at Southington	May-17	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 12/2/19

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected/ Actual In-Service	Present Stage
Add a new control house at Southington 115 kV substation	Dec-18	4
Add a new 115 kV line from Frost Bridge to Campville	Dec-17	4
Separation of 115 kV DCT corresponding to the Frost Bridge to Campville (1191) line and the Thomaston to Campville (1921) line and add a breaker at Campville 115 kV substation	Jun-18	4
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Dec-16	4
Add a new 345/115 kV autotransformer at Barbour Hill substation	Dec-15	4
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Dec-15	4
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Apr-16	4

* Replaces the NEEWS Central Connecticut Reliability Project

Southwest Connecticut (SWCT) Projects

Status as of 12/2/19

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 12/2/19

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)	Dec-20	2
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 12/2/19

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)	Jun-20	3
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Jun-20	3

Southwest Connecticut Projects, cont.

Status as of 12/2/19

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)	Jun-21	2

Southwest Connecticut Projects, cont.

Status as of 12/2/19

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 12/2/19

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-21	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 12/2/19

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	May-20	3
Install third 115 kV line from West Walpole to Holbrook	May-20	3
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-20	2*

* Project ISD to be reassessed after MA-EFSB Approval

Greater Boston Projects, cont.

Status as of 12/2/19

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	3
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	Jan-20	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-20	3

Greater Boston Projects, cont.

Status as of 12/2/19

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	Dec-20	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 12/2/19

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	3
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

Pittsfield/Greenfield Projects

Status as of 12/2/19

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected/ Actual In-Service	Present Stage
Separate and reconductor the Cabot Taps (A-127 and Y-177 115 kV lines)	Mar-17	4
Install a 115 kV tie breaker at the Harriman Station, with associated buswork, reconductor of buswork and new control house	Nov-17	4
Modify Northfield Mountain 16R Substation and install a 345/115 kV autotransformer	Jun-17	4
Build a new 115 kV three-breaker switching station (Erving) ring bus	Mar-17	4
Build a new 115 kV line from Northfield Mountain to the new Erving Switching Station	Jun-17	4
Install 115 kV 14.4 MVAR capacitor banks at Cumberland, Podick and Amherst Substations	Dec-15	4

Pittsfield/Greenfield Projects, cont.

Status as of 12/2/19

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected/ Actual In-Service	Present Stage
Rebuild the Cumberland to Montague 1361 115 kV line and terminal work at Cumberland and Montague. At Montague Substation, reconnect Y177 115 kV line into 3T/4T position and perform other associated substation work	Dec-16	4
Remove the sag limitation on the 1512 115 kV line from Blandford Substation to Granville Junction and remove the limitation on the 1421 115 kV line from Pleasant to Blandford Substation	Dec-14	4
Loop the A127W line between Cabot Tap and French King into the new Erving Substation	Mar-17	4
Reconductor A127 between Erving and Cabot Tap and replace switches at Wendell Depot	Apr-15	4

Pittsfield/Greenfield Projects, cont.

Status as of 12/2/19

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected/ Actual In-Service	Present Stage
Install a 115 kV 20.6 MVAR capacitor at the Doreen substation and operate the 115 kV 13T breaker N.O.	Oct-17	4
Install a 75-150 MVAR variable reactor at Northfield substation	Dec-17	4
Install a 75-150 MVAR variable reactor at Ludlow substation	Dec-17	4
Construct a 115 kV three-breaker ring bus at or adjacent to Pochassic 37R Substation, loop line 1512-1 into the new three-breaker ring bus, construct a new line connecting the new three-breaker ring bus to the Buck Pond 115 kV Substation on the vacant side of the double-circuit towers that carry line 1302-2, add a new breaker to the Buck Pond 115 kV straight bus and reconnect lines 1302-2, 1657-2 and transformer 2X into new positions	Jun-20	3

SEMA/RI Reliability Projects

Status as of 12/2/19

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1714	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	Nov-20	3
1742	Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Nov-20	3
1715	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	Jun-20	3
1716	Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	4
1717	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 12/2/19

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Nov-20	2
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Dec-20	2
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	Nov-21	2
1721	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	Dec-21	2
1722	Extend the Line 114 from the Dartmouth town line (Eversource- NGRID border) to Bell Rock substation	Dec-21	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Sep-21	2

SEMA/RI Reliability Projects, cont.

Status as of 12/2/19

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	Dec-21	1
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Nov-20	1
1727	Retire the Barnstable SPS	Dec-21	1
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-21	1
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-21	1
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-21	1

SEMA/RI Reliability Projects, cont.

Status as of 12/2/19

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	1
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Dec-21	1
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Dec-21	1
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Dec-21	3

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

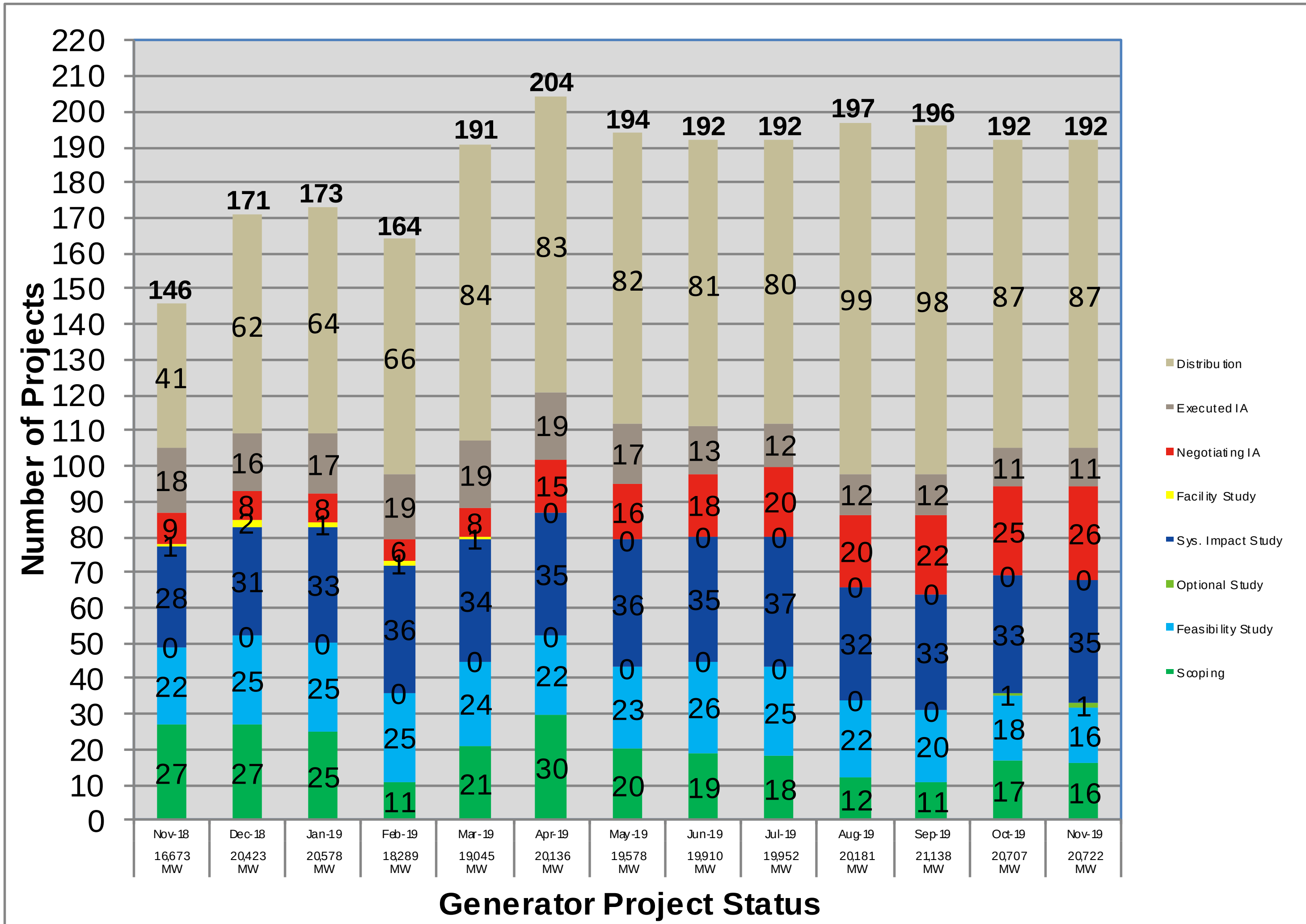
SEMA/RI Reliability Projects, cont.

Status as of 12/2/19

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1741	Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
1782	Reconductor the J16S line	Dec-20	2
1724	Replace the Kent County 345/115 kV transformer	Nov-20	2
1789	West Medway 345 kV circuit breaker upgrades	Dec-21	2
1790	Medway 115 kV circuit breaker replacements	Dec-21	3

Status of Tariff Studies



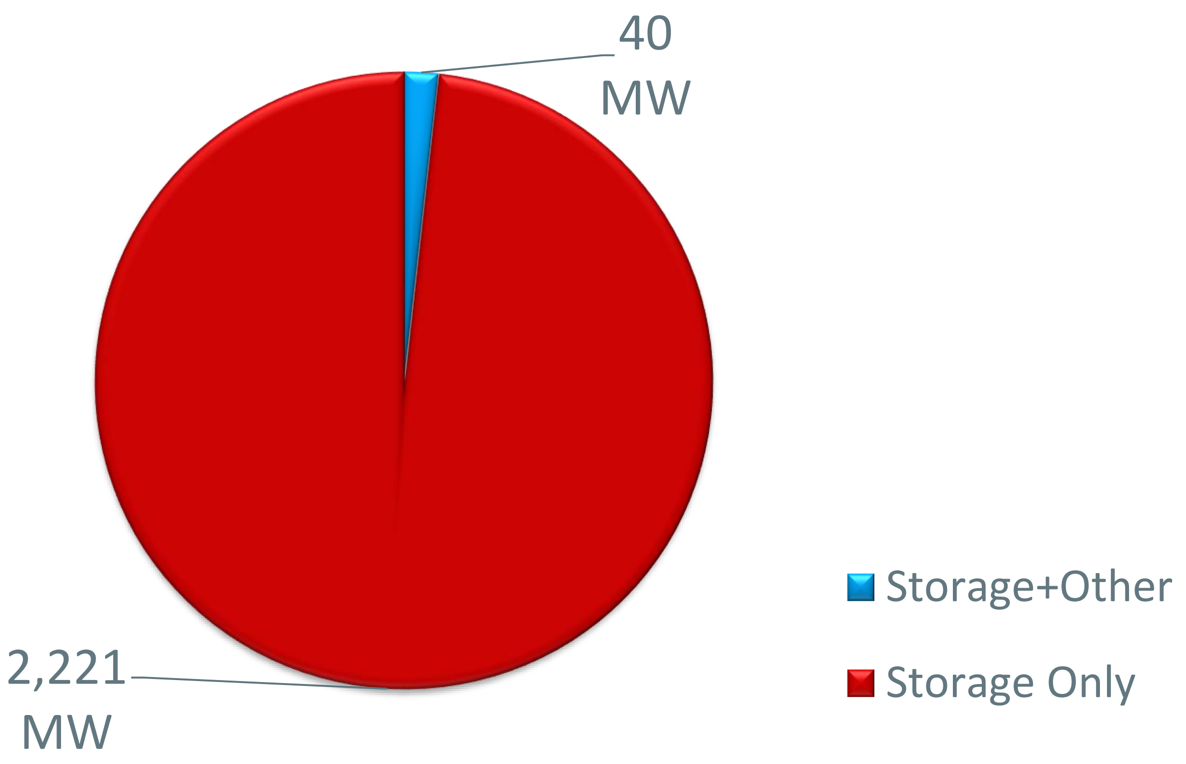
Note: November 2019 based on partial data

As of October 2019, there are 4 ETU's in Scoping, 6 in FS, 3 in SIS, 0 in FAC, 1 Negotiating IA, and 1 with Executed IA

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

What is in the Queue (as of November 22, 2019)

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



OPERABLE CAPACITY ANALYSIS

Winter 2019/20 Analysis

Winter 2019/20 Operable Capacity Analysis

50/50 Load Forecast (Reference)	January - 2020[2] CSO (MW)	January - 2020[2] SCC (MW)
Operable Capacity MW [1]	31,365	33,502
Active Demand Capacity Resource (+) [5]	436	332
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	917	917
Non Commercial Capacity (+)	28	28
Non Gas-fired Planned Outage MW (-)	510	532
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,207	4,648
Net Capacity (NET OPCAP SUPPLY MW)	25,229	26,799
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,476	20,476
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,781	22,781
Operable Capacity Margin	2,448	4,018

[1]Operable Capacity is based on data as of **November 18, 2019** 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 **November 18, 2019.**

[2] Load forecast that is based on the 2019 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 11, 2020.**

[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 2019/20 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	January - 2020[2] CSO (MW)	January - 2020[2] SCC (MW)
Operable Capacity MW [1]	31,365	33,502
Active Demand Capacity Resource (+) [5]	436	332
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	917	917
Non Commercial Capacity (+)	28	28
Non Gas-fired Planned Outage MW (-)	510	532
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,674	5,165
Net Capacity (NET OPCAP SUPPLY MW)	24,762	26,282
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,173	21,173
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,478	23,478
Operable Capacity Margin	1,284	2,804

[1] Operable Capacity is based on data as of **November 18, 2019** 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 **November 18, 2019.**

[2] Load forecast that is based on the 2019 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 11, 2020.**

[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 2019/20 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

December 1, 2019 - 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]
11/30/2019	31300	413	971	28	1442	333	3200	2325	25412	19232	2305	21537	3875
12/7/2019	31300	413	971	28	1108	333	3200	2786	25285	19532	2305	21837	3448
12/14/2019	31300	413	1071	28	569	333	3200	2968	25742	19543	2305	21848	3894
12/21/2019	31300	413	971	28	15	0	3200	3621	25876	19608	2305	21913	3963
12/28/2019	31300	413	971	28	15	0	3200	3967	25530	19993	2305	22298	3232
1/4/2020	31365	436	917	28	351	279	2800	3806	25510	20476	2305	22781	2729
1/11/2020	**31365**	**436**	**917**	**28**	**510**	**0**	**2800**	**4207**	**25229**	**20476**	**2305**	**22781**	**2448**
1/18/2020	31365	436	917	28	484	0	2800	4014	25448	20476	2305	22781	2667
1/25/2020	31365	436	917	28	477	0	2800	3737	25732	20245	2305	22550	3182
2/1/2020	31344	456	917	28	565	0	3100	3737	25343	19967	2305	22272	3071
2/8/2020	31344	456	917	28	565	0	3100	3322	25758	19937	2305	22242	3516
2/15/2020	31344	456	917	28	498	0	3100	3045	26102	19664	2305	21969	4133
2/22/2020	31344	456	917	28	418	0	3100	2492	26735	18636	2305	20941	5794
2/29/2020	31344	456	917	28	1282	0	2200	2076	27187	18273	2305	20578	6609
3/7/2020	31344	456	917	28	1239	0	2200	1938	27368	18069	2305	20374	6994
3/14/2020	31344	456	917	28	1619	647	2200	737	27542	17690	2305	19995	7547
3/21/2020	31344	456	917	28	2235	650	2200	319	27341	17102	2305	19407	7934

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 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,323 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 2019/20 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

December 1, 2019 - 90-10 FORECAST using CSO

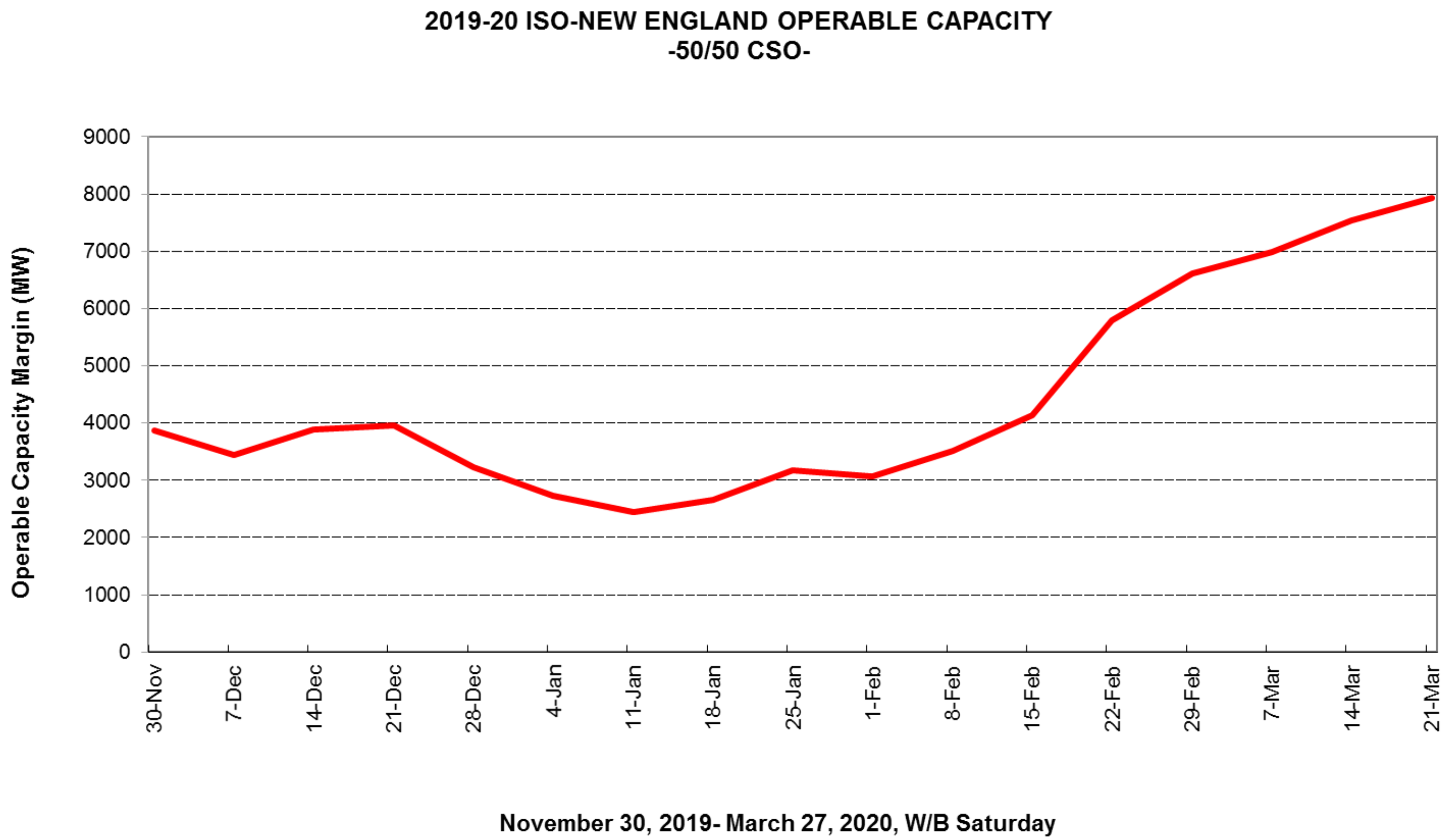
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, August, and Mid September

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]
11/30/2019	31300	413	971	28	1442	333	3200	2620	25117	19886	2305	22191	2926
12/7/2019	31300	413	971	28	1108	333	3200	3132	24939	20194	2305	22499	2440
12/14/2019	31300	413	1071	28	569	333	3200	3335	25375	20206	2305	22511	2864
12/21/2019	31300	413	971	28	15	0	3200	4023	25474	20273	2305	22578	2896
12/28/2019	31300	413	971	28	15	0	3200	4408	25089	20674	2305	22979	2110
1/4/2020	31365	436	917	28	351	279	2800	4260	25056	21173	2305	23478	1578
1/11/2020	**31365**	**436**	**917**	**28**	**510**	**0**	**2800**	**4674**	**24762**	**21173**	**2305**	**23478**	**1284**
1/18/2020	31365	436	917	28	484	0	2800	4460	25002	21173	2305	23478	1524
1/25/2020	31365	436	917	28	477	0	2800	4153	25316	20934	2305	23239	2077
2/1/2020	31344	456	917	28	565	0	3100	4153	24927	20648	2305	22953	1974
2/8/2020	31344	456	917	28	565	0	3100	3691	25389	20617	2305	22922	2467
2/15/2020	31344	456	917	28	498	0	3100	3384	25763	20336	2305	22641	3122
2/22/2020	31344	456	917	28	418	0	3100	2768	26459	19277	2305	21582	4877
2/29/2020	31344	456	917	28	1282	0	2200	2307	26956	18903	2305	21208	5748
3/7/2020	31344	456	917	28	1239	0	2200	2153	27153	18693	2305	20998	6155
3/14/2020	31344	456	917	28	1619	647	2200	891	27388	18302	2305	20607	6781
3/21/2020	31344	456	917	28	2235	650	2200	427	27233	17697	2305	20002	7231

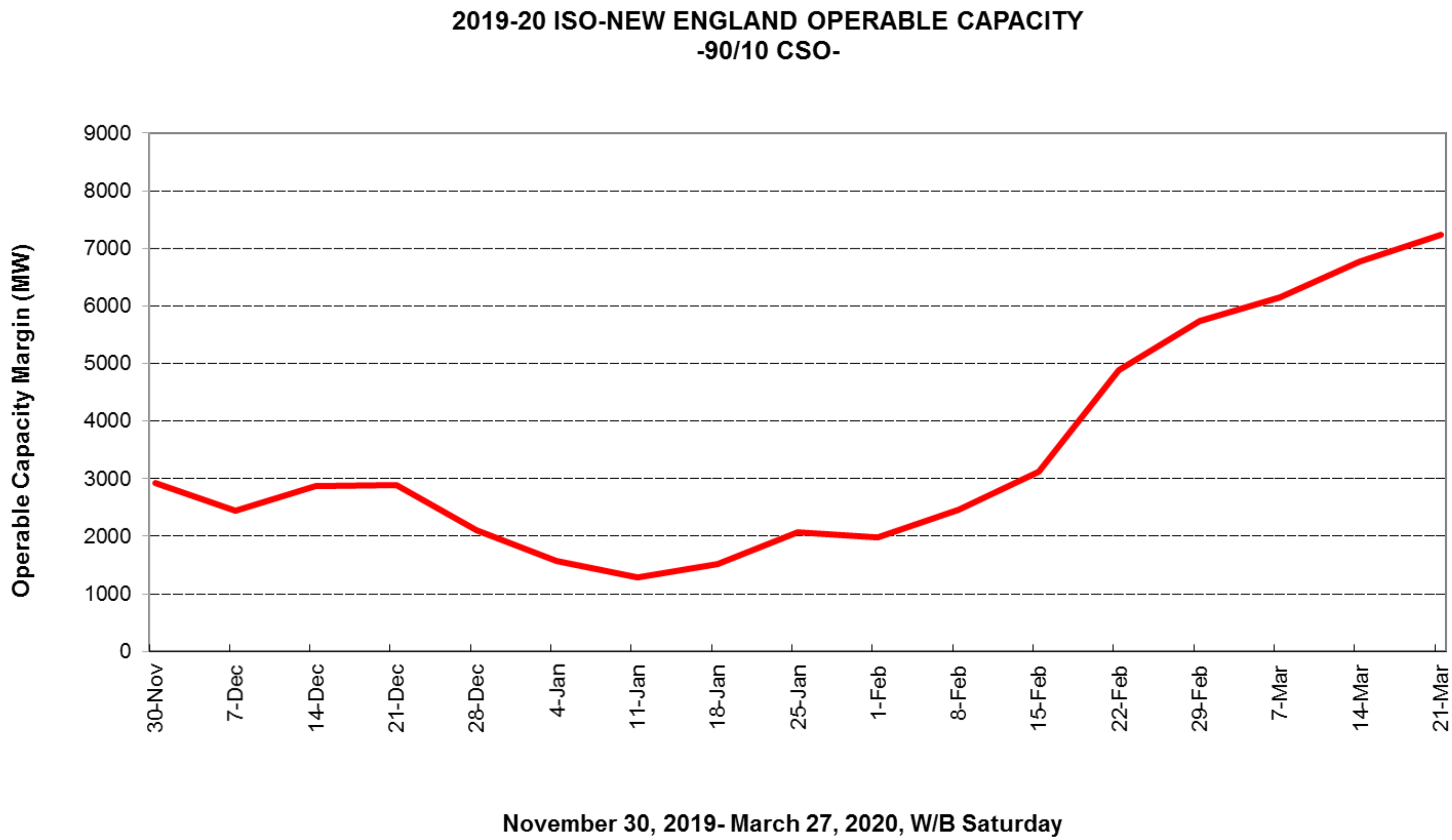
1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). 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 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 27,212 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 2019/20 Operable Capacity Analysis
50/50 Forecast (Reference)



Winter 2019/20 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