Summary of ISO New England Board and Committee Meetings

April 6, 2018 Participants Committee Meeting

Since the last update, the Audit and Finance Committee and the Nominating and Governance Committee both met in Boston on March 15.

The Audit and Finance Committee met with KPMG, along with management, and reviewed the 2017 audited financial statements and discussed disclosure controls. The Committee voted to recommend the adoption of the audited financial statements by the Board of Directors. Next, the Committee met further with representatives from KPMG and reviewed the work plan for the 2018 Service Organization Controls report. The Committee discussed the scope of the work, including objectives, audit team and methodology. The Committee then held an executive session with KPMG. Next, the Committee was presented with the Internal Audit Department's 2018 audit plan. The Committee discussed the budget and staffing for major areas of coverage, including external audits and reviews, and the audit areas to be reviewed internally. Following this discussion, the Committee approved the 2018 audit plan. The Committee then received an update on current Internal Audit Department activities and the risk assessment process and audit planning cycle. Finally, the Committee discussed the renewal of working capital lines, and received updates on financial performance against the 2018 budget.

The Nominating and Governance Committee received a report on Joint Nominating Committee activities, and considered the 2018 evaluation process for the Board and Committees. The Committee also discussed the Company's communications plan for 2018.

APRIL 6, 2018 | TELECONFERENCE

NEPOOL PARTICIPANTS COMMITTEE
04/06/18 MEETING, AGENDA ITEM #4

NEPOOL Participants Committee Report

April 2018

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy market value over the period was $339M, down $62M from February 2018 and down $68M from March 2017
    - March natural gas prices over the period were 4.6% lower than February 2018 average values
    - Average RT Hub Locational Marginal Prices ($34.25/MWh) over the period were 7.2% lower than February averages
    - Average March 2018 natural gas prices and RT Hub LMPs over the period were down 5.4% and down 1.6%, respectively, from March 2017 average
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 97.1% during March, down from 98.5% during February*
    - The minimum value for the month was 92.4% on Saturday, March 17**

Data are through March 27, 2018 (RT NCPC through March 26) unless otherwise noted.

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

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

Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - March NCPC payments totaled $3.5M over the period, up $1.5M from February 2018 and down $1.7M from March 2017
    - First Contingency* payments totaled $2M, up $145K from February 2018
      - $2M paid to internal resources, up $142K from February
        - » $1.2M charged to DALO, $441K to RT Deviations, $431K to RTLO
    - Voltage payments totaled $1.4M, up $1.4M from February
  - NCPC payments over the period as percent of Energy Market value were 1%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $226K; Rapid Response Pricing (RRP) Opportunity Cost - $143K; Posturing - $61K; Generator Performance Auditing (GPA) - $1K;**

Highlights, cont.

- 2017 Economic Study draft report scheduled for 2nd quarter review by the Planning Advisory Committee (PAC)
- The 2018 Long-term Load Forecast, Energy-Efficiency Forecast, and Solar PV Forecast will be presented at the April 26 PAC meeting
- Stakeholder comments on the Northeast Coordinated System Plan (NCSP17) are due by close of business on April 12
- Show-of-Interest requests and Substitution Auction Supply-Side Participation requests for Forward Capacity Auction #13 are due by April 27

Forward Capacity Market (FCM) Highlights

- CCP #8 (2017-2018)
  - New, non-commercial resources are expected to be commercial by the start of CCP #9.
- CCP #9 (2018-2019)
  - Third and final annual reconfiguration auction was held March 1-5, and all transactions were accepted. Results were posted on March 16.
- CCP #10 (2019-2020)
  - Second bilateral transaction window will be May 2-4, and results to be posted by June 8.
  - The next opportunity to trade will be the second reconfiguration auction will be August 1-3, and results to be posted by August 17.
  - Third bilateral transaction window will be December 5-7, and results to be posted by January 11, 2019.

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP #11 (2020-2021)
  - First reconfiguration auction will be June 1-5, and results to be posted by June 19
  - Second reconfiguration auction will be August 1-5, 2019, and results to be posted by September 3, 2019
- CCP #12 (2021-2022)
  - First reconfiguration auction will be June 3-5, 2019, and results to be posted by June 3, 2019

FCM Highlights, cont.

- CCP #13 (2022-2023)
  - Potential capacity zone boundaries have been established and were discussed at the March 29 RC meeting. Final capacity zones will be determined in May and discussed at the Power Supply Planning Committee meeting.
  - Enhancements to the FCM Participation Guide to reflect recent changes for price-responsive demand and Competitive Auctions with Sponsored Policy Resources (CASPR) are underway.
  - Existing Capacity Qualification is complete.
  - Retirement and permanent delist bids have been received and, on March 28, capacity market exit requests were posted.
    - Approximately 2,009 MW of priced retirement requests and 40 MW of permanent delist bids.
    - Substitution Auction Demand Bid requests were received on March 23.
    - Static and export delist bids are due June 8.
  - Show-of-Interest requests and Substitution Auction Supply-Side participation requests are due April 27.
    - Renewable technology resource election cap is approximately 514 MW.
  - Stakeholder discussions continue at the RC regarding the Installed Capacity Requirement/Local Sourcing Requirement.

FERC Order 1000

- Intraregional Planning
  - 20 companies have achieved Qualified Transmission Project Sponsor (QTPS) status
  - 2018 Annual QTPS Certification
    - All 20 QTPSs submitted completed Annual QTPS Certification forms within the January 1 - 31 Certification Window
    - ISO notified the 20 QTPSs on February 16 that they met the 2018 Annual Certification requirements and, as such, QTPS status is maintained

Highlights, cont.

- The lowest 50/50 and 90/10 Spring Operable Capacity Margin Week is projected for week beginning May 19, 2018.

- The lowest 50/50 and 90/10 Preliminary Summer Operable Capacity Margin Week is projected for week beginning June 2, 2018.
  - **Note**: Preliminary Summer projections reflect 2018-2019 Capacity Supply Obligations.
  - As of June 1, 2018 the active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Day-Ahead and Real-Time Energy Markets.

2017/18 Winter Reliability Program As of December 1, 2017

- **Oil Program**
  - As of December 1st, participation from 86 units for a total of 3.868 million barrels of oil
  - 2.867 million barrels of the total inventory on December 1 are eligible for compensation per the winter program rules
  - Total oil program cost exposure is expected to be $29.62M (@$10.33/barrel)
- **LNG Program**
  - As of December 1st, no participation
- **DR Program**
  - As of December 1st, participation from 3 assets providing 7.5 MW of interruption capability
  - Total DR program cost exposure is anticipated to be $23.2K

2017/18 Winter Program Usage

- Winter Program Oil Inventory Changes:
  - Dec 2017: 548,410 BBLs
  - Jan 2018: 524,447 BBLs
  - Feb 2018: 192,113 BBLs
  - Mar 15: 43,536 BBLs
- Winter Program DR Events:
  - Dec 2017: None
  - Jan 2018: None
  - Feb 2018: None
  - Mar 2018: None
- Final Program Ending Eligible Inventory
  - 2,566,435 BBLS

Winter Reliability Program Costs & Billing

- Expected Program Costs:
  - Oil: $24.4M* ($22.2M collected; $2.2M outstanding)
  - DR: $33K ($33K collected; $5K remaining to be paid)
- Billing/Payment Schedule:
  - Initial Billings were based on 75% of initial inventory
  - Trued-up charges for unused fuel will be issued on April 17, 2018
  - Payment to generators for unused fuel inventory will be in May 14, 2018 bill

* Fuel inventory cost with preliminary availability adjustment

Andrews Square Fault

3-14-2018

System Conditions Just Prior To The Event

- New England Load 15,147 MW
- New England Internal Generation 12,671 MW
- Weather
  - Boston: 30°F clear skies
  - Worcester: 27°F with light snow
- Tie Schedules
  - NY North: -500
  - NNC: +91
  - CSC: +100
  - NB: -597
  - HQ P2: -1400
  - HQ HG: -225
  - Net -2531 into New England
- Eastern New England was still in recovery from the previous blizzard

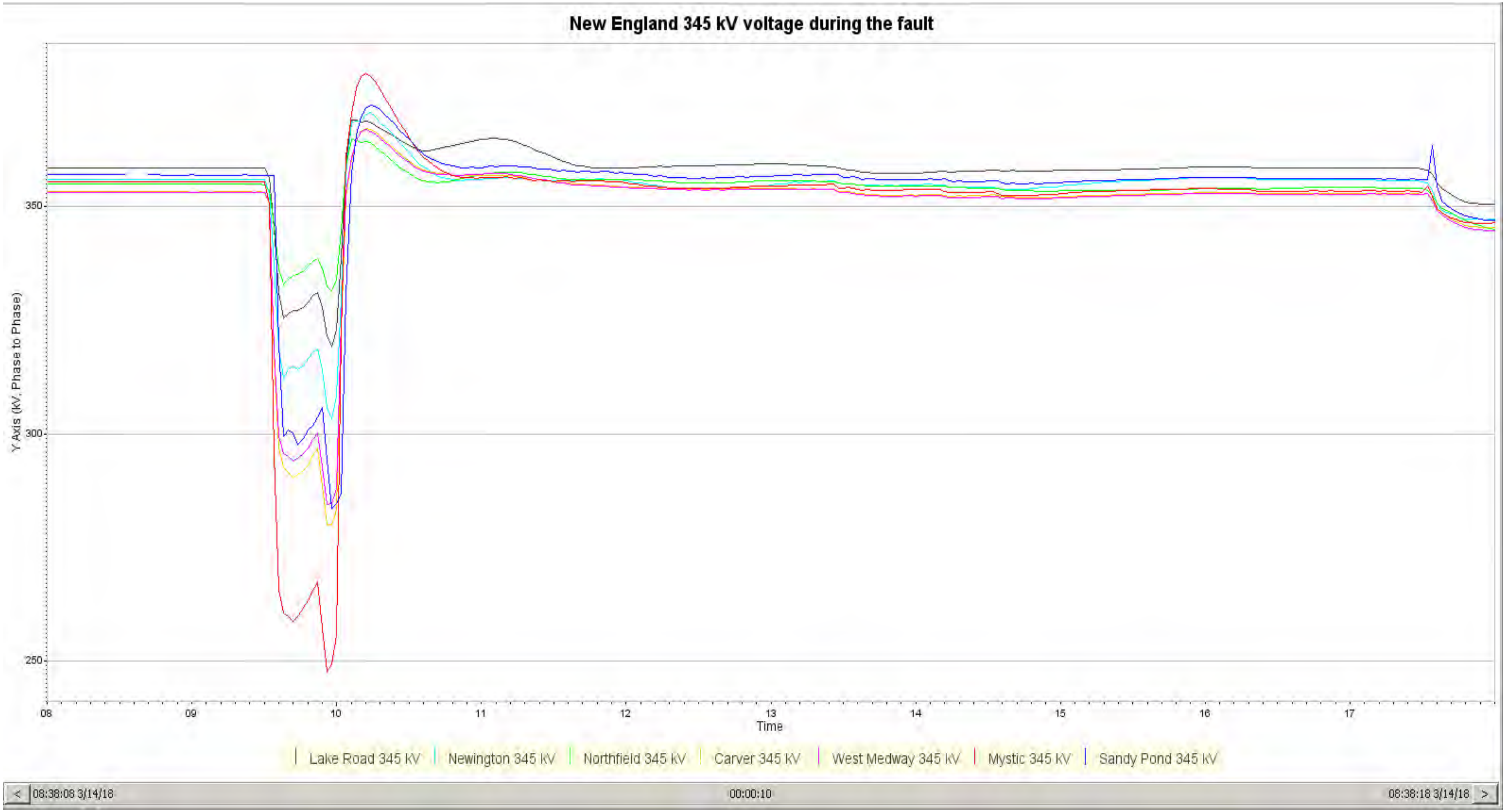
Narrative of Events

- At 08:38 on March 14, 2018 a fault occurred at the 115kV Andrews Square substation in Boston.
  - The initial investigation determined that snow pack on the high-side transformer bushing on one of the 115kV to 13.8kV transformers caused a fault
  - The delayed clearing of the fault resulted in depressed voltage on the 115 kV and 345 kV system
  - Multiple 115 kV breakers in the area operated
- At 08:38+
  - Mystic 9 and Phase 2 station service tripped resulting in a loss of approximately 2000 MW of energy
  - Following this event, an under voltage relay tripped auxiliary equipment at Phase 2, leading to tripping of 1400 MW
  - Mystic 9 tripping was due to loss of station service. The station service under voltage set points are being evaluated.

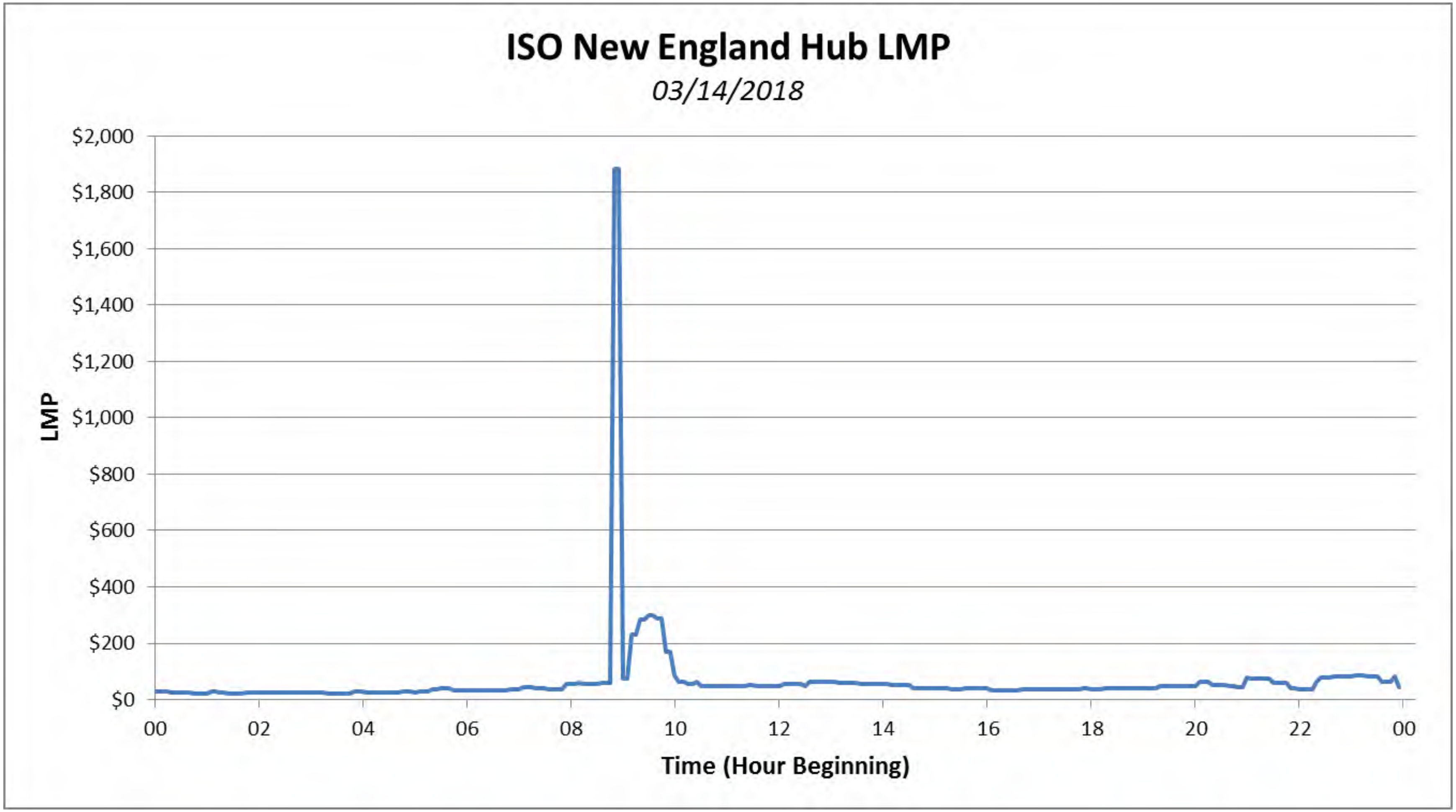
Narrative of Events, cont.

- The system experienced low voltages along the NE-NY border as well as multiple areas in New England
  - The Pleasant Valley-Long Mountain 398 Line (345 kV line between CT & NY) was out of service for work in New York.
    - The outage of this line contributed to the magnitude of the low voltages
  - Heavy flows into NE from the eastern interconnection caused NY to have to implement emergency procedures to back down its Central-East interface flows.
  - System Operators were able to recover the Area Control Error and relieve all impacted interfaces to meet all reliability criteria.

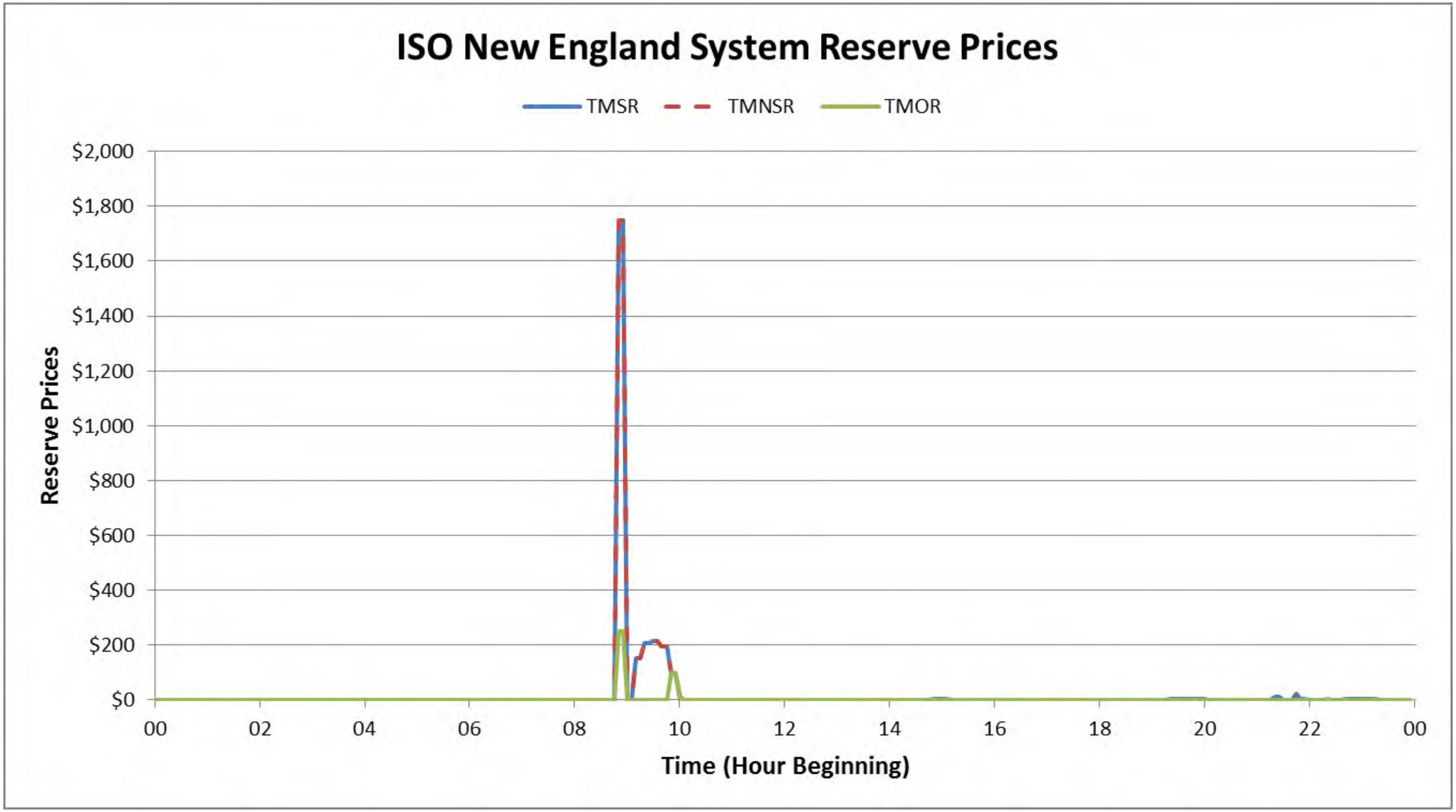
Voltages at New England stations during and immediately after the fault



Energy Prices During the Event



Reserve Prices During the Event



SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (-1.1°F) Max: 64°F, Min: 16°F Precipitation: 5.07" – Above Normal Normal: 4.32" Snow: 23.3" – Above Normal	Hartford	Temperature: Below Normal (-0.6°F) Max: 60°F, Min: 17°F Precipitation: 2.65" - Below Normal Normal: 3.62" Snow: 16.6" – Above Normal

Peak Load:	16,735 MW	March 7, 2018	19:00 (ending)

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

Procedure	Declared	Cancelled	Note
M/LCC 2	3/7/2018 09:00	3/9/2018 21:00	Severe Weather
M/LCC 2	3/12/2018 14:00	3/15/2018 12:00	Severe Weather
	Continued only in NStar	3/16/2018 16:00	Severe Weather
M/LCC 2	3/20/2018 16:00	3/22/2018 12:00	Severe Weather

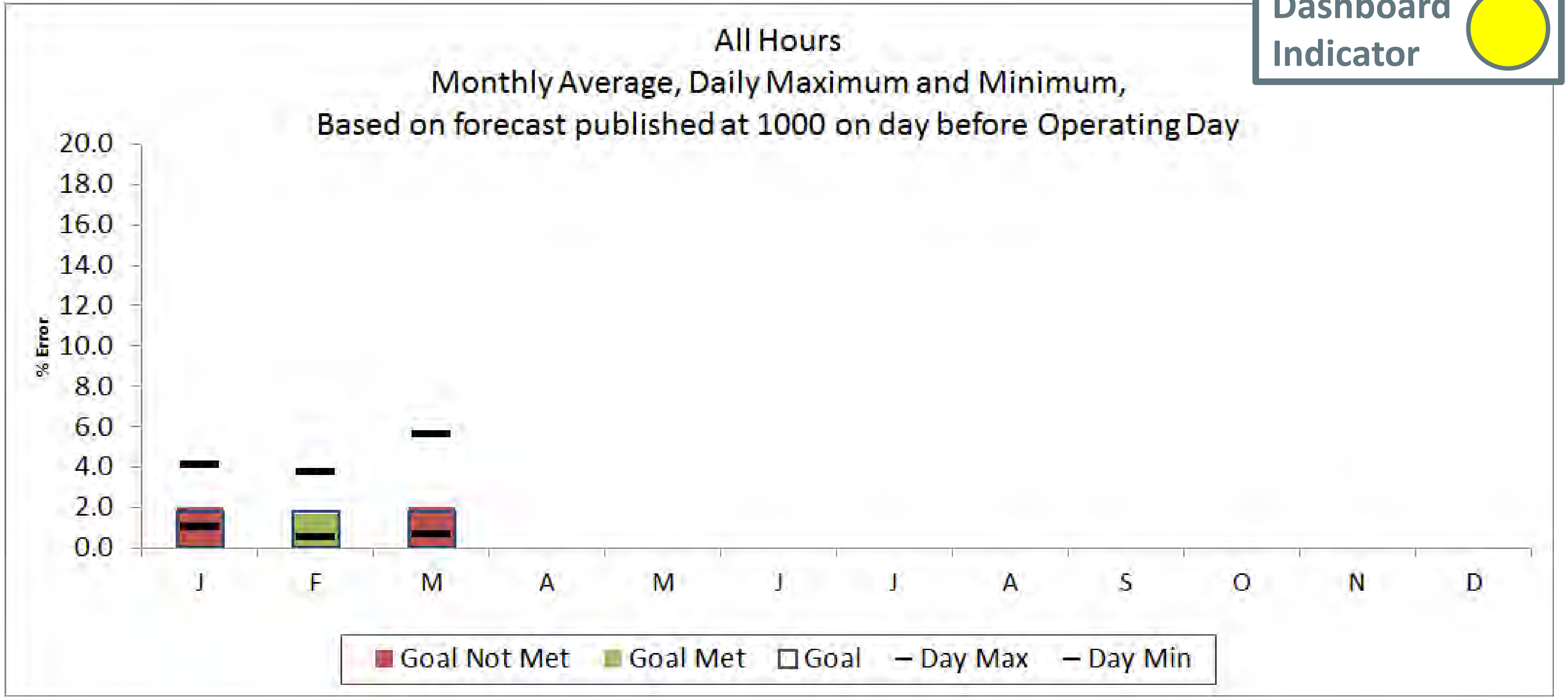
System Operations, cont.

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
3/8/2018	ISO-NE	1600
3/14/2018	ISO-NE	2006
3/19/2018	NYISO	400
3/19/2018	ISO-NE	660

2018 System Operations - Load Forecast Accuracy

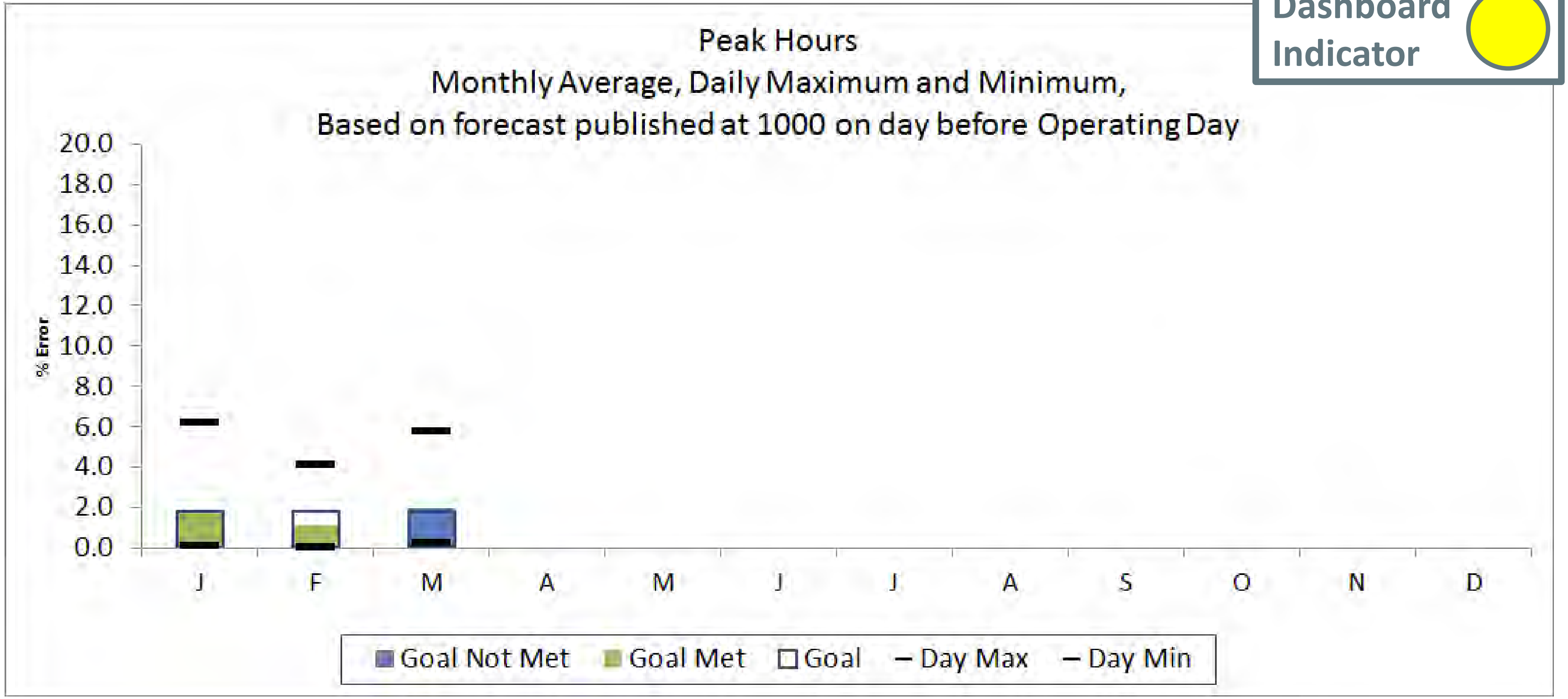
Dashboard Indicator ●



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.05	3.69	5.58										5.58
Day Min	1.02	0.53	0.63										0.53
MAPE	2.04	1.67	2.05										1.93
Goal	1.80	1.80	1.80										

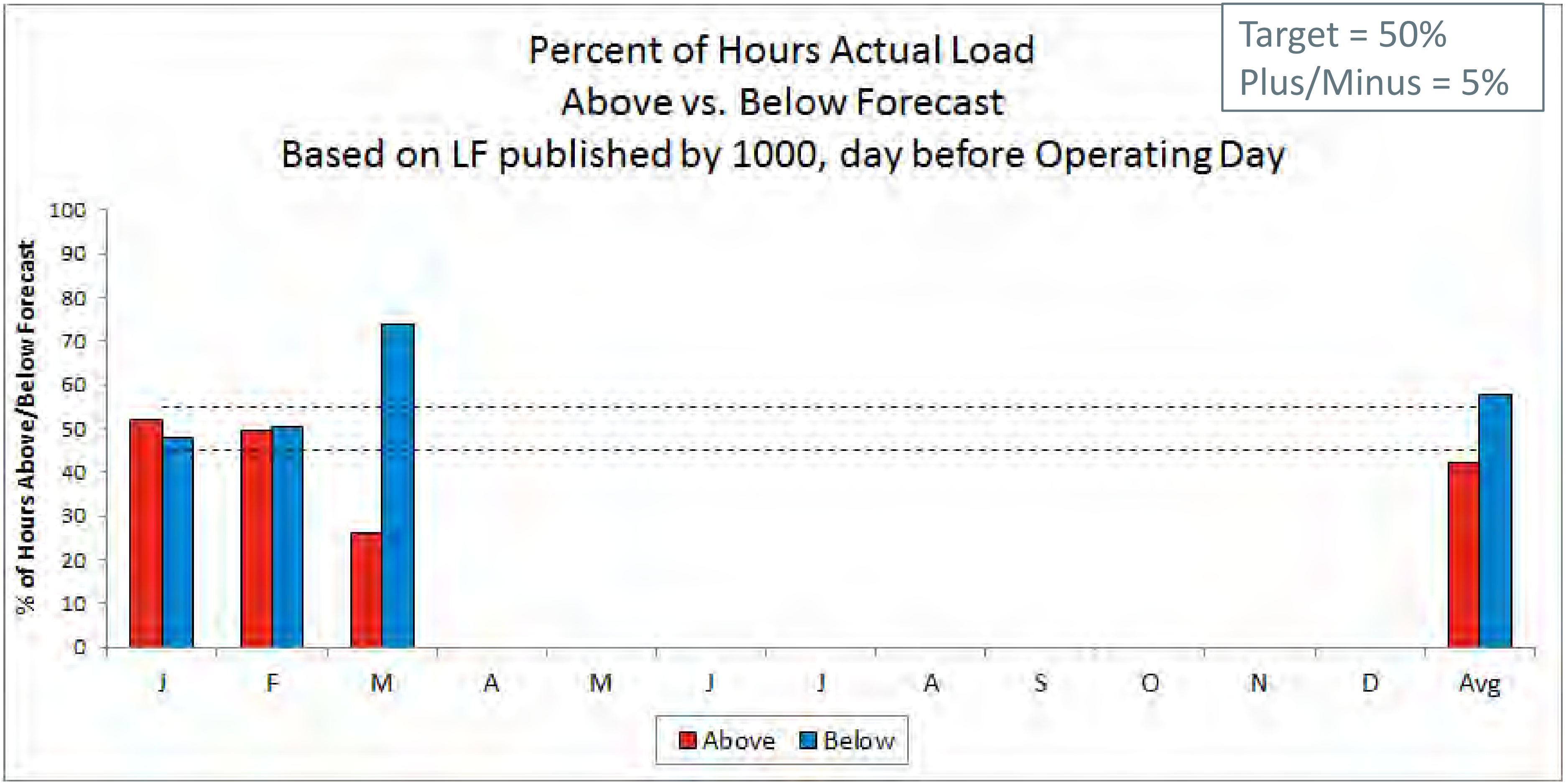
2018 System Operations - Load Forecast Accuracy, cont.

Dashboard Indicator 🟡



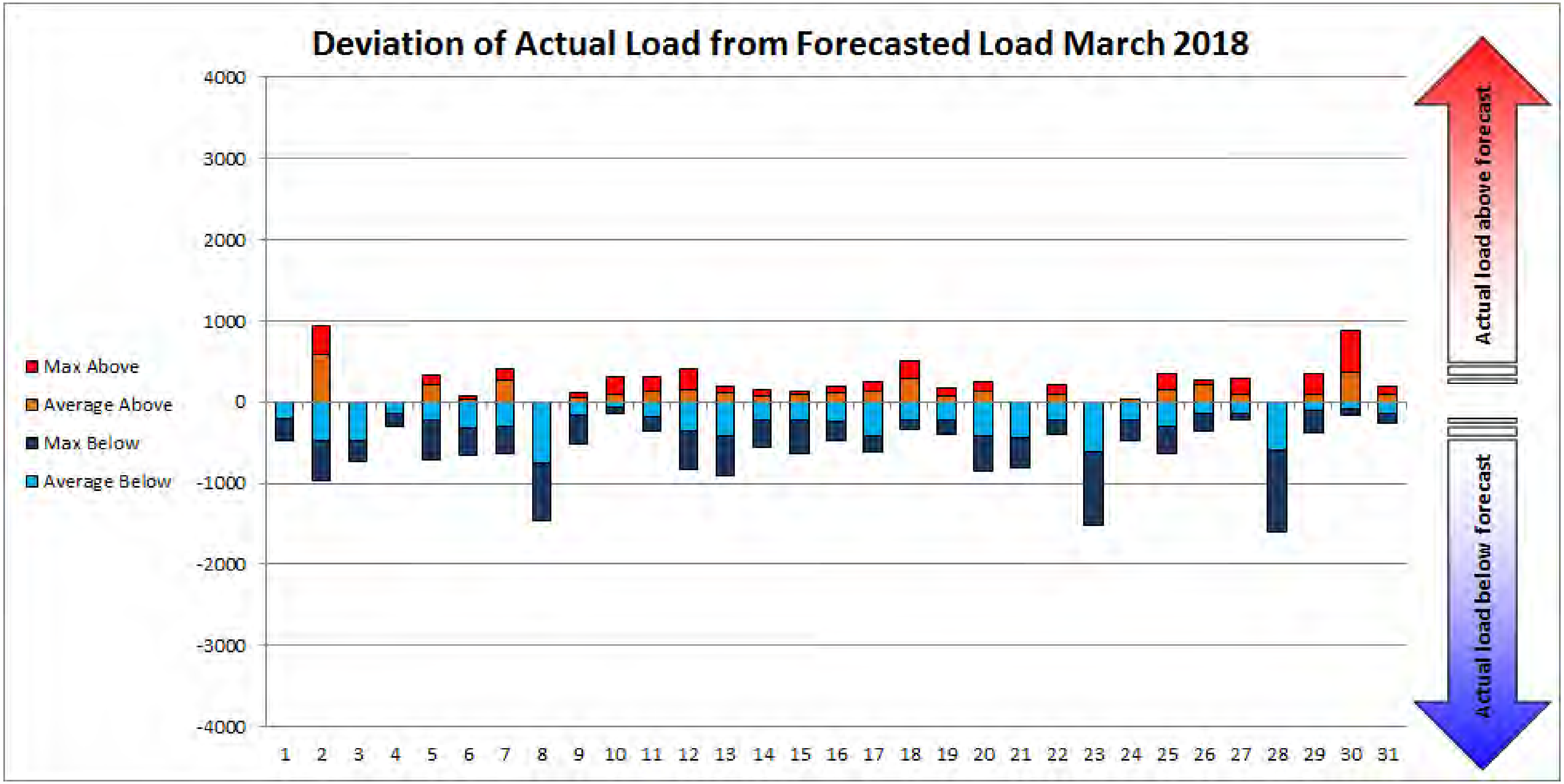
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	6.15	4.08	5.76										6.15
Day Min	0.04	0.03	0.25										0.03
MAPE	1.73	1.14	1.91										1.61
Goal	1.80	1.80	1.80										

2018 System Operations - Load Forecast Accuracy, cont.

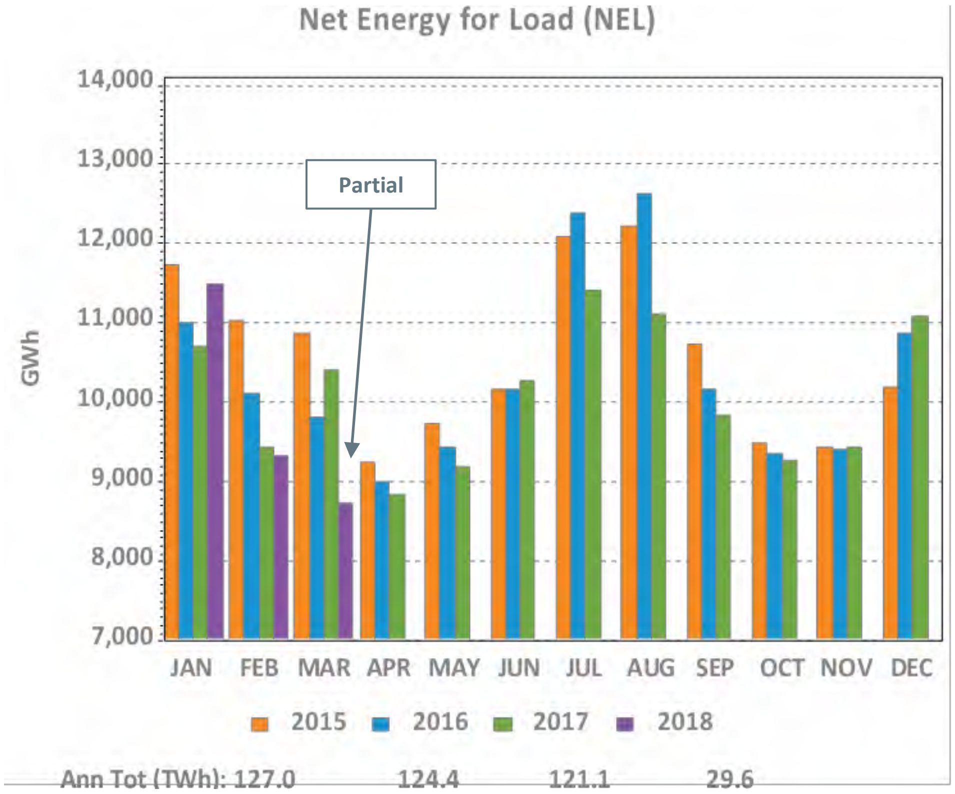


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	52	49.7	26.1										42
Below %	48	50.3	73.9										58
Avg Above	222.2	193.9	98.9										222
Avg Below	-242.6	-180.6	-278.3										-278
Avg All	0	14	-192										-62

2018 System Operations - Load Forecast Accuracy, cont.

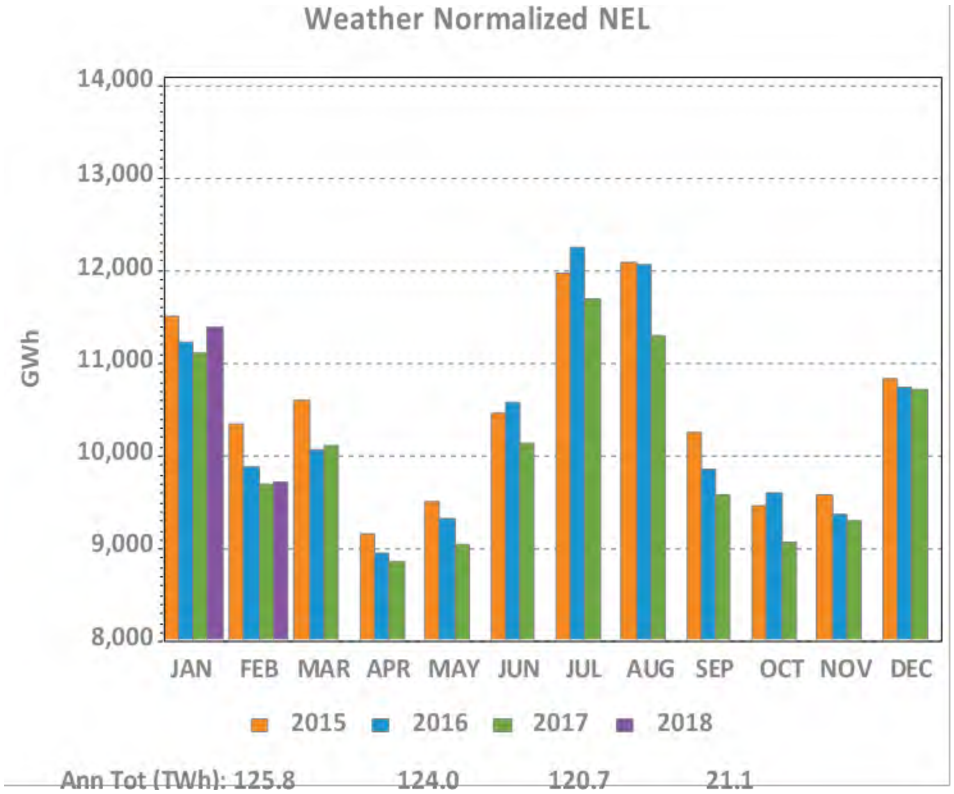


Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL



Net Energy for Load (NEL)

Ann Tot (TWh): 127.0 124.4 121.1 29.6

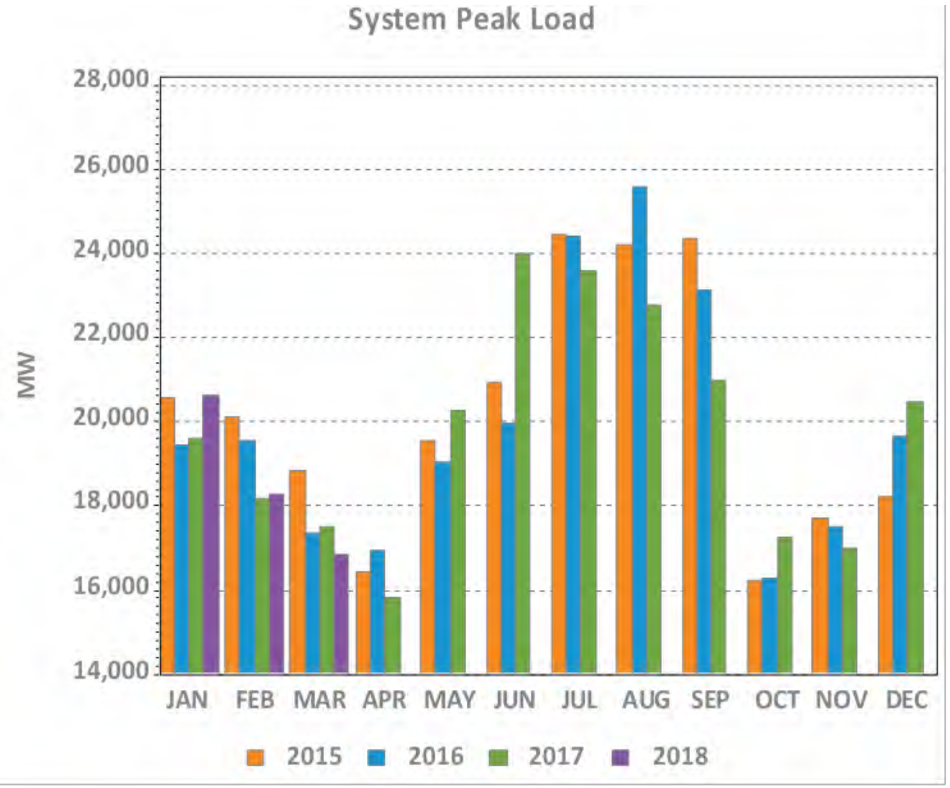


Weather Normalized NEL

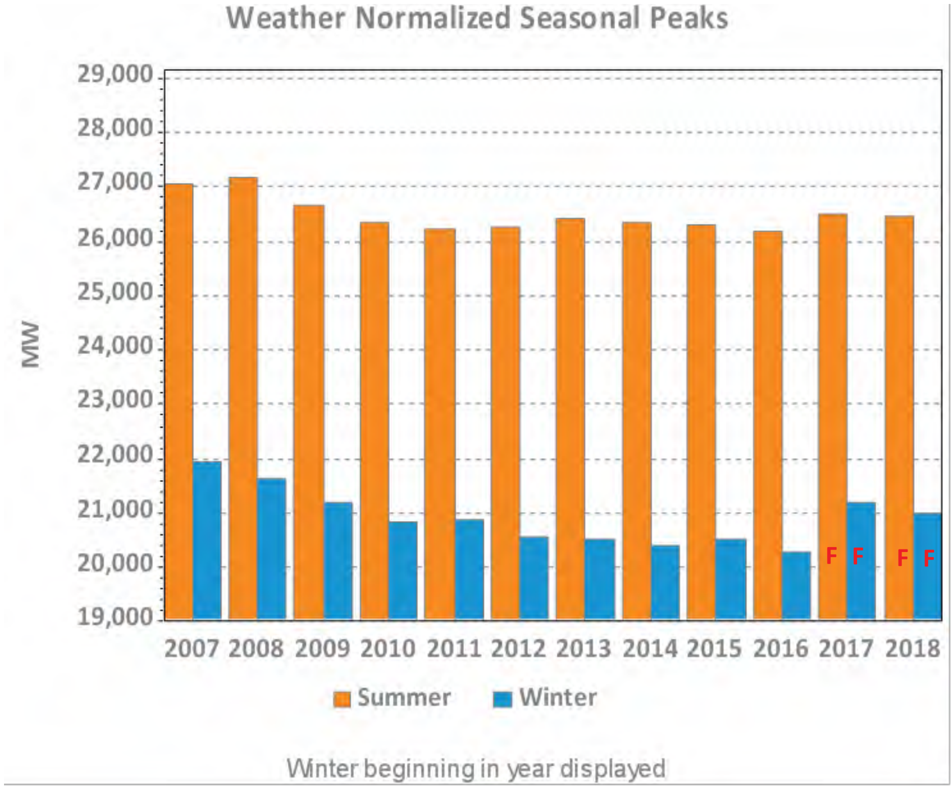
Ann Tot (TWh): 125.8 124.0 120.7 21.1

NEPOOL NEL is the total net 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



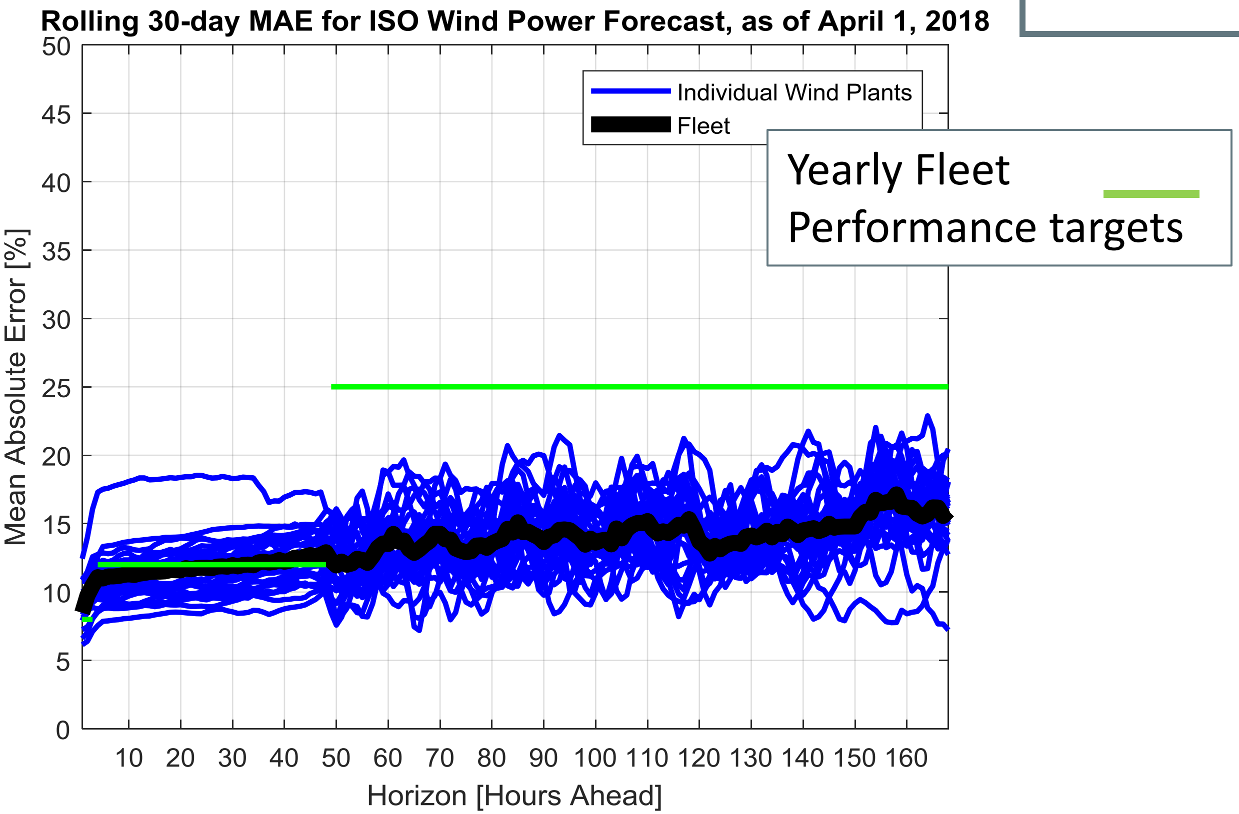
*Revenue quality metered value



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

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

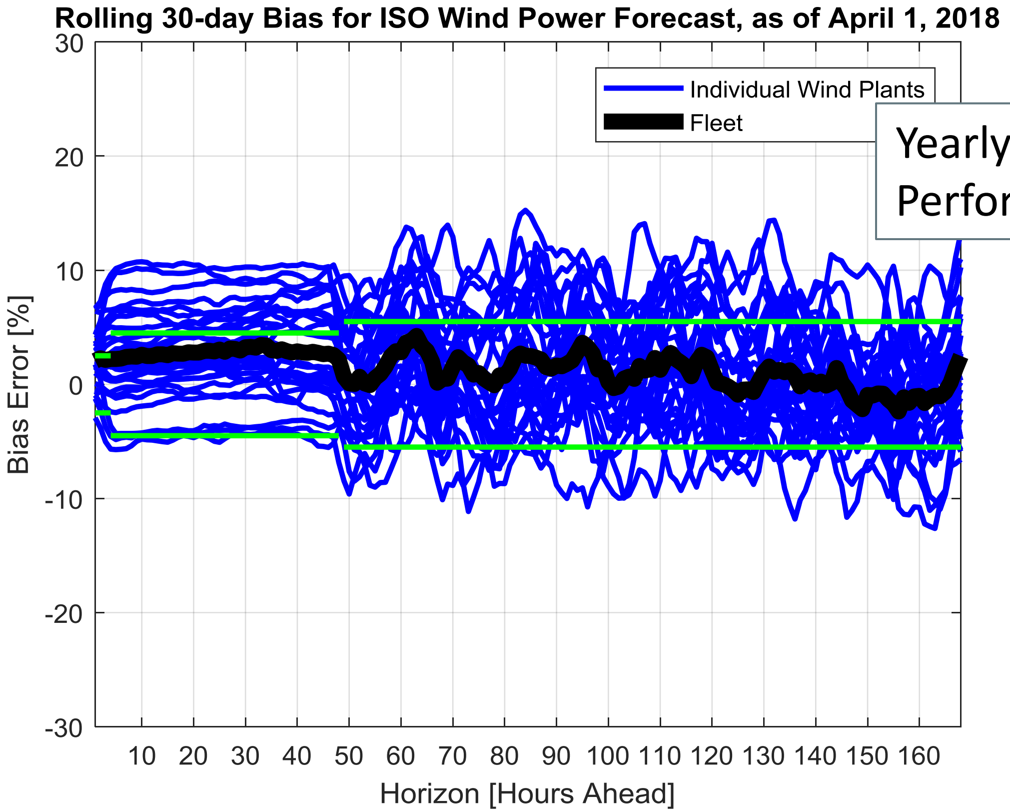
Dashboard Indicator 🟢



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

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

Dashboard Indicator ●

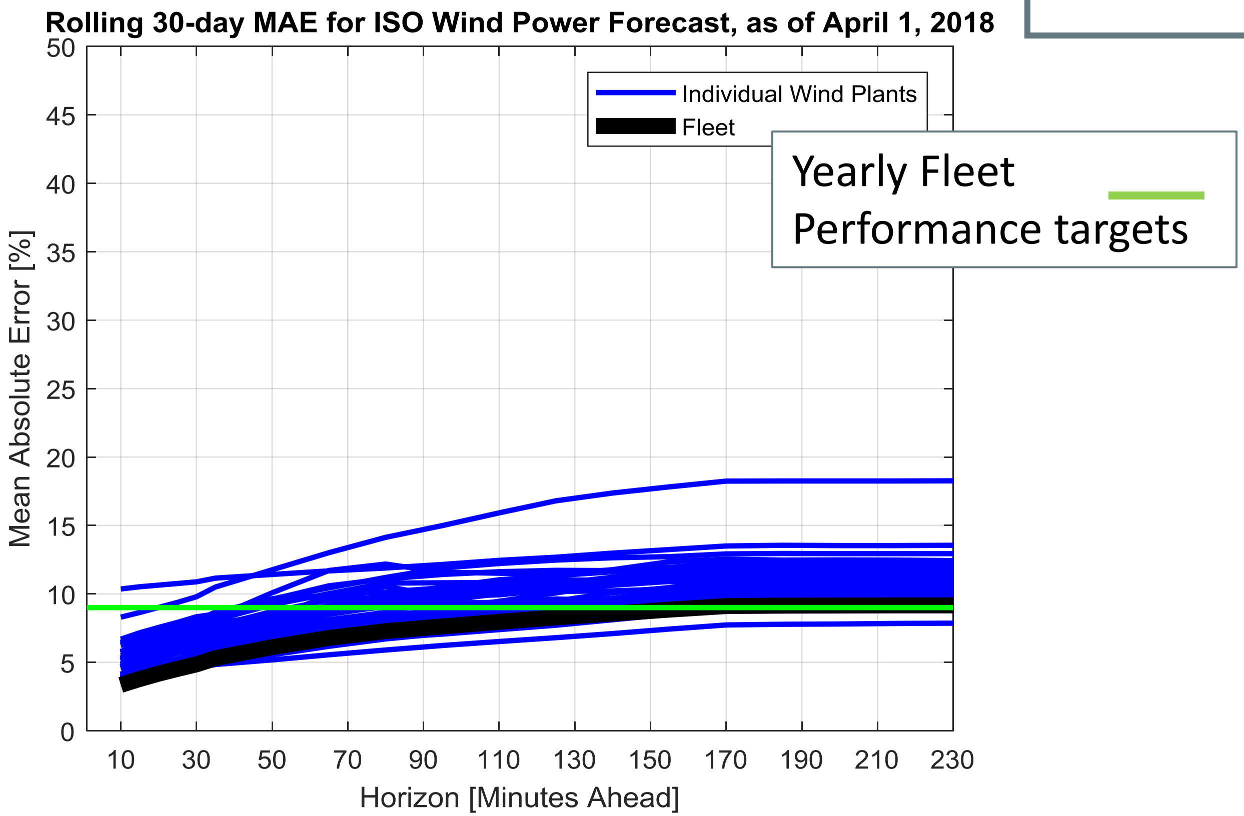


Yearly Fleet Performance targets 🟩

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 ●

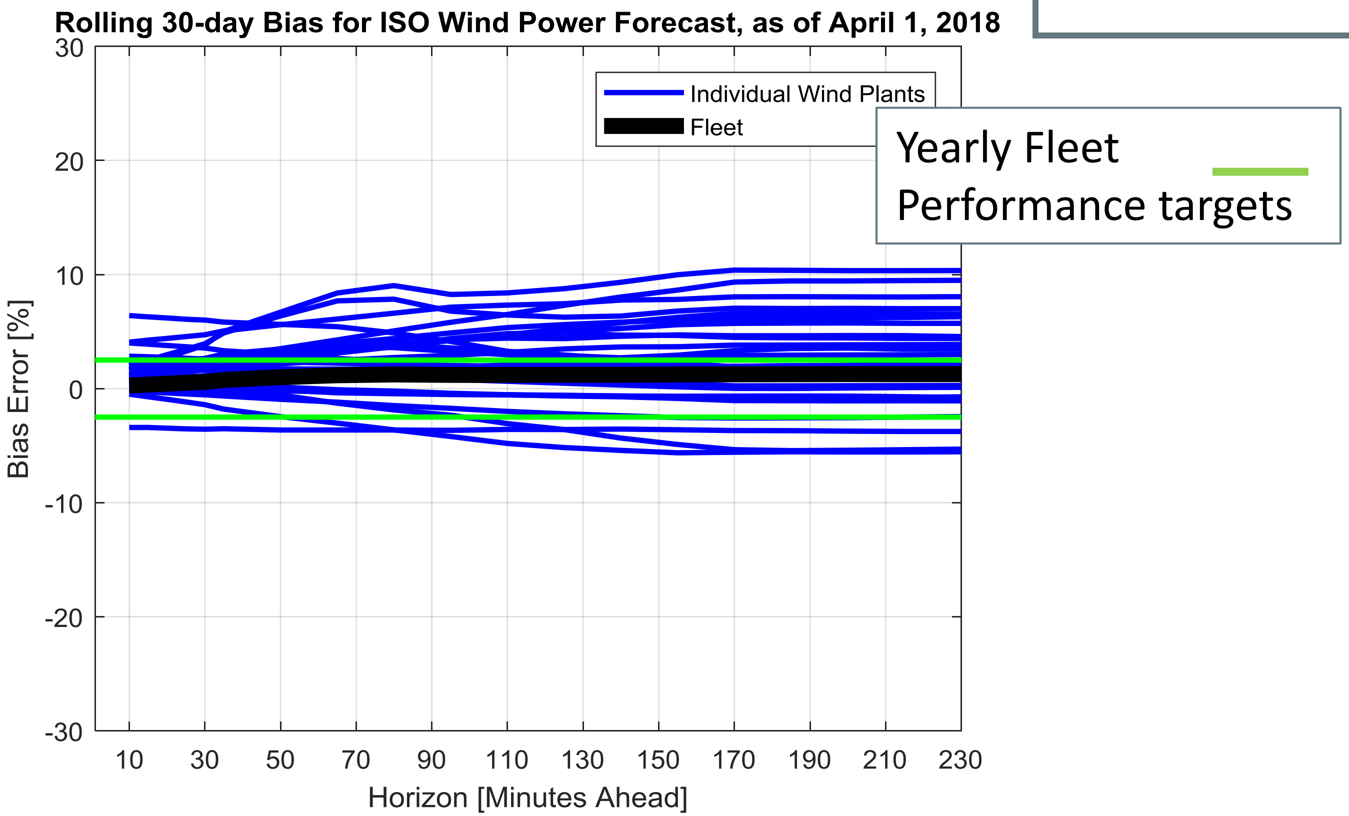


Yearly Fleet Performance targets

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

Wind Power Forecast Error Statistics: Short Term Forecast Bias

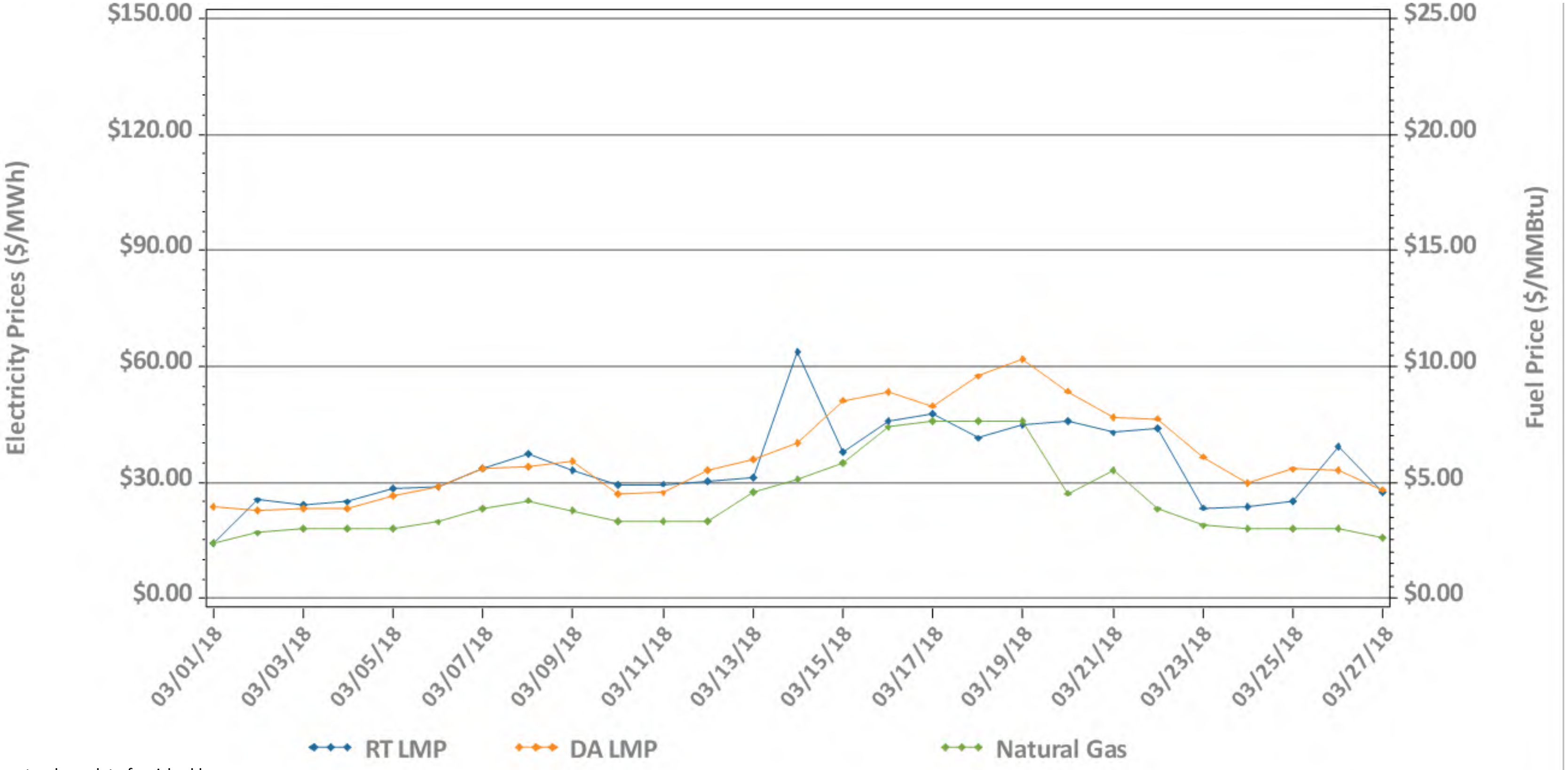
Dashboard Indicator ●



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

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: March 1-27, 2018

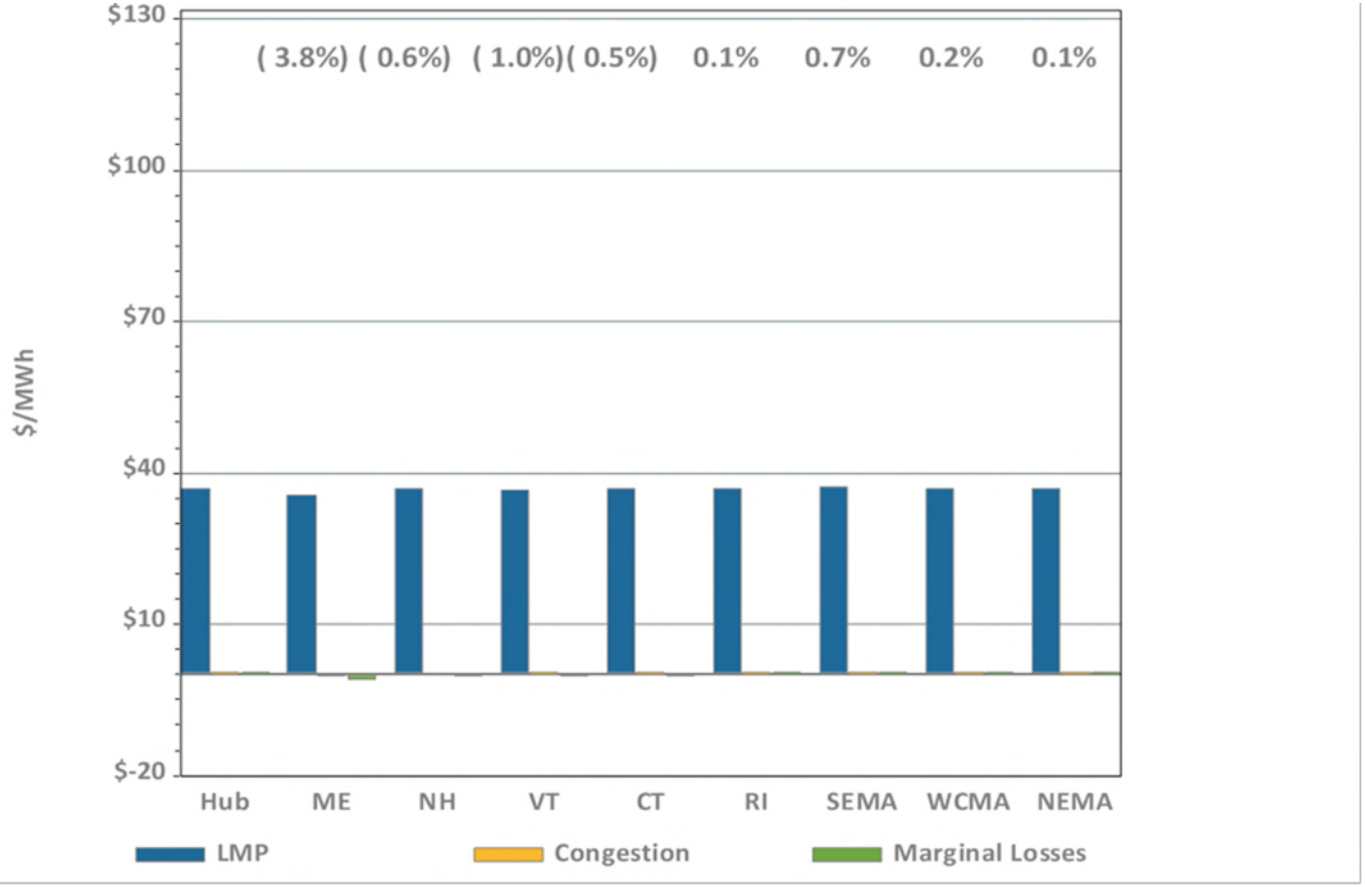


Underlying natural gas data furnished by:

ICE Global markets in clear view

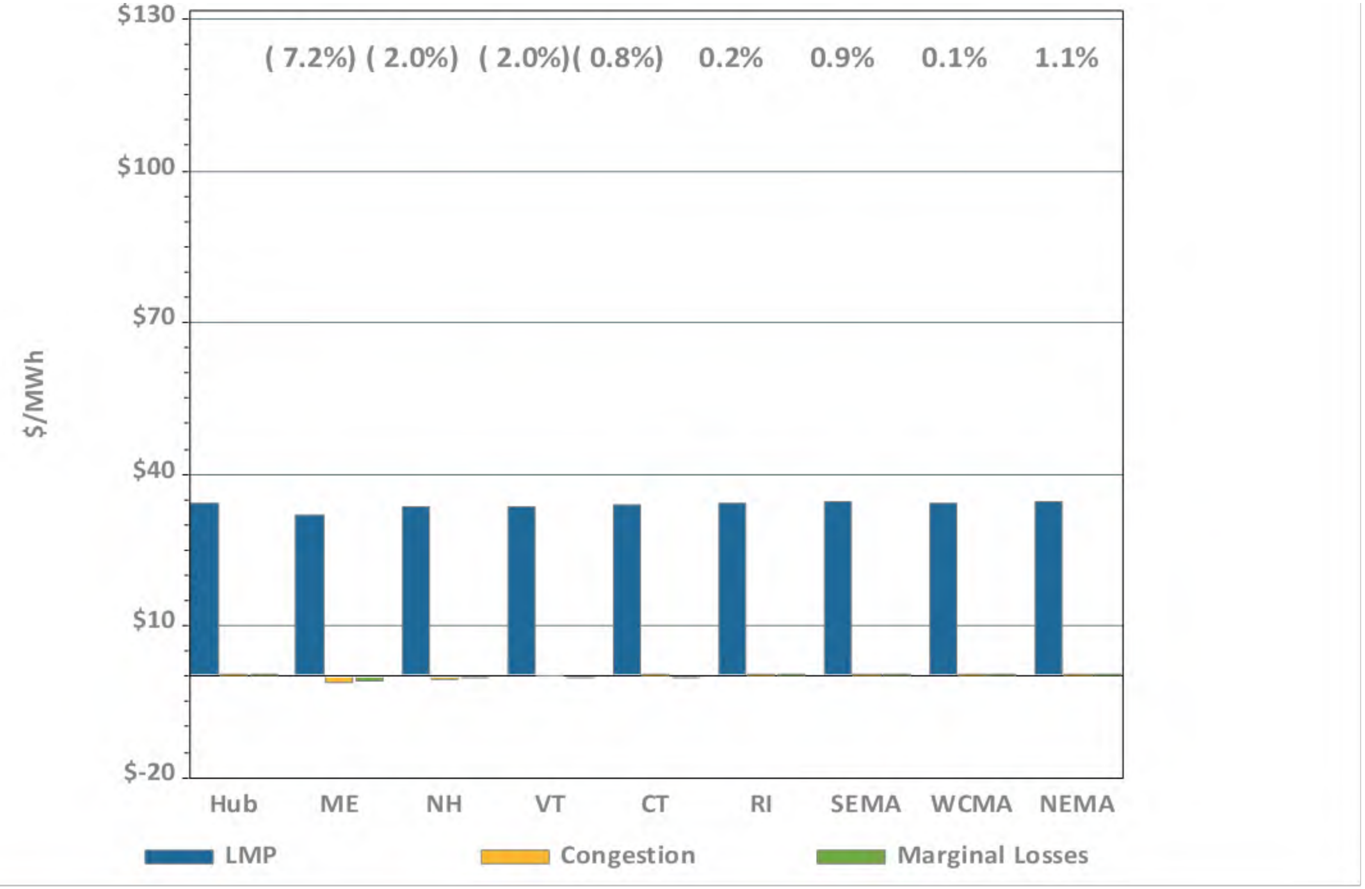
Average price difference over this period (DA-RT): $2.69
Average price difference over this period ABS(DA-RT): $6.07
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 18%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, March 2018



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

RT LMPs Average by Zone & Hub, March 2018

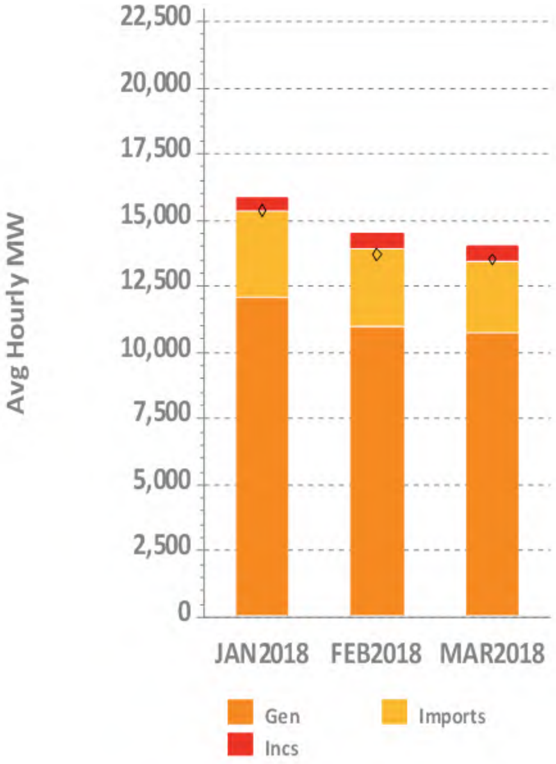


Definitions

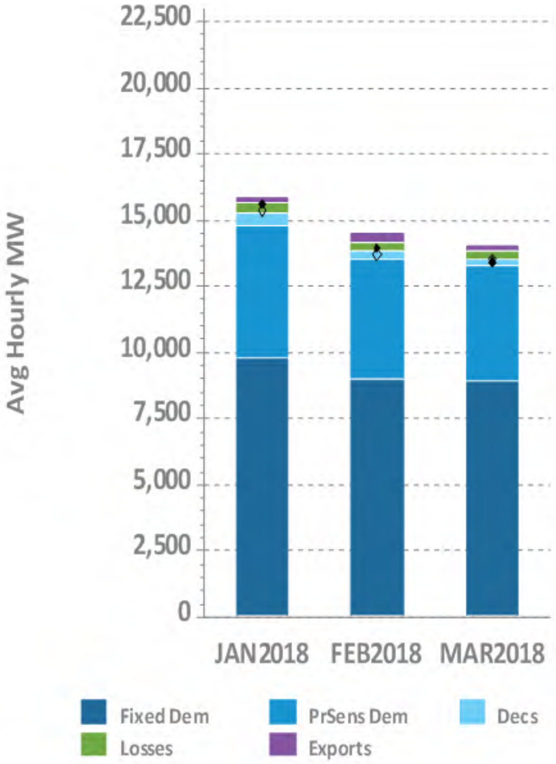
Day-Ahead Concept	Definition
Day-Ahead Load Obligation **(DALO)**	The sum of day-ahead cleared load (including asset load, pump load, exports, and virtual purchases and excluding modeled transmission losses)
Day-Ahead Cleared Physical Energy	The sum of day-ahead cleared generation and cleared net imports

Components of Cleared DA Supply and Demand – Last Three Months

Supply



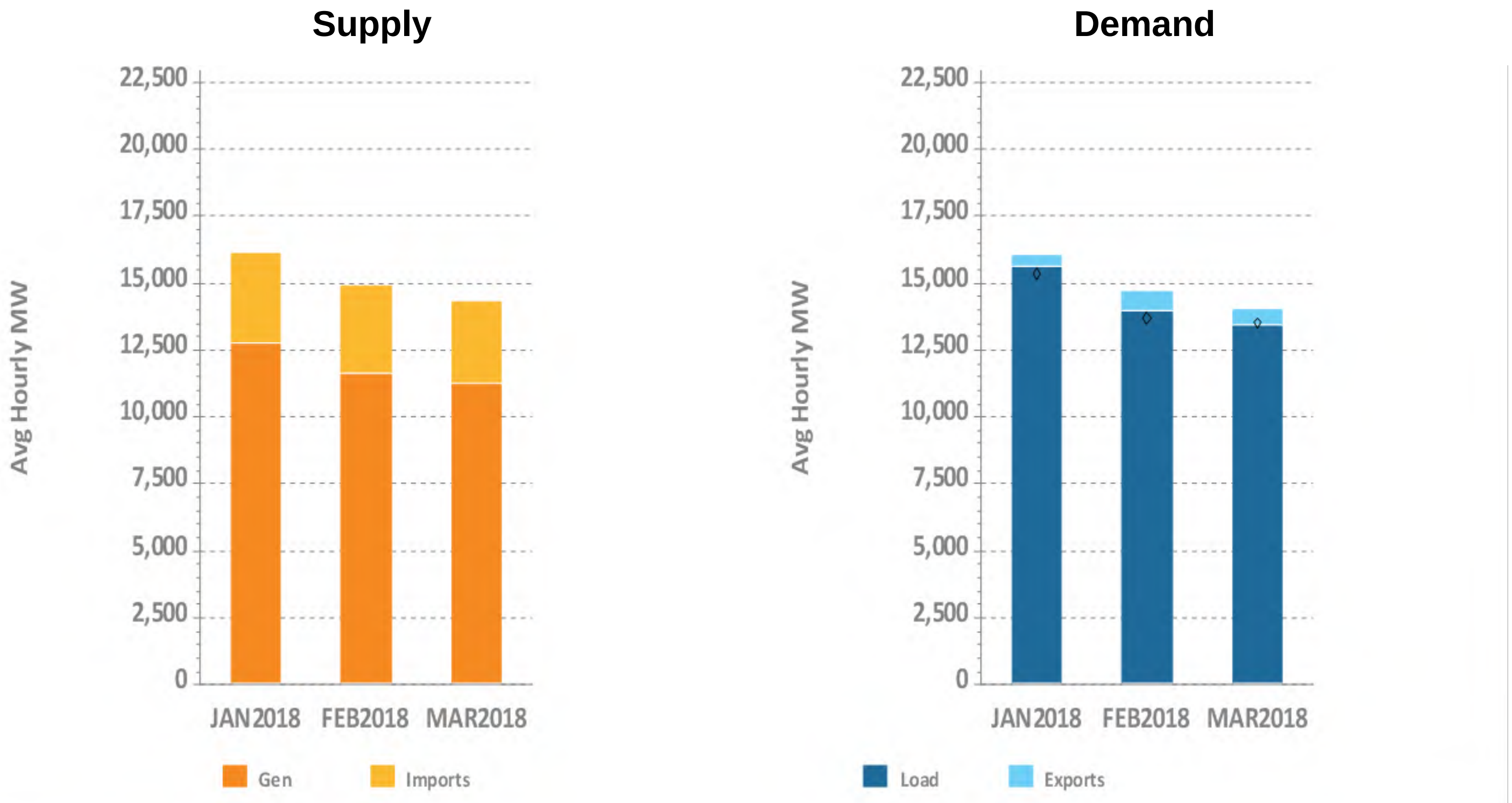
Demand



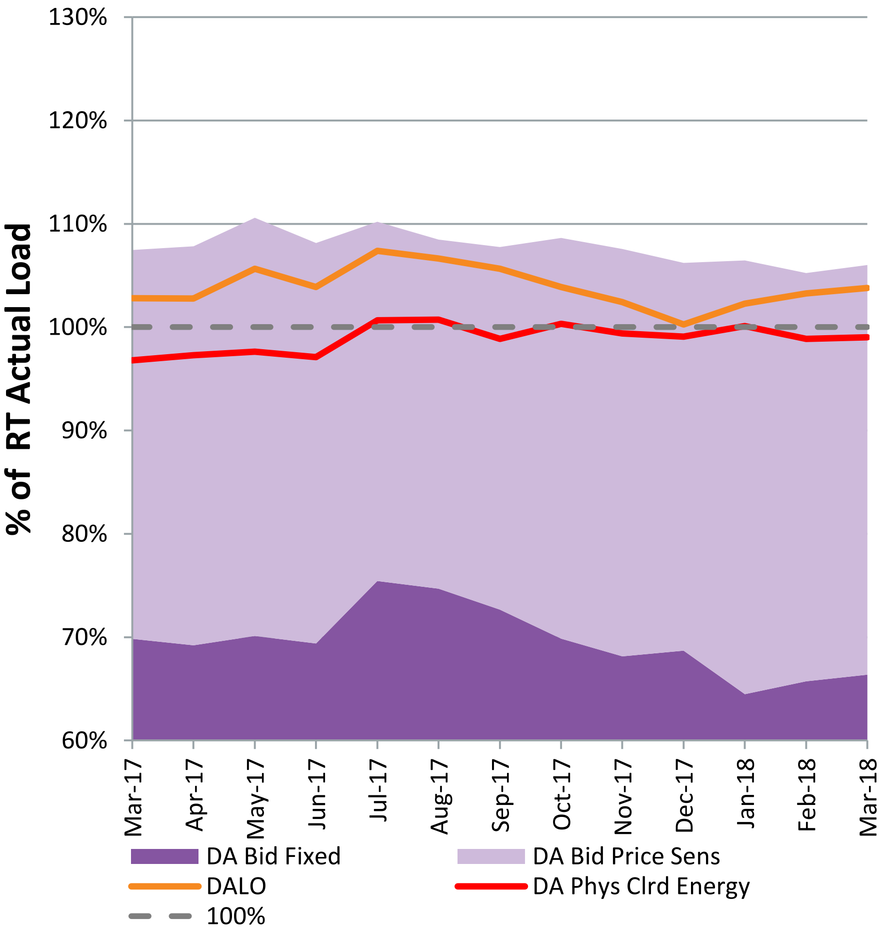
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

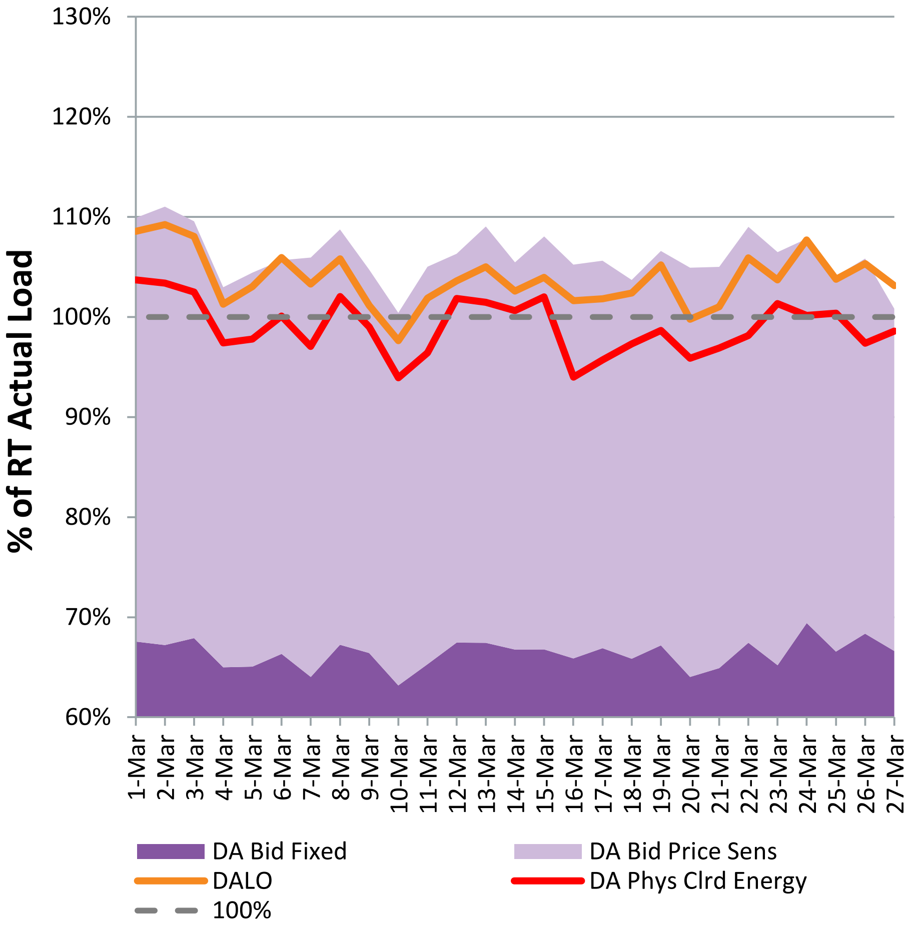
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

Components of RT Supply and Demand – Last Three Months



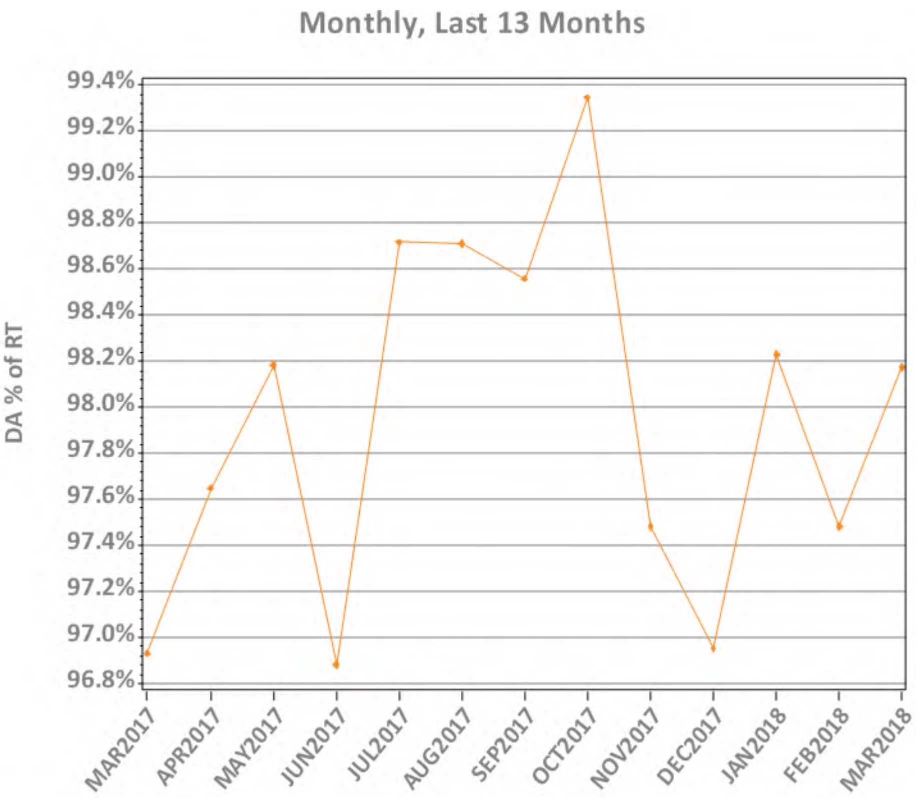
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

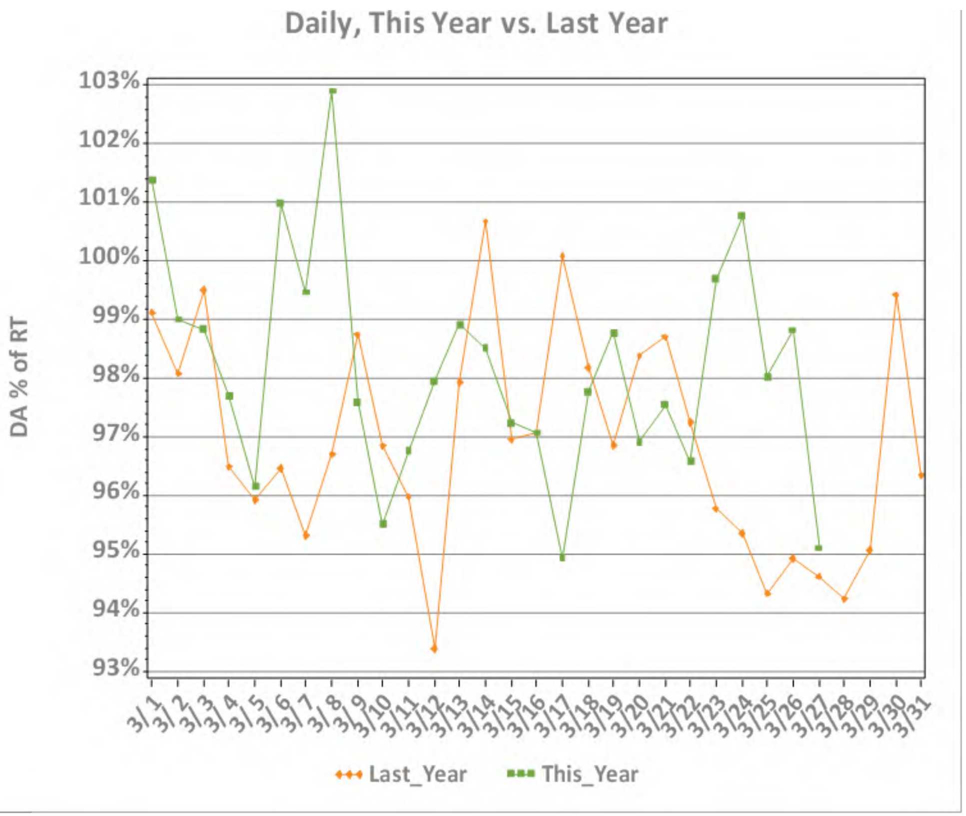




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load. DA Bid categories reflect internal load asset bidding behavior (Virtual demand and export bid behavior not reflected).

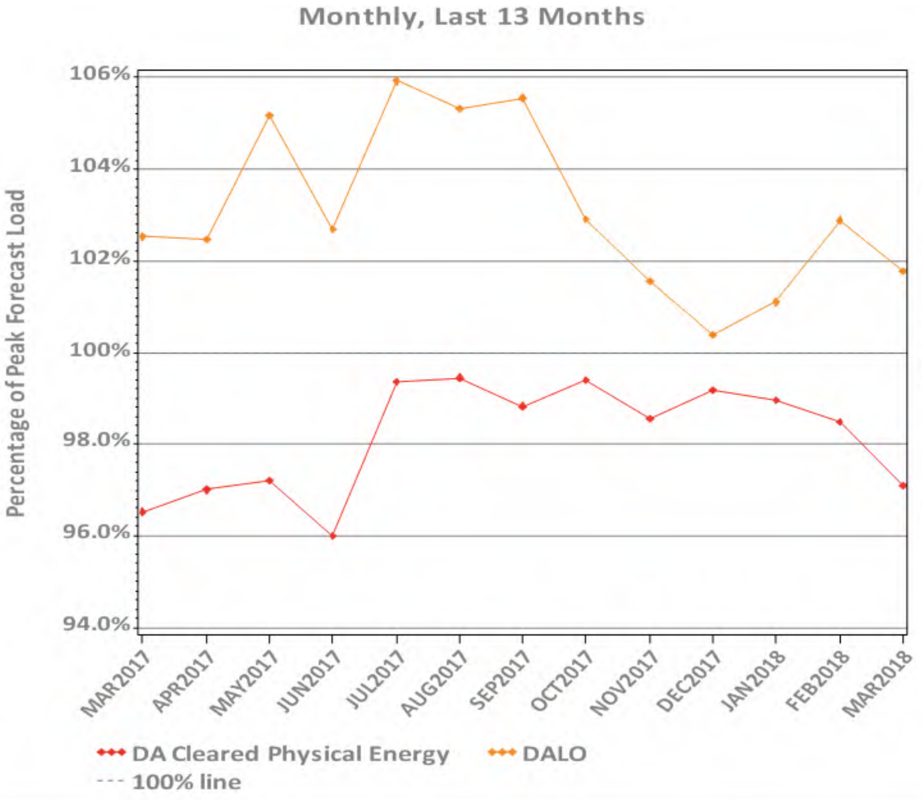
DA vs. RT Load Obligation: February, This Year vs. Last Year



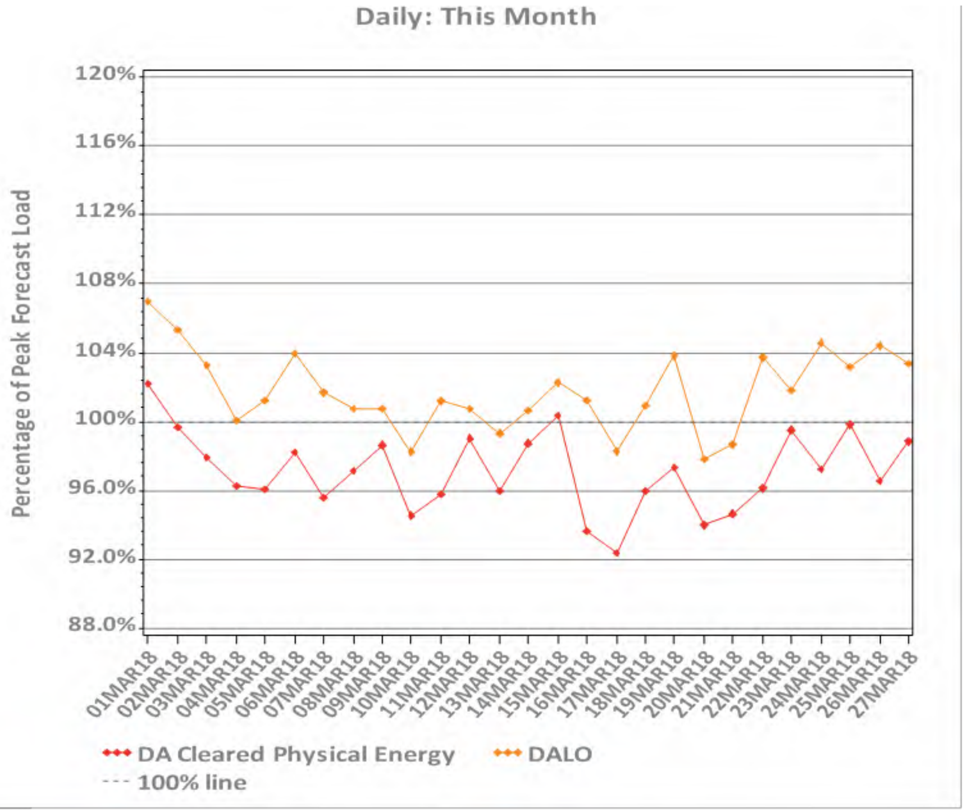


*Hourly average values

DA Volumes as % of Forecast in Peak Hour



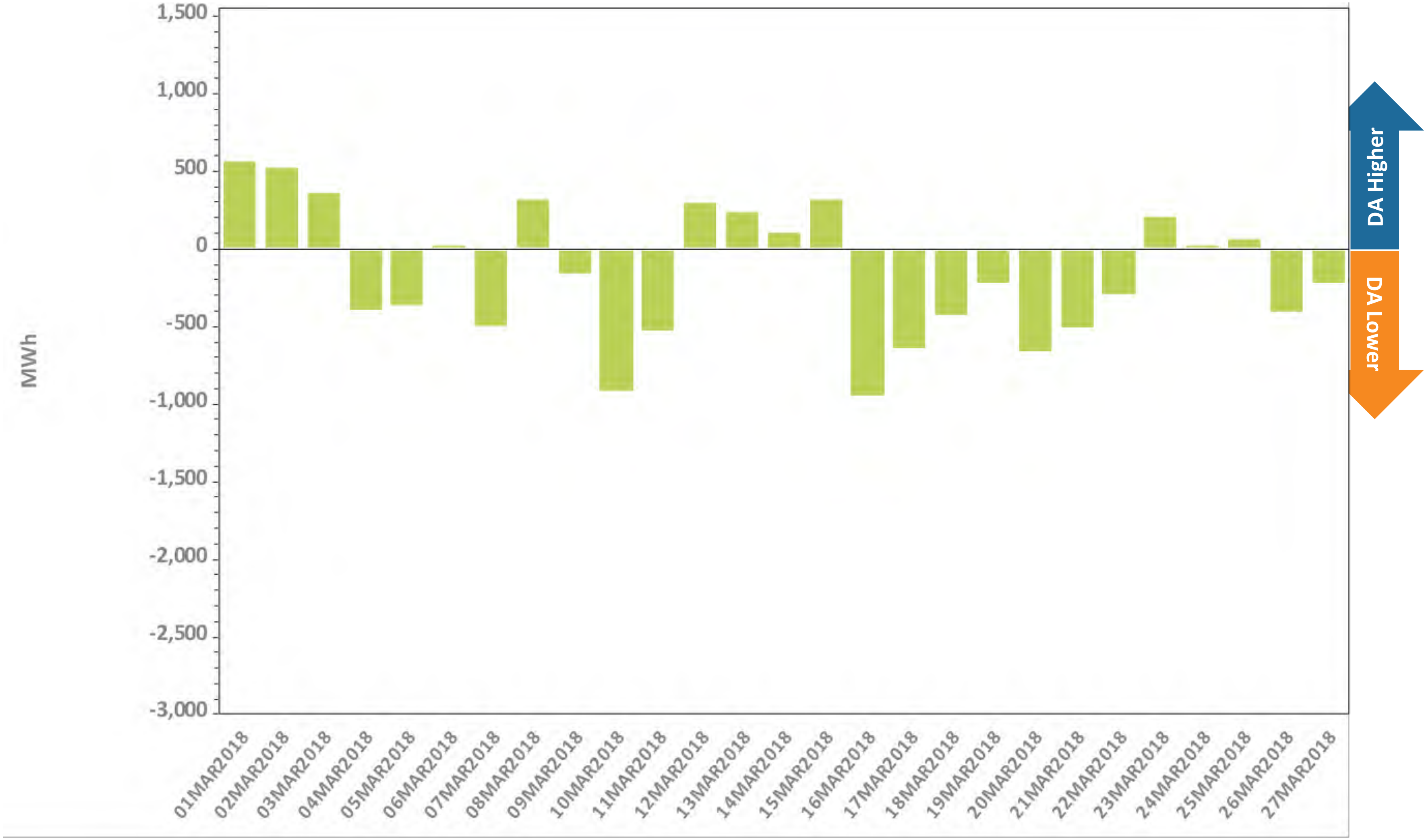
Monthly, Last 13 Months



Daily: This Month

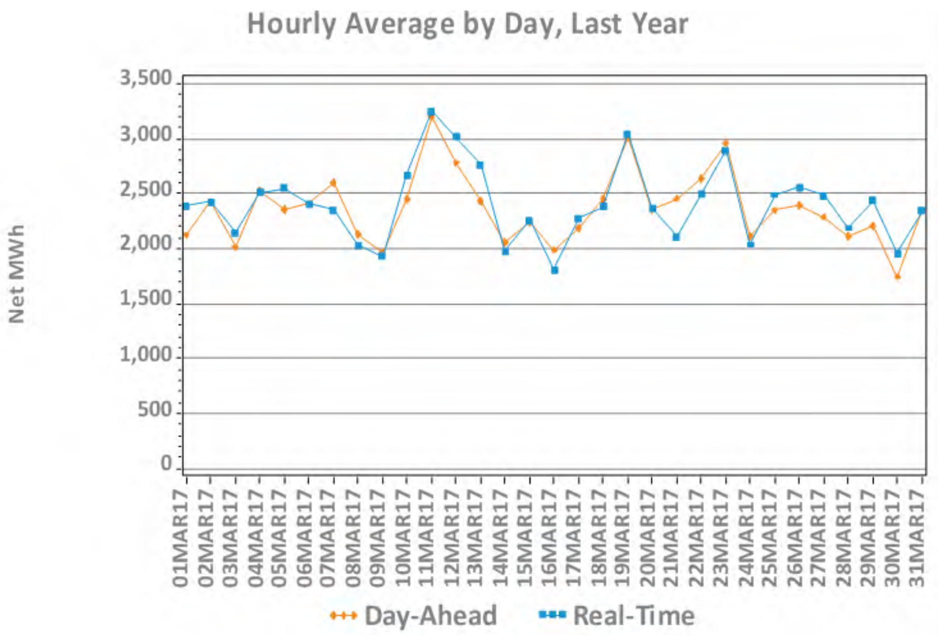
***There were no supplemental commitments required for capacity during the Reserve Adequacy Assessment (RAA) during March.**

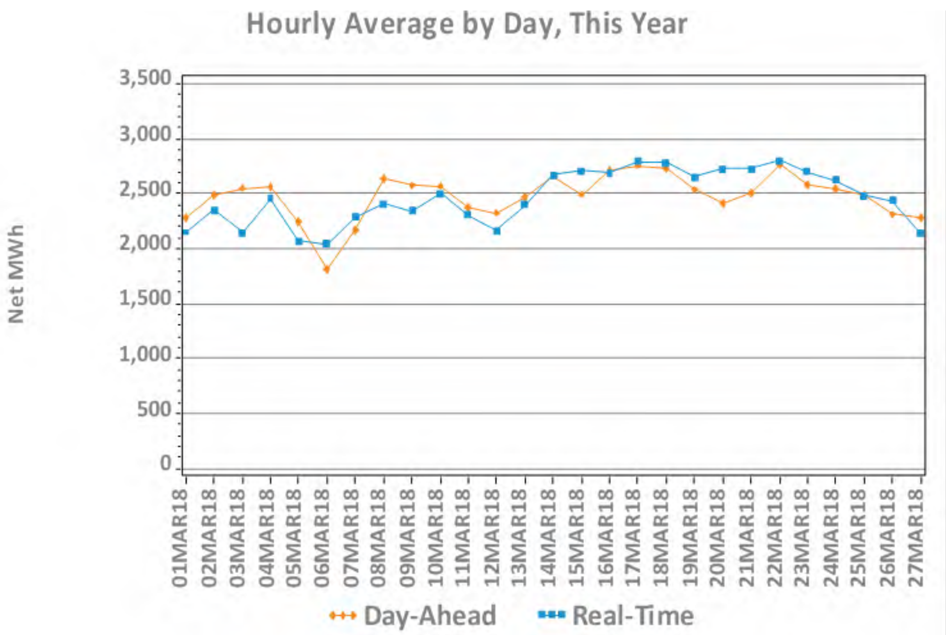
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

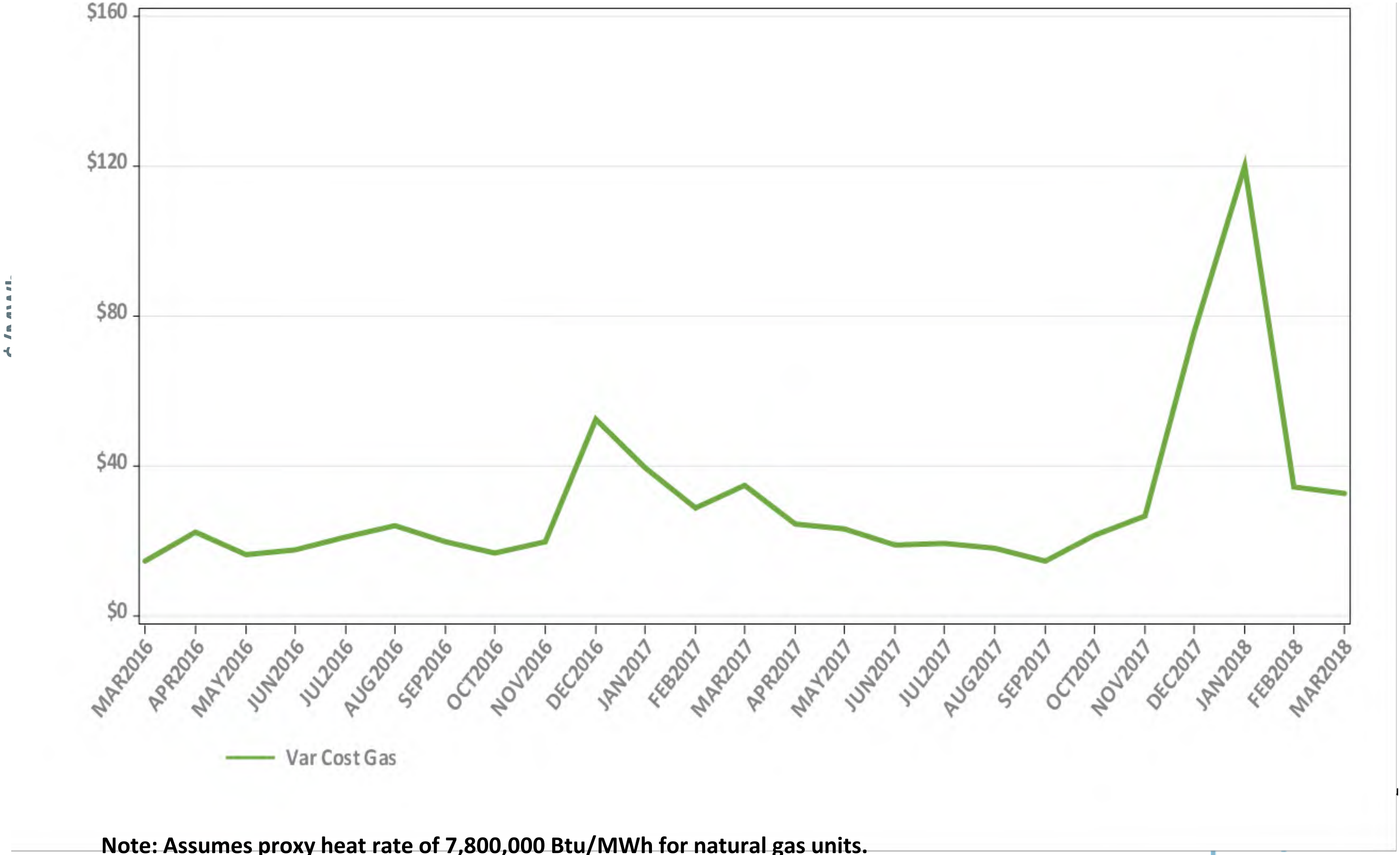
DA vs. RT Net Interchange March 2018 vs. March 2017


Hourly Average by Day, Last Year


Hourly Average by Day, This Year

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



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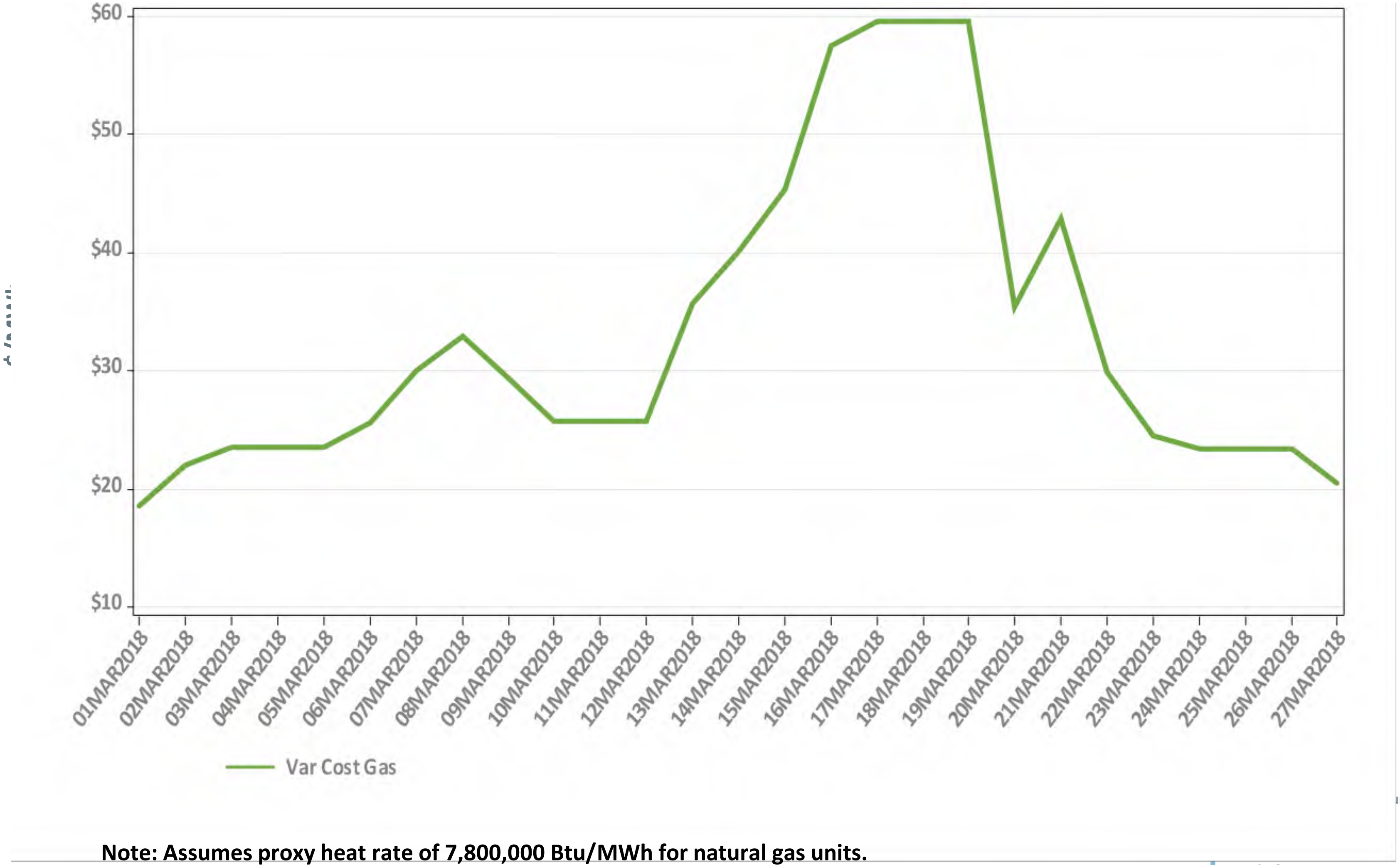
Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

ice Global markets in clear view

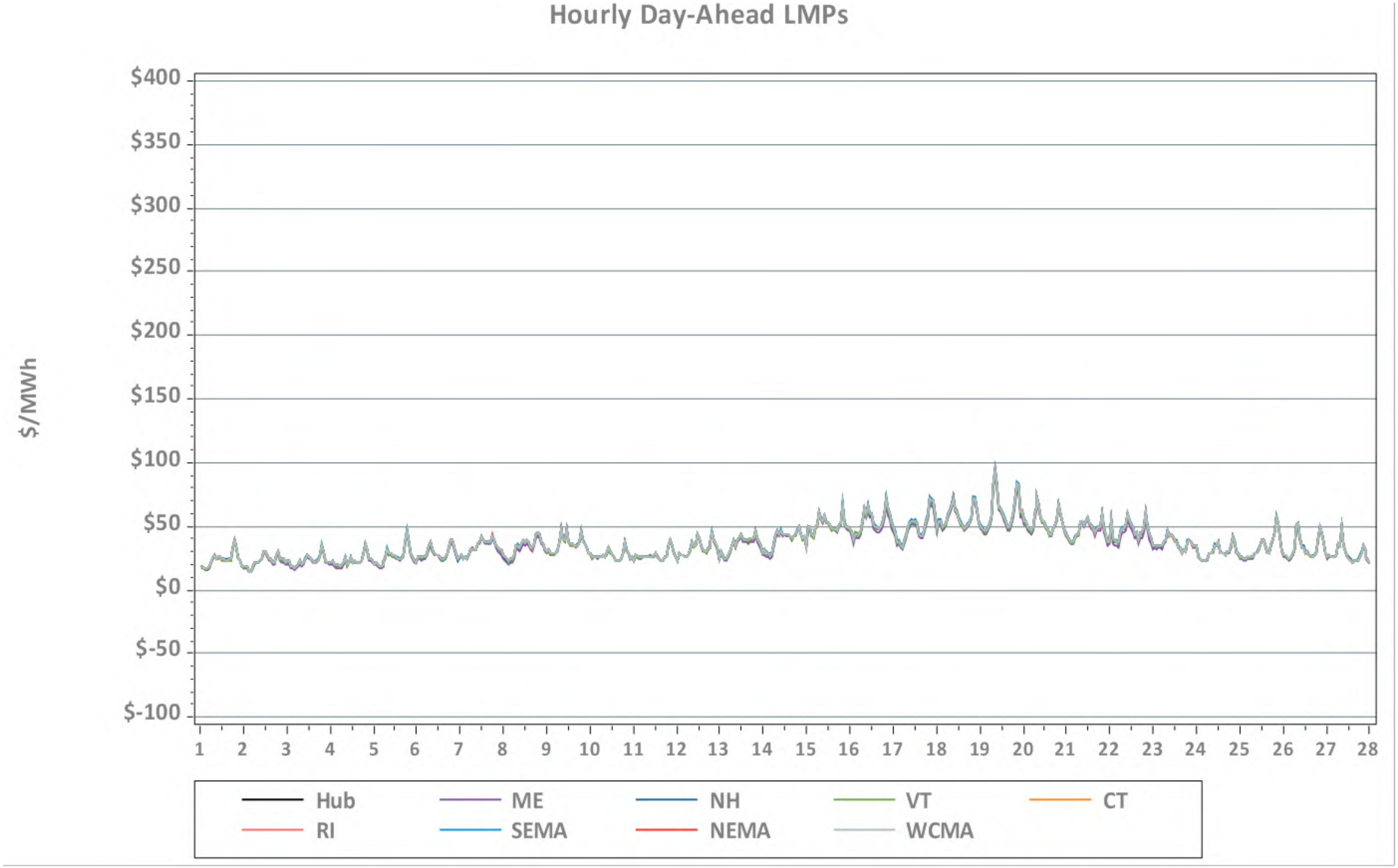
Variable Production Cost of Natural Gas: Daily



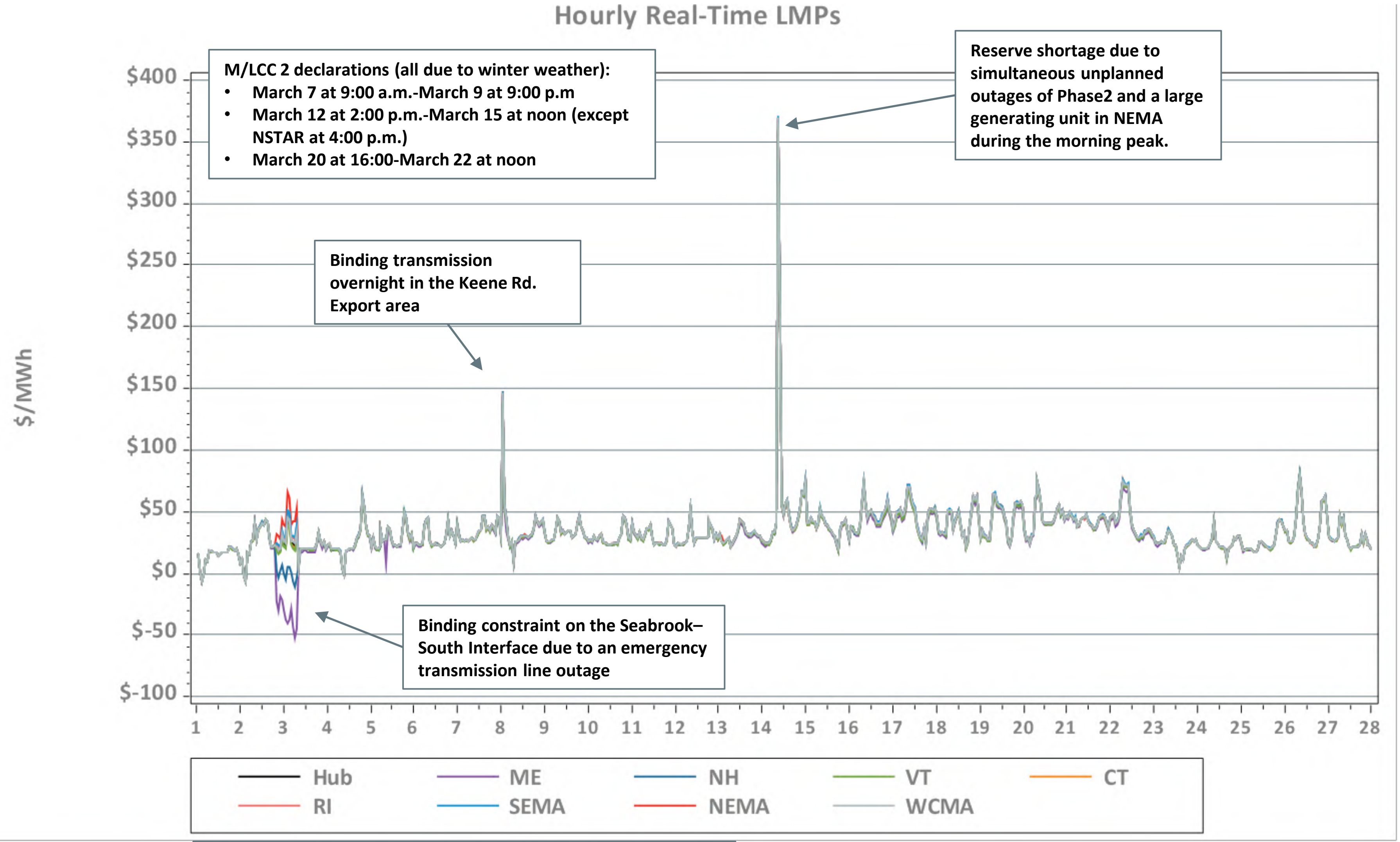
Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

ice Global markets in clear view

Hourly DA LMPs, March 1-27, 2018



Hourly RT LMPs, March 1-27, 2018



Hourly Real-Time LMPs

M/LCC 2 declarations (all due to winter weather):
- March 7 at 9:00 a.m.-March 9 at 9:00 p.m
- March 12 at 2:00 p.m.-March 15 at noon (except NSTAR at 4:00 p.m.)
- March 20 at 16:00-March 22 at noon

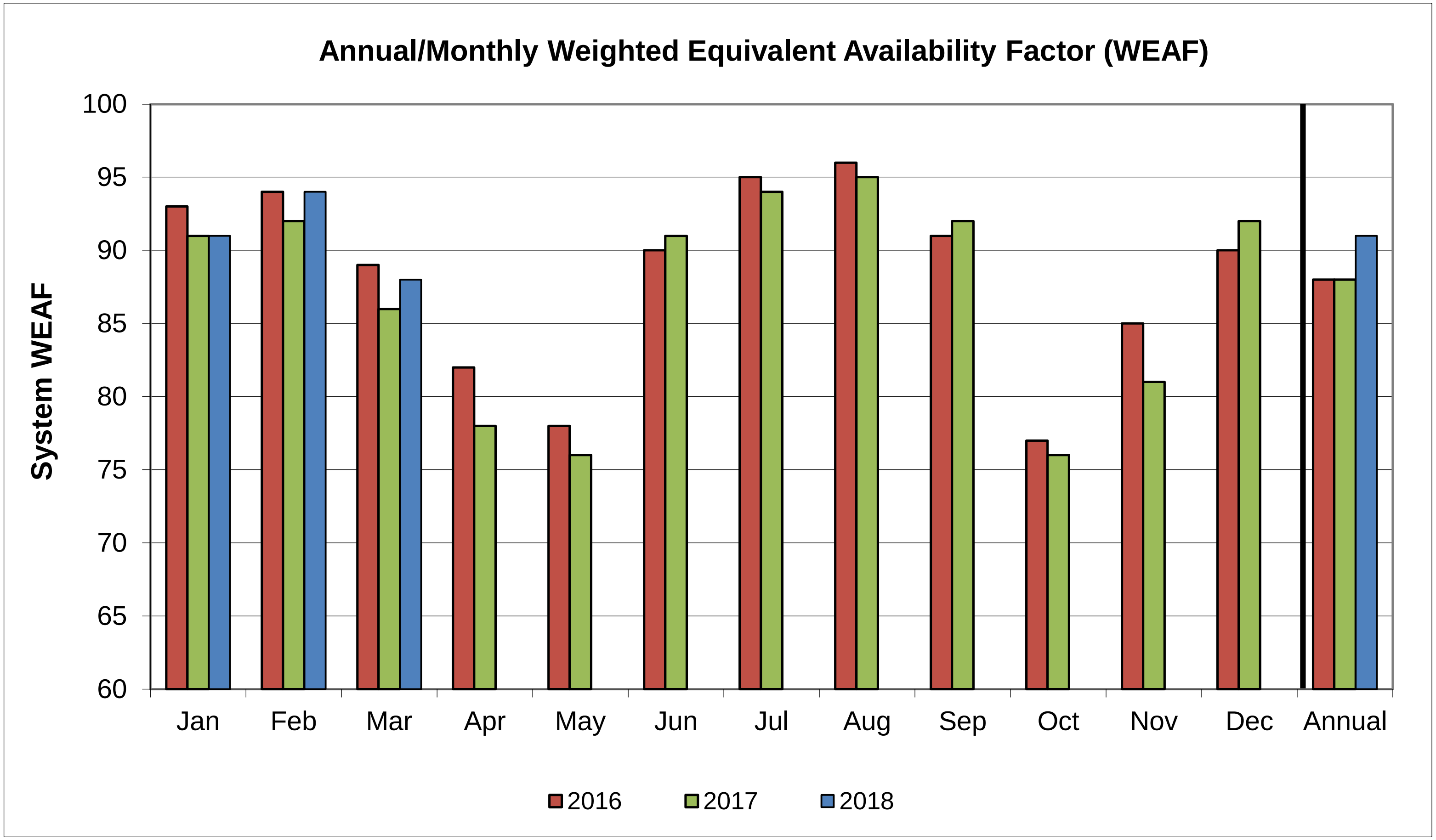
Reserve shortage due to simultaneous unplanned outages of Phase2 and a large generating unit in NEMA during the morning peak.

Binding transmission overnight in the Keene Rd. Export area

Binding constraint on the Seabrook–South Interface due to an emergency transmission line outage

* No Minimum Generation Emergencies were declared in March.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2018	91	94	88										91
2017	91	92	86	78	76	91	94	95	92	76	81	92	88
2016	93	94	89	82	78	90	95	96	91	77	85	90	88

Data as of 4/2/18

BACK-UP DETAIL

LOAD RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for April 2018

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	89.9	0.0	164.5	0.0	254.5
NH	11.0	0.0	92.9	0.0	103.9
VT	29.0	0.0	116.2	0.0	145.2
CT	77.0	0.2	60.3	457.8	595.3
RI	10.1	0.0	211.5	0.0	221.6
SEMA	18.4	0.0	313.7	0.0	332.1
WCMA	29.1	0.0	294.1	54.8	378.0
NEMA	27.4	0.0	596.2	0.0	623.6
Total	**291.8**	**0.2**	**1,849.5**	**512.6**	**2,654.1**

*** Real Time Demand Response**

**** Real Time Emergency Generation**

[1] Negative CSO resulting from reconfiguration auction activity

NOTE: CSO values include T&D loss factor (8%).

NEW GENERATION

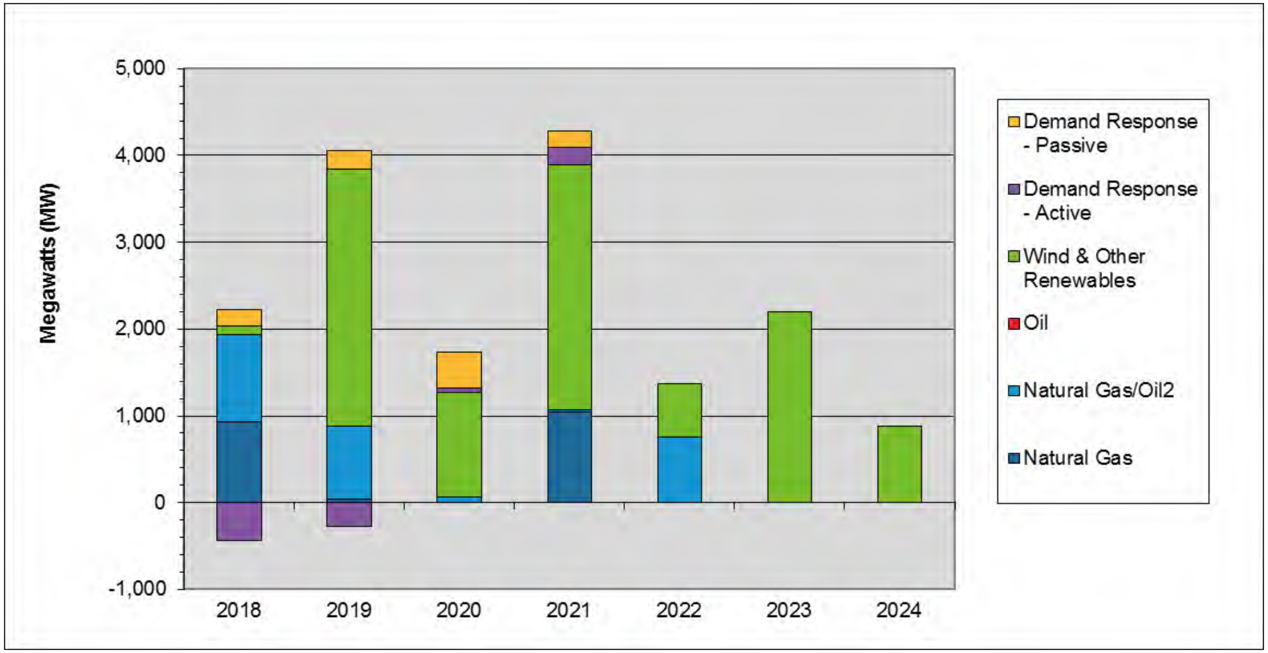
New Generation Update

Based on Queue as of 3/30/18

- Twenty projects totaling 1,401 MW have applied for interconnection study with in-service dates ranging from 2018 to 2022 since the last update
  - 16 PV (288 MW in CT & 50 MW in NH)
  - 2 Battery Storage (293 MW Total in MA)
  - 1 Combined Cycle (755 MW in CT)
  - 1 Fuel Cell (15 MW in CT)
- One project withdrew from the queue and no projects went commercial, resulting in a net increase in new generation projects of 835 MW
- In total, 109 generation projects are currently being tracked by the ISO, totaling approximately 15,500 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2018	2019	2020	2021	2022	2023	2024	Total MW	% of Total[1]
Demand Response - Passive	196	212	422	184	0	0	0	1,014	6.3
Demand Response - Active	-433	-270	42	204	0	0	0	-456	-2.8
Wind & Other Renewables	96	2,958	1,212	2,820	613	2,193	880	10,772	67.2
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	1,009	844	62	23	755	0	0	2,693	16.8
Natural Gas	926	43	0	1,045	0	0	0	2,014	12.6
Totals	**1,794**	**3,788**	**1,739**	**4,276**	**1,368**	**2,193**	**880**	**16,037**	**100.0**

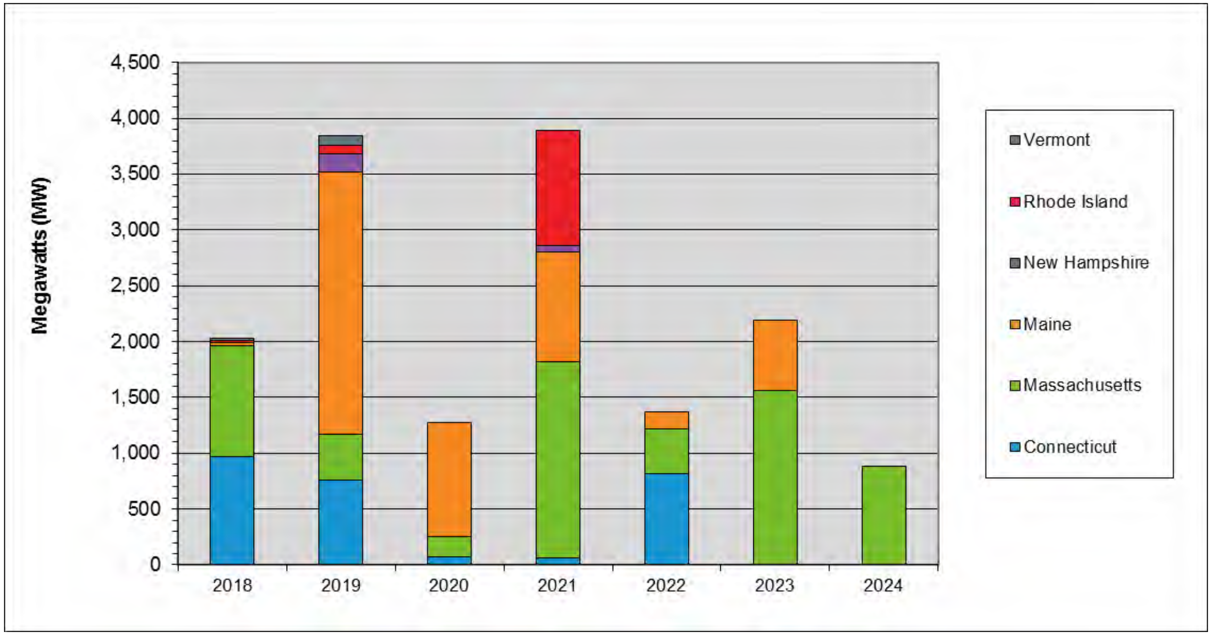
[1] Sum may not equal 100% due to rounding

[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 in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2018	2019	2020	2021	2022	2023	2024	Total MW	% of Total[1]
Vermont	20	90	0	0	0	0	0	110	0.7
Rhode Island	21	74	0	1,030	0	0	0	1,125	7.3
New Hampshire	0	158	0	55	0	0	0	213	1.4
Maine	30	2,356	1,018	982	150	630	0	5,166	33.4
Massachusetts	989	411	185	1,763	400	1,563	880	6,191	40.0
Connecticut	971	756	71	58	818	0	0	2,674	17.3
Totals	**2,031**	**3,845**	**1,274**	**3,888**	**1,368**	**2,193**	**880**	**15,479**	**100.0**

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

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Fuel Type	**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	3	99	0	0	3	99
Landfill Gas	0	0	0	0	0	0
Natural Gas	9	2,077	2	816	7	1,261
Natural Gas/Oil	8	2,693	2	1,009	6	1,684
Oil	0	0	0	0	0	0
Solar	47	1,448	0	0	47	1,448
Wind	34	8,430	1	30	33	8,400
Battery storage	7	695	0	0	7	695
Total	109	15,479	5	1,855	104	13,624

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

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	4	120	0	0	4	120
Intermediate	10	3,239	2	1,517	8	1,722
Peaker	61	3,690	2	308	59	3,382
Wind Turbine	34	8,430	1	30	33	8,400
Total	109	15,479	5	1,855	104	13,624

- 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	3	99	1	5	1	28	1	66	0	0
Landfill Gas										
Natural Gas	9	2,077	2	78	6	1,899	1	100	0	0
Natural Gas/Oil	8	2,693	0	0	3	1,312	5	1,381	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	47	1,448	0	0	0	0	47	1,448	0	0
Wind	34	8,430	0	0	0	0	0	0	34	8,430
Battery storage	7	695	0	0	0	0	7	695	0	0
Total	109	15,479	4	120	10	3,239	61	3,690	34	8,430

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 9

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*	647.26	596.701	-50.559	553.857	-42.844	525.843	-28.014	484.972	-40.871	438.282	**-46.690**	407.62	-30.662
	Passive Demand	2,156.151	2,153.94	-2.211	2,150.196	-3.744	2,150.196	0	2,389.958	239.762	2,394.341	**4.380**	2,548.346	154.005
Demand Total		**2,803.411**	**2,750.641**	**-52.77**	**2,704.053**	**-46.588**	**2,676.039**	**-28.014**	**2,874.93**	**198.891**	**2,832.623**	**-42.310**	**2,955.966**	**123.343**
Generator	*Non-Intermittent*	29,550.564	29,558.181	7.617	29,783.831	225.65	29,803.997	20.166	29,833.445	29.448	29,720.393	**-113.060**	29,700.519	-19.874
	Intermittent	891.616	864.924	-26.692	872.425	7.501	853.414	-19.011	870.558	17.144	855.947	**-14.611**	788.037	-67.91
Generator Total		**30,442.18**	**30,423.105**	**-19.075**	**30,656.256**	**233.151**	**30,657.41**	**1.155**	**30,704.003**	46.593	**30,576.34**	**-127.660**	**30,488.556**	**-87.784**
Import Total		**1,449**	**1,449**	**0**	**1,449**	**0**	**1,449**	**0**	**1,449**	0	**1,599**	**150.000**	**1,568**	**-31.000**
*****Grand Total**		**34,694.591**	**34,622.746**	**-71.845**	**34,809.309**	**186.563**	**34,782.45**	**-26.859**	**35,027.933**	245.483	**35,007.963**	**-19.970**	**35,012.522**	**4.559**
Net ICR (NICR)		**34,189**	**33,883**	**-306**	**33,883**	**0**	**33,421**	**-462**	**33,421**	0	**33,247**	**-174**	**33,247**	0

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

** 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.

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

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								
	Passive Demand	2,368.631	2,366.783	-1.848	2,363.949	-2.834								
Demand Total		**2,746.156**	**2734.01**	**-12.146**	**2,828.664**	**94.654**								
Generator	*Non-Intermittent*	30,520.433	30,462.67	-57.763	30,048.398	-414.272								
	Intermittent	850.143	893.189	43.046	904.311	11.122								
Generator Total		**31,370.576**	**31,355.86**	**-14.716**	**30,952.709**	**-403.151**								
Import Total		**1,449.8**	**1,449.8**	**0**	**1,451**	**1.2**								
*****Grand Total**		**35,566.532**	**35,539.668**	**-26.864**	**35,232.373**	**-307.295**								
Net ICR (NICR)		**34,151**	**33,755**	**-396**	**33,755**	**0**								

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

** 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.

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

Capacity Supply Obligation FCA 11

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*	419.928												
	Passive Demand	2,791.019												
Demand Total		**3,210.947**												
Generator	*Non-Intermittent*	30,494.8												
	Intermittent	894.217												
Generator Total		**31,389.02**												
Import Total		**1,235.4**												
*****Grand Total**		**35,835.368**												
Net ICR (NICR)		**34,075**												

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

** 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.

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

Capacity Supply Obligation FCA 12

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*	624.445												
	Passive Demand	2,975.361												
Demand Total		**3,599.806**												
Generator	*Non-Intermittent*	29,130.754												
	Intermittent	880.317												
Generator Total		**30,011.071**												
Import Total		**1217**												
*****Grand Total**		**34,827.877**												
Net ICR (NICR)		**33,725**												

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

** 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.

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

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/ Passive	Existing	New	Grand Total
2010-11	Active	1246.399	603.675	1850.074
	Passive	119.211	584.277	703.488
	Grand Total	1365.61	1187.952	2553.562
2011-12	Active	1768.392	184.99	1953.382
	Passive	719.98	263.25	983.23
	Grand Total	2488.372	448.24	2936.612
2012-13	Active	1726.548	98.227	1824.775
	Passive	861.602	211.261	1072.863
	Grand Total	2588.15	309.488	2897.638
2013-14	Active	1794.195	257.341	2051.536
	Passive	1040.113	257.793	1297.906
	Grand Total	2834.308	515.134	3349.442
2014-15	Active	2062.196	41.945	2104.141
	Passive	1264.641	221.072	1485.713
	Grand Total	3326.837	263.017	3589.854
2015-16	Active	1935.406	66.104	2001.51
	Passive	1395.885	247.449	1643.334
	Grand Total	3331.291	313.553	3644.844
2016-17	Active	1116.468	0.23	1116.698
	Passive	1386.56	244.775	1631.335
	Grand Total	2503.028	245.005	2748.033
2017-18	Active	1066.593	13.486	1080.079
	Passive	1619.147	341.37	1960.517
	Grand Total	2685.74	354.856	3040.596
2018-19	Active	565.866	81.394	647.26
	Passive	1870.549	285.602	2156.151
	Grand Total	2436.415	366.996	2803.411
2019-20	Active	357.221	20.304	377.525
	Passive	2018.201	350.43	2368.631
	Grand Total	2375.422	370.734	2746.156
2020-21	Active	334.634	85.294	419.928
	Passive	2236.727	554.292	2791.019
	Grand Total	2571.361	639.586	3210.947
2021-22	Active	480.941	143.504	624.445
	Passive	2604.793	370.568	2975.361
	Grand Total	3085.734	514.072	3599.806

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

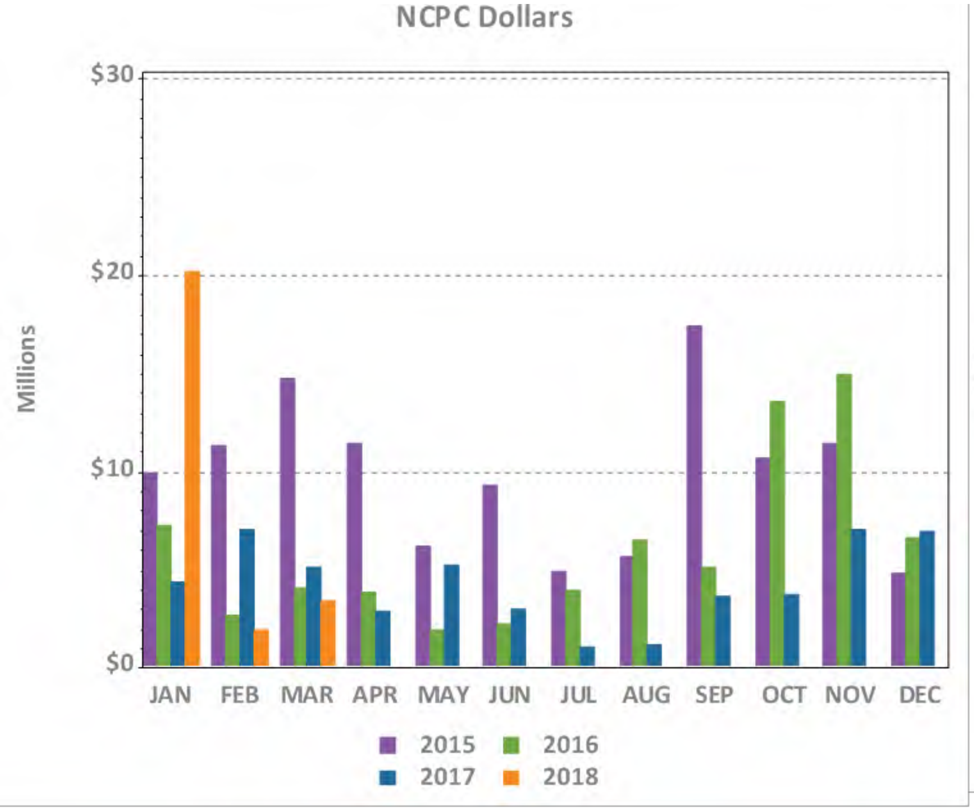
Definitions

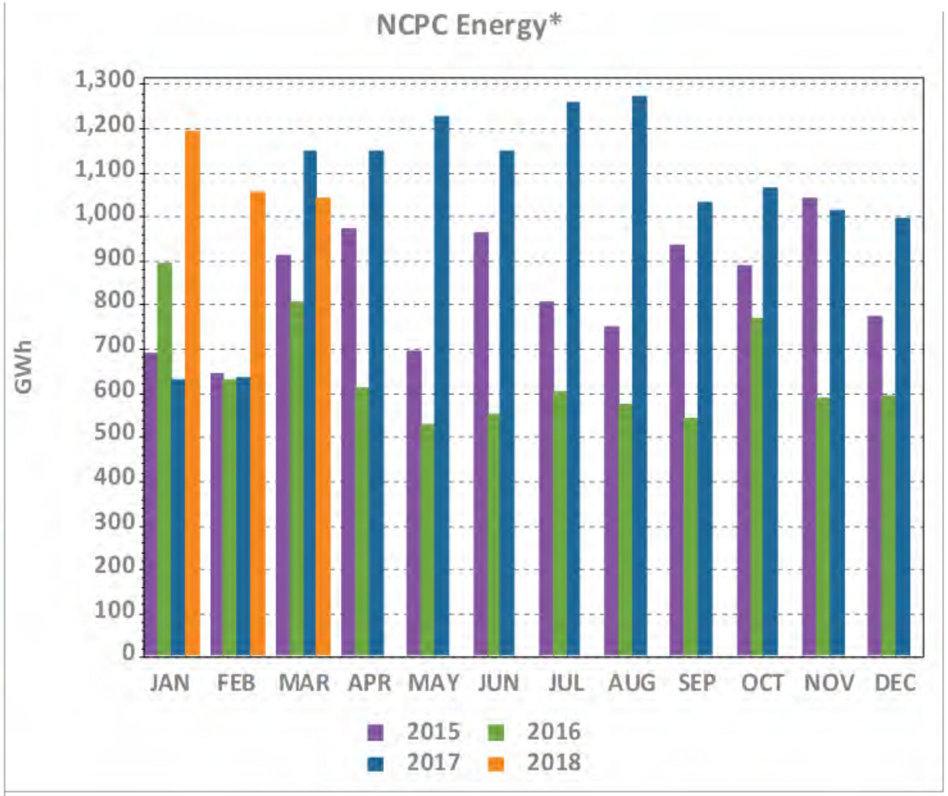
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

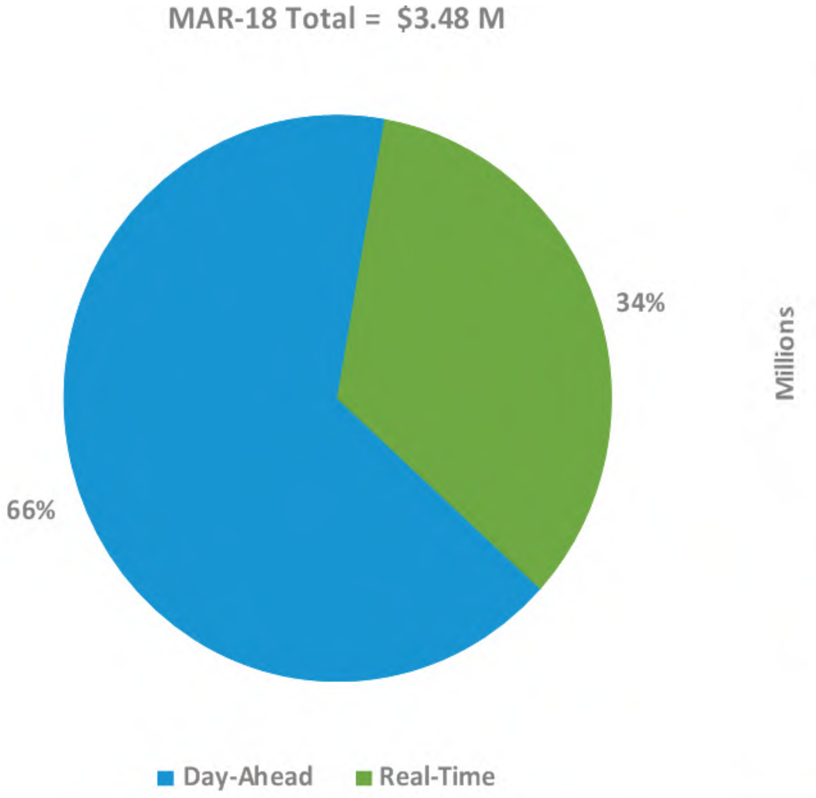
Year-Over-Year Total NCPC Dollars and Energy

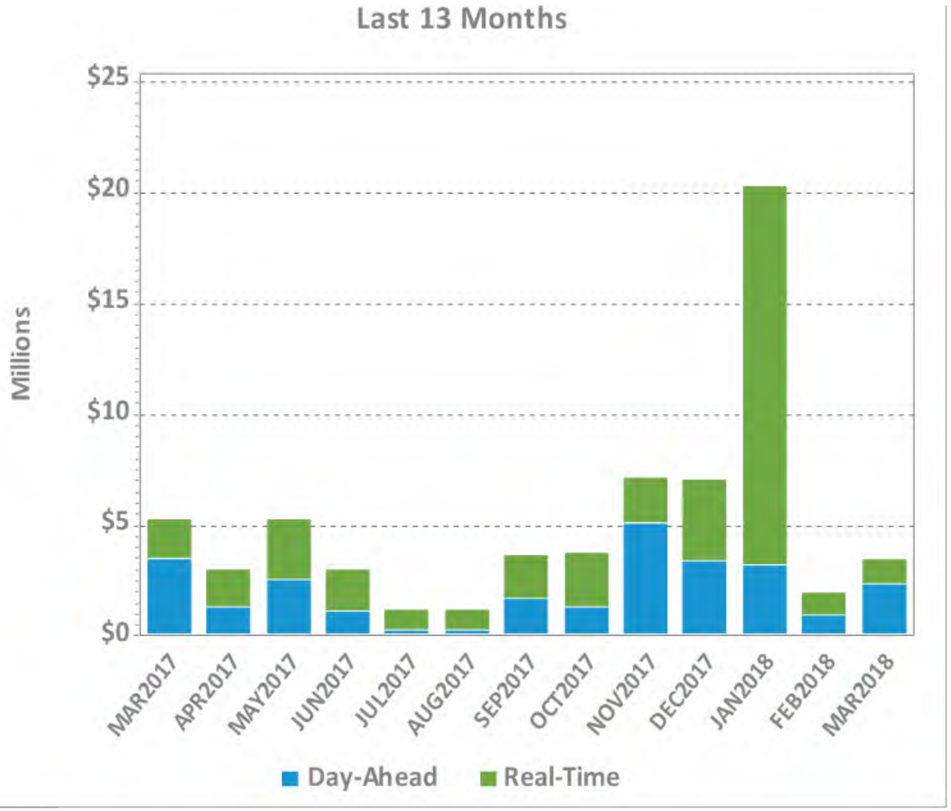




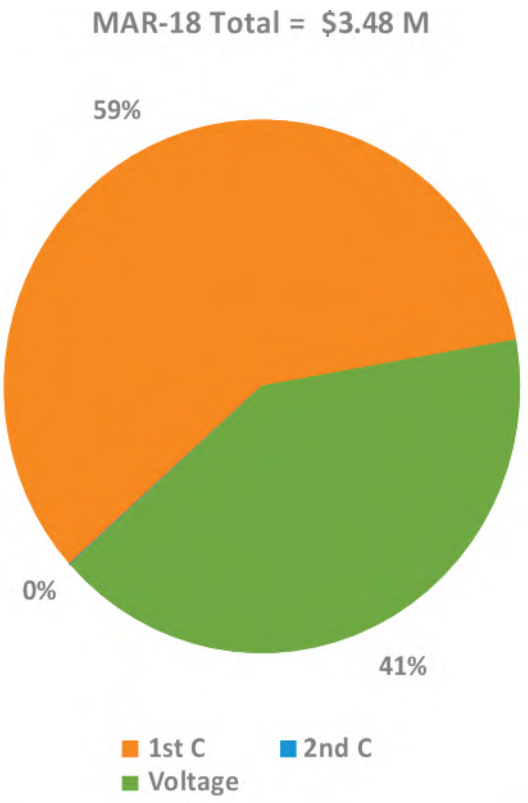
* **NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

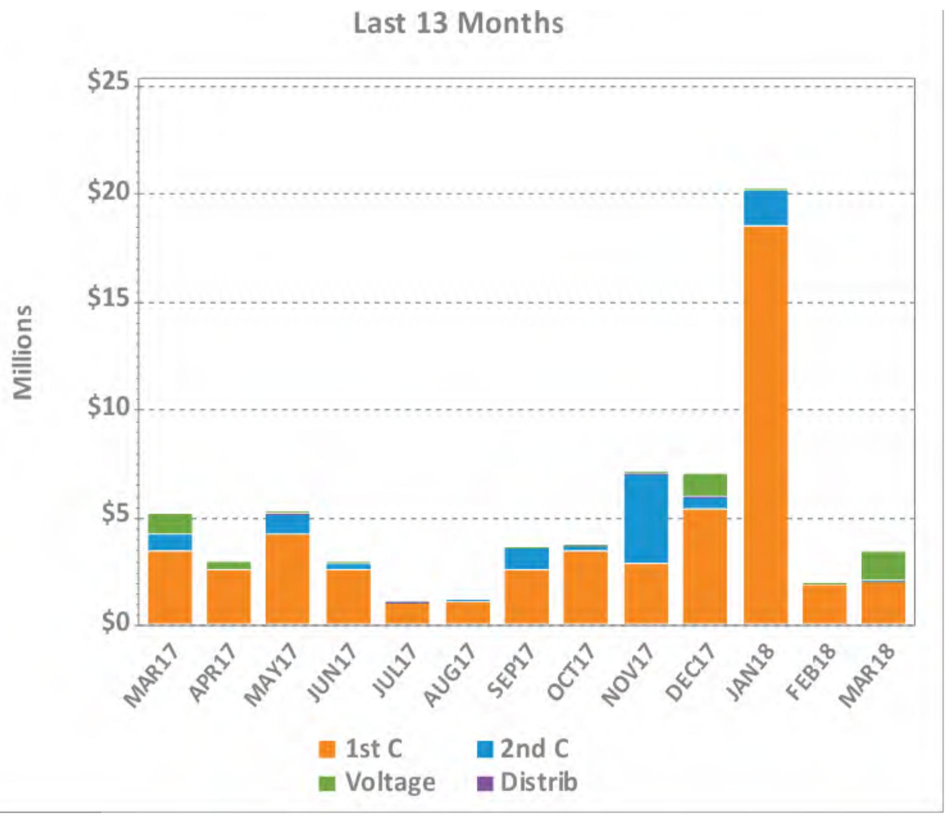
DA and RT NCPC Charges





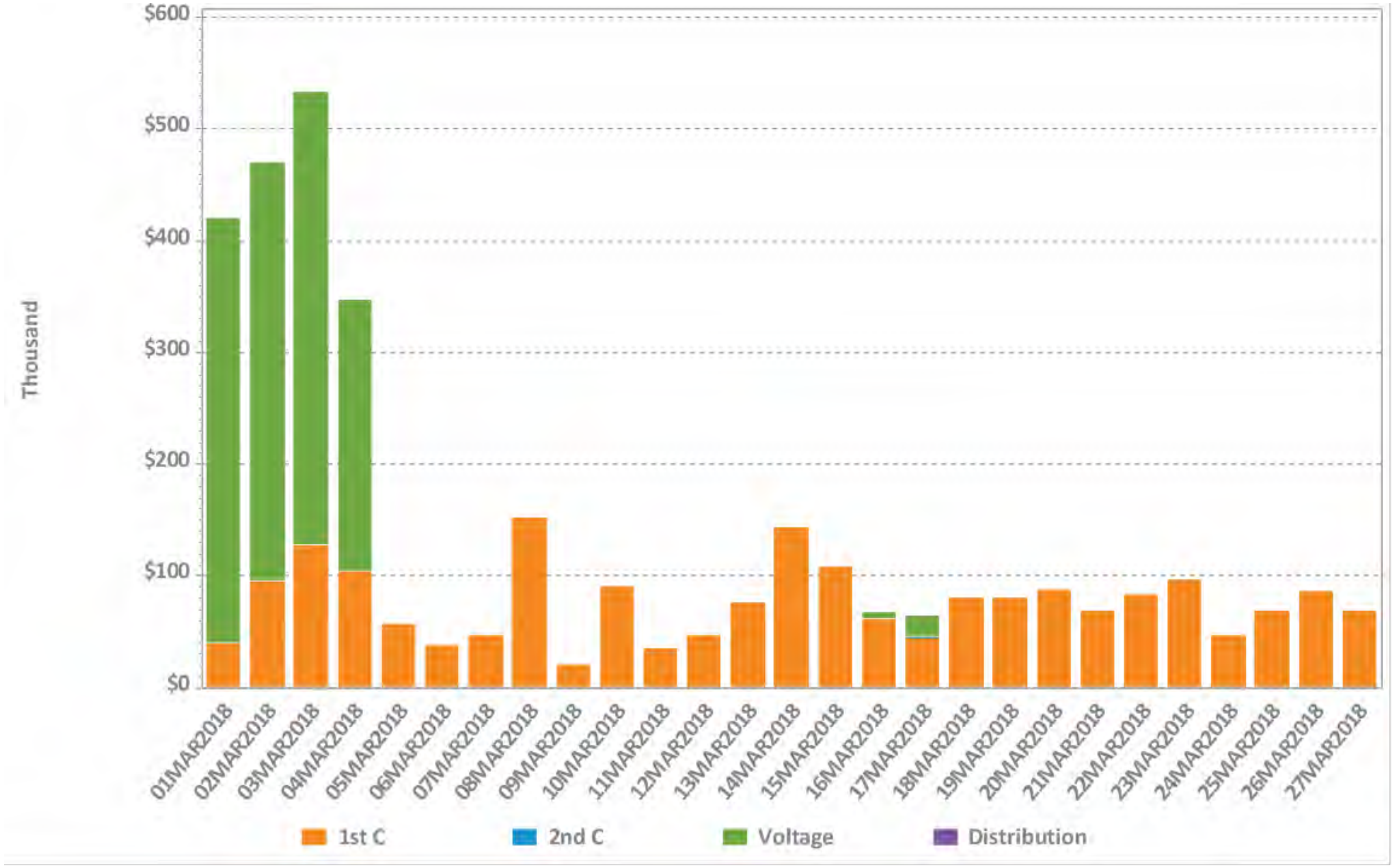
NCPC Charges by Type



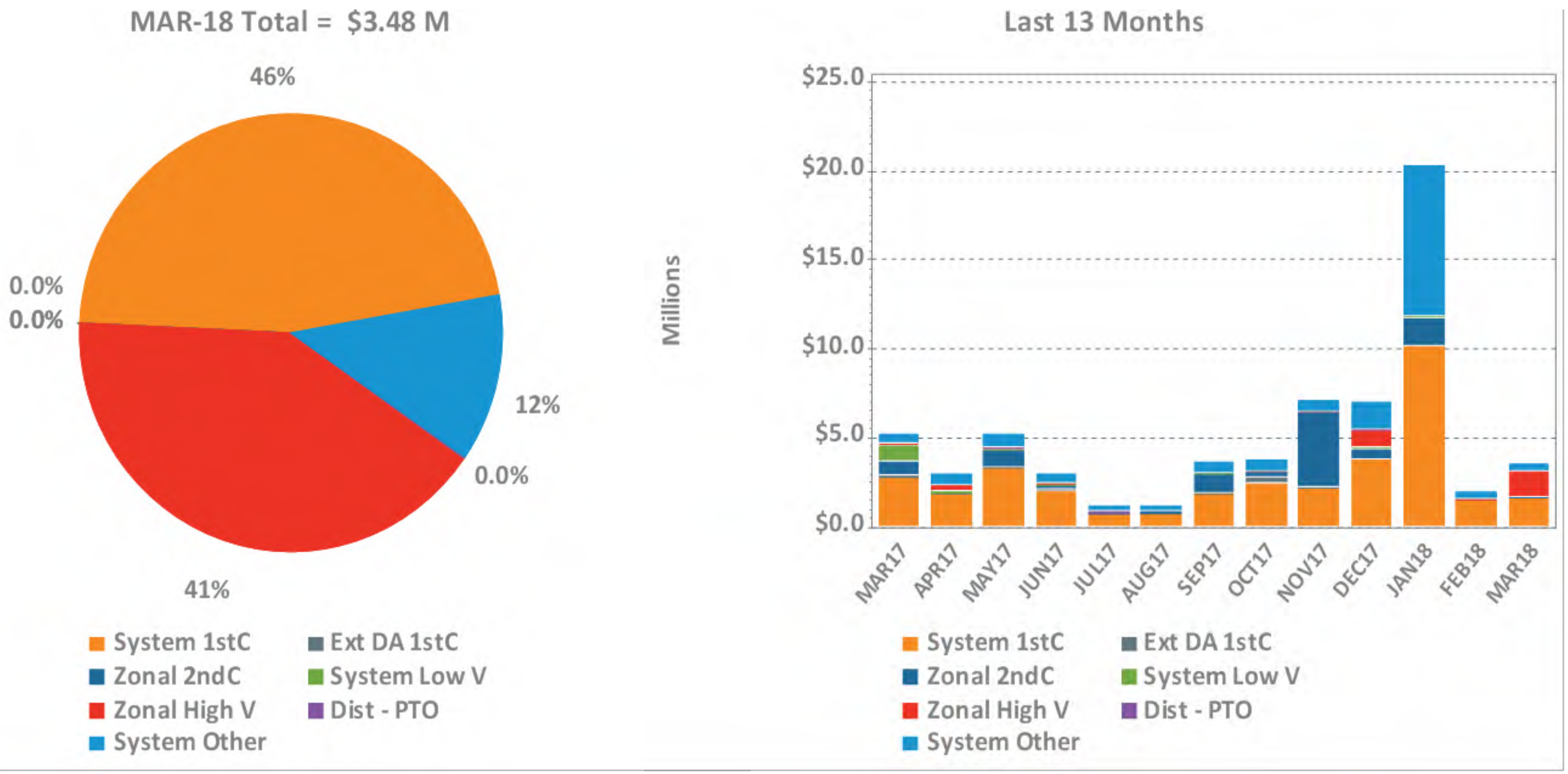


1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type

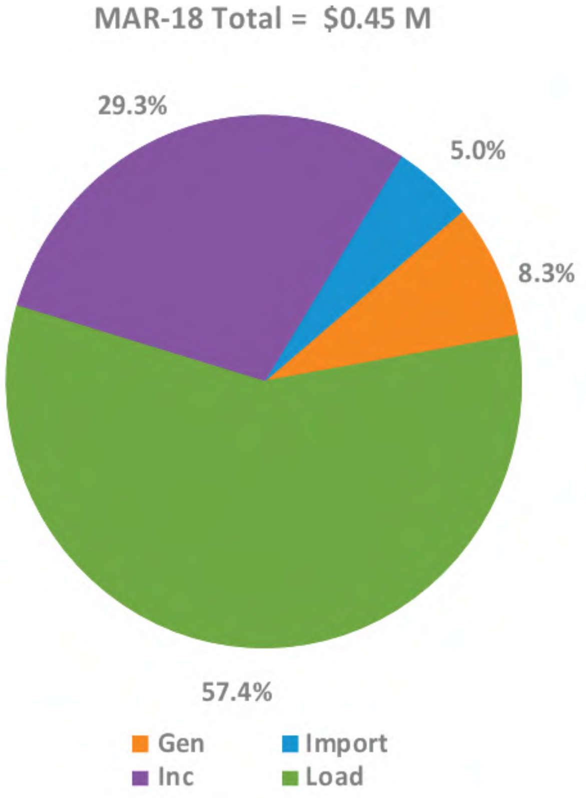


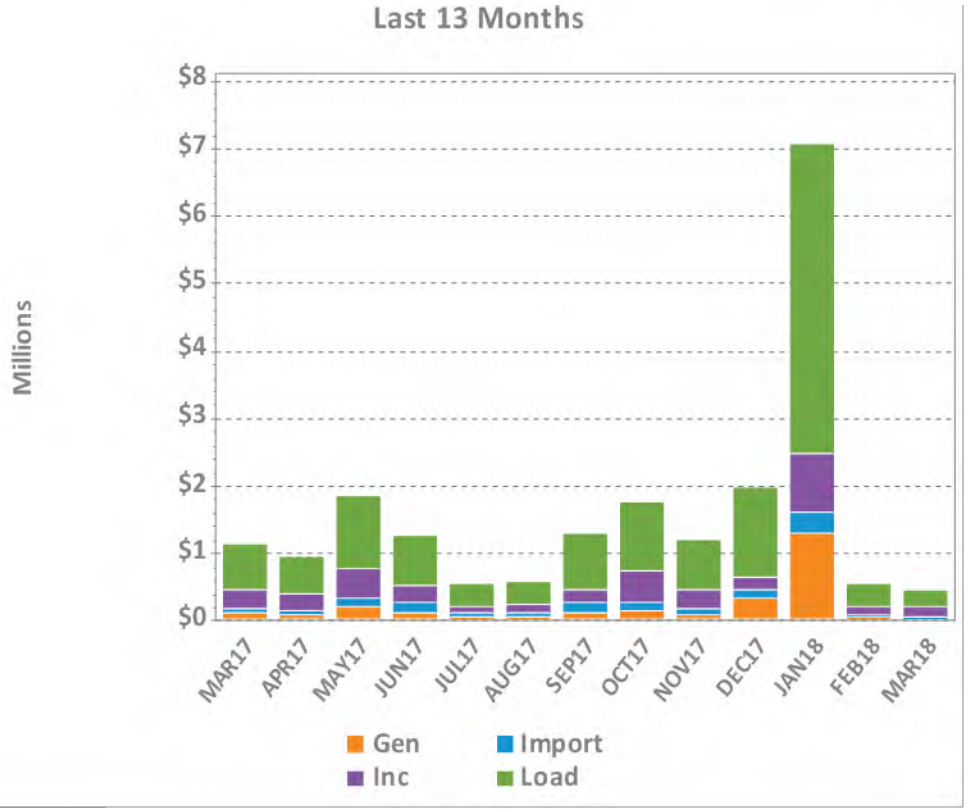
NCPC Charges by Allocation



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





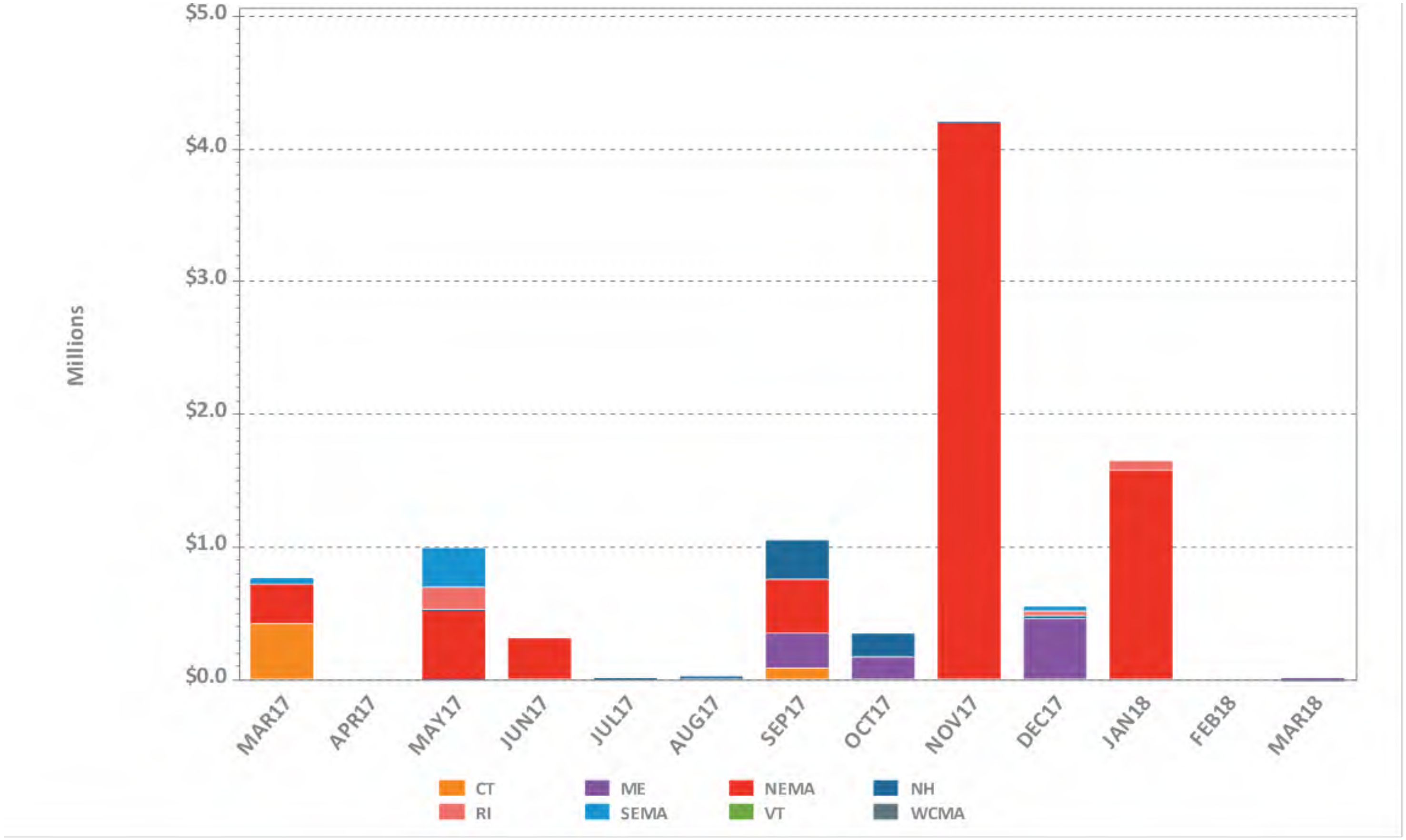
Gen – Generator deviations

Inc – Increment Offer deviations

Import – Import deviations

Load – Load obligation deviations

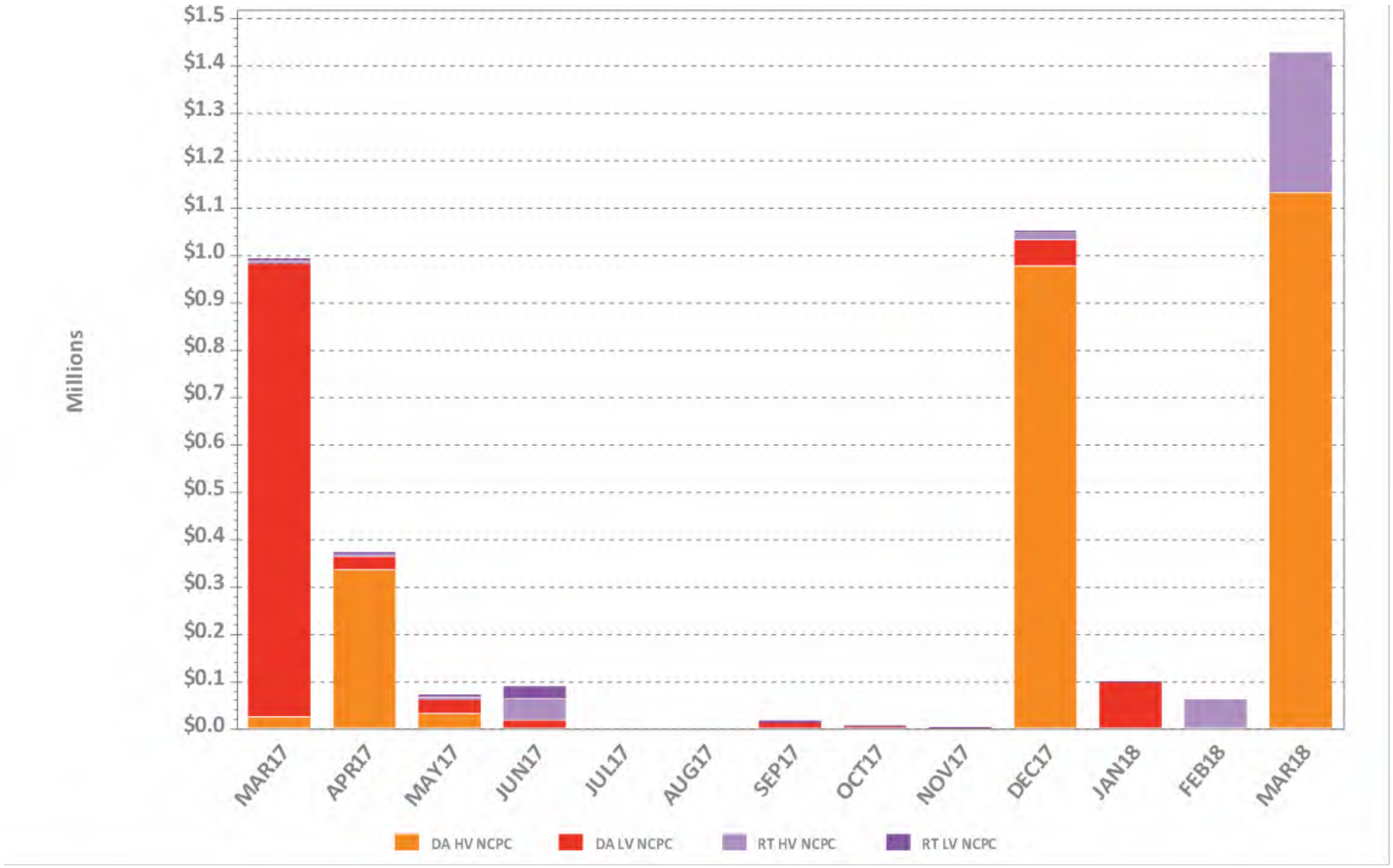
LSCPR Charges by Reliability Region



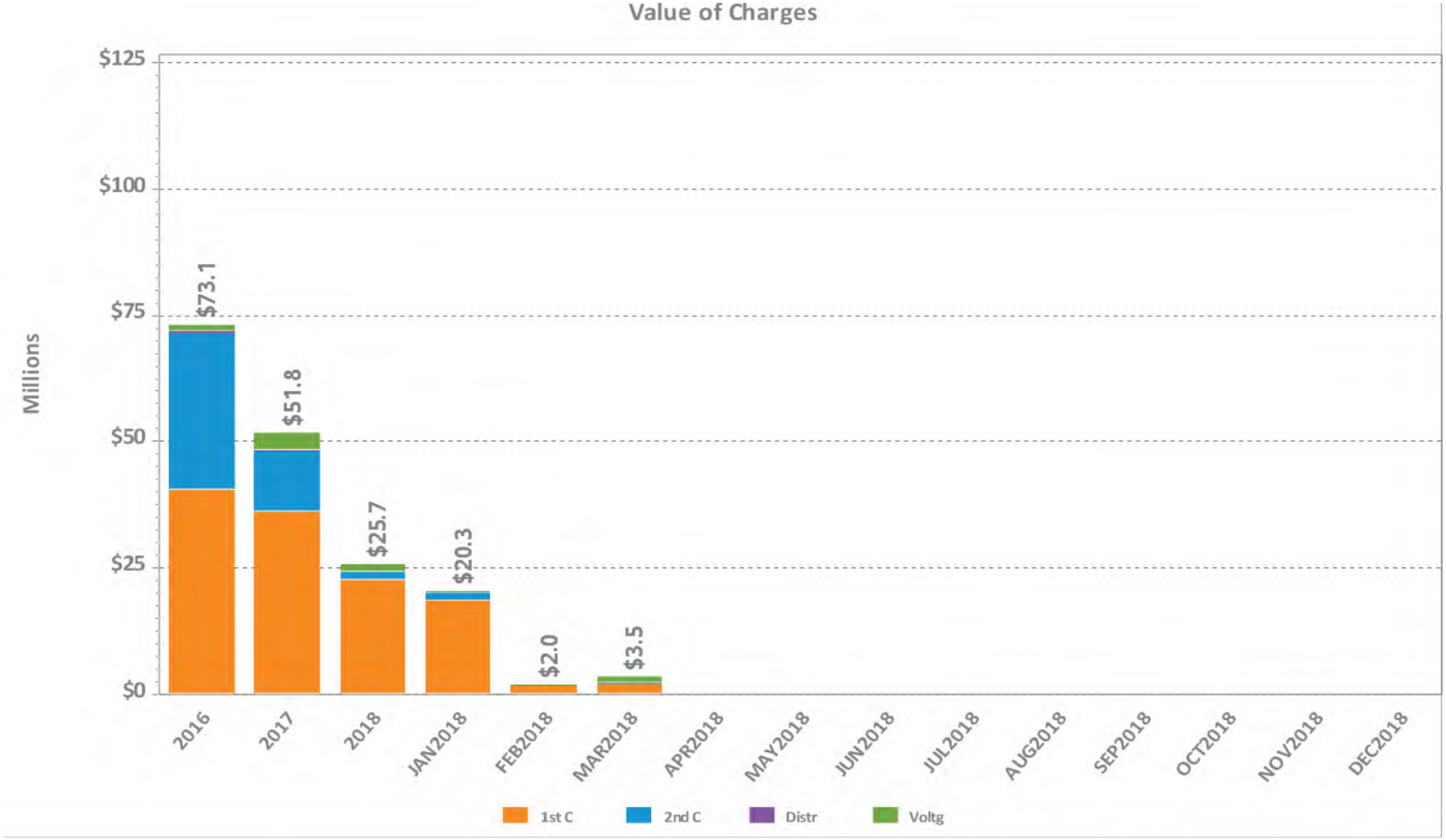
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

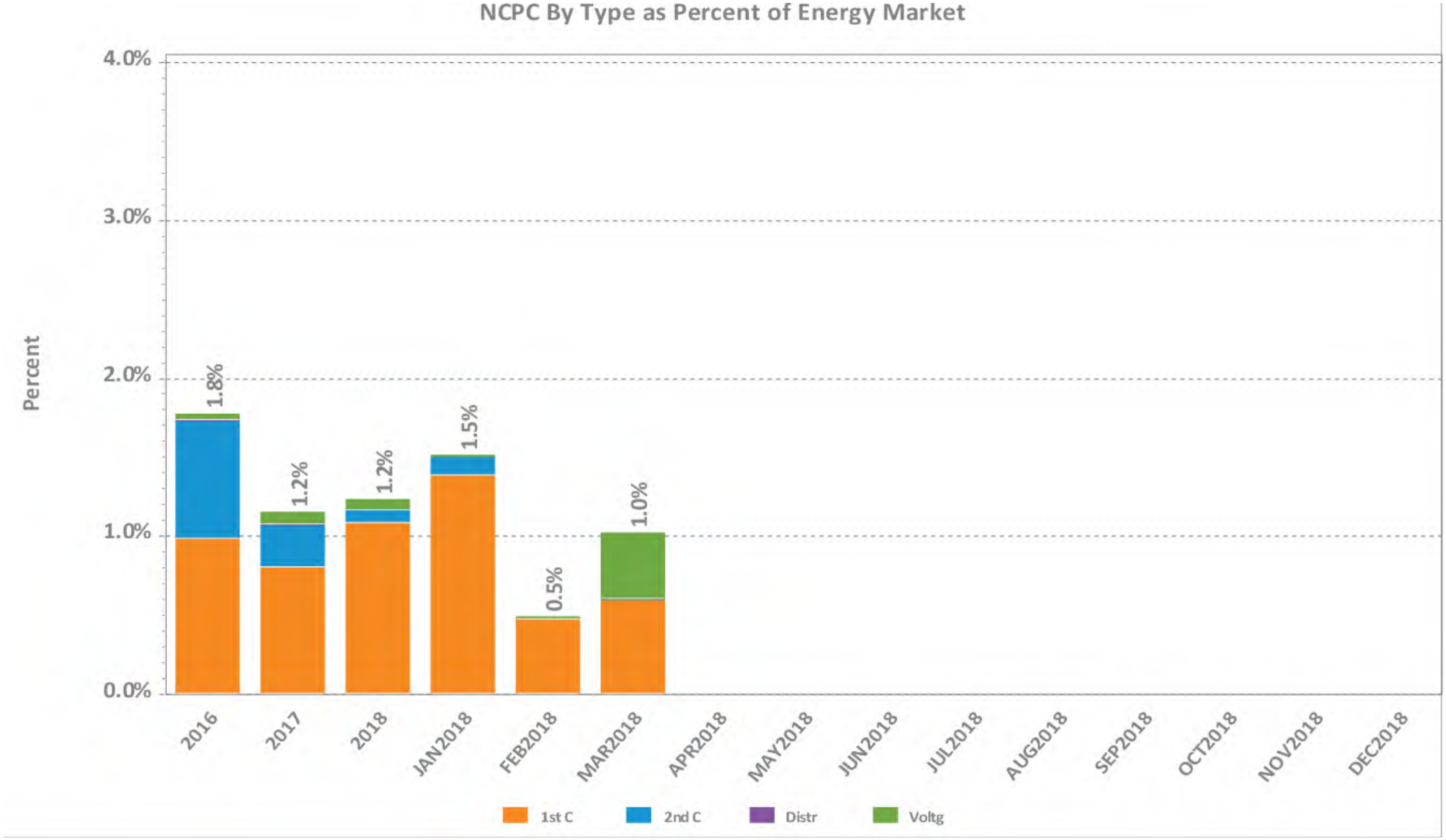
NCPC Charges for Voltage Support and High Voltage Control



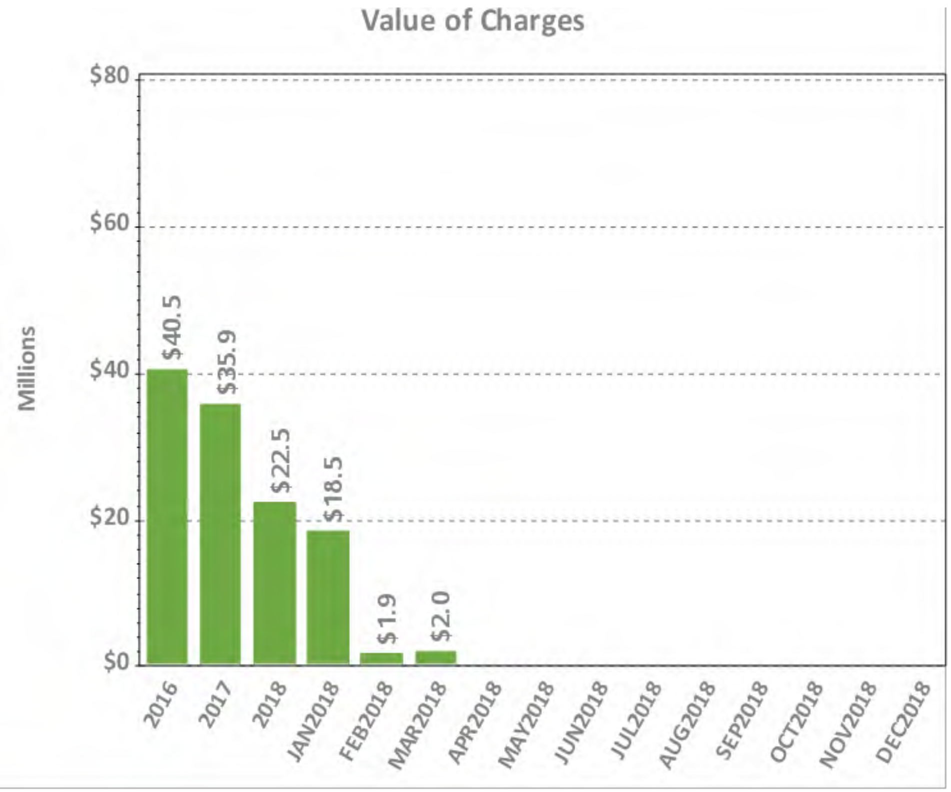
NCPC Charges by Type

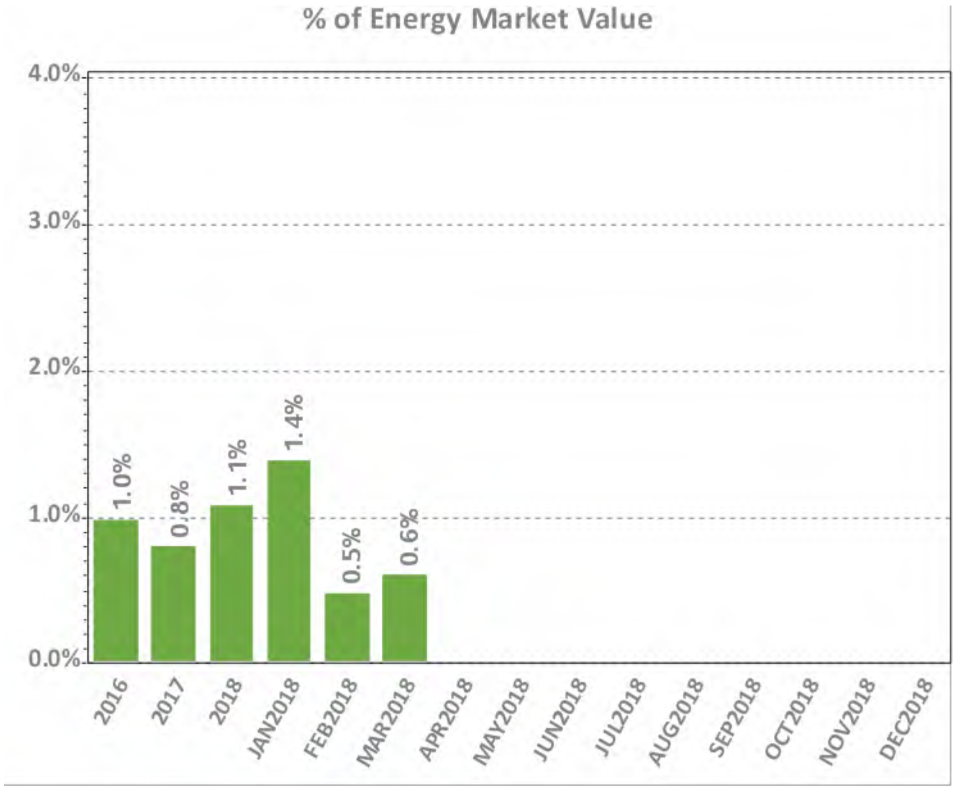


NCPC Charges as Percent of Energy Market



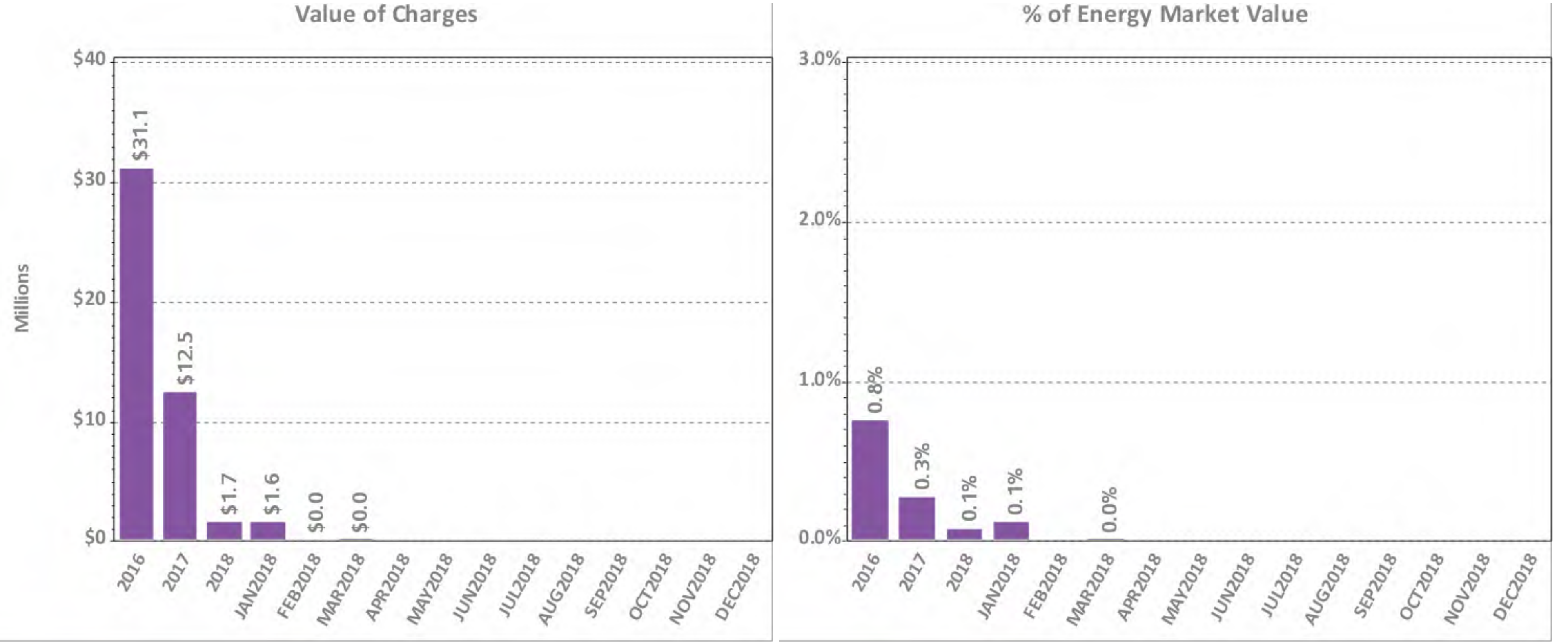
First Contingency NCPC Charges





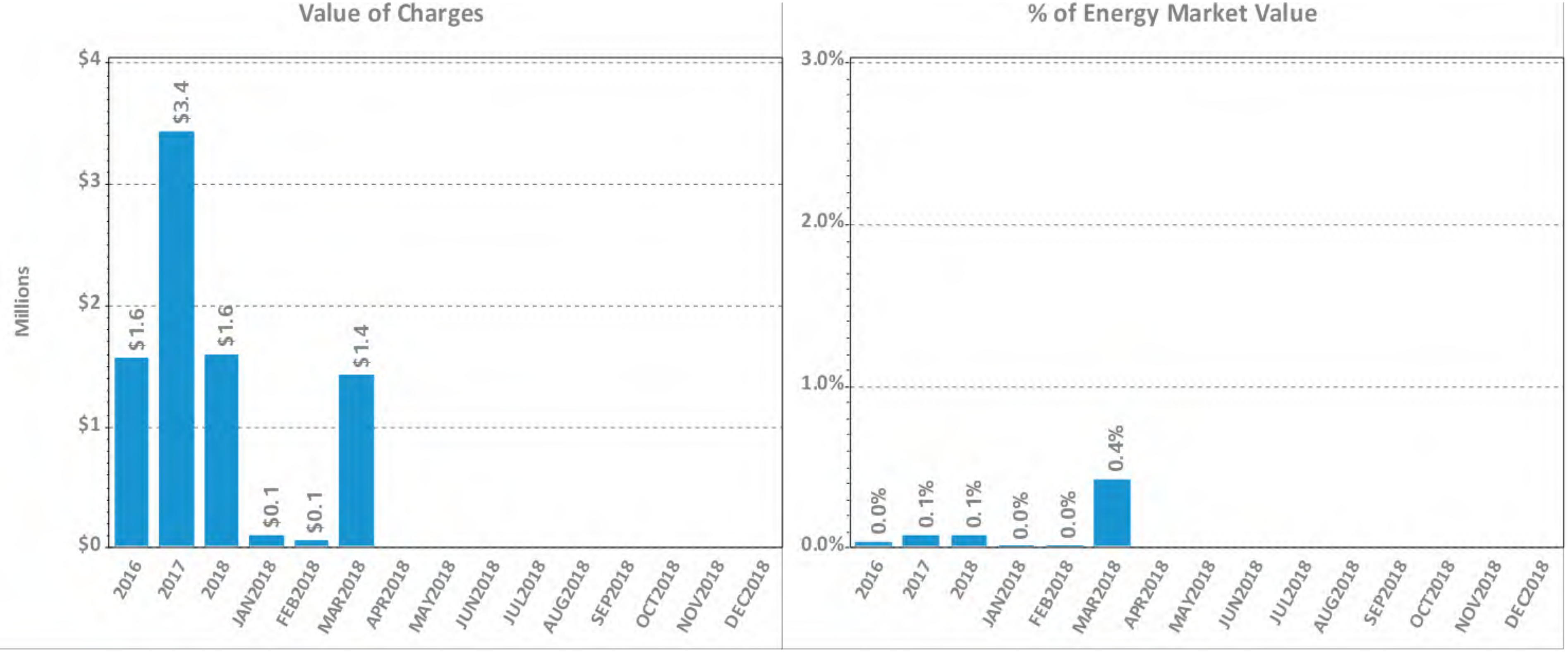
Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

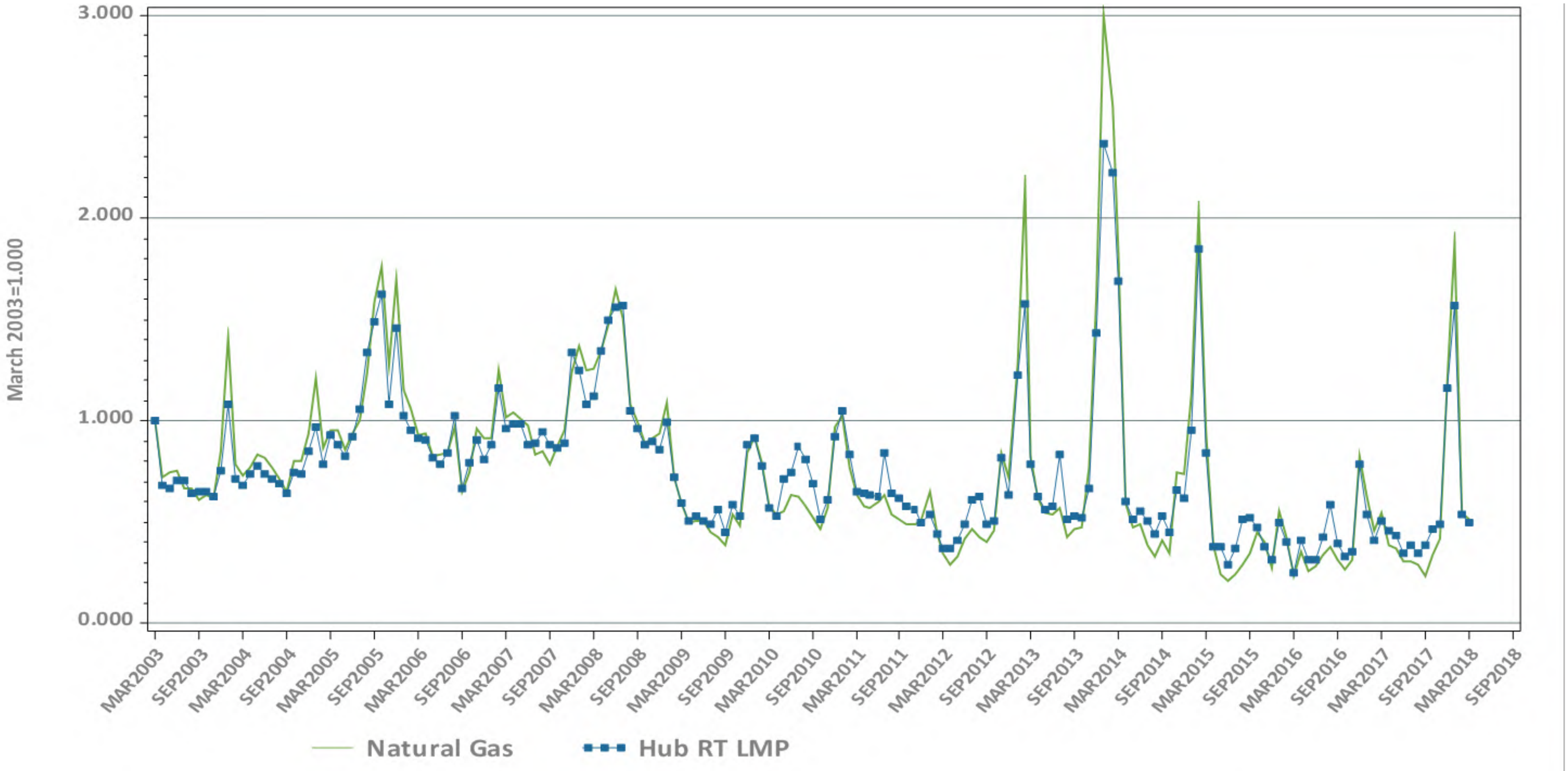
DA vs. RT LMPs ($/MWh)

Arithmetic Average

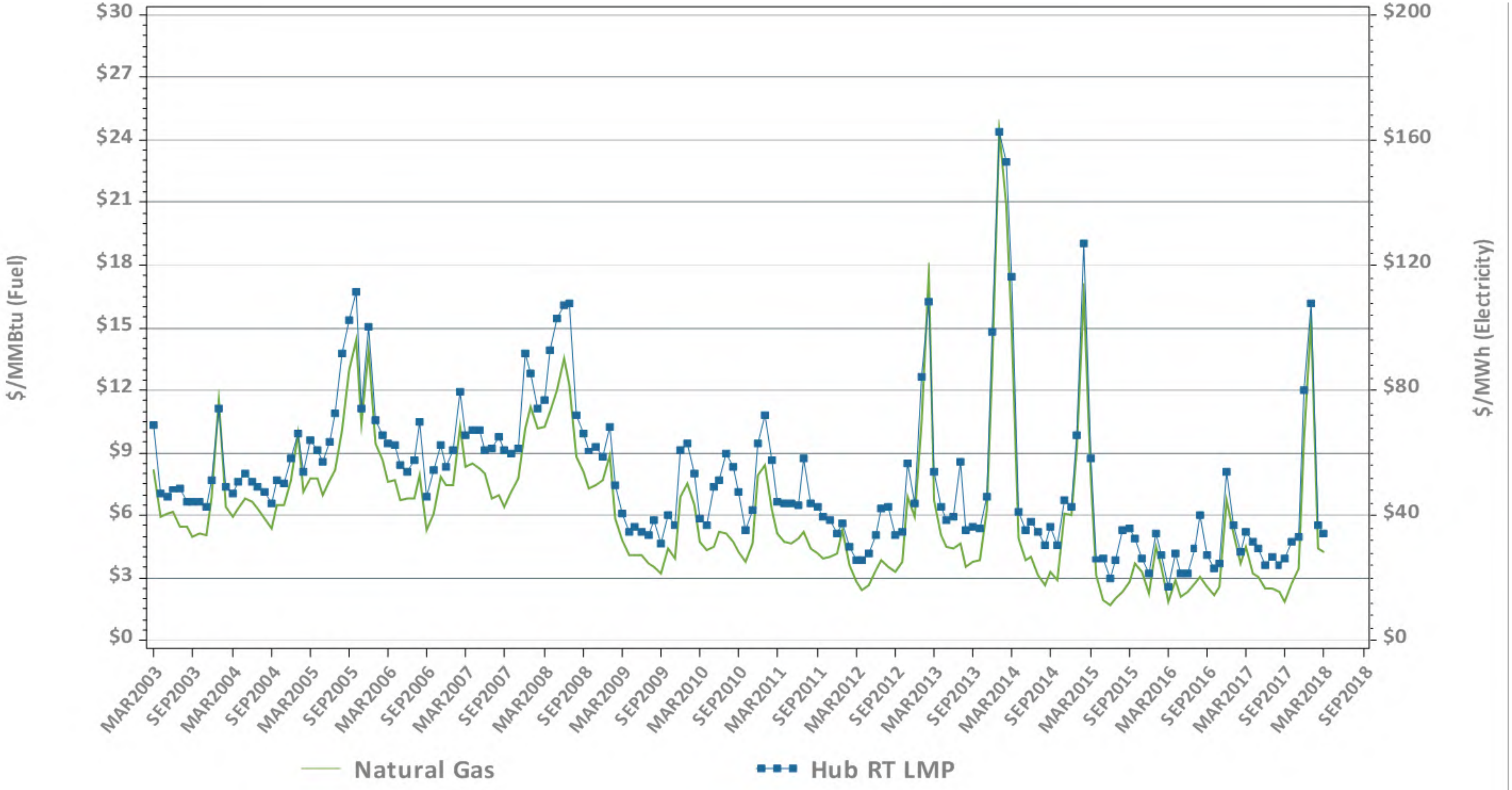
Year 2016	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$30.66	$29.77	$29.07	$29.64	$29.66	$29.66	$29.88	$29.85	$29.78
Real-Time	$29.74	$29.00	$27.81	$28.60	$28.49	$28.87	$29.01	$28.98	$28.94
RT Delta %	-3.0%	-2.6%	-4.3%	-3.5%	-3.9%	-2.7%	-2.9%	-2.9%	-2.8%
Year 2017	**NEMA**	**CT**	**ME**	**NH**	**VT**	**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%

March-17	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$35.54	$36.04	$34.51	$35.29	$35.24	$35.50	$35.55	$35.87	$35.75
Real-Time	$34.73	$35.13	$31.99	$34.04	$33.83	$34.57	$34.69	$34.87	$34.81
RT Delta %	-2.3%	-2.5%	-7.3%	-3.5%	-4.0%	-2.6%	-2.4%	-2.8%	-2.6%
March-18	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$36.70	$36.48	$35.30	$36.46	$36.29	$36.67	$36.93	$36.71	$36.94
Real-Time	$34.29	$33.66	$31.54	$33.26	$33.28	$33.99	$34.24	$33.98	$34.25
RT Delta %	-6.6%	-7.7%	-10.7%	-8.8%	-8.3%	-7.3%	-7.3%	-7.5%	-7.3%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	3.3%	1.2%	2.3%	3.3%	3.0%	3.3%	3.9%	2.4%	3.3%
Yr over Yr RT	-1.3%	-4.2%	-1.4%	-2.3%	-1.6%	-1.7%	-1.3%	-2.6%	-1.6%

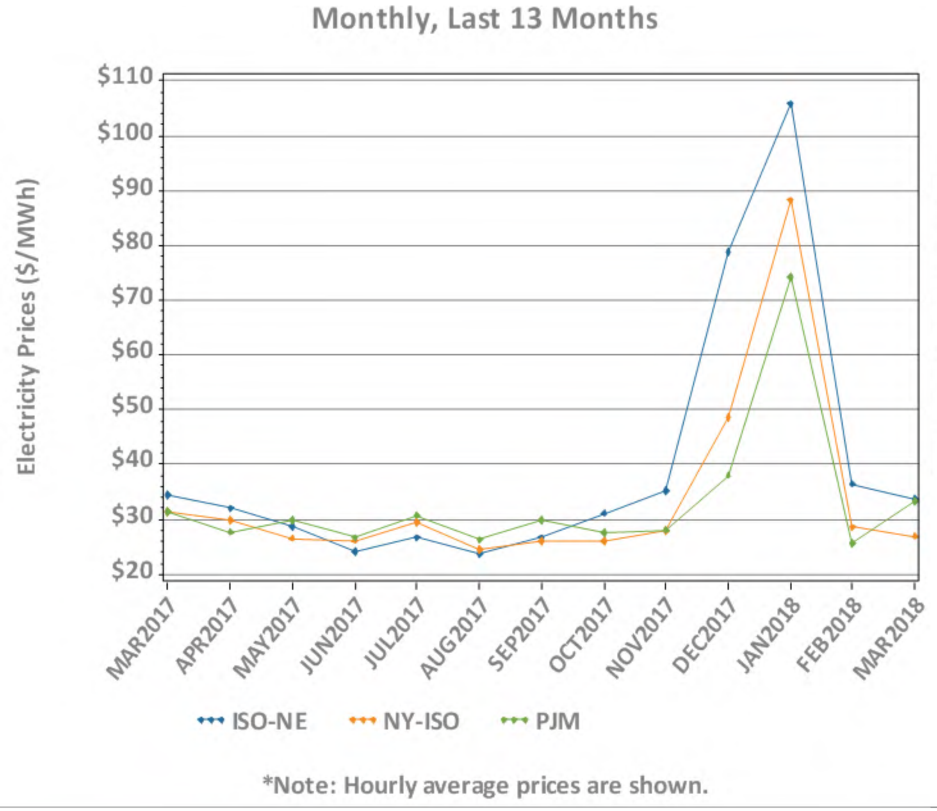
Monthly Average Fuel Price and RT Hub LMP Indexes



Monthly Average Fuel Price and RT Hub LMP

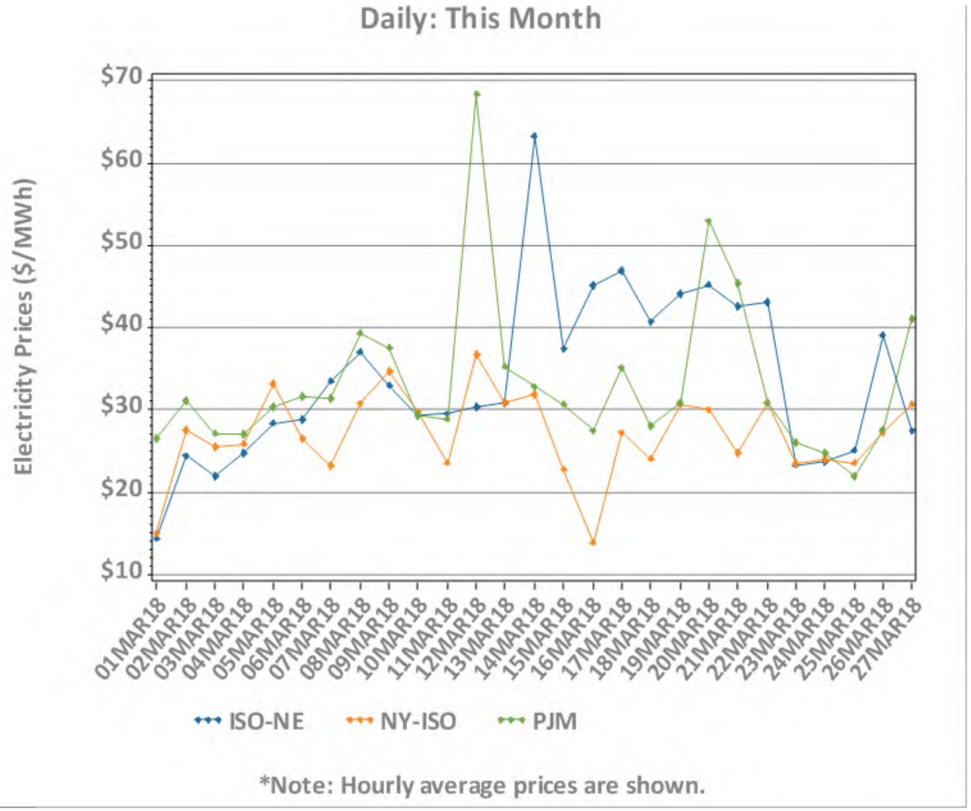


New England, NY, and PJM Hourly Average Real Time Prices by Month



Monthly, Last 13 Months

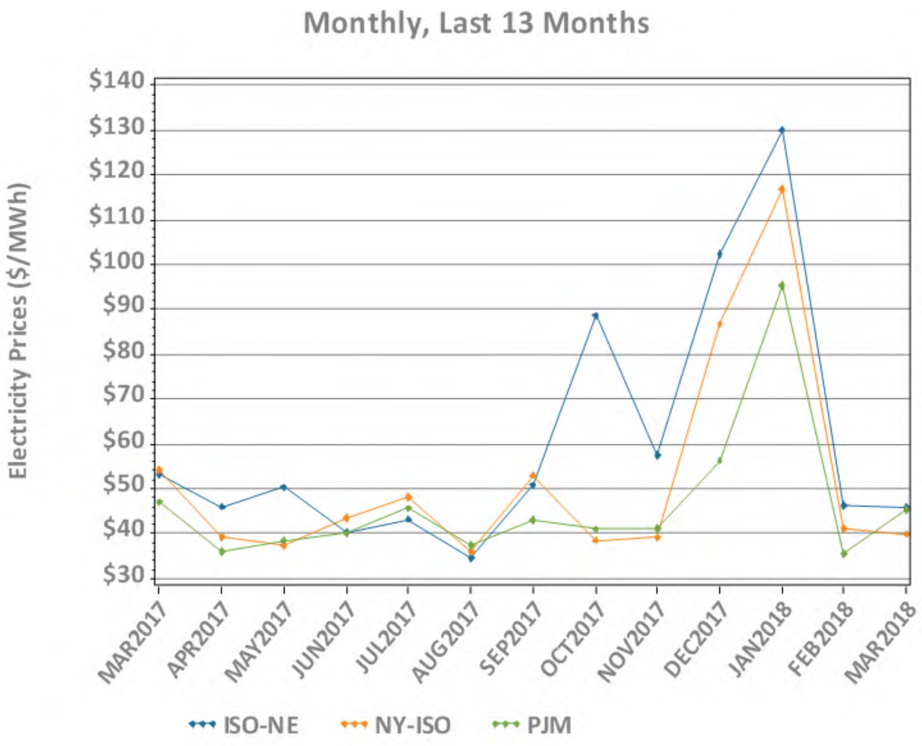
*Note: Hourly average prices are shown.

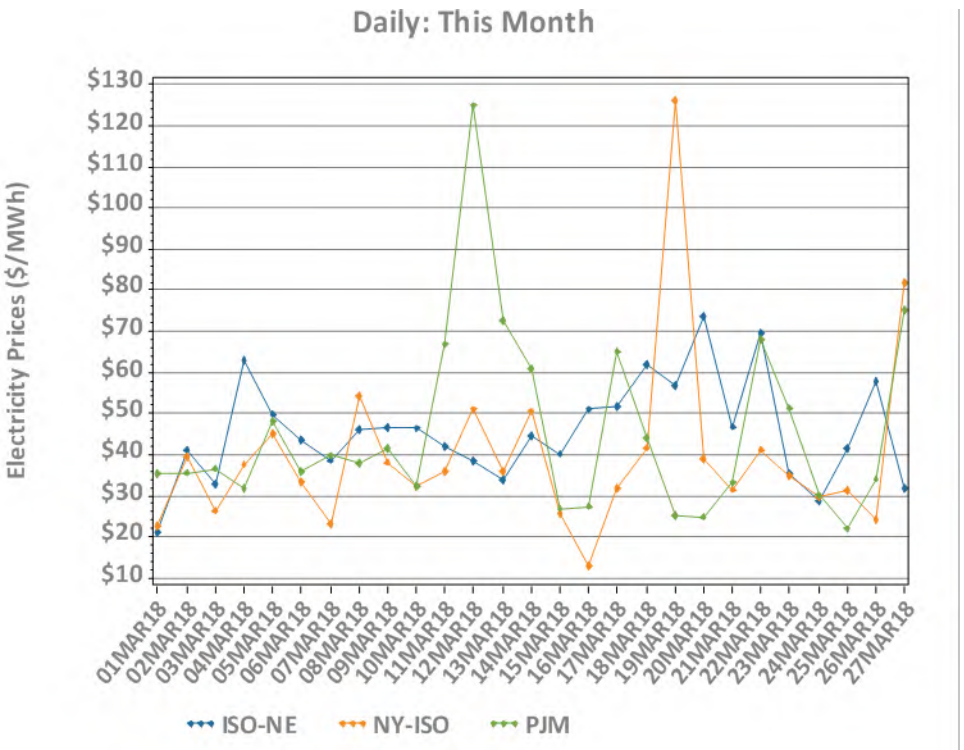


Daily: This Month

*Note: Hourly average prices are shown.

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





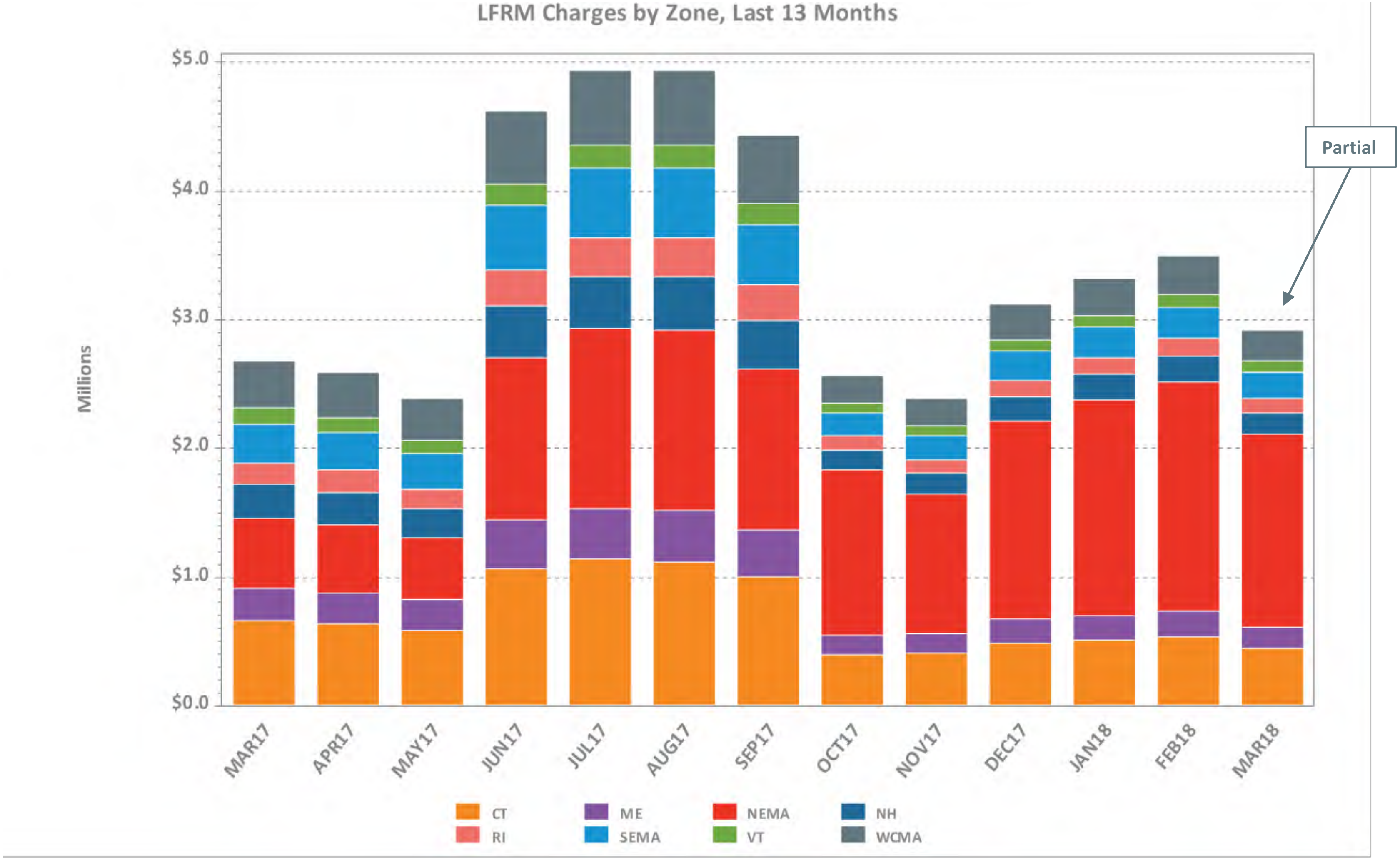
***Forecasted New England daily peak hours reflected**

Reserve Market Results – March 2018

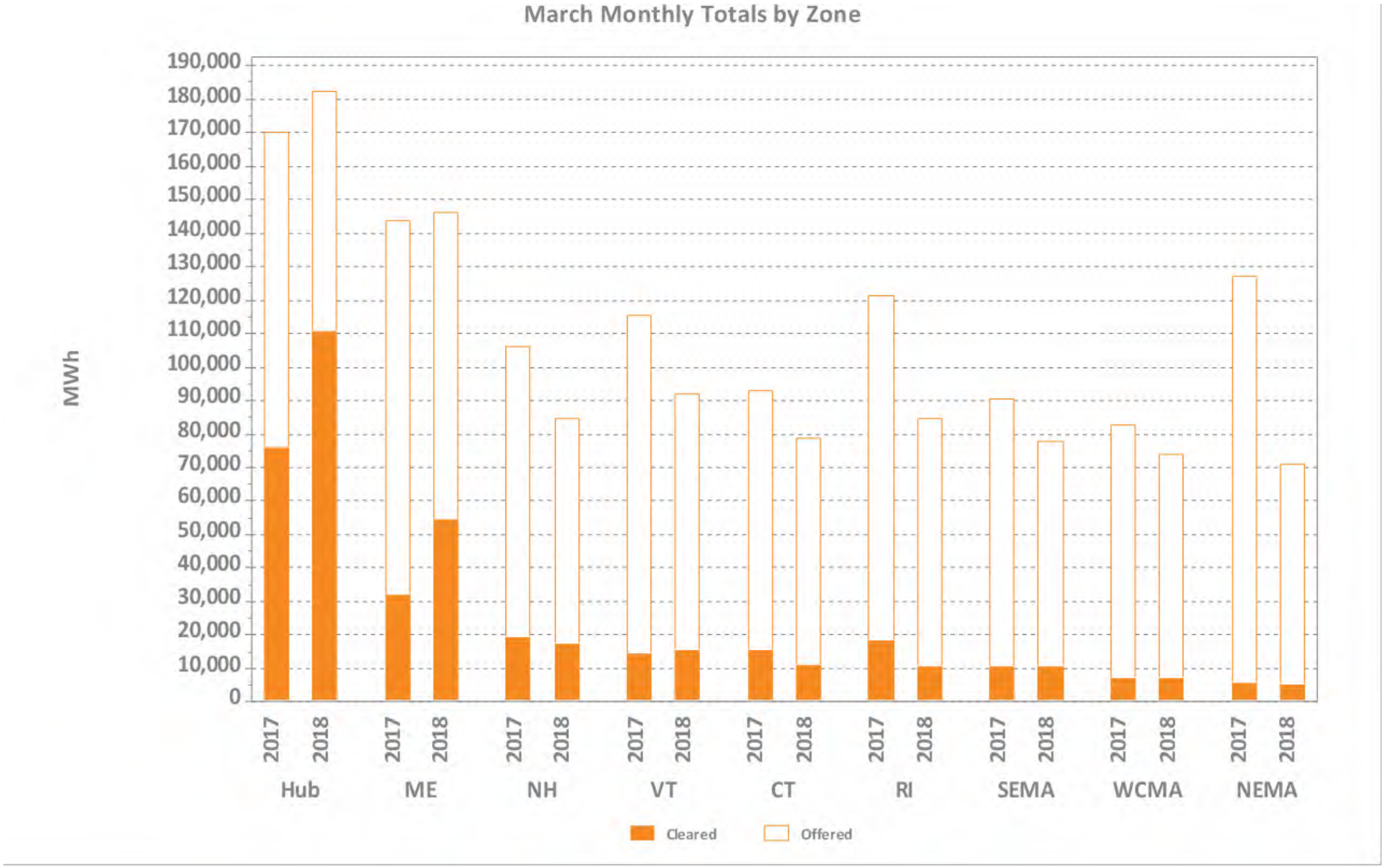
- Maximum potential Forward Reserve Market payments of $3.1M were reduced by credit reductions of $61K, failure-to-reserve penalties of $97K and failure-to-activate penalties of $34K, resulting in a net payout of $2.9M or 94% of maximum
  - Rest of System: $1.07M/1.09M (98%)
  - Southwest Connecticut: $0.1M/0.14M (75%)
  - Connecticut: $0.44M/0.47M (93%)
  - NEMA: $1.3M/1.4M (93%)
- $1.2M total Real-Time credits were reduced by $402K in Forward Reserve Energy Obligation Charges for a net of $808K in Real-Time Reserve payments
  - Rest of System: 135 hours, $587K
  - Southwest Connecticut: 135 hours, $129K
  - Connecticut: 135 hours, $57K
  - NEMA: 135 hours, $35K

*** "Failure to reserve" results in both credit reductions and penalties in the Locational Forward Reserve Market.**

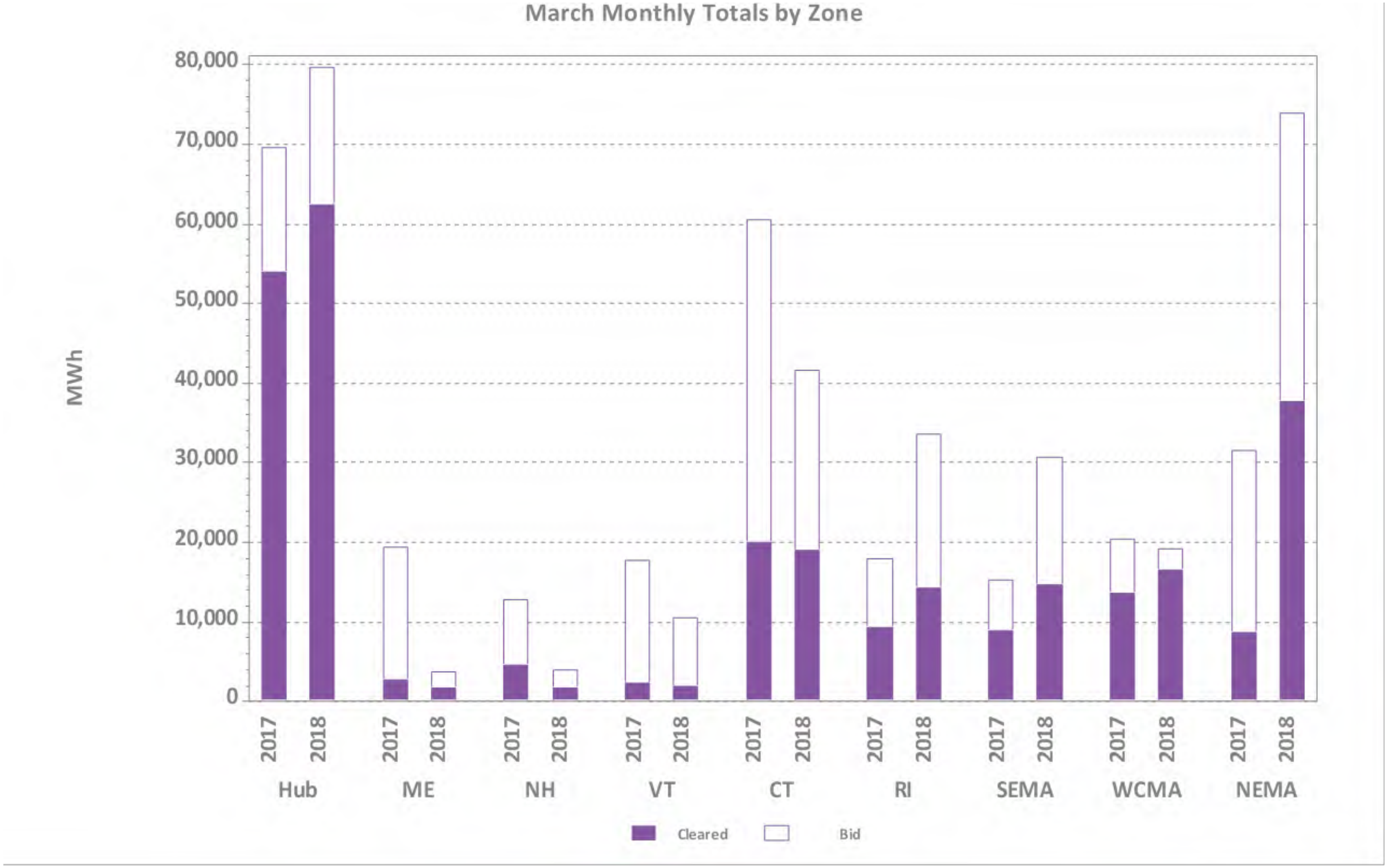
LFRM Charges to Load by Load Zone ($)



Zonal Increment Offers and Cleared Amounts



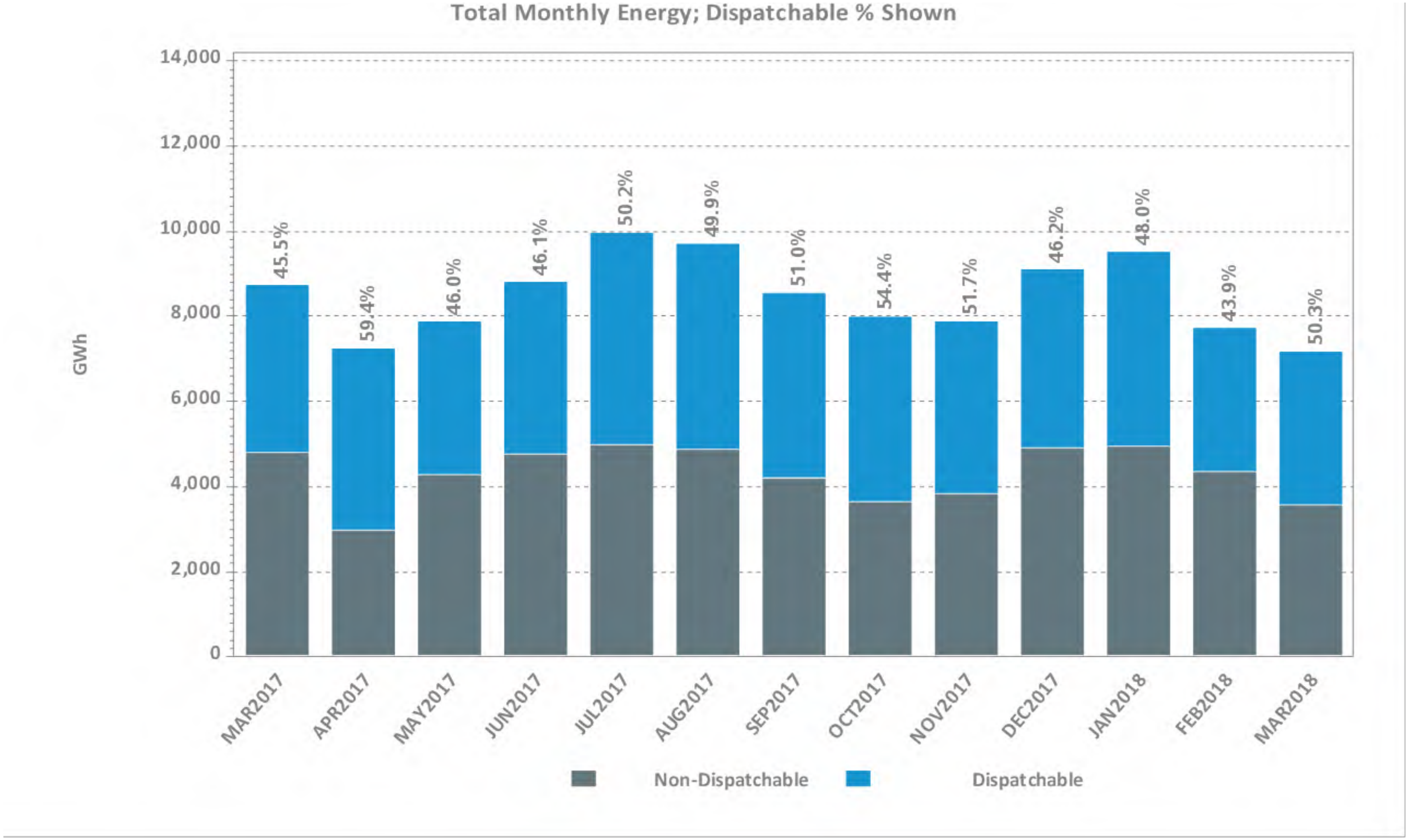
Zonal Decrement Bids and Cleared Amounts



Total Increment Offers and Decrement Bids

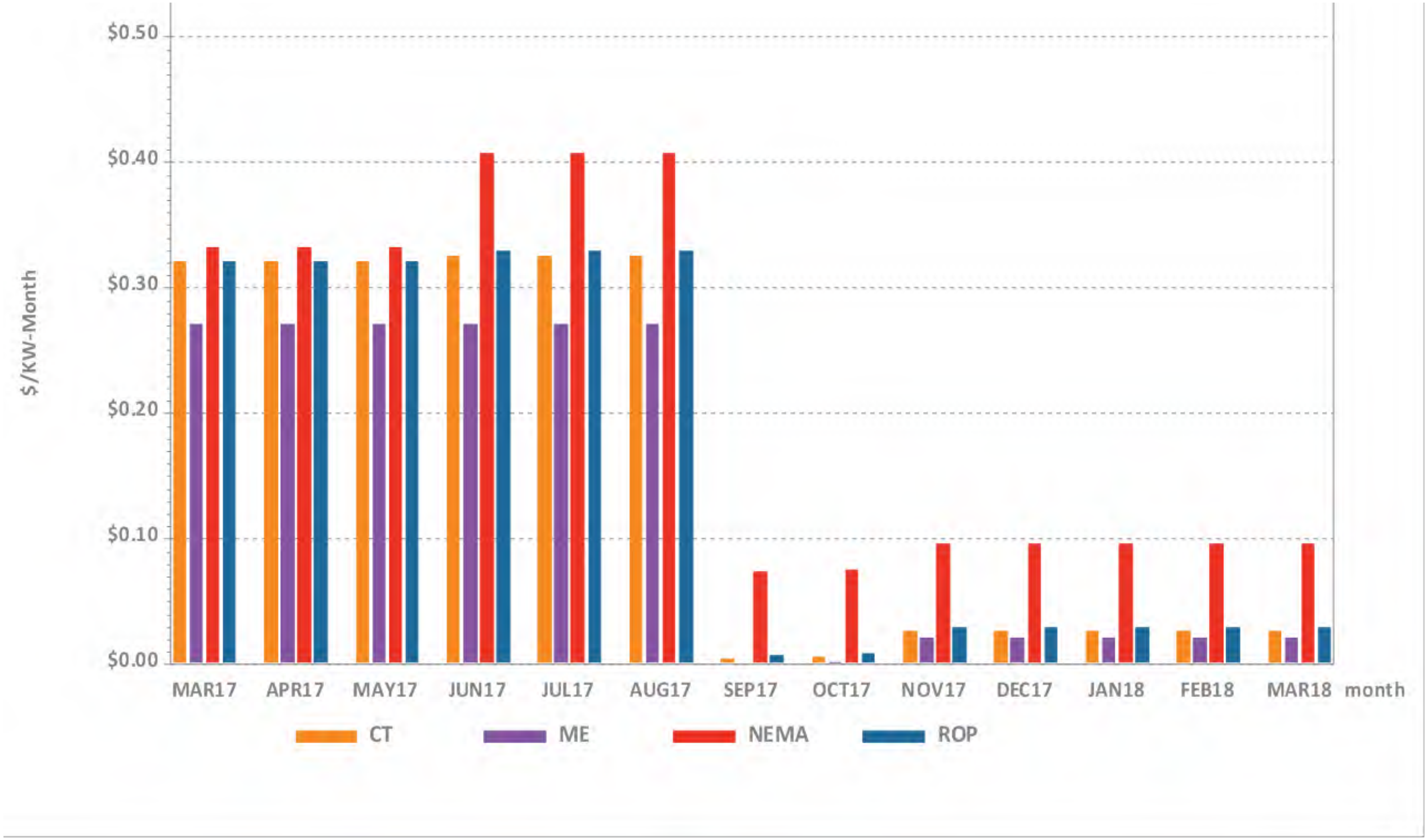
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



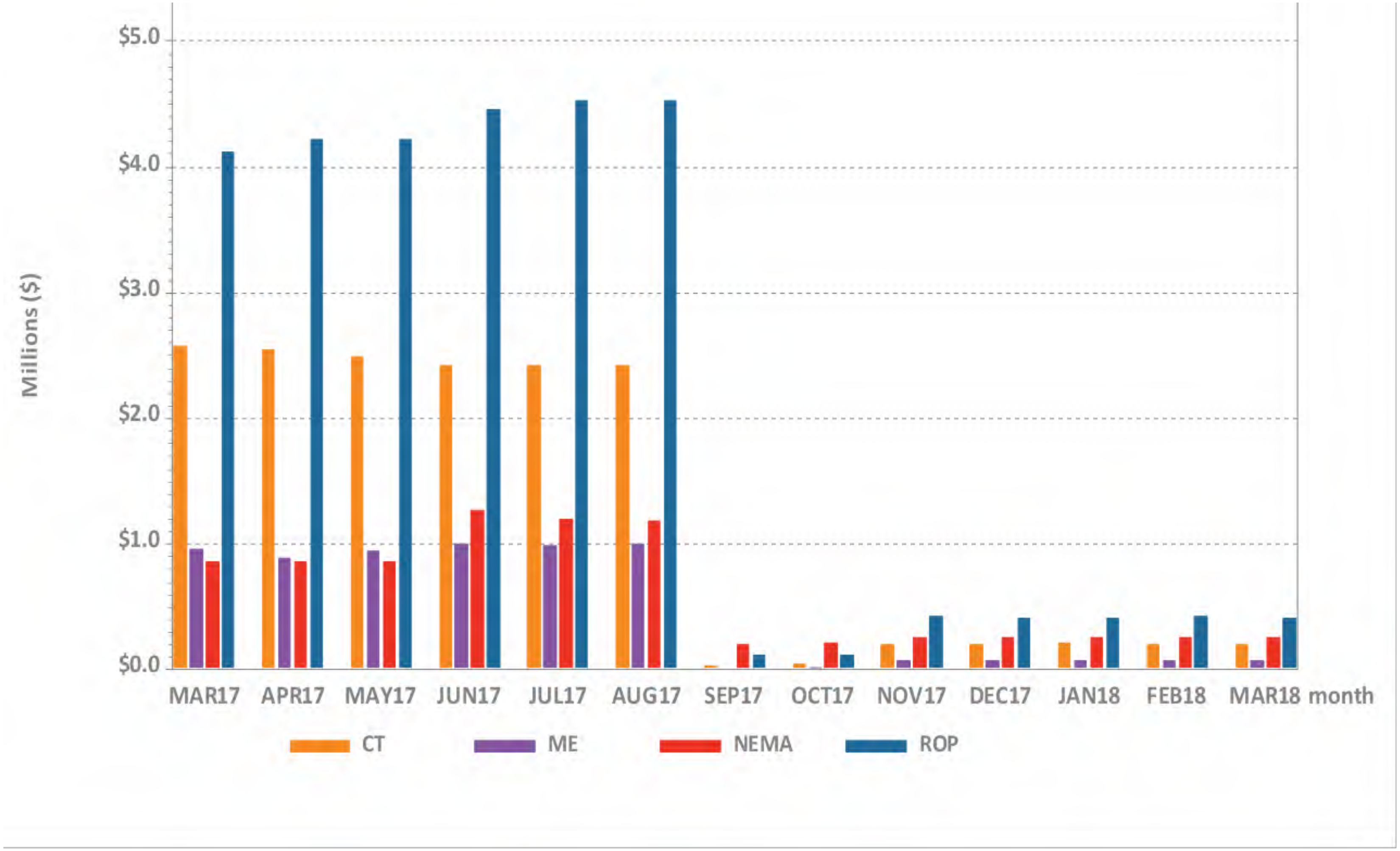
* Dispatchable MWh here are defined to be generation output that is not self-scheduled (i.e., not self-committed or 'must run' by the customer).

Rolling Average Peak Energy Rent (PER)



Individual monthly PER values are published to the ISO web site here: Home > Markets > Other Markets Data > Forward Capacity Market > Reports and are subject to resettlement.

PER Adjustments



REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- April 26 PAC Meeting Agenda Topics*
  - Post-Winter 2017/18 Gas Review
  - NGA Gas Update
  - New England EE, PV and Load Forecast Update
  - Flood Plains Discussion
  - FCA 13 Zonal Boundary Determinations
  - SEMA/RI 2026 Preferred Solution Update - J16S
  - Updating Needs Assessments to Reflect Latest Forecasts

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

Load, Energy Efficiency, and Photovoltaic Forecast

- The forecast development process for 2018 is nearing completion. Draft forecasts were presented to PAC in March with follow-up in April. The forecasts will be published in the 2018 CELT report by May 1.
  - Load Forecast
    - Gross forecasts
      - Annual energy is approximately 0.3% higher in 2026
      - Summer 50/50 is approximately 2.7% lower in 2026
      - Summer 90/10 is approximately 2.8% lower in 2026
    - Net forecasts
      - Annual energy forecast is approximately 4.5% lower in 2026
      - Summer 50/50 forecast is approximately 6.0% lower in 2026
      - Summer 90/10 forecast is approximately 5.8% lower in 2026
  - Energy-Efficiency (EE) Forecast
    - EE forecast is approximately 16.2% higher in 2026
  - Photovoltaic (PV) Forecast
    - BTM PV forecast is approximately 0.6% higher in 2026

Interregional Planning

- Comments on the Northeast Coordinated System Plan 2017 (NCSP17) are due by close of business on April 12
- Next Interarea Planning Stakeholder Advisory Committee meeting is scheduled for May 18 from 9:00am – 12:00pm

Environmental Matters

- The ISO tracks environmental regulatory developments affecting new and existing generators and transmission infrastructure
  - 2017-2018 cold snap: daily system emissions (NO_x, SO_2, CO_2) increased markedly during 16-day period (12/24/2017-1/8/2018):
    - NO_x emissions averaged 65 short tons daily (typically average 14 tons per day in December)
    - SO_2 emissions averaged 95 short tons daily (typically average 6 tons per day in December), strongly correlated with coal and residual oil-fired generation
    - CO_2 emissions averaged over 220,000 short tons daily (typically average 65,000 short tons per day in December), totaled 3.5 million short tons
  - In Massachusetts, generators subject to the GWSA 310 CMR 7.74 generator emissions cap estimated to have emitted 1.6 million short tons by 2/28/18
    - Private trades of GWSA allowances rumored at price of $20/metric ton, volumes unknown, works out to cost adder of $8.80/MWh for averaged affected combined cycle
    - MA DEP expected to shortly propose rule amendments that may include allowing early allowance trading, extending “emergency deferred compliance” option to emergencies that occur throughout the calendar year instead of just the year-end
    - No public auctions for 2019 allowances expected before 10/1/2018

GWSA – Global Warming Solutions Act

2017 Economic Study Update

- The 2017 Study examined three cases with the same basic assumptions that were used in the 2016 Study Scenario 3, but with changes in the resource mix to reflect differing amounts of energy efficiency, onshore wind, offshore wind, and a case with 2,100 MW of nuclear retirements
  - 2017 Economic Study draft results were presented at the 2/14/18 PAC meeting
  - The draft report is scheduled to be posted 2nd quarter

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.

Connecticut River Valley

Status as of 3/30/18

Project Benefit: Addresses system needs in the Connecticut River Corridor in Vermont

Upgrade	**Expected/ Actual In-Service**	**Present Stage**
Rebuild 115 kV line K31, Coolidge-Ascutney	Aug-17	4
Ascutney Substation - Add a +50/-25 MVAR dynamic reactive device	Aug-18	3
Hartford Substation - Split 25 MVAR capacitor bank into two 12.5 MVAR banks	Dec-16	4
Chelsea Station - Rebuild to a three-breaker ring bus	Jan-18	4

New Hampshire/Vermont 10-Year Upgrades

Status as of 3/30/18

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	Dec-19	2
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 3/30/18

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 3/30/18

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 3/30/18

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	3
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 3/30/18

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 new 115 kV underground cable from Newington to Southwest Hartford and associated terminal equipment including a 2% series reactor	Dec-18	3
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Dec-18	3
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)	Dec-18	3

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 3/30/18

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)	Dec-18	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	3
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Jun-19	3
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 3/30/18

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	3
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	Dec-18	3
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 3/30/18

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	Dec-18	3
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	3
Loop the 1570 line in and out the Pootatuck substation	Jul-18	3
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	4

Southwest Connecticut Projects, cont.

Status as of 3/30/18

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	3
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Oct-18	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	3
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	May-18	3
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Oct-18	3
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	May-18	3

Southwest Connecticut Projects, cont.

Status as of 3/30/18

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-19	2
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Jun-19	2

Southwest Connecticut Projects, cont.

Status as of 3/30/18

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)	Apr-19	3
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Sep-20	2

Southwest Connecticut Projects, cont.

Status as of 3/30/18

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 3/30/18

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	Dec-18	2
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-19	2
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-18	2

Greater Boston Projects, cont.

Status as of 3/30/18

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	Jun-18	2
Separate Q-169 and F-158N DCT	Dec-15	4
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-19	3
Install third 115 kV line from West Walpole to Holbrook	Sep-19	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-19	1

Greater Boston Projects, cont.

Status as of 3/30/18

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	May-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	Dec-18	3
Install a 115 kV breaker on the East bus at K Street	Jun-16	4
Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	May-19	2
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-19	2

Greater Boston Projects, cont.

Status as of 3/30/18

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-18	3
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	Dec-18	3
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Dec-18	3
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 3/30/18

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	Dec-18	3
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-18	2
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 3/30/18

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 3/30/18

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

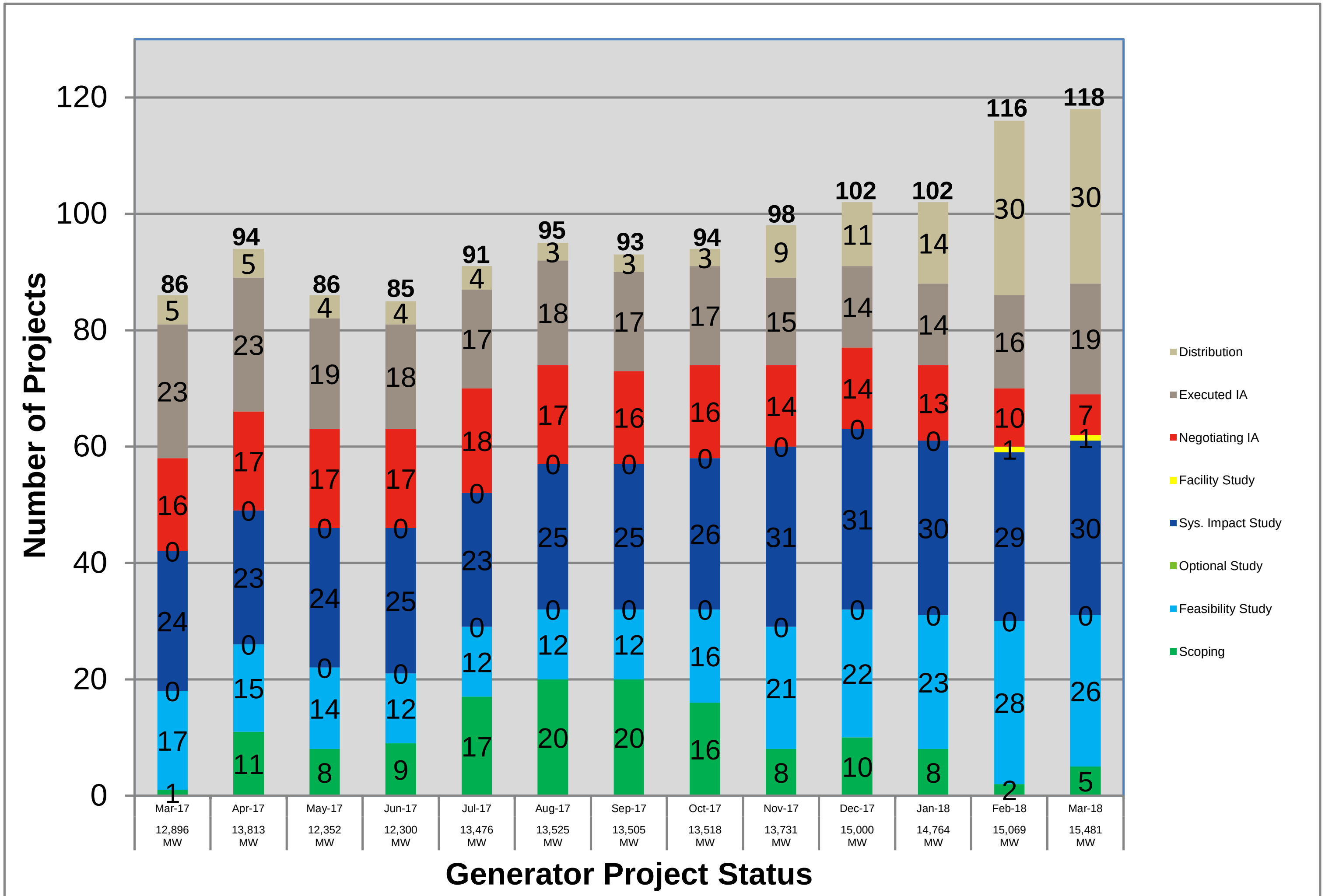
Pittsfield/Greenfield Projects, cont.

Status as of 3/30/18

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	Dec-19	1

Status of Tariff Studies



Note: March 2018 based on partial data

Note: As of March 2018, there are 12 ETU's in SIS, 3 in FS, 1 in Scoping, 1 in FAC, and 3 in Neg. IA

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OPERABLE CAPACITY ANALYSIS

Spring 2018

Spring 2018 Operable Capacity Analysis

50/50 Load Forecast (Reference)	**May - 2018[2]** **CSO**	**May - 2018[2]** **SCC**
Operable Capacity MW [1]	29,839	31,332
OP CAP From OP-4 RTDR (+)	375	375
OP CAP From OP-4 RTEG (+)	2	2
Operable Capacity with OP-4 DR and RTEG	30,216	31,709
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,013	1,013
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	2,580	2,717
Gas Generator Outages MW (-)	1070	611
Allowance for Unplanned Outages (-) [5]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	24,179	25,994
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,693	20,693
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,998	22,998
Operable Capacity Margin [3]	1,181	2,996

[1] Operable Capacity is based on data as of **March 22, 2018** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **March 22, 2018.**

[2] Load forecast that is based on the preliminary CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 19, 2018**.

[3] Includes OP4 actions associated with RTEG and RTDR

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

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

Spring 2018 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	**May - 2018[2] CSO**	**May - 2018[2] SCC**
Operable Capacity MW [1]	29,839	31,332
OP CAP From OP-4 RTDR (+)	375	375
OP CAP From OP-4 RTEG (+)	2	2
Operable Capacity with OP-4 DR and RTEG	30,216	31,709
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,013	1,013
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	2,580	2,755
Gas Generator Outages MW (-)	1070	611
Allowance for Unplanned Outages (-) [5]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	24,179	25,956
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	22,616	22,616
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,921	24,921
Operable Capacity Margin [3]	-742	1,035

[1] Operable Capacity is based on data as of **March 22, 2018** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **March 22, 2018.**

[2] Load forecast that is based on the preliminary CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 19, 2018**.

[3] Includes OP4 actions associated with RTEG and RTDR

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

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

Spring 2018 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)

ISO-NE 2018 OPERABLE CAPACITY ANALYSIS

April 1, 2018 - 50/50 FORECAST using CSO values with RTDR and RTEG

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, and August and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	ACTIVE DEMAND CAPACITY MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER. RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW [14]	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW [15]	OPCAP FROM OP4 REAL-TIME EMER. GEN MW [16]	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW [17]
3/31/2018	29,903		1,163	0	4,707	1,277	2,700	0	22,382	16,464	2,305	18,769	3,613	292	3,905	0	3,905
4/7/2018	29,903		1,163	0	4,608	1,478	2,700	0	22,280	16,205	2,305	18,510	3,770	292	4,062	0	4,062
4/14/2018	29,903		1,063	0	4,199	1,835	2,700	0	22,232	15,680	2,305	17,985	4,247	292	4,539	0	4,539
4/21/2018	29,903		1,063	0	4,772	1,068	2,700	0	22,426	15,408	2,305	17,713	4,713	292	5,005	0	5,005
4/28/2018	29,839		1,124	0	4,794	1,043	3,400	0	21,726	14,748	2,305	17,053	4,673	375	5,048	2	5,050
5/5/2018	29,839		1,124	0	3,194	1,836	3,400	0	22,533	18,725	2,305	21,030	1,503	375	1,878	2	1,880
5/12/2018	29,839		1,124	0	2,280	2,094	3,400	0	23,189	19,745	2,305	22,050	1,139	375	1,514	2	1,516
5/19/2018	**29,839**		**1,013**	**0**	**2,580**	**1,070**	**3,400**	**0**	**23,802**	**20,693**	**2,305**	**22,998**	**804**	**375**	**1,179**	**2**	**1,181**
5/26/2018	29,839		1,124	0	1,182	549	3,400	0	25,832	21,733	2,305	24,038	1,794	375	2,169	2	2,171

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) http://www.iso-ne.com/system-planning/system-plans-studies/celt
10. Peak Load Forecast as provided in the preliminary 2018 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,729 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)
14. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
15. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (13 + 14 = 15)
16. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW.
Reserve Margins and Distribution Loss Factor Gross Ups are Included.
17. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (15 + 16 = 17)
This does not include Emergency Energy Transactions (EETs).

Spring 2018 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2018 OPERABLE CAPACITY ANALYSIS

April 1, 2018 - 90/10 FORECAST using CSO values with RTDR and RTEG

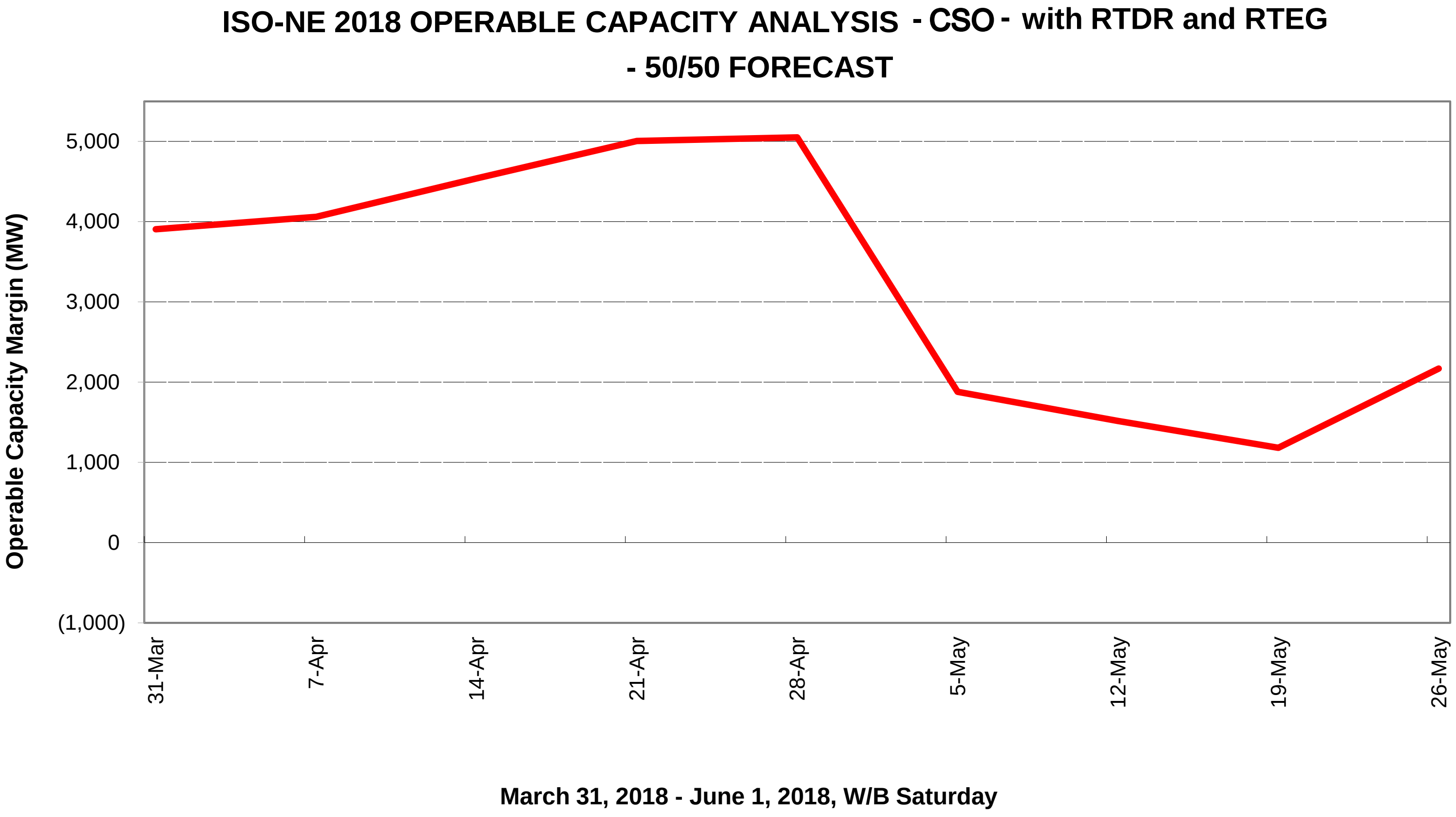
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW [14]	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW [15]	OPCAP FROM OP4 REAL-TIME EMER. GEN MW [16]	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW [17]
3/31/2018	29,903		1,163	0	4,707	1,277	2,700	0	22,382	17,994	2,305	20,299	2,083	292	2,375	0	2,375
4/7/2018	29,903		1,163	0	4,608	1,478	2,700	0	22,280	17,711	2,305	20,016	2,264	292	2,556	0	2,556
4/14/2018	29,903		1,063	0	4,199	1,835	2,700	0	22,232	17,137	2,305	19,442	2,790	292	3,082	0	3,082
4/21/2018	29,903		1,063	0	4,772	1,068	2,700	0	22,426	16,840	2,305	19,145	3,281	292	3,573	0	3,573
4/28/2018	29,839		1,124	0	4,794	1,043	3,400	0	21,726	16,119	2,305	18,424	3,302	375	3,677	2	3,679
5/5/2018	29,839		1,124	0	3,194	1,836	3,400	0	22,533	20,465	2,305	22,770	(237)	375	138	2	140
5/12/2018	29,839		1,124	0	2,280	2,094	3,400	0	23,189	21,580	2,305	23,885	(696)	375	(321)	2	(319)
5/19/2018	**29,839**		**1,013**	**0**	**2,580**	**1,070**	**3,400**	**0**	**23,802**	**22,616**	**2,305**	**24,921**	**(1,119)**	**375**	**(744)**	**2**	**(742)**
5/26/2018	29,839		1,124	0	1,182	549	3,400	0	25,832	23,753	2,305	26,058	(226)	375	149	2	151

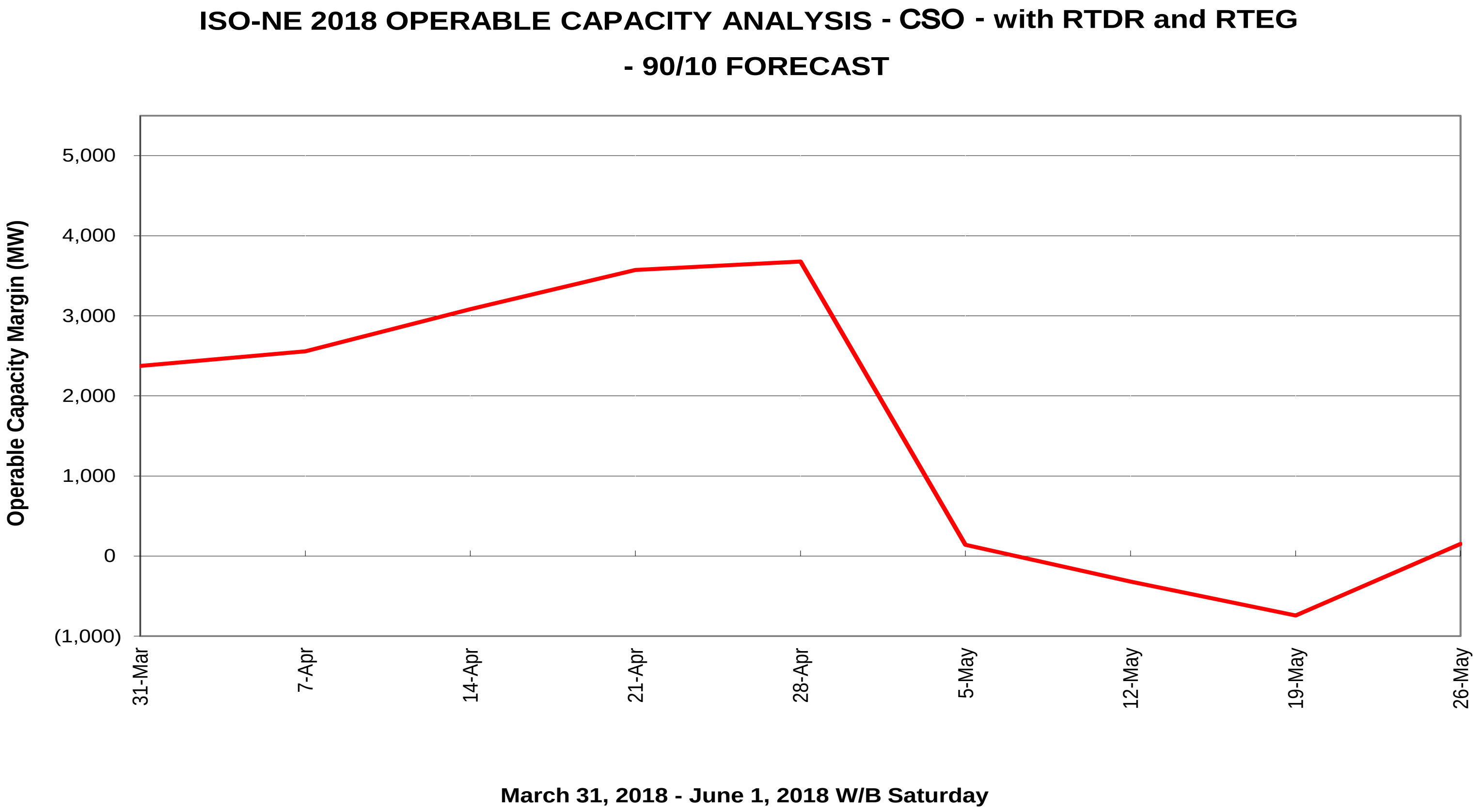
1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM).
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) http://www.iso-ne.com/system-planning/system-plans-studies/celt
10. Peak Load Forecast as provided in the preliminary 2018 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 28,120 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)
14. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
15. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (13 + 14 = 15)
16. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW.
Reserve Margins and Distribution Loss Factor Gross Ups are Included.
17. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (15 + 16 = 17)
This does not include Emergency Energy Transactions (EETs).

Spring 2018 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)



Spring 2018 Operable Capacity Analysis (MW)
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Preliminary Summer 2018

Summer 2018 Operable Capacity Analysis

50/50 Load Forecast (Reference)	June - 2018[2] CSO	June - 2018[2] SCC
Operable Capacity MW [1]	29,522	29,634
Active Demand Capacity Resource (+) [5]	408	408
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,468	1,468
Non Commercial Capacity (+)	824	824
Non Gas-fired Planned Outage MW (-)	15	15
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	29,407	29,519
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	25,729	25,729
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,034	28,034
Operable Capacity Margin [3]	1373	1485

[1] Operable Capacity is based on data as of **March 22, 2018** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **March 22, 2018.**

[2] Load forecast that is based on the preliminary CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 2, 2018.**

[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.

Summer 2018 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	June - 2018[2] CSO	June - 2018[2] SCC
Operable Capacity MW [1]	29,522	29,634
Active Demand Capacity Resource (+) [5]	408	408
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,468	1,468
Non Commercial Capacity (+)	824	824
Non Gas-fired Planned Outage MW (-)	15	15
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	29,407	29,519
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	28,120	28,120
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	30,425	30,425
Operable Capacity Margin [3]	-1,018	-906

[1] Operable Capacity is based on data as of **March 22, 2018** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **March 22, 2018.**

[2] Load forecast that is based on the preliminary CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 2, 2018.**

[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.

Summer 2018 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)

ISO-NE 2018 OPERABLE CAPACITY ANALYSIS

April 1, 2018 - 50/50 FORECAST using CSO values with RTDR and RTEG

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, and August and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	ACTIVE DEMAND CAPACITY MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	PLANNED OUTAGES	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER. RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW [14]	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW [15]	OPCAP FROM OP4 REAL-TIME EMER. GEN MW [16]	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW [17]
6/2/2018	**29,522**	**408**	**1,468**	**824**	**15**	**15**	**0**	**2,800**	**0**	**29,407**	**25,729**	**2,305**	**28,034**	**1,373**				
6/9/2018	29,522	408	1,468	824	0	0	0	2,800	0	29,422	25,729	2,305	28,034	1,388				
6/16/2018	29,522	408	1,468	824	0	0	0	2,800	0	29,422	25,729	2,305	28,034	1,388				
6/23/2018	29,522	408	1,468	824	14	14	0	2,800	0	29,408	25,729	2,305	28,034	1,374				
6/30/2018	29,522	408	1,468	824	14	14	0	2,100	0	30,108	25,729	2,305	28,034	2,074				
7/7/2018	29,522	408	1,468	824	14	14	0	2,100	0	30,108	25,729	2,305	28,034	2,074				
7/14/2018	29,522	408	1,468	824	0	0	0	2,100	0	30,122	25,729	2,305	28,034	2,088				
7/21/2018	29,522	408	1,468	824	0	0	0	2,100	0	30,122	25,729	2,305	28,034	2,088				
7/28/2018	29,522	408	1,468	824	14	14	0	2,100	0	30,108	25,729	2,305	28,034	2,074				
8/4/2018	29,522	408	1,468	824	0	0	0	2,100	0	30,122	25,729	2,305	28,034	2,088				
8/11/2018	29,522	408	1,468	824	0	0	0	2,100	0	30,122	25,729	2,305	28,034	2,088				
8/18/2018	29,522	408	1,468	824	14	14	0	2,100	0	30,108	25,729	2,305	28,034	2,074				
8/25/2018	29,522	408	1,468	824	0	0	0	2,100	0	30,122	25,729	2,305	28,034	2,088				
9/1/2018	29,522	408	1,468	824	0	0	0	2,100	0	30,122	25,729	2,305	28,034	2,088				
9/8/2018	29,522	408	1,468	824	0	0	0	2,100	0	30,122	25,729	2,305	28,034	2,088				

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 preliminary 2018 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,729 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)
14. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
15. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (13 + 14 = 15)
16. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
17. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (15 + 16 = 17) This does not include Emergency Energy Transactions (EETs).

http://www.iso-ne.com/system-planning/system-plans-studies/celt

Summer 2018 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2018 OPERABLE CAPACITY ANALYSIS

April 1, 2018 - 90/10 FORECAST using CSO values with RTDR and RTEG

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, and August and Mid September.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW [14]	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW [15]	OPCAP FROM OP4 REAL-TIME EMER. GEN MW [16]	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW [17]
6/2/2018	**29,522**	**408**	**1,468**	**824**	**15**	**0**	**2,800**	**0**	**29,407**	**28,120**	**2,305**	**30,425**	**(1,018)**				
6/9/2018	29,522	408	1,468	824	0	0	2,800	0	29,422	28,120	2,305	30,425	(1,003)				
6/16/2018	29,522	408	1,468	824	0	0	2,800	0	29,422	28,120	2,305	30,425	(1,003)				
6/23/2018	29,522	408	1,468	824	14	0	2,800	0	29,408	28,120	2,305	30,425	(1,017)				
6/30/2018	29,522	408	1,468	824	14	0	2,100	0	30,108	28,120	2,305	30,425	(317)				
7/7/2018	29,522	408	1,468	824	14	0	2,100	0	30,108	28,120	2,305	30,425	(317)				
7/14/2018	29,522	408	1,468	824	0	0	2,100	0	30,122	28,120	2,305	30,425	(303)				
7/21/2018	29,522	408	1,468	824	0	0	2,100	0	30,122	28,120	2,305	30,425	(303)				
7/28/2018	29,522	408	1,468	824	14	0	2,100	0	30,108	28,120	2,305	30,425	(317)				
8/4/2018	29,522	408	1,468	824	0	0	2,100	0	30,122	28,120	2,305	30,425	(303)				
8/11/2018	29,522	408	1,468	824	0	0	2,100	0	30,122	28,120	2,305	30,425	(303)				
8/18/2018	29,522	408	1,468	824	14	0	2,100	0	30,108	28,120	2,305	30,425	(317)				
8/25/2018	29,522	408	1,468	824	0	0	2,100	0	30,122	28,120	2,305	30,425	(303)				
9/1/2018	29,522	408	1,468	824	0	0	2,100	0	30,122	28,120	2,305	30,425	(303)				
9/8/2018	29,522	408	1,468	824	0	0	2,100	0	30,122	28,120	2,305	30,425	(303)				

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
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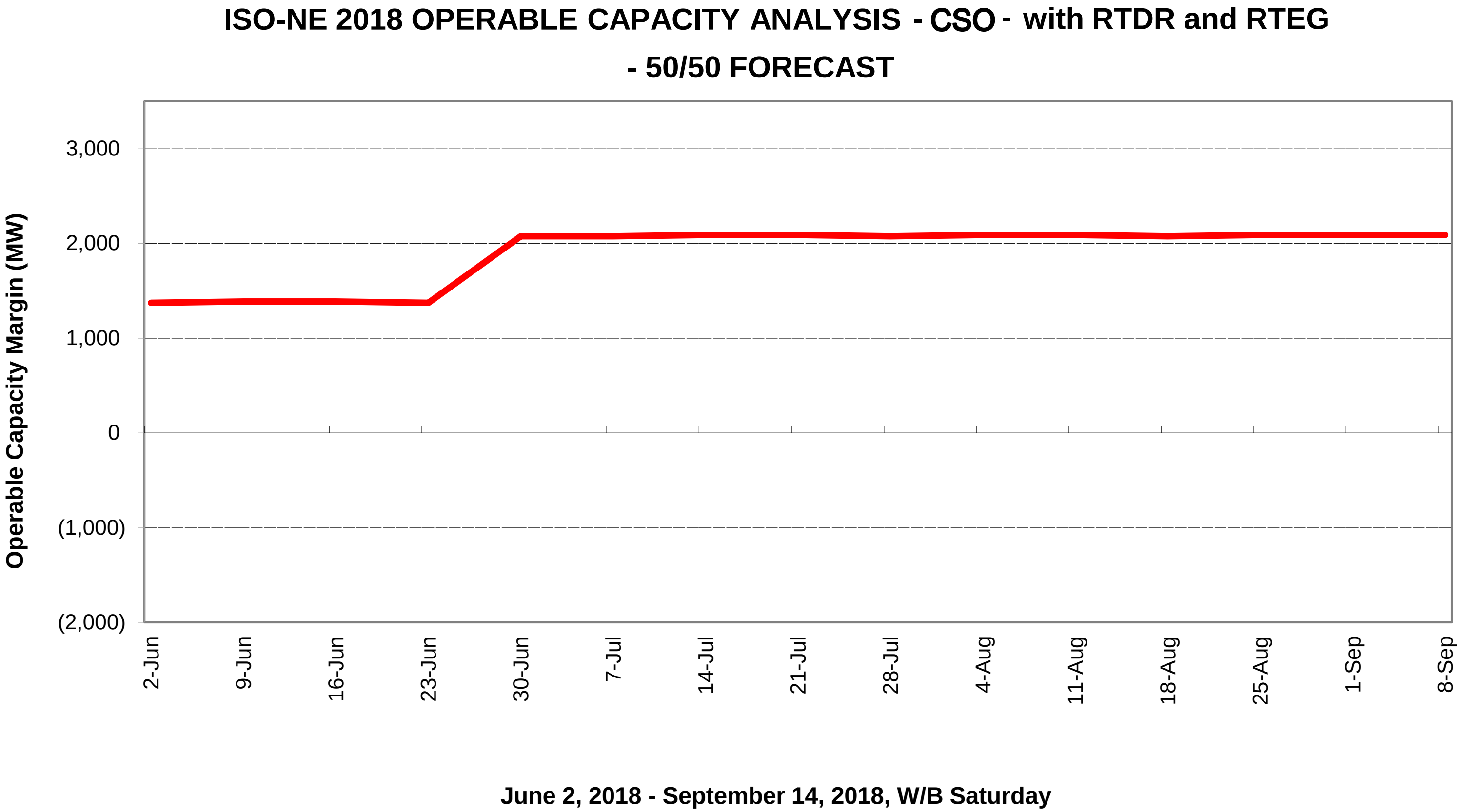
This does not include Emergency Energy Transactions (EETs).

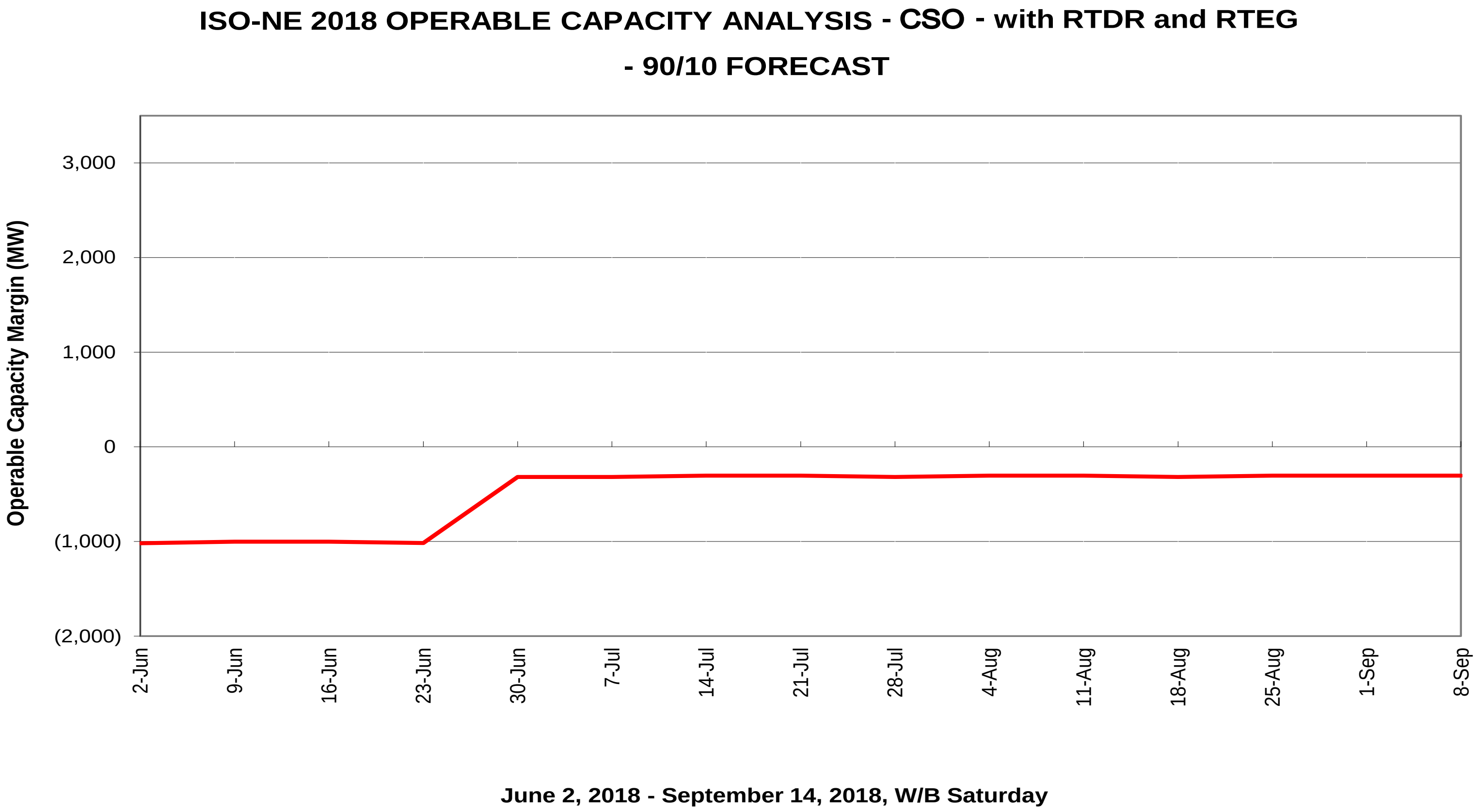
Summer 2018 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)



Summer 2018 Operable Capacity Analysis (MW)

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 depletion of 30-minute reserve.	0 [1] 600
2	Dispatch real time Demand Resources.	**March & April 292 [3]** **May 375 [3]**
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 Dispatch real time Emergency Generation	133 [4] **March 0 [3]** **April & May 2 [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 RTDR and RTEG MW values are based on FCM results as of March 22, 2018.
4. The MW values are based on a forecasted value of 26,482 MW system load for the 2017 CELT Report and the most recent voltage reduction test % achieved.

Possible Relief Under OP4: Appendix A, cont.

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	Voltage Reduction requiring 10 minutes or less	265 [4]
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		**March 2,835 [3]** **April 2,837 [3]** **May 2,920 [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 RTDR and RTEG MW values are based on FCM results as of March 22, 2018.
4. The MW values are based on a forecasted value of 26,482 MW system load for the 2017 CELT Report and the most recent voltage reduction test % achieved.

ISO new england

memo

To: NEPOOL Participants Committee

From: Vamsi Chadalavada, Executive Vice President and Chief Operating Officer

Date: April 3, 2018

Subject: Discussions of Near-Term Fuel Security Concerns

This memorandum addresses the ISO's planned action in response to the recent announcement of Exelon Generation that it has submitted resource retirement bids for the 13th Forward Capacity Auction (FCA 13) for Mystic units 7, 8, 9, and the Jet unit, totaling ~2000 MW. Exelon has indicated that, in order to meet its existing capacity supply obligations through FCA 12, it is acquiring the Distrigas facility, which is the only fuel supply source available to Mystic units 8 and 9.

In FCA 12, the ISO rejected the dynamic delist bids for Mystic units 7 and 8 for Capacity Commitment Period 2021-2022 due to reliability issues focused on transmission security. Now, Exelon's FCA 13 retirement bids create significant additional reliability concerns as they signal the potential permanent exit of Mystic station – specifically units 8 and 9, which operate at ~1600 MW in the winter months – and implicate the Distrigas facility. These retirements pose an unacceptable fuel security risk to the region during the winter months. Our recent operational experiences during the cold spell, the projected state of the power system in 2022 through 2024, and the future trends identified in our Operational Fuel Security Analysis, highlight the critical importance of this facility to the region's fuel security.

Since the ISO received Exelon's retirement bids, it has been analyzing the potential impacts of losing the Mystic and Distrigas facilities from a fuel security perspective. Given the reliability impacts identified in this analysis and the limited time to address this issue, the ISO will ask FERC to waive the requirements of the ISO's Tariff to allow the ISO to retain Mystic 8 and 9 to maintain fuel security on the system – an option not currently contained in the ISO Tariff. The ISO has previously observed that it may need to seek such authority for resources required for regional fuel security while it continues to work on future solutions.

We believe that it is important to notify stakeholders of our intention to file a waiver later this month in response to Exelon's submitted retirement bids. In order to be transparent and provide as much information as feasible to stakeholders, prior to filing its waiver request, the ISO will discuss this approach at the upcoming April Participants Committee meeting. Additionally, immediately following the April 10 Markets Committee meeting, the ISO will meet with its stakeholders to provide an explanation of its reliability analysis of these retirement bids.

The ISO believes it has limited options and needs to take this initial action in response to the Exelon retirement bids in FCA13. However, the ISO commits to work with stakeholders to develop a Tariff-based approach for retaining retiring resources needed for fuel security on a short-term, going-forward basis. We plan to commence discussions with stakeholders, beginning at the April 25 Reliability Committee meeting, on the necessary reliability criteria for retaining resources needed for fuel security in the Forward Capacity Market. The ISO would like to file associated Tariff language by November 2018, to be in effect for retirement bids in FCA 14. Stakeholder discussions will also be scheduled for the Markets Committee to address compensation and cost-allocation mechanisms.

Discussions with stakeholders regarding problem definition and associated market-based solutions to fuel-security risks in the longer term (related to its Operational Fuel Security Analysis) will continue as planned. The ISO recently finished its simulations of ~150 additional scenarios requested by stakeholders, which were discussed at the March 28 Reliability Committee. Next, the ISO and NEPOOL will start the planned stakeholder process from Q2 2018 – Q2 2019 to evaluate possible approaches to address the future risk trends. The ISO believes that this parallel approach allows the region to take appropriate reliability actions in the near-term, while continuing work on future measures related to fuel security.

I look forward to discussing these issues with you on Friday.

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of APRIL 4, 2018

The following activity, as more fully described in the attached litigation report, has occurred since the report dated February 28, 2018 was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

	1	PER Settlement Agreement (ER17-2153; EL16-120)	Mar 1	NESCOE seeks clarification of order approving PER Settlement
			Mar 16	NEPGA answers NESCOE request for clarification
	2	Base ROE Complaint IV (2016) (EL16-64)	Mar 15	TOs petition DC Circuit for review of *Base ROE Complaint IV Orders*
			Mar 27	Judge Glazer issues *Initial Decision* finding ROE of 10.57 %, which may reach a maximum ROE of 11.74 % with incentive adders, is not unjust and unreasonable, and hence is not unlawful
	3	206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19)	Apr 3	Settlement Judge Dring issues status report noting parties have reached a settlement in principle and recommending that settlement procedures be continued

II. Rate, ICR, FCA, Cost Recovery Filings

*	5	VTransco Recovery of Highgate Ownership Share Acquisition Costs (ER18-1259)	Mar 30	VTransco files to recover under regional transmission rates $639,780 in costs related to its acquisition of Highgate Transmission Facility ownership shares; comment date Apr 20
*	5	FCA12 Results Filing (ER18-940)	Feb 28	ISO-NE files results of twelfth FCA; comment date Apr 13
			Mar 5-26	Dominion, Eversource, Exelon, National Grid, NESCOE
	6	Emera MPD OATT Attachment J Revision (ER18-210)	Mar 26	Settlement Judge Dring issues status report indicating the parties have reached a settlement in principle and recommending settlement judge procedures be continued
			Mar 30	Chief Judge Cintron issues order continuing settlement judge procedures
*	7	ISO Securities: Authorization for Future Drawdowns (ES18-25)	Mar 28	ISO requests continued authorization for drawdowns under new Revolving Credit Line and Payment Default Shortfall Fund; comment date Apr 18

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

*	7	FCM Enhancements – Phase II (ER18-1287)	Apr 2	ISO-NE and NEPOOL jointly file changes; comment date Apr 23
*	8	PFP Enhancements (ER18-1223)	Mar 30	ISO-NE and NEPOOL jointly file changes; comment date Apr 20
			Mar 31-Apr 4	ConEd, Public Citizen intervene
*	8	PER Settlement Compliance Filing (ER18-1153)	Mar 22	ISO-NE submits compliance filing; comment date Apr 12
			Mar 26-Apr 2	NESCOE, ConEd, National Grid intervene
	8	Real-Time Reserve Designation & Settlement Rule Changes (ER18-897)	Mar 5-15	National Grid, Eversource, FirstLight, NRG/GenOn intervene
			Mar 29	FERC accepts changes, eff. Jun 1
	8	CSO Termination: Blue Sky West (ER18-704)	Mar 1	ISO-NE answers Blue Sky West Feb 23 protest
			Mar 23	FERC accepts termination of a portion of BSW's CSO, eff. Mar 24

	9	Updated Dynamic De-List Bid Threshold (ER18-620)	Mar 9	FERC accepts $4.30/kW-mo. threshold, eff. Mar 9, 2018
	10	CASPR (ER18-619)	Mar 9	FERC accepts CASPR Changes, eff. Mar 9, 2018 (§III.13.7 changes eff. Jun 1, 2018)
	12	ART Market Rule Changes (ER18-455)	Feb 28 Mar 1	FERC accepts changes, eff. Mar 1, 2018 Most changes become effective, remainder to be eff. Jun 1, 2018

IV. OATT Amendments / TOAs / Coordination Agreements

No Activity to Report

V. Financial Assurance/Billing Policy Amendments

*	13	FCM Energy Efficiency & Monthly Capacity Charge Changes (ER18-944)	Mar 1 Mar 22-23 Apr 3	ISO-NE and NEPOOL file changes Eversource, National Grid intervene FERC accepts changes, eff. Jun 1, 2018

VI. Schedule 20/21/22/23 Changes

*	13	Schedule 21-EM: BHD Tax Law & Settlement Changes (ER18-1213)	Mar 29	Emera Maine files changes to BHD Formula Rate; comment date Apr 19
	14	Schedule 21-EM: Brookfield LSA (ER18-901)	Mar 5	Emera submits corrected transmittal letter for Brookfield LSA filing
	15	Schedule 21-EM 2017 Annual Update (ER15-1434) Settlement Agreement (ER18-960)	Mar 5[69] Mar 19	Emera Maine submits annual update to its local trans. service rates and settlement agreement MPUC intervenes
	14	Schedule 21-EM: Recovery of BHE/MPS Merger-Related Costs (ER15-1434 et al.)	Mar 26	Settlement Judge Dring issues status report indicating that the parties have reached a settlement in principle and are memorializing their agreement, and recommending that settlement judge procedures be cont.
	14	Schedule 21-ES: PSNH/VEC LSA (ER18-745)	Mar 6	FERC accepts LSA, eff. Jan 1, 2018
	15	Schedule 21-VEC: VEC/PSNH LSA (NJ18-10)	Mar 6	FERC accepts LSA, eff. Jan 1, 2018

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

	16	Capital Projects Report - 2017 Q4 (ER18-841)	Mar 23	FERC accepts 2017 Q4 Report
*	17	Reserve Market Compliance (24th) Semi-Annual Report (ER06-613)	Apr 2	ISO-NE submits 24th semi-annual report
*	17	ISO-NE FERC Form 715	Mar 27	ISO-NE submits annual report of total MWh of transmission service

IX. Membership Filings

*	17	April 2018 Membership Filing (ER18-1235)	Mar 29	NEPOOL requests the termination of the Participant status of Phoenix Energy New England; comment date Apr 19

	17	March 2018 Membership Filing (ER18-923)	Mar 28	FERC accepts (i) the memberships of Bruce Power, CS Berlin Ops, HSE Hydro NH AC, and Optik Energy; and (ii) the termination of the Participant status of Cargill Power Markets and RBC Energy Services
	17	February 2018 Membership Filing (ER18-767)	Mar 29	FERC accepts the termination of the Participant status of Emera Energy Services Subsidiaries Nos. 10, 13 and 14, Epico USA, Shipley Choice, and WMECO
*	17	Suspension Notice – Indeck Energy-Alexandria (not docketed)	Mar 9 Mar 16	ISO-NE files notice of suspension from New England Markets Indeck Energy-Alexandria reinstated
*	17	Suspension Notice – Manchester Methane (not docketed)	Mar 9 Mar 16	ISO-NE files notice of suspension from New England Markets Manchester Methane reinstated
*	17	Suspension Notice – Chris Anthony (not docketed)	Mar 9 Mar 16	ISO-NE files notice of suspension from New England Markets Chris Anthony reinstated
*	17	Suspension Notice – Univ. Sys. of New Hampshire (not docketed)	Mar 16 Mar 16	ISO-NE files notice of suspension from New England Markets Univ. Sys. of NH reinstated

X. Misc. - ERO Rules, Filings; Reliability Standards

*	18	Revised Reliability Standard: PRC-025-2 (RD18-4)	Apr 20	NERC files revised standards for approval; comment date Apr 19
	19	NOPR: Revised Reliability Standards: CIP-005-6, CIP-010-3, CIP-013-1 (RM17-13)	Mar 14-26	Over 20 parties file comments, including NERC, IRC, EEI, Joint Trade Associations, and the MPUC
	20	Compliance and Certification Committee Charter Amendments (RR18-4)	Mar 15	NERC files for approval amendments to reflect participation of CCC observers in Regional Entity audits; comment date Apr 5
	20	Rules of Procedure Changes (RR18-1)	Mar 8	FERC approves revisions to Appendix 3D (Registered Ballot Body Criteria), eff. Mar 8
	21	Rules of Procedure Changes (Sections 600 and 900) (RR17-2)	Mar 6	AEP intervenes

XI. Misc. - of Regional Interest

*	21	203 Application: HIKO Energy/ Spark HoldCo (EC18-69)	Mar 13	HIKO Energy requests authorization for Spark HoldCo (a subsidiary of Supplier Sector member Spark Energy) to acquire all of its membership interests
*	21	203 Application: Boston Energy/ Diamond Energy (EC18-64)	Mar 6	Boston Energy (NRG Related Person) requests authorization for Diamond Energy (a Mitsubishi wholly-owned subsidiary) to acquire all of its membership interests
	21	203 Application: NRG/GIP III Zephyr Acquisition Partners (EC18-61)	Mar 16	Dominion intervenes
	22	203 Application: Dynegy/Vistra (EC18-23)	Apr 4	FERC authorizes merger of Dynegy with and into Vistra
	22	203 Application: Calpine/ECP (EC17-182)	Mar 16	Calpine notifies FERC that the transaction was consummated on Mar 8
	22	MOPR-Related Proceedings (PJM, NYISO) (EL16-49; EL13-62)	Mar 14	EPSA moves to lodge PSEG 8-K information (related to cancellation of funding for capital projects at is Salem nuclear facility)

*	23	D&E Agreement: NSTAR/NGrid (ER18-1290)	Apr 3	NSTAR files Agreement; comment date Apr 24
*	23	MPD OATT Changes (ER18-1244)	Mar 30	Emera Maine files changes to MPD OATT; comment date Apr 20
*	23	IA: CL&P/Fusion Solar (ER18-1192)	Mar 27	Eversource files IA between CL&P and Fusion Solar; comment date Apr 17
*	23	Use Rights Transfer Agreement: CMEEC/NSTAR/Nalcor (ER18-1170)	Mar 23	NSTAR files Agreement for the transfer of CMEEC's Phase I/II HVDC Use Rights to Nalcor; comment date Apr 13
			Apr 3	National Grid intervenes
	24	NSTAR/WMECO Succession Proceedings (ER18-749/751)	Mar 9	FERC accepts succession filings
	24	IA Cancellation: Superseded NGrid/Casella Waste Systems IA (ER18-791)	Mar 12	FERC accepts cancellation, eff. Dec 21, 2016
	24	LGIAs: PSNH/GSP Newington/GSP White Lake /GSP Lost Nation (ER18-785, -786, -787)	Mar 27	FERC accepts LGIAs, eff. Jan 10, 2018

XII. Misc. - Administrative & Rulemaking Proceedings

	25	DER Participation in RTO/ISOs (AD18-10; RM18-9)	Mar 29	FERC issues supplemental notice of Apr 10-11 tech conf.
	25	Grid Resilience in RTO/ISOs; DOE NOPR (AD18-7; RM18-1)	Mar 8	Foundation for Resilient Societies requests rehearing of FERC order terminating DOE NOPR rulemaking proceeding (RM18-1)
			Mar 9	ISO-NE submits comments
			Mar 14	Trade Associations request 30-day extension of time
			Mar 20	FERC issues 30-day extension, to May 9, for comments
*	26	NOI: 2017 Tax Law Effect on FERC-Jurisdictional Rates (RM18-12)	Mar 15	FERC issues NOI; comment date May 21
*	27	NOPR: Pipeline Rates (RM18-11)	Mar 15	FERC issues NOPR; comment date Apr 25
	27	NOPR: Withdrawal of Pleadings (RM18-7)	Mar 27	FERC extends comment deadline to Mar 28; one comment filed addressing grammatical error
	28	*Order 841*: Electric Storage Participation in RTO/ISO Markets (RM16-23; AD16-20)	Mar 16-20	CAISO, MISO, PJM, the AES Companies, AMP/APPA/NRECA, California Energy Storage Alliance, EEI, NARUC, PG&E, TAPS, and Xcel Energy Services file requests for clarif. and/or rehearing
	30	*Order 842*: Primary Frequency Response - Essential Reliability Services and the Evolving Bulk-Power System (RM16-6)	Mar 16	PJM, AES Companies request rehearing, reconsideration of *Order 842*
			Mar 19	Arizona Public Service requests rehearing
			Mar 30	PJM Power Providers Group/EPSA answer PJM request for rehearing
			Apr 2-3	PJM Utilities Coalition and PJM IMM answer PJM request
	30	NOI: FERC's Policy for Recovery of Income Tax Costs & ROE Policies (PL17-1)	Mar 15	FERC revises its policy so that a Master Limited Partnership pipeline will no longer be permitted to recover an income tax allowance in its cost of service

XIII. Natural Gas Proceedings

	33	New England Pipeline Proceedings		
		• Atlantic Bridge Project (CP16-9)	Mar 20	FERC authorizes construction of Salem Pike, Needham, Pine Hills and Plymouth meter and regulating stations
		• Constitution Pipeline (CP18-5)	Mar 14	FERC issues tolling order affording it additional time to consider Constitution Pipelines' request for reh'g of Jan 11, 2018 order
	35	Non-New England Pipeline Proceed'gs		
		• Southeast Mrk't Pipelines Project (CP14-554, CP15-16, CP15-17)	Mar 14	FERC issues order on remand reinstating certificates of public convenience and necessity; dissents from LaFleur and Glick
		• Millennium Pipeline Valley Lateral Project (CP16-9)	Apr 4	FERC approves amendment to Nov 9, 2016 certificate of public convenience and necessity

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

*	39	Base ROE Complaint IV (2016) (18-1077)	Mar 15	TOs petition DC Circuit of Appeals for review of *Base ROE Complaint IV Orders*; Court orders initial submissions by Apr 16; dispositive motions and certified index to record, by Apr 30
	40	Demand Curve Changes (17-1110**)	Mar 28	Court orders that the Apr 13 argument panel will be Circuit Judge Wilkins, and Senior Circuit Judges Sentelle and Randolph
	40	NEPGA PER Complaint and FCM Jump Ball and Compliance Proceedings (16-1023/1024)	Mar 15	Court issues mandate

MEMORANDUM

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: April 4, 2018

RE: Status Report on Current Regional Wholesale Power and Transmission Arrangements Pending Before the Regulators, Legislatures and Courts

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through April 3, 2018. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **PER Settlement Agreement (ER17-2153; EL16-120)**

On February 20, the FERC approved[2] the Offer of Settlement and settlement materials ("PER Settlement") filed by the Settling Parties[3] to resolve the issue set for hearing and settlement judge procedures by the FERC in this proceeding.[4] Under the FERC-approved PER Settlement, ISO-NE will calculate Adjusted Hourly Strike Price as the sum of the daily Strike Price (as calculated under the existing Tariff) and a newly-defined Hourly PER Adjustment. The Hourly PER Adjustment will be equal to the average over each hour of a newly-defined Five-Minute PER Strike Price Adjustment. The Five-Minute Strike Price Adjustment[5] will be equal to any positive difference between a five-minute Thirty Minute Operating Reserves Clearing Price or Ten-Minute Non-Spinning Reserves Clearing Price that exceeds the maximum allowable reserves clearing

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[1] Capitalized terms used but not defined in this filing are intended to have the meanings given to such terms in the Second Restated New England Power Pool Agreement (the "Second Restated NEPOOL Agreement"), the Participants Agreement, or the ISO New England Inc. ("ISO" or "ISO-NE") Transmission, Markets and Services Tariff (the "Tariff").

[2] *New England Power Generators Assoc. v. ISO New England Inc.*, 162 FERC ¶ 61,144 (Feb 20, 2018), *clarif. requested* ("*PER Settlement Order*").

[3] PER "Settling Parties" are: NEPGA, NESCOE, the Retail Energy Supply Association ("RESA"), NEPOOL, Exelon, H.Q. Energy Services (U.S.) ("HQUS"), Eversource, Dominion, Entergy, NRG, and Cogentrix. Intervenors in the proceeding not opposing the Settlement ("Non-Opposing Intervenors") are: ISO-NE, PSEG, Consolidated Edison Energy, Inc. ("ConEd"), Verso Corp., GenOn Energy Management LLC, National Grid, NextEra, the New Hampshire Electric Coop. ("NHEC"), and Calpine.

[4] *See New England Power Generators Assoc., Inc. v. ISO New England Inc., 158 FERC ¶ 61,034 (Jan. 19, 2017) ("PER Complaint Order"), reh'g and clarif. denied, 161 FERC ¶ 61,193 (Nov. 16, 2017)* ("*PER Complaint Rehearing Order*"). The *PER Complaint Order* (i) granted in part NEPGA's complaint and (ii) set in part for hearing and settlement judge procedures the question of the appropriate method of calculating the PER Strike Price under Market Rule 1 Section III.13.7.2.7.1.1.1. The FERC found that "for the period at issue in NEPGA's complaint (September 30, 2016 – May 31, 2018), the PER mechanism has become unjust and unreasonable as a result of the interaction between the PER mechanism and the higher Reserve Constraint Penalty Factors." Accordingly, the FERC required ISO-NE to revise the method by which it calculates the PER Strike Price as set forth in Tariff section III.13.7.2.7.1.1.1. But, finding NEPGA's request that the PER Strike Price be increased by $250 per MWh "raises issues of material fact that cannot be resolved based upon the record before us and that are more appropriately addressed in the hearing and settlement judge procedures", the FERC set the question of for hearing and settlement judge procedures under section 206 of the FPA. The FERC established a refund effective date of September 30, 2016 (the date of the complaint). In establishing a September 30, 2016 effective date, the FERC clarified that "any changes to the calculation of the PER Strike Price under ISO-NE Tariff section III.13.7.2.7.1.1.1 would be prospective only from September 30, 2016, as required by FPA section 206, and would not impact the application of any PER Adjustment occurring before September 30, 2016."

[5] Five-Minute PER Strike Price Adjustment will be calculated according to the following formula: Five-Minute PER Strike Price Adjustment = MAX (Thirty Minute Operating Reserves Clearing Price - $500/MWh, 0) + MAX (Ten Minute Non-Spinning Reserves Clearing Price – Thirty Minute Operating Reserves Clearing Price - $850/MWh, 0).

prices for those reserves products (i.e., the Reserve Constraint Penalty Factors) in effect before December 2014.

Clarification Requested. As previously reported, the PER Settlement did not resolve the issues of the applicability of the Strike Price methodology to FCA9.[6] In its comments, in which it neither supported nor objected to the proposed PER strike price methodology, ISO-NE requested that the FERC resolve how the Average Monthly PER will be calculated on and after June 1, 2018. NESCOE asked the FERC to reject the position advocated by NEPGA that the agreed-upon Adjusted Hourly Strike Price as defined in the Settlement should extend beyond May 31, 2018. NEPGA, NRG, HQUS, Dominion, and Verso jointly asked the FERC to approve the Settlement and order ISO-NE to make a compliance filing, but decline to address NESCOE's request until some later date. In the *PER Settlement Order*, the FERC found the issues of the applicability of the Strike Price methodology to FCA9 beyond the scope of the settlement agreement proceeding.[7] On March 1, NESCOE requested clarification of the *PER Settlement Order* on this issue. NEPGA answered NESCOE's request on March 16.

Compliance Filing. ISO-NE was directed to make a compliance filing in eTariff format to reflect the FERC's action in the *PER Settlement Order*.[8] That compliance filing was submitted on March 22, 2018 (*see* ER18-1153 below). The FERC stated that the *PER Settlement Order* "terminates Docket Nos. EL16-120-000 and ER17-2153-000."[9]

If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com), Jamie Blackburn (202-218-3905; jblackburn@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Base ROE Complaint IV (2016) (EL16-64)**

On March 27, Judge Glazer issued his initial decision on this matter.[10] The *Base ROE IV Initial Decision*, which addresses EMCOS' Complaint that the TOs' return on equity ("ROE") used in the Tariff's formula rate revenue requirement is too high, concludes instead that the currently-filed base ROE of 10.57 %, which may reach a maximum ROE of 11.74 % with incentive adders, is ***not*** unjust and unreasonable, and hence is not unlawful under section 206 of the Federal Power Act ("FPA").[11] The *Base ROE IV Initial Decision* found that "Neither the Complainants nor Staff has met their burden to produce a properly-specified [Discounted Cash Flow ("DCF")] analysis that demonstrates the [TOs'] existing base ROE is unjust and unreasonable."[12] In light of those conclusions, the *Base ROE IV Initial Decision* finds it unnecessary to reach the issue of what a just and

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[6] In its *PER Complaint Rehearing Order*, the FERC clarified that it "intended for ISO-NE to use the difference between the former strike price and the LMP for event hours that occurred prior to September 30, 2016, and for ISO-NE to use the new strike price only for event hours that occur after September 30, 2016 … [t]he Commission's order is clear in that it addresses a change to the calculation of the PER strike price as set forth in section 111.13.7.2.7.1.1.1 and such change is prospective only."

[7] *PER Settlement Order* at P 3.

[8] While the *PER Settlement Order* acknowledged NEPOOL's s request that, "in order to accommodate participation in the stakeholder process for modifying the market rules, the Commission allow at least sixty days following any Settlement approval for ISO-NE to file tariff revisions to implement the Settlement," the *PER Settlement Order* is silent on the timing for the compliance filing directed. Pursuant to Rule 1907 of the FERC's Rules of Practice and Procedure, unless otherwise provided, "when any … person subject to the jurisdiction of the Commission is required to do or perform any act by Commission order, … there must be filed with the Commission within 30 days following the date when such requirement became effective, a notice, under oath, stating that such requirement has been met or complied with." 18 CFR § 385.1907.

[9] *PER Settlement Order* at P 4.

[10] *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 162 FERC ¶ 63,026 (Mar. 27, 2018) ("*Base ROE Complaint IV Initial Decision*").

[11] *Id.* at P 2.; Finding of Fact (B).

[12] *Id.* Finding of Fact (A).

reasonable alternative base ROE ought to be. Challenges to the *Base ROE IV Initial Decision* must be filed on or before April 26, 2018.

As previously reported, the 4th ROE Complaint asked the FERC to reduce the TOs' current 10.57% return on equity ("Base ROE") to 8.93% and to determine that the upper end of the zone of reasonableness (which sets the incentives cap) is no higher than 11.24%.[13] The FERC established hearing and settlement judge procedures (and set a refund effective date of April 29, 2016) for the 4th ROE Complaint on September 20, 2016.[14] Settlement procedures did not lead to a settlement, were terminated, and hearings were held subsequently held December 11-15, 2017. The September 26, 2016 order was challenged on rehearing, but rehearing of that order was denied on January 16, 2018.[15] The *Base ROE Complaint IV Orders*, as described in Section XV below, have been appealed to, and are pending before, the DC Circuit.

If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **Base ROE Complaints I-IV: TOs' Motion to Dismiss or Consolidate Complaints I-IV (EL16-64; EL14-86; EL13-33; EL11-66)**

The TOs' October 5, 2017 motion to dismiss all four ROE complaints (captioned above) in light of the DC Circuit's *Emera Maine*[16] decision remains pending. The October 5 motion alternatively requested that the FERC consolidate the four ROE complaints for decision and use expedited procedures to resolve them. The TOs stated that this motion was motivated in part by *Emera Maine*, but also by what they describe as the "enormous investment uncertainty" resulting from the various litigation proceedings. On October 20, Complainant-Aligned Parties and EMCOS submitted answers opposing TOs' requests. The TOs' motion and the motions filed in response remain pending before the FERC.

- **206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19)**

With the parties reportedly having reached a settlement in principle and memorializing their agreement, settlement judge procedures remain on-going. As previously reported, the FERC instituted this Section 206 proceeding on December 28, 2015, finding that the ISO-NE Tariff unjust, unreasonable, and unduly discriminatory or preferential because the Tariff "lacks adequate transparency and challenge procedures with regard to the formula rates" for Regional Network Service ("RNS") and Local Network Service ("LNS").[17] The FERC also found that the RNS and LNS rates themselves "appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful" because (i) "the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates" and "could result in an over-recovery of costs" due

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[13] EMCOS identified three main considerations requiring submission of the 4th ROE Complaint: (1) the continuing decline of the market cost of equity capital, which makes TOs' currently authorized ROE "excessive, unjust and unreasonable, and therefore ripe for adjustment under FPA Section 206"; (2) "divergent rulings concerning the persistence of the "anomalous" capital market conditions"; and (3) "the extent to which the Commission's anomalous conditions rationale in Opinion No. 531 is intended to reflect changes in its long-standing reliance on the discounted cash flow ("DCF") methodology, and particularly the DCF midpoint, for determining ROE remains unclear."

[14] *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 156 FERC ¶ 61,198 (Sep. 20, 2016) ("*Base ROE Complaint IV Order*"), *reh'g denied*, 162 FERC ¶ 61,035 (Jan. 18, 2018) (together, the "*Base ROE Complaint IV Orders*").

[15] *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 162 FERC ¶ 61,035 (Jan. 18, 2018) ("*Base ROE Complaint IV Rehearing Order*").

[16] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*"). *Emera Maine* vacated the FERC's prior orders in the Base ROE Complaint I proceeding, and remanded the case for further proceedings consistent with its order. The Court agreed with both the TOs (that the FERC did not meet the Section 206 obligation to first find the existing rate unlawful before setting the new rate) and "Customers" (that the 10.57% ROE was not based on reasoned decision-making, and was a departure from past precedent of setting the ROE at the midpoint of the zone of reasonableness).

[17] *ISO New England Inc. Participating Transmission Owners Admin. Comm.*, 153 FERC ¶ 61,343 (Dec. 28, 2015), *reh'g denied,* 154 FERC ¶ 61,230 (Mar. 22, 2016).

to the "the timing and synchronization of the RNS and LNS rates".[18] Accordingly, the FERC established hearing and settlement judge procedures to develop just and reasonable formula rate protocols to be included in the ISO-NE Tariff and to examine the justness and reasonableness of the RNS and LNS rates. The FERC encouraged the parties to make every effort to settle this matter before hearing procedures are commenced.[19] Hearings continue to be held in abeyance pending the outcome of settlement judge procedures underway.[20] The FERC-established refund date is January 4, 2016.[21]

Settlement Judge Procedures. As previously reported, John P. Dring was designated the Settlement Judge in these proceedings. Five settlement conferences were held in 2016: January 19, March 24, April 28, August 30, and November 18 (telephonically); four settlement conferences were held in 2017: April 5, May 9, July 7, and November 13, 2017; and two settlement conferences, on January 9 and February 1, in 2018. Judge Dring's most recent status report was issued on April 3, noting that the parties have reached a settlement in principle, and are memorializing their agreement. Accordingly, he recommended that settlement procedures be continued. The Transmission Committee is being kept apprised, as appropriate, of settlement efforts. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Base ROE Complaints II & III (2012 & 2014) (EL13-33 and EL14-86) (consolidated)**

Judge Sterner's findings and the *2012/2014 ROE Initial Decision*, and pleadings in response thereto, remain pending before the FERC. As previously reported, the FERC, in response to second (EL13-33)[22] and third (EL14-86)[23] complaints regarding the TOs' 11.14% Base ROE, issued orders establishing trial-type, evidentiary hearings and separate refund periods. The first, in EL13-33, was issued on June 19, 2014 and established a 15-month refund period of December 27, 2012 through March 27, 2014;[24] the second, in EL14-86, was issued on November 24, 2014, established a 15-month refund period beginning July 31, 2014,[25] and, because of "common issues of law and fact", consolidated the two proceedings for purposes of hearing and decision, with the FERC finding it "appropriate for the parties to litigate a separate ROE for each refund period."[26] The TOs requested rehearing of both orders. On May 14, 2015, the FERC denied rehearing of both orders.[27] On July 13, 2015, the TOs appealed those orders to the DC Circuit Court of Appeals (*see* Section XIV below), and that appeal continues to be held in abeyance.

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[18] *Id.* at P 8.

[19] *Id.* at P 11.

[20] *Id.*

[21] The notice of this proceeding was published in the *Fed. Reg.* on Jan. 4, 2016 (Vol. 81, No. 1) p. 89.

[22] The 2012 Base ROE Complaint, filed by Environment Northeast (now known as Acadia Center), Greater Boston Real Estate Board, National Consumer Law Center, and the NEPOOL Industrial Customer Coalition ("NICC", and together, the "2012 Complainants"), challenged the TOs' 11.14% return on equity, and seeks a reduction of the Base ROE to 8.7%.

[23] The 2014 Base ROE Complaint, filed July 31, 2014 by the Massachusetts Attorney General ("MA AG"), together with a group of State Advocates, Publicly Owned Entities, End Users, and End User Organizations (together, the "2014 ROE Complainants"), seeks to reduce the current 11.14% Base ROE to 8.84% (but in any case no more than 9.44%) and to cap the Combined ROE for all rate base components at 12.54%. 2014 ROE Complainants state that they submitted this Complaint seeking refund protection against payments based on a pre-incentives Base ROE of 11.14%, and a reduction in the Combined ROE, relief as yet not afforded through the prior ROE proceedings.

[24] *Environment Northeast v. Bangor Hydro-Elec. Co.*, 147 FERC ¶ 61,235 (June 19, 2014) ("*2012 Base ROE Initial Order*"), *reh'g denied,* 151 FERC ¶ 61,125 (May 14, 2015).

[25] *Mass. Att'y Gen. v. Bangor Hydro*, 149 FERC ¶ 61,156 (Nov. 24, 2014), *reh'g denied,* 151 FERC ¶ 61,125 (May 14, 2015).

[26] *Id.* at P 27 (for the refund period covered by EL13-33 (i.e., Dec. 27, 2012 through Mar. 27, 2014), the ROE for that particular 15-month refund period should be based on the last six months of that period; the refund period in EL14-86 and for the prospective period, on the most recent financial data in the record).

[27] *Environment Northeast, et al. v. Bangor Hydro-Elec. Co., et al. and Mass. Att'y Gen. et al. -v- Bangor Hydro et al.,* 151 FERC ¶ 61,125 (May 14, 2015).

Hearings and Trial Judge Initial Decision. Initial hearings on these matters were completed on July 2, 2015. In mid-December 2015, Judge Sterner reopened the record for the limited purpose of having the DCF calculations re-run in accordance with the FERC's preferred approach and re-submitted. A limited hearing on that supplemental information was held on February 1, 2016. On March 22, 2016, Judge Sterner issued his 939-paragraph, 371-page Initial Decision, which lowered the base ROEs for the EL13-33 and EL14-86 refund periods from 11.14% to 9.59% and 10.90%, respectively.[28] The *Initial Decision* also lowered the ROE ceilings. Judge Sterner's decision, if upheld by the FERC, would result in refunds totaling as much as $100 million, largely concentrated in the EL13-33 refund period. Briefs on exceptions were filed by the TOs, Complainant-Aligned Parties ("CAPs"), EMCOS, and FERC Trial Staff on April 21, 2016; briefs opposing exceptions, on May 20, 2016. Judge Sterner's findings and *Initial Decision*, and pleadings in response thereto, remain pending, and will be subject to challenge, before the FERC. The *2012/14 ROE Initial Decision* and its findings can be approved or rejected, in whole or in part.

If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings

- **VTransco Recovery of Highgate Ownership Share Acquition Costs (ER18-1259)**

On March 30, 2018, VTransco filed to recover, under the regional formula rate, $639,780 in costs, including property transfer taxes, closing fees, and advisory fees, related to its acquisition recent of Highgate Transmission Facility ownership shares.[29] VTransco stated that, absent FERC action, it would recover the expenses solely from Vermont customers (under its grandfathered 1991 Vermont Transmission Agreement ("VTA")). VTransco asserts that, because the costs are related to VTransco's acquisition of ownership shares in the Highgate Transmission Facility, a facility utilized solely to provide Regional Network Service, it is just and reasonable to allow VTransco to recover the Highgate Transaction costs through the ISO-NE Tariff formula rate, rather than through the VTA. VTransco requested its request for rate recovery become effective May 29, 2018. Comments on this filing are due on or before April 20. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **FCA12 Results Filing (ER18-940)**

On February 28, ISO-NE filed the results of the twelfth FCA ("FCA12") held February 5-6, 2018. ISO-NE reported the following highlights:

- ♦ FCA12 Capacity Zones were the Southeastern New England ("SENE") Capacity Zone (the Northeastern Massachusetts ("NEMA")/Boston, Southeastern Massachusetts, and Rhode Island Load Zones), the Northern New England ("NNE") Capacity Zone (the Maine, New Hampshire and Vermont Load Zones) and the Rest-of-Pool Capacity Zone (the Connecticut and Western/Central Massachusetts Load Zones)
- ♦ FCA12 commenced with a starting price of $12.684/kW-mo. and concluded for the SENE, NNE and Rest-of-Pool after four rounds.
- ♦ Resources will be paid as follows:
  - ‣ $4.631/kW-mo. – all Capacity Zones

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[28] *Environment Northeast v. Bangor Hydro-Elec. Co. and Mass. Att'y Gen. v. Bangor Hydro-Elec. Co,* 154 FERC ¶ 63,024 (Mar. 22, 2016) ("*2012/14 ROE Initial Decision*").

[29] *See Green Mountain Power Corp.*, 159 FERC ¶ 62,191 (May 19, 2017) (order authorizing VTransco's acquisition of Green Mountain Power's ("GMP") ownership share in the Highgate Facilities). Of the Joint Owners, GMP was the only FERC-jurisdictional public utility (the other Joint Owners were the City of Burlington Electric Department, Vermont Public Power Supply Authority ("VPPSA"), Vermont Electric Cooperative, Inc. ("VEC"), and the Village of Johnson Water and Light Department). In the 203 application, VTransco stated that the transfer will result in efficiencies in operation and management of the facility by VELCO.

    - $4.631/kW-mo. – NY AC Ties imports (524 MW) and Highgate (57 MW)
    - $3.701/kW-mo. - Phase I/II HQ Excess external interface (442 MW)
    - $3.155/kW-mo. – New Brunswick imports (194 MW)
- No resources cleared as Conditional Qualified New Generating Capacity Resources
- No Long Lead Time Generating Facilities secured a Queue Position to participate as a New Generating Capacity Resource
- 2 de-list bids (for Mystic 7 (575 MW) and Mystic 8 (703 MW)) were rejected for reliability reasons

ISO-NE asked the FERC to accept the FCA12 rates and results, effective June 28, 2018. Comments on this filing are due on or before April 13, 2018. Thus far, Dominion, Eversource, Exelon, National Grid, and NESCOE have filed doc-less interventions. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Emera MPD OATT Attachment J Revision (ER18-210)**

On February 15, the FERC accepted Emera's proposed revision to Attachment J of the Maine Public District ("MPD") OATT,[30] but established hearing & settlement judge procedures because its "preliminary analysis indicates that Emera Maine's proposed tariff revision has not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful."[31] The FERC suspend the tariff revision for a nominal period, to become effective January 1, 2018, as requested, subject to refund. As previously reported, the prosed tariff revision was to permit adjustments to formula rate inputs (historical load, revenue, sales data) to reflect "known and measurable" anticipated changes, subject to a true-up. Emera stated that, absent an ability to adjust its formula rate calculations to account for material losses of load, like that of Houlton Water Company expected to occur early next year, Emera Maine will suffer a significant under-recovery in its transmission revenue requirement. The Maine Customer Group ("MCG")[32] protested the revision for a number of reasons, with the principal objection being the fact that "Emera already has a true-up mechanism in place under the MPD OATT to accommodate loss of Houlton load".

Settlement Judge Procedures. On February 21, Chief Judge Cintron designated Judge John P. Dring as the Settlement Judge in these proceedings. On March 26, Settlement Judge Dring issued a status report indicating the parties have reached a settlement in principle and are memorializing their agreement, and recommending settlement judge procedures be continued. On March 30, Chief Judge Cintron issued an order continuing settlement judge procedures.

If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **TOs' *Opinion 531-A* Compliance Filing Undo (ER15-414)**

Rehearing remains pending of the FERC's October 6, 2017 order rejecting the TOs' June 5, 2017 filing in this proceeding.[33] As previously reported, the June 5 filing was designed to reinstate TOs' transmission rates to those in place prior to the FERC's orders later vacated by the DC Circuit's *Emera Maine*[34] decision. In its *Order Rejecting Filing*, the FERC required the TOs to continue collecting their ROEs currently on file, subject

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[30] *Emera Maine*, 162 FERC ¶ 61,131 (Feb. 15, 2018).

[31] *Id.* at P 24.

[32] MCG consists of consists of: Maine's Office of the Public Advocate ("MOPA"), Houlton Water Company ("Houlton"), Van Buren Light and Power District ("Van Buren"), and Eastern Maine Electric Cooperative, Inc. ("EMEC").

[33] *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*"), *reh'g requested*.

[34] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*").

to a future FERC order.[35] The FERC explained that it will "order such refunds or surcharges as necessary to replace the rates set in the now-vacated order with the rates that the Commission ultimately determines to be just and reasonable in its order on remand" so as to "put the parties in the position that they would have been in but for [its] error." For the time being, so as not to "significantly complicate the process of putting into effect whatever ROEs the Commission establishes on remand" or create "unnecessary and detrimental variability in rates," the FERC has temporarily left in place the ROEs set in *Opinion 531-A*, pending an order on remand.[36] On November 6, the TOs requested rehearing of the *Order Rejecting Filing*. On December 4, 2017, the FERC issued a tolling order providing it additional time to consider the TOs' request for rehearing of the *Order Rejecting Filing*, which remains pending. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **ISO Securities: Authorization for Future Drawdowns (ES18-25)**

On March 28, the ISO requested the necessary FERC authorization for drawdowns under a new $20 million Revolving Credit Line and a new $4 million line of credit supporting the Payment Default Shortfall Fund, each of which are with TDBank, are for a term of three years ending June 30, 2021, and replace similar arrangements that will expire June 30, 2018.[37] Comments on this filing are due on or before April 18. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

- **FCM Enhancements – Phase II (ER18-1287)**

On April 2, 2018, ISO-NE and NEPOOL filed changes to streamline and improve various aspects of the FCM rules, and in particular, the rules governing the FCA qualification process ("FCM Enhancements – Phase II"). Specifically, the FCM Enhancements - Phase II (i) streamline the process used to increase the capability of an Existing Capacity Resource; (2) revise ISO-NE processes that can delay the return of financial assurance to intermittent generating and energy efficiency resources that are operational and able to meet their Capacity Supply Obligations; (3) memorialize the existing process by which ISO-NE determines that a new resource has become operational such that it is appropriate to release its financial assurance; (4) make several additional improvements to the FCM qualification process; and (5) clarify existing language related to the retirement and Permanent De-Listing of capacity resources, and make a number of other minor changes. ISO-NE requested a June 1, 2018 effective date for most of the changes.[38] The FCM Enhancements – Phase II were supported by the Participants Committee at its March 2, 2018 meeting (under a combination of Consent Agenda Item # 2 and discussion agenda item #3). Comments on this filing are due on or before April 23, 2018. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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[35] *Order Rejecting Filing* at P 1.

[36] *Id.* at P 36.

[37] *See ISO New England Inc.*, 139 FERC ¶ 62,248 (June 22, 2012) (initially authorizing borrowings through June 30, 2014); *ISO New England Inc.*, 147 FERC ¶ 62,091 (May 6, 2014) (continuing authorization through June 30, 2015); *ISO New England Inc.*, 151 FERC ¶ 62,185 (June 15, 2015) (continuing authorization through June 30, 2017); *ISO New England Inc.*, 159 FERC ¶ 62,143 (May 9, 2017) (continuing authorization through June 30, 2019).

[38] A June 1, 2020 effective date was requested for the final sentence of revised Section III.13.6.1.5.3 ("The summer and winter commercial capacity of a Demand Capacity Resource consisting solely of Energy Efficiency measures may be verified in any month of the year") and for the revisions to revised Section III.13.6.1.5.4(g).

- **PFP Enhancements (ER18-1223)**

On March 30, 2018, ISO-NE and NEPOOL filed changes that enhance and clarify the Pay-For-Performance ("PFP") Market Rules ("PFP Enhancements"). Specifically, the PFP Enhancements (i) delete provisions that would, in certain circumstances, result in an inappropriate disconnect between a resource's capacity "base" payment and its capacity "performance" payment during a scarcity event; (ii) add detail regarding how the Actual Capacity Provided (a component used in determining a resource's capacity performance payment during a scarcity event) will be calculated for Demand Capacity Resources; (iii) revise how the Capacity Balancing Ratio (another component used in determining a resource's capacity performance payment during a scarcity event) will be determined in cases where more than one reserve requirement violation caused the scarcity event; and (iv) effect conforming and clean-up changes. ISO-NE requested a June 1, 2018 effective date (the date PFP is to be implemented). The PFP Enhancements were supported by the Participants Committee at its February 2, 2018 meeting (Consent Agenda Item # 4). Comments on this filing are due on or before April 20, 2018. Thus far, ConEd and Public Citizen have filed doc-less interventions. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **PER Settlement Compliance Filing (ER18-1153)**

On March 22, 2018, in accordance with the Commission-accepted PER Settlement Agreement, ISO-NE filed changes to Market Rule section 13.7.2.7.1.1.1 revising the methodology for calculating the PER Strike Price for the period September 30, 2016 through May 31, 2018 (the "Refund Period"). The revised language increases the Daily PER Strike Price for the Refund Period. ISO-NE requested the changes become effective as of September 30, 2016. The Markets Committee recommended that the Participants Committee support the Compliance Changes, and the Compliance Changes will be considered by the Participants at the April 6 meeting (Consent Agenda Item #1). Comments on this filing are due on or before April 12, 2018. Thus far, ConEd, National Grid and NESCOE have filed doc-less interventions. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Real-Time Reserve Designation & Settlement Rule Changes (ER18-897)**

On March 29, the FERC accepted changes jointly filed by ISO-NE and NEPOOL that differentiate between Operating Reserve requirements and the reserve products used to satisfy those requirements and add details about how Operating Reserve is designated to individual resources in the operation of the Real-Time Energy Market. Specifically, the changes (i) enhance the differentiation between reserve requirements and the reserve products that can be used to meet those requirements; (ii) add detail as to how reserves are designated for individual resources in the operation of the Real-Time Energy Market; (iii) restructure and clarify the financial settlement for resources providing Real-Time Reserves; and (iv) implement a handful of clean-up and conforming edits to the Tariff. The changes were accepted, as requested, effective as of June 1, 2018. Unless the March 29 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **CSO Termination: Blue Sky West (ER18-704)**

As previously reported, ISO-NE filed on January 23, pursuant to Market Rule 1 § 13.3.4(c), to involuntarily terminate a portion of the CSO held by Project Sponsor Blue Sky West ("BSW") for Resource No. 37105 -- BSW's Bingham, ME wind generation facility. ISO-NE explained that the involuntary termination was for the portion of the CSO that had not achieved commercial operation and had not been covered by BSW. ISO-NE reported that it terminated the portion of the CSO for the FCA8 through FCA11 Capacity Commitment Periods concurrently with the termination filing. ISO-NE indicated that, upon FERC acceptance of the filing, it would draw down the amount of financial assurance provided by BSW with respect to the portion of the CSO to be terminated.

Emergency Motion to Reinstate Terminated MWs. On January 29, BSW filed an emergency motion asking the FERC to immediately reinstate the portion of BSW's CSO involuntarily terminated by ISO-NE on Jan 23 ("Disputed MWs") pending resolution of this CSO Termination Filing. The Emergency Motion presented a threshold issue of first impression, namely whether the involuntary termination of all or a portion of a CSO may become effective upon ISO-NE submission of an involuntary termination filing with the FERC (as ISO-NE asserted) or upon resolution of the involuntary termination filing (as Blue Sky West asserted). The distinction impacted the MWs with which Blue Sky West was eligible to participate in FCA12. ISO-NE answered the Emergency Motion on January 31. NEPOOL also submitted limited comments prior to the FERC-imposed February 1, 10am deadline for answers to the Emergency Motion (noting that the FERC needed to resolve the dispute between ISO-NE and BSW, and that, should the FERC conclude the Tariff required additional clarity, those changes be permitted to be proposed using the established NEPOOL Participant Processes). The FERC granted the Emergency Motion on February 2.[39] In directing the Disputed MWs be reinstated through March 24, 2018 (the end of the 60-day notice period required under FPA § 205), the FERC found that the filing, and ISO-NE's right to involuntarily terminate the Disputed MWs, could not be made, absent waiver, prior to March 24, 2018.

On the Merits of the Involuntary Termination of the Disputed MWs. On February 13, BSW protested the termination of the Disputed MWs. BSW asserted that CPS monitoring requirements for the as-built portion of its resource terminated when that portion of the resource achieved Commercial Operation on December 13, 2016 and, as a result, BSW was not required to cover any MW up to the as-built CSO after that time. BSW further argued that, should the FERC find that ISO-NE had the discretion to terminate the Disputed MWs based on more recent Seasonal Claimed Capability audit results, it would be unjust and unreasonable to do so in this case (particularly given the unseasonably low wind resource period during the ISO-NE-selected audit period, and ISO-NE's pending revisions to ISO-NE audit procedures). ISO-NE answered BSW's protest on March 1, 2018. Doc-less motions to intervene were filed by National Grid, NextEra and NRG/GenOn.

Partial CSO Termination Accepted. On March 23, the FERC accepted the involuntary termination of the portion of BSW's CSO requested by ISO-NE, effective March 24, 2018.[40] In accepting the termination, the FERC concluded that "ISO-NE reasonably interpreted the Tariff to allow for the partial termination of the Facility's unfulfilled CSO, as determined by the Facility's Seasonal Claimed Capability audit."[41] The FERC found that neither achieving "Commercial Operation" nor fulfilling "Critical Path Schedule milestones" precludes ISO-NE from terminating a resource's CSO under section III.13.3.4(c). "If there is an amount of energy that a resource is incapable of producing short of its CSO, it is reasonable that such portion of the resource would be eligible for termination under section III.13.3.4(c)."[42] The FERC also clarified its interpretation of the section addressing involuntary termination of all or a portion of a CSO (section III.13.3.4(c)). In short, the FERC held that a "section 205 filing is necessary to obtain a 'Commission ruling' on *any* aspect of an involuntary termination" prior to termination.[43] And, absent waiver, an involuntary termination of all or a portion of a CSO cannot be made effective prior to the end of the statutory 60-day notice period.

Unless the *Blue Sky West CSO Termination Order* is challenged, with any challenges due on or before April 23, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Updated Dynamic De-List Bid Threshold (ER18-620)**

On March 9, the FERC accepted changes that reduce the FCM Dynamic De-List Bid Threshold ("DDBT"),[44] beginning with FCA13, to \$4.30/kW-mo.[45] The lower DDBT was accepted effective as of March 9, 2018 (coincident

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[39] *ISO New England Inc.*, 162 ¶ 61,088 (Feb. 2, 2018).

[40] *ISO New England Inc.*, 162 FERC 61,265 (Mar. 23, 2018) ("*Blue Sky West CSO Termination Order*").

[41] *Id.* at P 25.

[42] *Id.* at P 26.

[43] *Id.* at P 29.

[44] The FCM Dynamic De-List Bid Threshold is an IMM-established value below which existing resources that have chosen to be price takers in an Forward Capacity Auction ("FCA") can opt to leave the auction without further review by the IMM. The Dynamic De-List Bid Threshold is designed to prevent the exercise of market power by maximizing the likelihood that the IMM reviews the pricing

with the start of the FCA13 qualification period), as requested. In accepting the lower threshold, the FERC stated that it need not find the proposed DDBT "the only reasonable methodology, or even the most accurate, but rather [just] that the methodology is just and reasonable."[46] It found the proposed DDBT just and reasonable. In response to protests, the FERC stated that "the fact that the IMM used different data than it has used in the past to calculate the [DDBT] does not, on its own, render ISO-NE's filing unjust and unreasonable" finding reasonable the IMM's alternative approach – the use of proxy bids."[47] The FERC disagreed with NEPGA's argument that the DDBT inappropriately sends a signal that bids above the threshold will not clear[48] and found arguments that the DDBT would exacerbate certain issues with ISO-NE's Static De-List Bid process beyond the scope of the proceeding.[49] Challenges, if any, to the *DDBT Order* are due on or before April 9. Unless the *DDBT Order* is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **CASPR (ER18-619)**

Also on March 9, the FERC accepted ISO-NE's Competitive Auctions with Sponsored Policy Resources ("CASPR") revisions.[50] The CASPR revisions were effective March 9, 2018 (with the exception of revisions to Section III.13.7 that are to become effective June 1, 2018).

Highlights from the *CASPR Order* included the following:

- ♦ ***Overall***. Guided by what the Order describes as "the first principles of capacity markets," the FERC found "ISO-NE's proposal to be an acceptable means of managing the impact of state policies in the New England region while maintaining just and reasonable rates."[51]
- ♦ ***Sponsored Policy Resource Definition***. The FERC found that the definition of Sponsored Policy Resource "does not unduly discriminate against resources that do not fit within that definition because those two classes of resources are not similarly situated."[52]
- ♦ ***Auction Design***. The FERC found the proposed auction design to be just and reasonable, persuaded by the ISO's arguments that requiring new, non-sponsored resources to participate in the substitution auction could discourage development of those resources, and that allowing new non-sponsored resources to participate in the substitution auction introduces concerns about fictitious entry that are difficult to address while still supporting the FCM's key function of attracting and sustaining investment in new capacity when needed.[53] While acknowledging that allowing existing resources to submit spread bids in the substitution auction (spread bidding) could present existing resources with an alternative way to express their willingness to exit the market at a specific severance payment amount, and thus could enhance liquidity in the substitution auction, the Order found such an allowance unnecessary for CASPR to be a just and reasonable means to

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competitiveness of all bids from existing resources in a position to increase the clearing price (exercise market power) by leaving the FCA. The Tariff requires that the threshold price be re-set no less than once every three years. In the January 8 filing, ISO-NE committed to recalculate the Dynamic De-List Bid Threshold for FCA15 to reflect the change in the Capacity Performance Payment Rate scheduled to be in place for FCA15.

[45] *ISO New England Inc. and New England Power Pool Participants Comm.*, 162 FERC ¶ 61,206 (Mar. 9, 2018) ("*DDBT Order*").

[46] *Id.* at P 33.

[47] *Id.* at P 34.

[48] *Id.* at P 38.

[49] *Id.* at P 39.

[50] *ISO New England Inc.*, 162 FERC ¶ 61,205 (Mar. 9, 2018) ("*CASPR Order*").

[51] Id. at P 22.

[52] Id. at P 45.

[53] Id. at P 74.

accommodate the exit of certain existing resources and the entry of new Sponsored Policy Resources into the FCM over time.[54] The FERC found it reasonable for load to assume additional costs associated with balancing the goals of providing Sponsored Policy Resources an opportunity to receive CSOs with the FCM's need to secure private investment in the long term.[55]

- ♦ ***Offer Behavior and Market Power***. The FERC agreed with the ISO that the likelihood and potential price impact of bid shading (lowering bids in the primary auction to improve the probability of retaining CSOs that would be bought out in the substitution auction) will be mitigated by various factors and does not render the changes unjust and unreasonable. Nevertheless, the FERC encouraged the ISO to work with its stakeholders to pursue market enhancements that will further protect against potentially uncompetitive market results.[56] The FERC disagreed with the position that demand-side market power in the substitution auction may render ISO-NE's proposal unjust and unreasonable.[57]
- ♦ ***Renewable Technology Resource ("RTR") Exemption Phase Out***. The FERC accepted the RTR exemption phase out, finding the transition proposal "a balanced approach for implementing CASPR's alternative means of accommodating state policies, while attenuating any potential adverse impacts on pending investments that could result from an immediate change to the market rules."[58]
- ♦ ***Other Issues***. The FERC disagreed with arguments that CASPR's restriction on inter-zonal CSO transfers is not just and reasonable, or that CASPR will increase the region's dependence on natural gas-fired generation and exacerbate current fuel security concerns. The FERC found unnecessary requests that it require periodic filings on ways to improve, or take additional actions with respect to, CASPR or the FCM.[59]
- ♦ ***MOPR***. Of general but particular interest, and specifically challenged in the separate concurrences/dissents of Commissioners LaFleur and Glick, is the *CASPR Order*'s discussion of the Minimum Offer Price Rule ("MOPR"). The *CASPR Order* states that, "absent a showing that a different method would appropriately address particular state policies, [the FERC] intend[s] to use the MOPR to address the impacts of state policies on the wholesale capacity markets." And, while the MOPR will be used "as our standard solution, we will consider supplemental or alternative proposals to manage the impact of state policies, provided that those proposals are sufficiently consistent with the above-mentioned principles of capacity markets."[60]

The *CASPR Order* included a concurrence in part from Commissioner LaFleur, a concurrence in part and dissent in part from Commissioner Glick, and a dissent from Commissioner Powelson.

- ♦ ***LaFleur***. In her concurrence in part, Commissioner LaFleur strongly supported the FERC's approval of CASPR, but noted her disagreement with the generic guidance set forth in the order regarding how the FERC intends to address the impacts of state policies on the wholesale capacity markets, which she explained was "not directly pertinent to the CASPR proposal, and in my view is not necessary to support the [*CASPR Order*]". Commissioner LaFleur stated her intent to "closely monitor the effectiveness of this market construct in practice" and her appreciation for "ISO-NE's commitment to continue to work with stakeholders on the definition of sponsored policy resources if state laws and regulations change."

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[54] Id. at P 77.

[55] Id. at P 78.

[56] Id. at P 85.

[57] Id. at P 86.

[58] Id. at P 99.

[59] Id. at PP 115-122.

[60] Id. at P 22.

- ♦ ***Glick***. In his concurrence in part and dissent in part, Commissioner Glick agreed with the decision to accept the CASPR proposal, but disagreed strongly with the *CASPR Order*'s suggestion that state sponsored resources must either be subject to a MOPR or some alternative mechanism for "accommodating" the effects of state public policies, finding that rationale "ill-conceived, misguided, and a serious threat to consumers, the environment and … the long-term viability of the [FERC]'s capacity market construct." He expressed his concern that a "broad application of the MOPR usurps the authority over generation resource decisions that Congress left to the states when it enacted the Federal Power Act" and should be applied "in only the limited circumstance for which it was originally intended: to prevent the exercise of buyer-side market power."
- ♦ ***Powelson***. In his dissent, Commissioner Powelson found that the two goals that CASPR tries to achieve (allowing states to accomplish certain policy goals, while also protecting the viability of the FCM) are fundamentally in conflict, cannot coexist in one market and CASPR will likely only accomplish one goal at the expense of the other. In his view, the CASPR proposal "will not provide a meaningful [price] signal to the market place" and may send a message "that the best way to ensure the future viability of a particular resource is to seek state support." He acknowledged that states "are entitled to procure any resources they prefer," but "if states do want to be in control of those choices, they should also assume the responsibility for resource adequacy and reliability." Commissioner Powelson ultimately opined that the *CASPR Order* "threatens the viability of the FCM to serve as a mechanism to ensure resource adequacy in ISO-NE, and therefore, it is unjust and unreasonable and should be rejected."

Challenges to the *CASPR Order* are due on or before April 9, 2018. If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ART Market Rule Changes (ER18-455)**

On February 28, 2018, the FERC accepted changes that established a new capacity market bilateral transaction, an Annual Reconfiguration Transaction ("ART"), and made other changes to the FCM rules ("ART Market Rule Changes"). Most of the changes became effective on March 1, 2018, with the remainder to become effective on June 1, 2018. The February 28 order was not challenged and is final an unappealable. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **CONE & ORTP Updates (ER17-795)**

Rehearing remains pending of the FERC's October 6 order accepting updated FCM Cost of New Entry ("CONE"), Net CONE and Offer Review Trigger Price ("ORTP") values filed by ISO-NE in January.[61] In accepting the changes, the FERC disagreed with the challenges to ISO-NE's choice of reference technology (gas-fired simple cycle combustion-turbine) and on-shore wind capacity factor (32%). The changes were accepted effective as of March 15, 2017, as requested. On November 6, NEPGA requested rehearing of the *CONE/ORTP Updates Order*. On December 4, 2017, the FERC issued a tolling order providing it additional time to consider NEPGA's request for rehearing of the *CONE/ORTP Updates Order*, which remains pending. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **2013/14 Winter Reliability Program Remand Proceeding (ER13-2266)**

Still pending before the FERC is ISO-NE's compliance filing in response to the FERC's August 8, 2016 remand order.[62] In the *2013/14 Winter Reliability Program Remand Order*, the FERC directed ISO-NE to

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[61] *ISO New England Inc.*, 161 FERC ¶ 61, 035 (Oct. 6, 2017)("*CONE/ORTP Updates Order*"), *reh'g requested*.

[62] *ISO New England Inc.*, 156 FERC ¶ 61,097 (Aug. 8, 2016) ("*2013/14 Winter Reliability Program Remand Order*"). As previously reported, the DC Circuit remanded the FERC's decision in ER13-2266, agreeing with TransCanada that the record upon which the FERC relied

request from Program participants the basis for their bids, including the process used to formulate the bids, and to file with the FERC a compilation of that information, an IMM analysis of that information, and the ISO's recommendation as to the reasonableness of the bids, so that the FERC can further consider the question of whether the Bid Results were just and reasonable.[63] ISO-NE submitted its compliance filing on January 23, 2017, reporting the IMM's conclusion that "the auction was not structurally competitive and a 'small proportion' of the total cost of the program may be the result of the exercise of market power" but that the "vast majority of supply was offered at prices that appear reasonable and that, for a number of reasons, it is difficult to assess the impact of market power on cost." Based on the IMM and additional analysis, ISO-NE recommended that "there is insufficient demonstration of market power to warrant modification of program." In February 13 comments, both TransCanada and the MA AG protested ISO-NE's conclusion and recommendation that modification of the program was unwarranted. TransCanada requested that FERC establish a settlement proceeding where market participants could "exchange confidential information to determine what the rates should be" and refunds and "such other relief as may be warranted" provided. On February 28, ISO-NE answered the TransCanada and MA AG protests. On March 10, 2017, TransCanada answered ISO-NE's February 28 answer. This matter is pending before the FERC. If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

No Activity to Report

V. Financial Assurance/Billing Policy Amendments

- **FCM Monthly Capacity Charge & Energy Efficiency Changes (ER18-944)**

On March 1, 2018, ISO-NE and NEPOOL jointly filed changes to the Financial Assurance Policy ("FAP") to (i) include both positive and negative monthly capacity payments in the monthly capacity charge ("MCC") component of the FCM Delivery Financial Assurance ("FA") formula (potentially reducing FA requirements; (ii) to exclude from the calculation of PFP-related FA during the months of February through May and September through November the CSOs associated with Energy Efficiency ("EE") measures (as they are unable to receive negative Capacity Performance Payments); and (iii) reflect additional clean-up and conforming revisions. The MCC and EE changes were supported by the Participants Committee at the November 3, 2017 and January 5, 2018 meetings, respectively. Comments on this filing were due on or before March 22, 2018; none were filed. Eversource and National Grid (out-of-time) filed doc-less interventions. On April 3, the FERC accept the changes, effective as of June 1, 2018, as requested. Unless the April 3 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

VI. Schedule 20/21/22/23 Changes

- **Schedule 21-EM: BHD Tax Law & Settlement Changes (ER18-1213)**

On March 29, 2018, Emera Maine filed changes to the Emera Maine, Bangor-Hydro District ("BHD") Formula Rate to reflect: (i) the reduction to the marginal corporate income tax rate resulting from the 2017 Tax Law and the 2017 Annual Update Settlement Agreement (*see* ER18-960 below) and (ii) recent IRS guidance regarding tax normalization accounting for ratemaking. Comments on this filing are due on or before April 19,

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is devoid of any evidence regarding how much of the 2013/14 Winter Reliability Program cost was attributable to profit and risk mark-up (without which the FERC could not properly assess whether the Program's rates were just and reasonable), and directing the FERC to either offer a reasoned justification for the order in ER13-2266 or revise its disposition to ensure that the Program rates are just and reasonable. *TransCanada Power Mktg. Ltd. v. FERC,* 2015 U.S. App. LEXIS 22304 (D.C. Cir. 2015).

[63] *2013/14 Winter Reliability Program Remand Order* at P 17.

2018. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-EM: Brookfield LSA (ER18-901)**

On February 23, 2018, ISO-NE and Emera filed a non-conforming three-party Local Service Agreement ("LSA") between Brookfield Energy Marketing, LP ("Brookfield"), Emera Maine and ISO-NE for Firm Local Point-to-Point Service under Schedule 21-EM. Under the LSA, Emera Maine will continue to provide 85 MW of firm, point-to-point transmission service from its Powersville Road Substation at the $13.82/kW-yr. rate set forth in a 2003 transmission service agreement that will expire May 16, 2018. On March 5, the Filing Parties submitted a corrected transmittal letter to correct certain errors regarding the physical configuration of Emera Maine's lines and substations. No comments on this filing were submitted and this filing is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-ES: PSNH/VEC LSA (ER18-745)**

On March 6, the FERC accepted the non-conforming three-party Local Service Agreement ("LSA") between Vermont Electric Cooperative ("VEC"), PSNH and ISO-NE for Non-Firm Local Point-to-Point Service filed under Schedule 21-ES. The LSA is non-conforming in that it contains provisions reflecting a long-standing agreement between PSNH and VEC to provide each other with back-up transmission service. The LSA was accepted effective as of January 1, 2018, as requested. Unless the March 6 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-EM: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434 et al.)**

On June 2, 2016, the FERC accepted, but established hearing and settlement judge procedures for,[64] March 31 filings by Emera Maine in which Emera Maine sought authorization to recover certain merger-related costs viewed by the FERC's Office of Enforcement's Division of Audits and Accounting ("DAA") to be subject to the conditions of the orders authorizing Emera Maine's acquisition of, and ultimate merger with, Maine Public Service ("Merger Conditions"). As previously reported, the Merger Conditions imposed a hold harmless requirement, and required a compliance filing demonstrating fulfillment of that requirement, should Emera Maine seek to recover transaction-related costs through any transmission rate. Following its recent audit of Emera Maine, DAA found that Emera Maine "inappropriately included the costs of four merger-related capital initiatives in its formula rate recovery mechanisms" and "did not properly record certain merger-related expenses incurred to consummate the merger transaction to appropriate non-operating expense accounts as required by [FERC] regulations [and] inappropriately included costs of merger-related activities through its formula rate recovery mechanisms" without first making a compliance filing as required by the merger orders.

In the *June 2 Order*, the FERC found that the Compliance Filings raise issues of material fact that could not be resolved based on the record, and are more appropriately addressed in the hearing and settlement judge procedures.[65] The FERC reiterated several points with respect to transaction-related cost recovery explained in prior FERC orders and provided guidance on other transaction-related cost recovery points.[66] The FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and will hold the hearing in abeyance pending the outcome of settlement judge procedures.[67]

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[64] *Emera Maine and BHE Holdings*, 155 FERC ¶ 61,230 (June 2, 2016) ("*June 2 Order*").

[65] *Id.* at P 24.

[66] *Id.* at PP 25-26.

[67] *Id.* at P 27.

The separate compliance filing dockets were consolidated for the purposes of settlement, hearing and decision.[68]

Settlement Judge Procedures. ALJ John Dring is the settlement judge for these proceedings. There have been five settlement conferences: three in 2016 -- June 29, October 25, and December 1; and two in 2017 -- September 6 and November 9, 2017. In his most recent March 26, 2018 status report, Judge Dring indicated that the parties have reached a settlement in principle, and are memorializing their agreement. Accordingly, he recommended that settlement judge procedures be continued.

Hearing Procedures? On October 11, Emera Maine requested that the Chief Judge establish an expedited hearing under specific terms and conditions set forth in Exhibit A to its October 11 motion ("Expedited Hearing"). The October 11 motion also asked that the answer period to its request be shortened to five days and that an order ruling on the motion be issued no later than October 18, 2017. On October 13, the Maine Customer Group, MPUC, ReEnergy Biomass Operations LLC, and FERC Trial Staff (collectively, "Intervenors and FERC Trial Staff"), filed an answer opposing the October 11 motion's request for a shortened answer period. On October 13, Chief Judge Cintron issued an order ("October 13 Order") which denied the request to shorten the answer period and identified additional questions that all participants in the proceeding were permitted the opportunity to address in their answers to the October 11 motion. Responses to the October 13 Order were filed by Emera Maine, Maine PUC/OPA, Maine Customer Group, and FERC Trial Staff ("October 26 Responses"). On November 13, Emera Maine responded to the October 26 Responses. The October 11 motion, October 26 Responses and Emera Maine's answer to the October 26 Responses are pending before Chief Judge Cintron.

If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-EM 2017 Annual Update (ER15-1434) Settlement Agreement (ER18-960)**

Emera Maine submitted its 2017 annual informational filing updating its local transmission service charges under Schedule 21-EM on June 6, 2017 ("2017 Annual Update"). On October 20, 2017, the MPUC challenged the application of the Attachment J Formulas under the "Protocols for Implementing and Reviewing Charges Established by the Attachment J Formulas". Since that challenge was filed, Emera Maine and the MPUC engaged in settlement discussions regarding the MPUC's challenge. On March 2,[69] Emera Maine made two filings in connection with those settlement efforts. First, it filed in ER15-1434 a corrected version of the spreadsheet submitted with the 2017 Annual Update showing Emera Maine's charges under Schedule 21-EM for the June 1, 2017 to May 31, 2018 rate year. Second, Emera Maine filed, in ER18-960, a settlement agreement that required the filing of the corrected spreadsheet, and included a commitment by Emera Maine to make a Section 205 filing by March 31, 2018 containing "such changes to the Attachment J Formulas, effective June 1, 2018, as necessary to reflect the [federal Tax Cuts and Jobs] Act's reduction to the marginal corporate income tax rate." [The settlement changes were filed on March 29 (*see* ER18-1213 above)] Comments on the Settlement Agreement were due on or before March 27; none were filed. The MPUC filed a doc-less intervention. The Settlement Agreement is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-VEC: VEC/PSNH LSA (NJ18-10)**

On March 6, the FERC accepted the non-conforming, three-party LSA between VEC, PSNH and ISO-NE for Non-Firm Local Point-to-Point Service under Schedule 21-VEC filed by ISO-NE and VEC. As previously reported, the LSA is non-conforming in that it contains provisions reflecting a long-standing agreement

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[68] *Id.* at P 21; Ordering Paragraph (B).

[69] The FERC was closed on Friday, March 2 due to the Nor'easter that hit Washington that day. Accordingly, the official filing date for all March 2 submissions was March 5, 2017, the first business day the FERC was open for business following the closure.

between PSNH and VEC to provide each other with back-up transmission service. The Agreement was docketed in an "NJ" docket due to VEC's representation that it is not a public utility subject to the obligations of Section 205 of the FPA. VEC asked that, if the filing of this rate schedule was not required (because, although VEC is the provider of service, VEC is not a public utility and the rates and charges for service do not affect regional service provided or are not collected by ISO-NE), the FERC reject the filing as moot or alternatively, give further guidance on how such agreements that are non-conforming should be handled in the future. The March 6 letter order did not address this request. The LSA was accepted, however, effective as of January 1, 2018, as requested. Unless the March 6 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

- **Capital Projects Report - 2017 Q4 (ER18-841)**

On March 23, the FERC accepted ISO-NE's Capital Projects Report and Unamortized Cost Schedule covering the fourth quarter ("Q4") of calendar year 2017 (the "Report"). As previously reported, the Q4 Report, which ISO-NE was required to file under Section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff, included the following new projects: (i) FCM Improvements ($965,000); (ii) Photovoltaic & Load Forecasting ($878,400); (iii) Intranet Platform Replacement ($855,000); and (iv) Mobile Application Project ($357,700). Projects with a significant changes were (i) FCA13 (2018 Budget decrease of $2 million (to be re-chartered/budgeted as "Annual Reconfiguration Transactions") - total project cost of $0); (ii) CASPR (2018 Budget decrease of $1.27 million; total project cost $1.73 million); (iii) 2018 Issue Resolution Phase II (2018 Budget of $750,000; project removed); (iv) IMM Data Analysis Phase II (2018 Budget decrease of $700,000, for total project costs of $600,000); and (v) CIMNET Simultaneous Feasibility Test with Data Transfer Enhancements (2017 Budget decrease of $204,600, with total estimated project cost remaining at $2.26 million). Unless the March 23 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- ***Opinion 531-A* Local Refund Report: FG&E (EL11-66)**

FG&E's June 29, 2015 refund report for its customers taking local service during *Opinion 531-A's* refund period remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Opinions 531-A/531-B* Regional Refund Reports (EL11-66)**

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by ISO-NE in compliance with *Opinions No. 531-A*[70] *and 531-B*[71] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Opinions 531-A/531-B* Local Refund Reports (EL11-66)**

The *Opinions 531-A and 531-B* refund reports filed by the following TOs for their customers taking local service during the refund period also remain pending before the FERC:

♦ Central Maine Power ♦ National Grid ♦ United Illuminating

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[70] *Martha Coakley, Mass. Att'y Gen.*, 149 FERC ¶ 61,032 (Oct. 16, 2014) ("*Opinion 531-A*").

[71] *Martha Coakley, Mass. Att'y Gen.*, Opinion No. 531-B, 150 FERC ¶ 61,165 (Mar. 3, 2015) ("*Opinion 531-B*").

- ♦ Emera Maine
- ♦ Eversource
- ♦ NHT
- ♦ NSTAR
- ♦ VT Transco

If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Reserve Market Compliance (24th) Semi-Annual Report (ER06-613)**

As directed by the original ASM II Order,[72] as modified,[73] ISO-NE submitted its 24th semi-annual reserve market compliance report on April 2, 2018. In the 24th report, ISO-NE explained, as in its prior compliance reports, that work on the forward TMSR market issues continues to be on hold due to its efforts on other priority projects. ISO-NE reported that it does not contemplate revisiting this issue until at least 2019. If there are questions on this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com).

- **ISO-NE FERC Form 715 (not docketed)**

On March 27, the ISO submitted its 2017 Annual Transmission Planning and Evaluation Report. These filings are not noticed for filing.

IX. Membership Filings

- **April 2018 Membership Filing (ER18-1235)**

On March 29, NEPOOL requested that the FERC accepted the termination of the Participant status of Phoenix Energy New England (Supplier Sector). Comments on this filing are due on before April 19.

- **March 2018 Membership Filing (ER18-923)**

On March 28, the FERC accepted (i) the memberships of Bruce Power [Related Person to TransCanada Power Marketing (Supplier Sector)], CS Berlin Ops [Related Person to Berlin Station (Generation Sector Group Seat)], HSE Hydro NH AC [Related Person to Nautilus Hydro and Pawtucket Power (Generation Sector Group Seat)], and Optik Energy (Supplier Sector); and (ii) the termination of the Participant status of Cargill Power Markets (Supplier Sector) and RBC Energy Services [Related Person to Royal Bank of Canada (Supplier Sector)]. Unless the March 28 order is challenged, this proceeding will be concluded.

- **February 2018 Membership Filing (ER18-767)**

On March 29, the FERC accepted the termination of the Participant status of Emera Energy Services Subsidiaries Nos. 10, 13 and 14 [Related Persons to Emera Maine (Transmission Sector)]; Epico USA (AR Sector RG Sub-Sector, Small RG Group members); Shipley Choice (Supplier Sector); and WMECO [former Related Person to Eversource (Transmission Sector)]. Unless the March 29 order is challenged, this proceeding will be concluded.

- **Suspension Notices (not docketed)**

Since the last Report, ISO-NE filed, pursuant to Section 2.3 of the Information Policy, a notice with the FERC noting that the following Participants were suspended from the New England Markets on the date indicated (at 8:30 a.m.) due to a Payment Default:

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[72] *See NEPOOL and ISO New England Inc.*, 115 FERC ¶ 61,175 (2006) ("*ASM II Order*") (directing the ISO to provide updates on the implementation of a forward TMSR market), *reh'g denied* 117 FERC ¶ 61,106 (2006).

[73] *See NEPOOL and ISO New England Inc.*, 123 FERC ¶ 61,298 (2008) (continuing the semi-annual reporting requirement with respect to the consideration and implementation of a forward market for Ten-Minute Spinning Reserve ("TMSR")).

Date of Suspension/ FERC Notice	*Participant Name*	*Date Reinstated*
Mar 7/9	Indeck Energy-Alexandria	Mar 16
Mar 7/9	Manchester Methane	Mar 16
Mar 7/9	Chris Anthony	Mar 16
Mar 14/16	University System of New Hampshire	Mar 16

Suspension notices are for the FERC's information only and are not docketed or noticed for public comment.

X. Misc. - ERO Rules, Filings; Reliability Standards

Questions concerning any of the ERO Reliability Standards or related rule-making proceedings or filings can be directed to Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Revised Reliability Standard: PRC-025-2 (RD18-4)**

On March 16, 2018, NERC filed for approval revised Reliability Standard PRC-025-2 (Generator Relay Loadability) to better address risks of unnecessary generator tripping where the voltage is depressed and the generator is capable of increased Reactive Power output and voltage support during the disturbance ("PRC-025 Changes"). Specifically, the PRC-025 Changes: (i) add a provision to the Relay Loadability Evaluation Criteria in Attachment 1, Table 1 ("Table 1") to address dispersed power producing resources that are unable to be set at 130% of the calculated current due to physical limitations of the protection equipment; (ii) add to Table 1 relay type description the protective relay 50 Element associated with instantaneous (i.e., without intentional time delay) tripping of overcurrent based protection; (iii) clarify in the Table 1 that an entity must apply settings to all the applications described therein; (iv) clarify that an entity, when employing simulation for setting relays associated with the transmission line interconnecting the generator or plant to the Transmission system, must simulate the 0.85 per unit depressed voltage at the remote end (i.e., Transmission system side) of the line; (v) replaces "Pick Up" with "Setting Criteria" in Table 1 heading, to better align the setting to the calculated or simulated capability of the generator with an associated margin; and (vi) clarify certain terminology and references. NERC requested that the PRC-025 Changes become effective on the first day of the first calendar quarter after approval, pursuant to the Implementation Plan included with the Changes. Comments on the PRC-025 Changes or due on or before April 19.

- **NOPR: Cyber Security Incident Reporting Reliability Standards (RM18-2)**

On December 21, 2017 the FERC issued a NOPR proposing to direct NERC to develop and submit modifications to the Critical Infrastructure Protection ("CIP") Reliability Standards to improve the reporting of Cyber Security Incidents, including incidents that might facilitate subsequent efforts to harm the reliable operation of the bulk electric system (e.g. (incidents that compromise, or attempt to compromise, a responsible entity's Electronic Security Perimeter ("ESP") or associated Electronic Access Control or Monitoring Systems ("EACMS")).[74] The mandatory reporting requirements are intended to improve awareness of existing and future cyber security threats and potential vulnerabilities. The reports would continue to go to the Electricity Information Sharing and Analysis Center ("E-ISAC"), but reports would also go to the Industrial Control Systems Cyber Emergency Response Team ("ICS-CERT"), with an annual, public, and anonymized summary of the reports. Comments on the *Cyber Security Incident Reporting NOPR* were due on or before February 26, 2018,[75] and were filed by over 15 parties, including by NY PSC, NRG and a number of individual commenters. This matter is pending before the FERC.

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[74] *Cyber Security Incident Reporting Reliability Standards*, 161 FERC ¶ 61,291 (Dec. 21, 2017) ("*Cyber Security Incident Reporting NOPR*").

[75] The *Cyber Security Incident Reporting NOPR* was published in the Fed. Reg. on Dec. 28, 2017 (Vol. 82, No. 248) pp. 61,499-61,505.

- **NOPR: Revised Reliability Standards: CIP-005-6, CIP-010-3, CIP-013-1 (RM17-13)**

On January 18, 2018, the FERC issued a NOPR proposing to approve revised CIP Reliability Standards -- CIP-005-6 (Cyber Security – Electronic Security Perimeter(s)), CIP-010-3 (Cyber Security – Configuration Change Management and Vulnerability Assessments) and CIP-013-1 (Cyber Security – Supply Chain Risk Management) (together, the "Supply Chain Cybersecurity Risk Management Changes").[76] The Supply Chain Cybersecurity Risk Management Changes are designed to further mitigate cybersecurity risks associated with the supply chain for BES Cyber Systems, consistent with *Order 829*. With respect to the proposed Reliability Standards' implementation plan and effective date, the FERC proposed to reduce the implementation period as proposed by NERC to the first day of the first calendar quarter that is 12 months following the effective date of a FERC order. In addition, the FERC proposed to direct NERC (i) to develop modifications to the CIP Reliability Standards to include Electronic Access Control and Monitoring Systems ("EACMS") associated with medium and high impact BES Cyber Systems within the scope of the supply chain risk management Reliability Standards; (ii) to evaluate the cyber security supply chain risks presented by Physical Access Control Systems ("PACS") and Protected Cyber Assets ("PCAs") in the study of cyber security supply chain risks requested by the NERC Board of Trustees ("BOT") in its resolutions of August 10, 2017; and (iii) to file the BOT-requested study's interim and final reports with the FERC upon their completion. Comments on the *Supply Chain Risk Management Standards NOPR* were due on or before March 26, 2018,[77] and were filed by over 20 parties, including NERC, ISO/RTO Council, EEI, Joint Trade Associations,[78] and the MPUC. This matter is pending before the FERC.

- **NOPR: Revised Reliability Standard: CIP-003-7 (RM17-11)**

On October 19, 2017 the FERC issued a NOPR proposing to approve changes to Reliability Standard CIP-003 (Cyber Security - Security Management Controls), its associated implementation plan, VRFs, VSLs, and revised NERC Glossary definitions of "Removable Media" and "Transient Cyber Asset", and the retirement of the currently-effective version of CIP-003 and the NERC Glossary definitions of "Low Impact External Routable Connectivity" and "Low Impact BES Cyber System Electronic Access Point" ("CIP-003 Changes").[79] The CIP-003 Changes (i) clarify the electronic access control requirements applicable to low impact BES Cyber Systems; (ii) add requirements related to the protection of transient electronic devices used for low impact BES Cyber Systems (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems); and (iii) require Responsible Entities to have a documented cyber security policy related to declaring and responding to CIP Exceptional Circumstances for low impact BES Cyber Systems. In addition, the FERC proposes to direct NERC to develop certain modifications to the NERC Reliability Standards to provide clear, objective criteria for electronic access controls for low impact BES Cyber Systems; and address the need to mitigate the risk of malicious code that could result from third-party transient electronic devices. The proposed implementation plan provides that the CIP-003-Changes become effective on the first day of the first calendar quarter that is 18 calendar months after the effective date of the FERC's order approving the CIP-003 Changes. Comments on the *CIP-003-7 NOPR* were due on or before December 26, 2017,[80] and were filed by NERC, ELCON, TAPS, and Trade Associations[81] (each urging the FERC to approve the CIP-003 Changes without directives or conditions) and by an

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[76] *Supply Chain Risk Management Reliability Standards*, 162 FERC ¶ 61,044 (Jan. 18, 2018) ("*Supply Chain Risk Management Standards NOPR*").

[77] *Supply Chain Risk Management Reliability Standards NOPR* was published in the Fed. Reg. on Jan. 25, 2018 (Vol. 83, No. 17) pp. 3,433-3,442.

[78] For purposes of this proceeding, "Joint Trade Associations" are the American Public Power Association ("APPA"), the Electricity Consumers Resource Council ("ELCON"), the Large Public Power Council ("LPPC"), the National Rural Electric Cooperative Association ("NRECA"), and the Transmission Access Policy Study Group ("TAPS").

[79] *Rev. Critical Infrastructure Protection Rel. Standard CIP-003-7 – Cyber Security – Security Management Controls*, 161 FERC ¶ 61,047 (Oct. 19, 2017) ("*CIP-003-7 NOPR*").

[80] The *CIP-007-3 NOPR* was published in the Fed. Reg. on Oct. 26, 2017 (Vol. 82, No. 206) pp. 49,541-49,549.

[81] "Trade Associations" are the American Public Power Association ("APPA"), Edison Electric Institute ("EEI") and the National Rural Electric Cooperative Association ("NRECA").

individual, Jonathan Applebaum, who submitted comments limited to, and contesting the sufficiency of, the proposed electronic access controls requirement. This matter is pending before the FERC.

- **NOPR: New Reliability Standards: PRC-027-1 and PER-006-1 (RM16-22)**

Comments on the *Protection System Changes NOPR*[82] remain pending. Asa previously reported, the FERC issued a NOPR on November 16, 2017 proposing to approve (i) two new Reliability Standards -- PRC-027-1 (Coordination of Protection Systems for Performance During Faults) and PER-006-1 (Specific Training for Personnel), (ii) associated Glossary definitions, (iii) an implementation plan, (iv) VRFs and VSLs, and (v) the retirement of PRC-001-1.1(ii) (together, the "Protection System Changes"). In addition, the FERC proposed to direct NERC to develop certain modifications to PRC-027-1. NERC stated that the purpose of the Protection System Changes is to: (1) maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System ("BES") Elements, such that those Protection Systems operate in the intended sequence during Faults; and (2) require registered entities to provide training to their relevant personnel on Protection Systems and Remedial Action Schemes ("RAS") to help ensure that the BES is reliably operated. NERC requested that the new Standards and definitions become effective on the first day of the first calendar quarter that is 24 months following the effective date of the FERC's order approving the Standards. Comments on the *Protection System Changes NOPR* were due on or before January 29, 2018[83] and were filed by over 15 parties. Since the last Report, Hydro One Networks Inc. submitted comments. The Protection System Changes are pending before the FERC.

- **Compliance and Certification Committee Charter Amendments (RR18-4)**

On March 15, 2018, NERC filed for approval amendments to the Compliance and Certification Committee ("CCC") Charter to reflect the participation of CCC observers in NERC audits of the Regional Entities in accordance with Appendix 4A of the NERC Rules of Procedure. Comments on this filing are due on or before April 5, 2018.

- **Rules of Procedure Changes (RR18-1)**

On March 8, the FERC approved revisions to Appendix 3D (Registered Ballot Body Criteria) of the NERC Rules of Procedure ("ROP"), which are designed to help ensure that the votes of Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs") are appropriately represented in Segment 2 of NERC's registered ballot body for voting on Reliability Standards. Specifically, the revisions limit participation in "Segment 2" to RTO/ISOs exclusively, excluding other individuals and entities who may be consultants or vendors to RTO/ISOs from participating in that Segment. The proposed revisions became effective as of the date of the order (March 8, 2018). Unless the March 8 order is challenged, this proceeding will be concluded.

- **Rules of Procedure Changes (RR17-6)**

On June 26, 2017, NERC filed for approval revisions to Sections 600 (Personnel Certification Program) and 900 (Training and Education) of the NERC Rules of Procedure ("ROP"). The purpose of the revisions is to (i) clarify the scope of the Personnel Certification Program, the Training and Education Program and the Continuing Education Program; and (ii) streamline and align the language of the ROP with current practices of those programs. NERC stated that the changes are part of its first comprehensive review to modernize and align the language of the ROP with current NERC practices. NERC requested that the proposed revisions be made effective upon FERC approval. Comments on this filing were due on or before July 17, 2017 and were filed jointly by the Alberta Electric System Operator ("AESO"), The California Independent System Operator ("CAISO"), The Independent Electricity System Operator ("IESO"), ISO-NE and PJM ("System Operators"). System Operators, while agreeing that changes to Sections 600 and 900 are needed, nevertheless disagreed with the proposed changes as written and the rationale for making those changes in the first instance. On October 17, NERC answered System Operators' comments. This matter remains pending before the FERC.

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[82] *Coordination of Protection Systems for Performance During Faults and Specific Training for Personnel Rel. Standards*, 161 FERC ¶ 61,159 (Nov. 16., 2017) ("*Protection System Changes NOPR*").

[83] The *Protection System Changes NOPR* was published in the Fed. Reg. on Nov. 22, 2017 (Vol. 82, No. 224) pp. 55,535-55,541.

- **Rules of Procedure Changes (Consolidated Hearings Process) (RR17-2)**

On February 27, NERC amended its December 9, 2016 filing that proposed changes to the compliance hearing process. Under the 2016 changes, Regional Entities would be provided an option to select NERC to manage the hearing process, rather than just allowing for the Regional entities to conduct the hearing process. The February 27 amendments adjusts how members are appointed to the Hearing Body to address concerns raised by FERC Staff in response to the initial filing. In addition, NERC proposes changes related to the use of the terms "segment" and "sector", such that they will align with the Appendix 2 definitions and the Regional Delegation Agreements between NERC and each Regional Entity. NERC requested that the proposed revisions be made effective upon FERC approval. Comments on this filing were due on or before March 20, 2018; none were filed. AEP filed a doc-less motion to intervene. This matter is again pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: HIKO Energy/Spark HoldCo (EC18-69)**

On March 13, 2018, HIKO Energy requested authorization for Spark HoldCo, LLC, a subsidiary of Spark Energy (Spark), to acquire all of its membership interests. HIKO requested an order authorizing the transaction on or before May 12, 2018. Following the transaction, HIKO will become a Related Person to Spark Energy (Spark Energy and its Related Persons[84] are also members of the Supplier Sector). Comments on the application were due on or before April 3, 2018; none were filed. This matter is pending before the FERC.

- **203 Application: Boston Energy/Diamond Energy (EC18-64)**

On March 6, 2018, Boston Energy Trading and Marketing LLC ("Boston Energy"), a Related person to NRG Power Marketing, requested authorization for Diamond Energy Trading and Marketing, LLC, a wholly-owned subsidiary of Mitsubishi Corporation (Americas), to acquire all of its membership interests from NRG Energy Gas & Wind Holdings, Inc. Boston Energy requested an order authorizing the transaction on or before April 20, 2018. Comments on the application were due on or before March 27, 2018; none were filed. This matter is pending before the FERC.

- **203 Application: NRG/GIP III Zephyr Acquisition Partners (EC18-61)**

On February 23, 2018, NRG Energy Inc. ("NRG") requested authorization for a proposed transaction whereby GIP III Zephyr Acquisition Partners, L.P. ("Buyer") will acquire, among other things, interests currently held by NRG in NRG Yield, NRG Renew and their public utility subsidiaries and Carlsbad. Following the transaction, GenConn will no longer be an NRG Related Person. GenConn will remain a Related Person to UI, but will also be a Related Person of CPV Towantic. Applicants requested an order authorizing the transaction on or before May 24, 2018. Comments on the application were due on or before March 16, 2018; none were filed. Dominion and PJM filed doc-less interventions. This matter is pending before the FERC.

- **203 Application: PSNH/HSE Hydro NH (EC18-42)**

On February 28, the FERC authorized[85] the acquisition by HSE Hydro NH AC, LLC ("HSE Hydro NH")[86] of PSNH's portfolio of hydroelectric generation assets (the "PSNH Hydro Transaction").[87] Among other conditions, the February 28 order required notice within 10 days of the consummation of the transaction. Subject to the required consummation notice, this proceeding will be concluded.

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[84] Spark Energy's Related Person Participants are: National Gas & Electric, LLC; Oasis Power, LLC (d/b/a Oasis Energy), Electricity Maine, LLC; Electricity NH, LLC (d/b/a ENH Power); Major Energy Electric Services LLC; Perigee Energy, LLC; Provider Power Mass, LLC; and Verde Energy USA, Inc.

[85] *Pub. Srvc. Co. of NH and HSE Hydro NH AC, LLC*, 162 FERC ¶ 62,122 (Feb. 28, 2018).

[86] HSE Hydro NH is a Related Person to Generation Sector Group Seat members Nautilus Hydro and Pawtucket Power.

[87] PSNH's hydro portfolio (61.8 MW) includes the following facilities: Smith (15.78 MW); Amoskeag (17.5 MW); Garvins Falls/Hooksett (7.09 MW); Ayers Island (8.94 MW); Eastman Falls (6.1 MW); Jackman (3.54 MW); Gorham (1.68 MW); Canaan (1.17 MW).

- **203 Application: Dynegy/Vistra (EC18-23)**

On April 4, the FERC authorized a proposed transaction pursuant to which Dynegy will merge with and into Vistra Energy Corp. ("Vistra"), with Vistra being the surviving corporation (the "Vistra Transaction").[88] Among other conditions, the order required notice within 10 days of the consummation of the transaction.

- **203 Application: MATEP (EC18-10)**

On January 23, 2018, the FERC authorized[89] a transaction pursuant to which MATEP LLC, which purchases all of the output its QF affiliate's 95.8 MW cogeneration facility located in Boston's Longwood Medical and Academic Area, will be owned by a joint venture between indirect subsidiaries of Engie and Axium US and will become a Related Person to Generation Sector member ENGIE Energy Marketing. Among other conditions, the order required notice within 10 days of the consummation of the transaction. Subject to that notice, this proceeding will be concluded.

- **203 Application: Calpine/ECP (EC17-182)**

On March 16, Calpine notified the FERC that the transaction authorized on February 21, 2018 (the "Calpine/ECP Transaction")[90] was consummated on Mar 8, 2018. As a result of the Calpine/ECP Transaction, Calpine and Wheelabrator Participants[91] are now Related Persons. This proceeding is now concluded.

- **203 Application: GenOn Reorganization (EC17-152)**

On October 31, 2017, the FERC approved certain conversions of GenOn notes into common equity of, and corporate structure changes that will result in, a "reorganized GenOn".[92] Reorganized GenOn will emerge as a result of a plan of reorganization to be confirmed by the United States Bankruptcy Court for the Southern District of Texas in connection with GenOn's Chapter 11 restructuring (the "Restructuring"). As a result of the Restructuring, Reorganized GenOn will likely not be a subsidiary of, and GenOn Energy Management will thus likely no longer be a Related Person to, NRG. Among other conditions, the order required notice within 10 days of the consummation of the transaction. Subject to that notice, this proceeding will be concluded.

- **203 Application: Green Mountain Power/ENEL Hydros (EC17-76)**

On May 9, the FERC authorized GMP's acquisition of the following small hydroelectric generation facilities (each a QF, collectively 8.39 MW of total generating capacity) from subsidiaries of Enel Green Power North America, Inc.: Hoague-Sprague, Kelley's Falls, Lower Valley, Glen, Rollinsford, South Berwick, Somersworth, and Woodsville.[93] Among other conditions, the order required notice within 10 days of the consummation of the transaction, which as of date of this Report has not been filed. Subject to that notice, this proceeding will be concluded.

- **MOPR-Related Proceedings (PJM, NYISO) (EL16-49; EL13-62)**

In two proceedings which, unless narrowly limited solely to the unique facts of the directly applicable markets (PJM in EL16-49; NYISO in EL13-62), could impact the New England market through FERC jurisdictional or other determinations, NEPOOL filed limited comments requesting that any Commission action or decision be limited narrowly to the facts and circumstances as presented in the applicable market. NEPOOL urged that any changes that may be ordered by the Commission in the proceedings not circumscribe the results of NEPOOL's stakeholder process or predetermine the outcome of that process through dicta or a ruling

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[88] *Dynegy Inc. Vistra Energy Corp.*, 163 FERC ¶ 61,013 (Apr. 4, 2018).

[89] *MATEP LLC*, 162 FERC ¶ 62,046 (Jan. 23, 2018).

[90] *Calpine Corp. and ECP ControlCo, LLC*, 162 FERC ¶ 61,148 (Feb. 21, 2018).

[91] The Calpine Participants are Calpine Energy Services, Calpine Energy Solutions, Champion Energy Marketing, and North American Power and Gas; the Wheelabrator Participants are Wheelabrator North Andover and Wheelabrator Bridgeport.

[92] *GenOn Energy Inc.*, 161 FERC ¶ 62,063 (Oct. 31, 2017).

[93] *Green Mountain Power Corp.,* 159 FERC ¶ 62,144 (May 9, 2017).

concerning different markets with different history and different rules. NEPOOL's comments were filed on January 24 in the NYISO proceeding; January 30 in the PJM proceeding, and are pending before the FERC. Since the last Report, EPSA filed motions to lodge information in each proceeding. In the PJM proceeding, EPSA moved to lodge a July 14, 2017 Memorandum Opinion and Order of the United States District Court for the Northern District of Illinois, Eastern Division, which dismissed challenges to the zero emissions credits ("ZECs") legislation enacted by the State of Illinois. In the NYISO proceeding, in a substantively similar motion, EPSA moved to lodge a Memorandum and Order of the New York District Court dismissing challenges to the ZECs program implemented by the NYPSC. In each case, EPSA reiterated its position that unless addressed, the ZEC programs will adversely impact the respective markets. Answers to the EPSA motions to lodge were filed by Exelon and the NYPSC in the NYISO Proceeding and by Exelon, First Energy, the Load Group, NRECA, Talen Companies, and the Illinois Commerce Commission in the PJM Proceeding. On March 14, 2018, EPSA moved to lodge information contained in a Form 8-K that PSEG filed with the Securities and Exchange Commission (related to the cancellation of funding for future capital projects at its Salem nuclear facility). These proceedings remain pending before the FERC. If you have any questions concerning these proceedings, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **D&E Agreement: NSTAR/National Grid (ER18-1290)**

On April 3, NSTAR filed an Agreement for Design, Engineering and Construction services between itself and National Grid (the "D&E Agreement"). The purpose of the D&E Agreement is to set forth the terms and conditions under which National Grid will reimburse NSTAR for the costs associated with performing design, engineering and construction services on jurisdictional transmission facilities necessary for NEP to interconnect one of its retail customers (the Wynn Casino). NSTAR requested that the D&E Agreement be accepted for filing as of the date of filing, April 3, 2018. Comments on this filing are due on or before April 24. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **MPD OATT Changes (ER18-1244)**

On March 30, 2018, Emera Maine filed changes to Attachment J of the MPD OATT to reflect the reduction to the marginal corporate income tax rate resulting from the 2017 Tax Law and the 2017 Annual Update Settlement Agreement (*see* ER18-960 above). Comments on this filing are due on or before April 20, 2018. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA: CL&P/Fusion Solar (ER18-1192)**

On March 27, Eversource filed a two-party IA between CL&P and Fusion Solar to govern the interconnection of Fusion Solar's 20 MW solar generating facility in Sprague, CT, which is interconnected to CL&P's distribution system. A March 27, 2018 effective date, the commercial operation date of the facility, was requested. Comments on this filing are due on or before April 17, 2018. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Use Rights Transfer Agreement: CMEEC/NSTAR/Nalcor (ER18-1170)**

On March 23, NSTAR filed an Agreement that transfers CMEEC's Use Rights on the Phase I/II HVDC Transmission Facilities, ultimately, to Nalcor Energy Marketing Corporation, for the July 1, 2018 through October 31, 2020 period ("Transfer Agreement"). Because CMEEC, as a non-jurisdictional entity, does not have a mechanism to directly transfer its Use Rights to Nalcor (a Schedule 20A under the ISO-NE OATT), CMEEC is transferring its Use Rights to NSTAR who, in turn, is transferring those Use Rights to Nalcor. CMEEC's IRH management committee voting rights, financial obligations and all other rights and responsibilities provided for in the Support Agreements and the Restated Use Agreement that are not directly related to the Use Rights and the exercise thereof by Nalcor are not being transferred to Nalcor. NSTAR requested that the Transfer Agreement be accepted for filing as of May 23, 2018. Comments on this filing are due on or before

April 13, 2018. Thus far, National Grid has submitted a doc-less intervention. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA Cancellation: Superseded NGrid/Casella Waste Systems IA (ER18-791)**

On March 12, the FERC accepted National Grid's notice of cancellation of a 2013 Interconnection Agreement ("IA") between Massachusetts Electric Company ("NGrid") and Casella Waste Systems. NGrid stated that the IA was recently superseded by a conforming three-party SGIA among ISO-NE, NGrid and Southbridge Recycling and Disposal Park, Inc. As requested, the notice of cancellation was accepted effective as of December 21, 2016 (the date the SGIA superseded the IA and is reported in ISO-NE's EQRs). Unless the March 12 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIAs: PSNH/GSP Newington/GSP White Lake /GSP Lost Nation (ER18-785, -786, -787)**

On March 27, the FERC accepted three two-party LGIAs between PSNH and GSP Newington (ER18-785), GSP White Lake (ER18-786) , and GSP Lost Nation (ER18-787). The LGIAs reflect the interconnection arrangements for Newington Station (420 MW gas-oil steam), Lost Nation (19.3 MW oil combustion (gas)) and White Lake (23.2 MW oil combustion (gas)), each acquired by the respective Granite Shore Power subsidiaries on January 10, 2018.[94] The LGIAs cover previously existing interconnections, unmodified in connection with the change in ownership, and were not required to have ISO-NE as a party. The LGIAs were accepted effective as of January 10, 2018, as requested. Unless the March 27 orders are challenged, this matter will be concluded. If there are questions on these LGIAs, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **NSTAR/WMECO Succession Proceedings (ER18-749/751)**

On March 9, the FERC accepted a pair of filings that reflected the merger of WMECO with and into NSTAR, including a Notice of Succession identifying all the WMECO jurisdictional documents to which NSTAR succeeded and notices cancelling WMECO's eTariff database and certain WMECO jurisdictional documents not filed in WMECO's eTariff database. Unless the March 9 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **FERC Enforcement Action: Order of Non-Public, Formal Investigation (IN15-10)**

MISO Zone 4 Planning Resource Auction Offers. On October 1, 2015, the FERC issued an order authorizing Enforcement to conduct a non-public, formal investigation, with subpoena authority, regarding violations of FERC's regulations, including its prohibition against electric energy market manipulation, that may have occurred in connection with, or related to, MISO's April 2015 Planning Resource Auction for the 2015/16 power year.

Unlike a staff NOV, a FERC order converting an informal, non-public investigation to a formal, non-public investigation does not indicate that the FERC has determined that any entity has engaged in market manipulation or otherwise violated any FERC order, rule, or regulation. It does, however, give OE's Director, and employees designated by the Director, the authority to administer oaths and affirmations, subpoena witnesses, compel their attendance and testimony, take evidence, compel the filing of special reports and responses to interrogatories, gather information, and require the production of any books, papers, correspondence, memoranda, contracts, agreements, or other records.

- **FERC Audit of ISO-NE (PA16-6)**

The FERC's audit of ISO-NE docketed in this proceeding is on-going. As previously reported, the FERC informed ISO-NE on November 24, 2015 that it would evaluate ISO-NE's compliance with: (1) the transmission

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[94] See *Pub. Service Co. of New Hampshire, Granite Shore Power LLC*, 161 FERC ¶ 62,231 (Dec. 27, 2017).

provider obligations described in the Tariff, (2) *Order 1000* as it relates to transmission planning and expansion, and interregional coordination, (3) accounting requirements of the Uniform System of Accounts under 18 C.F.R. Part 101, (4) financial reporting requirements under 18 C.F.R. Part 141; and (5) record retention requirements under 18 CFR Part 125. The FERC indicated that the audit will cover the July 10, 2013 period through the present.

XII. Misc. - Administrative & Rulemaking Proceedings

- **DER Participation in RTO/ISOs (AD18-10; RM18-9)**

In *Order 841*[95] (see RM16-23 below), the FERC initiated a new proceeding in order to continue to explore the proposed distributed energy resource ("DER") aggregation reforms it was considering in the *Storage NOPR*.[96] All comments filed in response to the *Storage NOPR* will be incorporated by reference into Docket No. RM18-9 and any further comments regarding the proposed distributed energy resource aggregation reforms, including comments regarding the technical conference described below, should be filed in RM18-9.

Technical Conference (AD18-10). On April 10-11, the FERC will hold a technical conference to gather additional information to help the FERC determine what action to take on DER aggregation reforms proposed in the *Storage NOPR* and to explore issues related to the potential effects of DERs on the bulk power system. Panel topics include:

- Economic Dispatch, Pricing and Settlement of DER Aggregations
- Discussion of Operational Implications of DER Aggregation with State and Local Regulators
- DER Participation in RTO/ISO Markets
- DER Installation Data Collection and Availability
- Incorporating DERs in Modeling, Planning and Operations Studies
- Coordination of DER Aggregations Participating in RTO/ISO Markets
- Ongoing Operational Coordination

On March 29, the FERC issued a supplemental notice of the technical conference, providing additional information and identifying panel speakers. Those interested in attending are encouraged to register at: https://www.ferc.gov/whats-new/registration/04-10-18-form.asp.

- **Grid Resilience in RTO/ISOs; DOE NOPR (AD18-7; RM18-1)**

On January 8, 2018, the FERC terminated the DOE NOPR rulemaking proceeding (RM18-1)[97] and initiated a new Grid Resilience in RTO/ISOs proceeding (AD18-7).[98] In terminating the DOE NOPR proceeding, the FERC concluded that the Proposed Rule and comments received did not support FERC action under Section 206 of the

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[95] *Electric Storage Participation in Markets Operated by Regional Transmission Orgs. and Indep. Sys. Operators*, Order No. 841, 162 FERC ¶ 61,127 (Feb. 15, 2018), *clarif. requested* ("*Order 841*").

[96] *Electric Storage Participation in Markets Operated by Regional Transmission Orgs. and Indep. Sys. Operators*, 157 FERC ¶ 61,121 (Nov. 17, 2016) ("*Storage NOPR*").

[97] As previously reported, the FERC opened the DOE NOPR proceeding in response to a September 28, 2017 proposal by Energy Secretary Rick Perry, issued under a rarely-used authority under §403(a) of the Department of Energy ("DOE") Organization Act, that would have required RTO/ISOs to develop and implement market rules for the full recovery of costs and a fair rate of return for "eligible units" that (i) are able to provide essential energy and ancillary reliability services, (ii) have a 90-day fuel supply on site in the event of supply disruptions caused by emergencies, extreme weather, or natural or man-made disasters, (iii) are compliant with all applicable environmental regulations, and (iv) are not subject to cost-of-service rate regulation by any State or local authority. More than 450 comments were submitted in response to the DOE NOPR, raising and discussing an exceptionally broad spectrum of process, legal, and substantive arguments. A summary of those initial comments was circulated under separate cover and can be found with the posted materials for the November 3, 2017 Participants Committee meeting. Reply comments and answers to those comments were filed by over 100 parties.

[98] *Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,012 (Jan. 8, 2018), *reh'g requested*.

FPA, but did suggest the need for further examination by the FERC and market participants of the risks that the bulk power system faces and possible ways to address those risks in the changing electric markets. On February 7, Foundation for Resilient Societies ("FRS") requested rehearing of the January 8 order terminating the DOE NOPR proceeding. The FERC issued a tolling order on March 8, 2018 affording it additional time to consider the FRS request for rehearing, which remains pending.

Grid Resilience Administrative Proceeding (AD18-7). In the January 8 order, the FERC initiated AD18-7 to evaluate the resilience of the bulk power system in RTO/ISO regions, directed each RTO/ISO to submit information on certain resilience issues and concerns, and committed to use the information submitted to evaluate whether additional FERC action regarding resilience is appropriate. RTO submissions were due on or before March 9, 2018.

ISO-NE Response. In its response, ISO-NE identified fuel security[99] as the most significant resilience challenge facing the New England region. ISO-NE reported that it has established a process to discuss market-based solutions to address this risk, and indicated that it believed it will need through the second quarter of 2019 to develop a solution and test its robustness through the stakeholder process. In the meantime, ISO-NE indicated that it would continue to independently assess the level of fuel-security risk to reliable system operation and, if circumstances dictate, would take, with FERC approval when required, actions it determines to be necessary to address near-term reliability risks. ISO-NE's response was broken into 3 parts: (i) an introduction to fuel-security risk; (ii) background on how ISO-NE's work in transmission planning, markets, and operations support the New England bulk power system's resilience; and (iii) answers to the specific questions posed in the January 8 order.

Following a 30-day extension issued on March 20, reply comments by interested entities are now due on or before May 9, 2018. NEPOOL's reply comments will be discussed at the May 4 Participants Committee meeting.

- **NOI: 2017 Tax Law Effect on FERC-Jurisdictional Rates (RM18-12)**

On March 15, the FERC opened an inquiry ("NOI")[100] seeking comments on the effect of the 2017 Tax Cuts and Jobs Act ("2017 Tax Law") (which reduced the federal corporate income tax rate from a maximum 35% to a flat 21%) on FERC-jurisdictional rates. Of particular interest is whether, and if so how, the FERC should address changes relating to accumulated deferred income taxes ("ADIT"),[101] bonus depreciation,[102] or other rates (not otherwise being addressed in the concurrently issued show cause orders). Comments on the NOI must be submitted on or before May 21, 2018.[103]

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[99] ISO-NE defined fuel security as "the assurance that power plants will have or be able to obtain the fuel they need to run, particularly in winter – especially against the backdrop of coal, oil, and nuclear unit retirements, constrained fuel infrastructure, and the difficulty in permitting and operating dual-fuel generating capability."

[100] *Inquiry Regarding the Effect of the Tax Cuts and Jobs Act on Comm.-Jurisdictional Rates*, 162 FERC ¶ 61,223 (Mar. 15, 2018).

[101] ADIT arises from differences between the methods of computing taxable income for IRS reporting purposes and computing income for regulatory accounting and ratemaking purposes. As a result of the Tax Cuts and Jobs Act, a portion of an ADIT liability that was collected from customers will no longer be due to the IRS, is considered excess ADIT, and must be returned to customers in a cost-of-service ratemaking context.

[102] Bonus depreciation is a tax incentive given to companies to encourage certain types of investment. Bonus depreciation allows companies to deduct a percentage of the cost of a qualified property in the year the property is placed into service, in addition to other depreciation deductions. Under the Act, bonus depreciation is no longer available for "assets acquired in the trade or business of the furnishing or sale of electrical energy, water, or sewage disposal services; gas or steam through a local distribution system; or transportation of gas or steam by pipeline."

[103] The NOI was published in the *Fed. Reg.* on Mar. 21, 2018 (Vol. 83, No. 55) pp. 12,371 – 12,376.

- **NOPR: Pipeline Rates (RM18-11)**

On March 15, 2018, the FERC issued a NOPR[104] that proposes a procedure through which the cost-based rates of natural gas pipelines are to be examined to determine which, if any, of those entities are collecting unjust and unreasonable rates in light of the 2017 Tax Law's reduction in the corporate tax rate from 35 to 21 % and the disallowance in the Tax Policy Statement (*see* PL17-1 below) of income tax allowances for MLP pipelines. The *Pipeline Rates NOPR* would require interstate pipelines to (a) file a one-time report, FERC Form No. 501-G, that would provide financial information from the pipeline's 2017 FERC Form 2; and (b) voluntarily make a filing to address the changes to the pipeline's recovery of tax costs, or explain why no action is needed. Pipelines can respond in one of four ways:

1. A limited Natural Gas Act ("NGA") section 4 filing to reduce the pipeline's cost-based rates by the percentage reduction in its cost of service shown in its FERC Form No. 501-G;
2. A commitment to file either a prepackaged uncontested rate settlement or a general NGA section 4 rate case by December 31, 2018;
3. The filing of a statement explaining why no change in rates is required; or
4. The taking of no other action (other than the submittal of the one-time report).[105]

Comments to the Pipeline Rates NOPR are due on or before April 25, 2018.[106]

- **NOPR: Withdrawal of Pleadings (RM18-7)**

On February 15, 2018, the FERC issued a NOPR proposing to adopt a more accurate title for, and clarify the text of, Rule 216 of the FERC's Rules of Practice and Procedure.[107] The FERC proposes to change Rule 216's the title from "Withdrawal of pleadings and tariff or rate filings (Rule 216)" to "Withdrawal of pleadings (Rule 216)", to change the first sentence of Rule 216(a) to read, "Any person may seek to withdraw its pleading by filing a notice of withdrawal," and to refer to "person" rather than "party," in Rule 216(c). Comments on the *Pleadings Withdrawal NOPR* were initially due on or before March 26, 2018,[108] later extended to March 28. A single comment, addressing what was described as a "jarring grammatical error", was filed. This matter is pending before the FERC.

- **NOPR: LGIA/LGIP Reforms (RM17-8)**

As previously reported, the FERC issued a NOPR[109] on December 15, 2016 proposing reforms designed to improve certainty,[110] promote more informed interconnection,[111] and enhance interconnection

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[104] *Interstate and Intrastate Natural Gas Pipelines; Rate Changes Relating to Federal Income Tax Rate*, 162 FERC ¶ 61,226 (Mar. 15, 2018) ("*Pipeline Rates NOPR*").

[105] If the pipeline chooses the latter two options, FERC will consider after reviewing both the one-time report and the comments of others whether to initiate an NGA Section 5 investigation.

[106] The *Pipeline Rates NOPR was* published in the *Fed. Reg.* on Mar. 26, 2018 (Vol. 83, No. 58) pp. 12,888 – 12,901.

[107] *Withdrawal of Pleadings*, 162 FERC ¶ 61,111 (Feb. 15, 2018) ("*Pleadings Withdrawal NOPR*").

[108] The *Pleadings Withdrawal NOPR* was published in the *Fed. Reg.* on Feb. 23, 2018 (Vol. 83, No. 37 pp. 8,019-8,020.

[109] *Reform of Generator Interconnection Procedures and Agreements*, 157 FERC ¶ 61,212 (Dec. 15, 2016) ("*LGIP/LGIA Reforms NOPR*"). The *LGIP/LGIA Reforms NOPR* was published in the *Fed. Reg.* on Jan. 13, 2017 (Vol. 82, No. 9 pp. 4,464-4,501.

[110] To accomplish this goal, the FERC proposes to: (1) revise the *pro forma* LGIP to require transmission providers that conduct cluster studies to move toward a scheduled, periodic restudy process; (2) remove from the *pro forma* LGIA the limitation that interconnection customers may only exercise the option to build transmission provider's interconnection facilities and standalone network upgrades if the transmission owner cannot meet the dates proposed by the interconnection customer; (3) modify the *pro forma* LGIA to require mutual agreement between the transmission owner and interconnection customer for the transmission owner to opt to initially self-fund the costs of the construction of network upgrades; and (4) require that the RTO/ISO establish dispute resolution procedures for interconnection disputes. The Commission also seeks comment on the extent to which a cap on the network upgrade costs for which interconnection customers are responsible can mitigate the potential for serial restudies without inappropriately shifting cost responsibility. *Id.* at P 6.

processes.[112] Based, in part, on input received in response to AWEA's petition for changes to the *pro forma* LGIP/LGIA, and the FERC's May 13, 2016 technical conference to explore generator interconnection issues (as reported previously under Docket Nos. RM16-12; RM15-21), the FERC identified proposed reforms which it states could remedy potential shortcomings in the existing interconnection processes. The FERC also sought comment on whether any of its proposed reforms should be applied to the *pro forma* SGIP/SGIA.[113] 60 sets of comments on and answer to the *LGIP/LGIA Reforms NOPR* were submitted, including comments by: NEPOOL (approved at the April 7 Participants Committee meeting), ISO-NE, Avangrid, EDF Renewable, EDP Renewables, Eversource, Exelon, Invenergy, National Grid, NextEra, APPA/LPPC/NRECA, AWEA, EEI, ELCON, ESA, and Public Interest Organizations. The *LGIP/LGIA Reforms NOPR* is pending before the FERC.

- **NOPR: Uplift Cost Allocation and Transparency in RTO/ISO Markets (RM17-2)**

On January 19, 2017, the FERC issued a NOPR proposing to require each RTO and ISO that currently allocates the costs of Real-Time uplift due to deviations to do so only to those market participants whose transactions are reasonably expected to have caused the real-time uplift costs.[114] In addition, the FERC proposed to revise its regulations to enhance transparency by requiring that each RTO/ISO post uplift costs paid (dollars) and operator-initiated commitments (MWs) on its website; and define in its tariff its transmission constraint penalty factors, as well as the circumstances under which those penalty factors can set LMPs, and any procedure for changing those factors. Comments and reply comments on the *Uplift/Transparency NOPR* were filed by over 40 parties, including: ISO-NE, Brookfield, Calpine, DC Energy, Direct, Exelon, Potomac Economics, Saracen, EEI, APPA/NRECA, Appian Way Energy Partners, AWEA, ELCON, EPSA, Financial Marketers Coalition, and the IRC. The *Uplift/Transparency NOPR* is pending before the FERC.

- ***Order 841*: Electric Storage Participation in RTO/ISO Markets (RM16-23; AD16-20)**

On February 15, the FERC issued *Order 841*, which requires each RTO/ISO to revise its tariff "to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitates their participation in the RTO/ISO markets." The participation model must:

(1) ensure that a resource using the participation model is eligible to provide all capacity, energy and ancillary services that the resource is technically capable of providing in the markets;
(2) ensure that a resource using the participation model can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer consistent with existing market rules that govern when a resource can set the wholesale price;

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[111] The FERC proposes to: (1) require transmission providers to outline and make public a method for determining contingent facilities in their LGIPs and LGIAs based upon guiding principles in the Proposed Rule; (2) require transmission providers to list in their LGIPs and on their OASIS sites the specific study processes and assumptions for forming the networking models used for interconnection studies; (3) require congestion and curtailment information to be posted in one location on each transmission provider's OASIS site; (4) revise the definition of "Generating Facility" in the pro forma LGIP and LGIA to explicitly include electric storage resources; and (5) create a system of reporting requirements for aggregate interconnection study performance. The FERC also seeks comment on proposals or additional steps that the Commission could take to improve the resolution of issues that arise when affected systems are impacted by a proposed interconnection. *Id.* at P 7.

[112] The FERC proposes to: (1) allow interconnection customers to limit their requested level of interconnection service below their generating facility capacity; (2) require transmission providers to allow for provisional agreements so that interconnection customers can operate on a limited basis prior to completion of the full interconnection process; (3) require transmission providers to create a process for interconnection customers to utilize surplus interconnection service at existing interconnection points; (4) require transmission providers to set forth a separate procedure to allow transmission providers to assess and, if necessary, study an interconnection customer's technology changes (e.g., incorporation of a newer turbine model) without a change to the interconnection customer's queue position; and (5) require transmission providers to evaluate their methods for modeling electric storage resources for interconnection studies and report to the Commission why and how their existing practices are or are not sufficient. *Id.* at P 8.

[113] *Id.* at P 11.

[114] *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 158 FERC ¶ 61,047 (Jan. 19, 2017) ("*Uplift/Transparency NOPR*").

(3) account for the physical and operational characteristics of electric storage resources through bidding parameters or other means; and
(4) establish a minimum size requirement for participation in the RTO/ISO markets that does not exceed 100 kW.

Additionally, each RTO/ISO must specify that the sale of electric energy from the RTO/ISO markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale locational marginal price. RTO/ISOs must file any necessary tariff changes on or before November 30, 2018 (270 days from *Order 841*'s publication in the Federal Register)[115] and implement those tariff provisions within one year of that compliance filing. *Order 841* will become effective June 4, 2018.

Order 841 did not adopt the *Storage NOPR's* proposed reforms related to DER aggregations. Instead, *Order 841* instituted a new rulemaking proceeding and technical conference (*see* AD18-10/RM18-9 above) to gather additional information to help the FERC determine what action to take with respect to DER aggregation. Requests for Clarification and/or Rehearing of Order 841 were filed by CAISO, MISO, PJM, the AES Companies, AMP/APPA/NRECA, California Energy Storage Alliance, EEI, NARUC, PG&E, TAPS, and Xcel Energy Services. The requests for clarification and/or rehearing are pending, with FERC action required on or before April 12, 2018 (30 days from the date the first request for clarification was filed), or the requests will be deemed denied by operation of law.

- **NOPR: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)**

The FERC's *Data Collection NOPR* remains pending. As previously reported, the FERC issued a July 21, 2016 NOPR, which superseded both its *Connected Entity NOPR* (RM15-23) and *Ownership NOPR* (RM16-3), proposing to collect certain data for analytics and surveillance purposes from market-based rate ("MBR") sellers and entities trading virtual products or holding FTRs and to change certain aspects of the substance and format of information submitted for MBR purposes.[116] The *Data Collection NOPR* presents substantial revisions from what the FERC proposed in the *Connected Entity NOPR*, and responds to the comments and concerns submitted by NEPOOL in that proceeding. Among other things, the changes proposed in the *Data NOPR* include: (i) a different set of filers; (ii) a reworked and substantially narrowed definition of Connected Entity; and (iii) a different submission process. With respect to the MBR program, the proposals include: (i) adopting certain changes to reduce and clarify the scope of ownership information that MBR sellers must provide; (ii) reducing the information required in asset appendices; and (iii) collecting currently-required MBR information and certain new information in a consolidated and streamlined manner. The FERC also proposes to eliminate MBR sellers' corporate organizational chart submission requirement adopted in *Order 816*. Comments on the *Data Collection NOPR* were due on or before September 19, 2016[117] and were filed by over 30 parties, including: APPA, Avangrid, Brookfield, EPSA, Macquarie/DC Energy/Emera Energy Services, NextEra, and NRG.

- ***Order 833*: Critical Energy/Electric Infrastructure Information (CEII) Procedures (RM16-15)**

Rehearing of *Order 833*[118] remains pending. As previously reported, *Order 833* amended FERC regulations to implement provisions of the Fixing America's Surface Transportation ("FAST") Act that pertain to the designation, protection and sharing of Critical Electric Infrastructure Information ("CEII") and amend other

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[115] *Order 841* was published in the *Fed. Reg.* on Mar. 6, 2018 (Vol. 83, No. 44) pp. 9,580-9,633.

[116] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 156 FERC ¶ 61,045 (July 21, 2016) ("*Data Collection NOPR*").

[117] The *Data Collection NOPR* was published in the *Fed. Reg.* on Aug. 4, 2016 (Vol. 81, No. 150) pp. 51,726-51,772.

[118] *Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Info.; Availability of Certain N. Amer. Elec. Rel. Corp. Databases to the Comm.*, Order No. 833, 157 FERC ¶ 61,123 (Nov. 17, 2016) ("*Order 833*"), *reh'g requested*.

regulations that pertain to CEII. The amended procedures will be referred to as the Critical Energy/Electric Infrastructure Information (CEII) procedures. *Order 833* became effective February 21, 2017.[119] On December 19, 2016, EEI requested rehearing of *Order 833*. The FERC issued a tolling order on January 17, 2017 affording it additional time to consider the EEI request for rehearing, which remains pending.

- ***Order 842*: Primary Frequency Response - Essential Reliability Services and the Evolving Bulk-Power System (RM16-6)**

On February 15, the FERC issued *Order 842*,[120] which requires all newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install and enable primary frequency response capability as a condition of interconnection. The FERC also established certain uniform minimum operating requirements, including maximum droop and deadband parameters and provisions for timely and sustained response. *Order 842* requirements will also apply to *existing* large and small generating facilities that take any action that requires the submission of a new interconnection request that results in the filing of an executed or unexecuted interconnection agreement on or after *Order 842*'s effective date. These requirements will not apply to existing generating facilities, a subset of combined heat and power ("CHP") facilities, or generating facilities regulated by the Nuclear Regulatory Commission. The FERC did not impose a headroom requirement for new generating facilities, and did not mandate that new generating facilities receive compensation for complying with the primary frequency response requirements. To implement these requirements, the FERC modified the *pro forma* LGIA and the *pro forma* SGIA. *Order 842* will become effective May 15, 2018.[121] Requests for rehearing and/or clarification and reconsideration of *Order 842* were filed by PJM, the AES Companies and Arizona Public Service. Answers to the PJM request were filed by PJM Power Providers Group and EPSA ("Competitive Suppliers"), the PJM Utilities Coalition, and the PJM IMM. The requests are pending, with FERC action required on or before April 16, 2018 (30 days from the date the first request was filed), or the requests will be deemed denied by operation of law.

- **NOI: FERC's Policy for Recovery of Income Tax Costs & ROE Policies (PL17-1)**

On March 15, 2018, the FERC found that an impermissible double recovery results from granting a Master Limited Partnership pipeline ("MLP") both an income tax allowance and an ROE pursuant to the DCF methodology.[122] Accordingly, the FERC issued a revised policy statement that it will no longer permit an MLP to recover an income tax allowance in its cost of service. The finding follows an NOI[123] that sought comments regarding how to address any double recovery resulting from the FERC's income tax allowance and ROE policies in light of the D.C. Circuit's *United Airlines*[124] holding. The FERC indicated that it will address the application of *United Airlines* to non-MLP partnership forms as those issues arise in subsequent proceedings. The revised policy statement took effect on March 21, 2018.

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[119] *Order 833* was published in the *Fed. Reg.* on Dec. 21, 2016 (Vol. 81, No. 245) pp. 93,732-93,753.

[120] *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, Order No. 842, 162 FERC ¶ 61,128 (Feb. 15, 2018) ("*Order 842*"), *reh'g requested*.

[121] *Order 842* was published in the *Fed. Reg.* on Mar. 6, 2018 (Vol. 83, No. 44) pp. 9,636-9,677.

[122] *Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs*, 162 FERC ¶ 61,227 (Mar. 15, 2018).

[123] *Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs,* 157 FERC ¶ 61,210 (Dec. 15, 2016).

[124] *United Airlines Inc. v. FERC*, 827 F.3d 122, 134, 136 (D.C. Cir. 2016) ("*United Airlines*") (holding that the FERC failed to demonstrate that there is no double recovery of taxes for a partnership pipeline as a result of the income tax allowance and ROE determined pursuant to the DCF methodology, and remanding the decisions to the FERC to develop a mechanism "for which the Commission can demonstrate that there is no double recovery" of partnership income tax costs). *Id.* at 137.

XIII. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **FERC Staff Inquiry in Response to EDF Allegations of Pipeline Capacity Withholding (not docketed)**

On February 27, the FERC issued a press release stating that a staff inquiry revealed no evidence of anticompetitive withholding of natural gas pipeline capacity on Algonquin Gas Transmission by New England shippers. The inquiry arose out of allegations made by the Environmental Defense Fund ("EDF") in an August 2017 white paper, which asserted that local gas distribution companies in New England had engaged in practices to withhold pipeline capacity on the Algonquin system in order to drive up gas and/or power prices in the region. FERC staff reviewed both publicly available and non-public data. On the basis of that review, staff determined that "EDF's study was flawed and led to incorrect conclusions about the alleged withholding. Commission staff found no evidence of capacity withholding." The Commission will take no further action on the matter.

- **Petition for Initiation of Show Cause Proceedings: Cont'd Justness & Reasonable of Rates Post-Tax Act (RP18-415)**

On January 31, 2018, a number of natural gas industry trade associations and companies ("Petitioners")[125] petitioned the FERC to initiate show cause proceedings against all interstate natural gas pipeline and storage companies, other than those required to file updated rate justifications on an on-going basis or required to file rate cases in 2018, to require them to demonstrate that their existing jurisdictional rates continue to be just and reasonable, and to require immediate rate reductions if and as appropriate, in light of reduced tax rates implemented pursuant to the 2017 Tax Law. Petitioners explained they were pursuing a "show cause" approach in order to avoid "unreasonable delay" in relief to consumers. Over 20 sets of comments and answers were received. Given the issuance of the *Pipeline Rates NOPR*, which effectively dismisses the Petition, reporting on this Petition is concluded.

- **Natural Gas-Related Enforcement Actions**

The FERC continues to closely monitor and enforce compliance with regulations governing open access transportation on interstate natural gas pipelines:

BP (IN13-15). On July 11, 2016, the FERC issued *Opinion 549*[126] affirming Judge Cintron's August 13, 2015 Initial Decision finding that BP America Inc., BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, "BP") violated Section 1c.1 of the Commission's regulations ("Anti-Manipulation Rule") and section 4A of the Natural Gas Act ("NGA").[127] Specifically, after extensive discovery and hearing procedures, Judge Cintron found that BP's Texas team engaged in market manipulation by changing their trading patterns, between September 18, 2008 through the end of November 2008, in order to suppress next-day natural gas prices at the Houston Ship Channel ("HSC") trading point in order to benefit correspondingly long position at the Henry Hub trading point. The FERC agreed, finding that the "record shows that BP's trading practices during the Investigative Period were fraudulent or deceptive, undertaken with the requisite scienter, and carried out in connection with Commission-jurisdictional transactions."[128] Accordingly, the FERC assessed a

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[125] "Petitioners", estimated to account for a majority of shippers on nearly every interstate natural gas pipeline, as well as a majority of contracted firm capacity, include the following trade associations and companies: American Forest and Paper Assoc., American Public Gas Assoc., Indep. Petroleum Assoc. of America, Nat. Gas Supply Assoc., and Process Gas Consumers Group, Aera Energy, Anadarko Energy Services, Chevron U.S.A., ConocoPhillips, Hess Corp., Petrohawk Energy, WPX Energy Marketing, LLC, and XTO Energy.

[126] *BP America Inc.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*").

[127] *BP America Inc.,* 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*").

[128] *BP Penalties Order* at P 3.

$20.16 million civil penalty and required BP to ***disgorge $207,169*** in "unjust profits it received as a result of its manipulation of the Houston Ship Channel Gas Daily index." The $20.16 million civil penalty was at the top of the FERC's Penalty Guidelines range, reflecting increases for having had a prior adjudication within 5 years of the violation, and for BP's violation of a FERC order within 5 years of the scheme. BP's penalty was mitigated because it cooperated during the investigation, but BP received no deduction for its compliance program, or for self-reporting. The *BP Penalties Order* also denied BP's request for rehearing of the order establishing a hearing in this proceeding.[129] BP was directed to pay the civil penalty and disgorgement amount within 60 days of the *BP Penalties Order*. On August 10, 2016 BP requested rehearing of the *BP Penalties Order*. On September 8, the FERC issued a tolling order, affording it additional time to consider BP's request for rehearing of the *BP Penalties Order*, which remains pending.

On September 7, 2016, BP submitted a motion for modification of the *BP Penalties Order's* disgorgement directive because it cannot comply with the disgorgement directive as ordered. BP explained that the entity to which disgorgement was to be directed, the Texas Low Income Home Energy Assistance Program ("LIHEAP"), is not set up to receive or disburse amounts received from any person other than the Texas Legislature. In response, on September 12, the FERC stayed the disgorgement directive (until an order on BP's pending request for rehearing is issued), but indicated that interest will continue to accrue on unpaid monies during the pendency of the stay.[130]

BP moved, on December 11, 2017, to lodge, to reopen the proceeding, and to dismiss, or in the alternative, for reconsideration based on changes in the law it asserted are dispositive and that have occurred since BP filed its request for rehearing of the *BP Penalties Order*. FERC Staff asked for, and was granted, additional time, to January 25, 2018, to file its Answer to BP's December 11 motion. FERC Staff filed its answer on January 25, 2018, and revised that answer on January 31. On February 9, BP replied to FERC Staff's revised answer. This matter is again pending before the FERC.

Total Gas & Power North America, Inc. et al. (IN12-17). On April 28, 2016, the FERC issued a show cause order[131] in which it directed Total Gas & Power North America, Inc. ("TGPNA") and its West Desk traders and supervisors, Therese Tran f/k/a Nguyen ("Tran") and Aaron Hall (collectively, "Respondents") to show cause why Respondents should not be found to have violated NGA Section 4A and the FERC's Anti-Manipulation Rule through a scheme to manipulate the price of natural gas at four locations in the southwest United States between June 2009 and June 2012.[132]

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA - ***$213.6 million***; Hall - ***$1 million*** (jointly and severally with TGPNA); and Tran - ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents filed their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered

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[129] *BP America Inc.*, 147 FERC ¶ 61,130 (May 15, 2014) ("*BP Hearing Order*"), *reh'g denied,* 156 FERC ¶ 61,031 (July 11, 2016).

[130] *BP America Inc.*, 156 FERC ¶ 61,174 (Sep. 12, 2016) ("*Order Staying BP Disgorgement*")

[131] *Total Gas & Power North America, Inc.,* 155 FERC ¶ 61,105 (Apr. 28, 2016) ("*TGPNA Show Cause Order*").

[132] The allegations giving rise to the Total Show Cause Order were laid out in a September 21, 2015 FERC Staff Notice of Alleged Violations which summarized OE's case against the Respondents. Staff determined that the Respondents violated section 4A of the Natural Gas Act and the Commission's Anti-Manipulation Rule by devising and executing a scheme to manipulate the price of natural gas in the southwest United States between June 2009 and June 2012. Specifically, Staff alleged that the scheme involved making largely uneconomic trades for physical natural gas during bid-week designed to move indexed market prices in a way that benefited the company's related positions. Staff alleged that the West Desk implemented the bid-week scheme on at least 38 occasions during the period of interest, and that Tran and Hall each implemented the scheme and supervised and directed other traders in implementing the scheme.

OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017. This matter remains pending before the FERC.

Staff Notices of Alleged Violations (IN__-___)

Rover. On July 13, 2017, the FERC issued a notice that Staff has preliminarily determined that, between February 2015 and September 2016, Rover Pipeline, LLC and Energy Transfer Partners, L.P. (collectively, "Rover") violated Section 7 of the Natural Gas Act by failing to fully and forthrightly disclose all relevant information to the FERC in Rover's application for a Certificate of Public Convenience and Necessity and attendant filings in Docket No. CP15-93. Staff alleges that Rover falsely promised it would avoid adverse effects to a historic resource that it was simultaneously working to purchase and destroy, and subsequently made several misstatements in its docketed responses to FERC questions about why it had purchased and demolished the resource.

Recall that Notices of Alleged Violations ("NoVs") are issued only after the subject of an enforcement investigation has either responded, or had the opportunity to respond, to a preliminary findings letter detailing Staff's conclusions regarding the subject's conduct.[133] NoVs are designed to increase the transparency of Staff's nonpublic investigations conducted under Part 1b of its regulations. A NoV does not confer a right on third parties to intervene in the investigation or any other right with respect to the investigation.

- **New England Pipeline Proceedings**
  The following New England pipeline projects are currently under construction or before the FERC:
  - ***Atlantic Bridge Project (CP16-9)***
    - 132,700 Dth/d of firm transportation to new and existing delivery points on the Algonquin system and 106,276 Dth/d of firm transportation service from Beverly, MA to various existing delivery points on the Maritimes & Northeast system.
    - 6.3 miles of replacement pipeline along Algonquin in NY and CT; new 7,700-horsepower compressor station in Weymouth, MA; more horsepower at existing compressor stations in CT and NY.
    - Seven firm shippers: Heritage Gas Limited, Maine Natural Gas Company, NSTAR Gas Company d/b/a Eversource Energy, Exelon Generation Company, LLC (as assignee and asset manager of Summit Natural Gas of Maine), Irving Oil Terminal Operations, Inc., New England NG Supply Limited, and Norwich Public Utilities.
    - Certificate of public convenience and necessity granted Jan. 25, 2017.[134]
    - Certain facilities,[135] providing 40,000 out of the project's total capacity of 132,705 dekatherms per day of incremental firm transportation service, placed into service on November 1, 2017.[136] Remaining Project capacity will be available when the remaining Project facilities are placed into service following Director of OEP authorization.
    - Authorization granted on March 20, 2018 to proceed with construction of Salem Pike, Needham, Pine Hills and Plymouth meter and regulating stations. Detailed information

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[133] *See Enforcement of Statutes, Regulations, and Orders*, 129 FERC ¶ 61,247 (Dec. 17, 2009), *order on requests for reh'g and clarification*, 134 FERC ¶ 61,054 (Jan. 24, 2011).

[134] Order Issuing Certificate and Authorizing Abandonment, *Algonquin Gas Transmission LLC and Maritimes & Northeast Pipeline, LLC*, 158 FERC ¶ 61,061 (Jan. 25, 2017), *order denying stay*, 160 FERC ¶ 61,015 (2017), *reh'g denied,* 161 FERC ¶ 61,255 (Dec. 13, 2017) ("*Atlantic Bridge Project Order*").

[135] The following facilities placed into service: Southeast Discharge Take-up and Relay (Fairfield County, CT); Modified Oxford Compressor Station (New Haven County, CT); Modified Chaplin Compressor Station (Windham County, CT); Modified Danbury (CT) Meter Station; and Modified Stony Point Compressor Station (Rockland County, NY).

[136] *Algonquin Gas Transmission, LLC,* 158 FERC ¶ 61,061 (Oct. 27, 2017).

regarding construction activities can be found in the weekly construction reports filed in this docket.

    - On February 16, 2018, Algonquin filed with the DC Circuit Court of Appeals, pursuant to Section 19(d)(2) of the Natural Gas Act, a petition for review of the MA DEP's failure to issue, condition, or deny a minor-source air permit for Algonquin's proposed natural gas compressor station in the Town of Weymouth, MA by the July 31, 2016 deadline established by the FERC. Algonquin seeks an order establishing a deadline for the MA DEP to issue, condition, or deny the permit.

- ***Constitution Pipeline (CP13-499) and Wright Interconnection Project (CP13-502)***
    - Constitution Pipeline Company and Iroquois Gas Transmission (Wright Interconnection) concurrently filed for Section 7(c) certificates on June 13, 2013.
    - 650,000 Dth/d of firm capacity from Susquehanna County, PA (Marcellus Shale) through NY to Iroquois/Tennessee interconnection (Wright Interconnection).
    - New 122-mile interstate pipeline.
    - Two firm shippers: Cabot Oil & Gas and Southwestern Energy Services.
    - Final EIS completed on Oct 24, 2014.
    - Certificates of public convenience and necessity granted Dec 2, 2014.
        - By letter order issued July 26, 2016, the Director of the Division of Pipeline Certificates (Director) granted Constitution's requested two-year extension of time to construct the project.
        - Construction was expected to begin Spring 2016 (after final Federal Authorizations), but has been plagued by delays (see below).
    - On April 22, 2016, New York State Department of Environmental Conservation (NY DEC) denied Constitution's application for a Section 401 permit under the Clean Water Act.
        - On August 18, 2017, the 2nd Circuit denied Constitution's petition for review of the NY DEC decision, concluding that (1) the court lacked jurisdiction over the Constitution's claims to the extent that they challenged the timeliness of the decision; and (2) the NY DEC acted within its statutory authority in denying the certification, and its denial was not arbitrary or capricious.
    - On October 11, 2017, Constitution filed with the FERC a petition for declaratory order ("Petition") requesting that the FERC find that NY DEC waived its authority under section 401 of the Clean Water Act by failing to act within a "reasonable period of time." (CP18-5)
        - On January 11, 2018, the FERC denied Constitution's Petition.[137] Although noting that states and project sponsors that engage in repeated withdrawal and refiling of applications for water quality certifications are acting, in many cases, contrary to the public interest and to the spirit of the Clean Water Act by failing to provide reasonably expeditious state decisions, the FERC did not conclude that the practice violates the letter of the statute, found factually that Constitution gave the NY DEC new deadlines, and found that the record did not show that the NY DEC in any instance failed to act on Constitution's application for more than the outer time limit of one year.[138]
        - On February 12, 2018, Constitution Pipeline requested rehearing of the January 11, 2018 order. The FERC issued a tolling order on March 14 affording it

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[137] *Constitution Pipeline Co.*, 162 FERC ¶ 61,014 (Jan. 11, 2018), *reh'g requested*.

[138] *Id.* at P 23.

additional time to consider Constitution Pipelines' request, which remains pending.

- On May 16, 2016, the New York Attorney General filed a complaint against Constitution at the FERC (CP13-499) seeking a stay of the December 2014 order granting the original certificates, as well as alleging violations of the order, the Natural Gas Act, and the Commission's own regulations due to acts and omissions associated with clear-cutting and other construction-related activities on the pipeline right of way in New York.
    - In July 2016, the FERC rejected the NY AG's filing as procedurally deficient, and declined to stay of the Certificate Order. The NY AG sought rehearing, and the Commission denied rehearing on November 22, 2016, noting again that the NY AG's complaint was still procedurally deficient.
- Tree felling and site preparation continues, but the long-term status of the pipeline is currently unknown. Constitution will submit its monitoring reports monthly rather than weekly until activities resume in 2018.

- **Non-New England Pipeline Proceedings**

  The following pipeline projects could affect ongoing pipeline proceedings in New England and elsewhere:

    - ***Southeast Market Pipelines Project* (CP14-554, CP15-16, CP15-17)**
        - Florida Southeast Connection, LLC, Transcontinental Gas Pipe Line Company, LLC and Sabal Trail Transmission, LLC (Sabal Trail) filed for a Section 7(c) certificates in Sept. – Nov. 2014.
        - The three separate but connected natural gas transmission pipeline projects total approximately 685.5 miles of natural gas transmission pipeline and provide transportation service for up to approximately 1.1 billion cubic feet per day of natural gas to markets in Florida and the southeast United States ("SMP Project").
        - Certificates of public convenience and necessity were granted Feb. 2, 2016.[139]
            - Project construction began in August 2016, and in June and July 2017, Commission Staff authorized the pipelines to commence service on the completed facilities.
        - On August 22, 2017, the DC Circuit vacated and remanded the FERC's certificate order, holding that the FERC's environmental review of the SMP Project failed to adequately consider the downstream effects of greenhouse gas emissions resulting from increased power generation.[140]
            - The DC Circuit held that FERC must either quantify and consider the project's downstream carbon emissions or explain in more detail why it cannot do so.
        - On September 27, 2017, the FERC issued a Draft Supplemental EIS, estimating the pipeline would potentially increase the Florida GHG emission inventory between 3.7 and 9.7 percent.
            - In the supplemental EIS, the FERC stated that it "could not find a suitable method to attribute discrete environmental effects to GHG emissions."
        - On March 14, 2018, the FERC issued an Order on Remand reinstating the certificates of public convenience and necessity. The majority found that while the FERC calculated the gross and net emissions, there was nothing to do with that information as there is "no widely accepted standard to ascribe significance to a given rate or volume of GHG emissions." The FERC also noted that it is only approving the means of transportation, and it is not the Commission's job to "decide national policy on the use of natural gas."

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[139] *Fla. Southeast Connection, LLC*, 154 FERC ¶ 61,080, 61 (Feb. 2, 2016) (order issuing certificate).

[140] *Sierra Club v. FERC*, 2017 U.S. App. LEXIS 15911 (D.C. Cir. Aug. 22, 2017).

    - Commissioner LaFleur dissented in part because she could not "support the Commission's responses to the Court on downstream GHG emissions and the Social Cost of Carbon."
    - Commissioner Glick also dissented, arguing that the FERC must consider the reasonably foreseeable indirect effects of the SMP Project. Glick argues that the "Commission must take a 'hard look' at climate change – the ultimate environmental impact," and should be more transparent in its decision-making. He concluded by noting "that t[he] order, by limiting analysis of the environmental impacts of a proposed pipeline, will both increase the Commission's litigation risk and contribute further to the cynicism of the pipeline siting process."

- ***Millennium Pipeline Valley Lateral Project*** **(CP16-17)**
  - On July 21, 2017, Millennium Pipeline Company, L.L.C. (Millennium) filed a Request for Notice to Proceed with Construction of its Valley Lateral Pipeline in Orange County, New York. Originally, the subject of a November 13, 2015 FERC certificate application, the Valley Lateral Pipeline was authorized by FERC on November 9, 2016.[141]
    - The Valley Lateral Pipeline will connect the existing Millennium Pipeline to the 680 MW CPV Valley Energy Center.
  - To receive a notice to proceed, Millennium was required to demonstrate that it had obtained all federally-required environmental permits and authorizations, including authorizations under the Clean Water Act (CWA). Millennium stated that the New York State Department of Environmental Conservation (New York DEC) had waived its authority to issue a water quality certification under Section 401 of the CWA by failing to act before the statutorily-imposed deadline.
    - In August 2017, the NY DEC denied the water quality certification to the Valley Lateral Project, citing the D.C. Circuit's recent ruling in *Sierra Club v. FERC* and the FERC's "lack of a complete environmental review."
  - By Letter Order issued on September 15, 2017, the FERC agreed with Millennium, finding that the New York DEC had waived its authority to issue or deny a water quality certification. Because the NY DEC had received Millennium's Section 401 certification in November 2015, but did not rule on it until August 2017, FERC ruled that NY DEC, as the certifying agency, had therefore failed to act within the statutory timeframe and had waived its certification authority.[142] The FERC's order effectively nullified the NY DEC's August 2017 rejection of the water quality certification.
    - The NY DEC, on October 13, 2017, filed a Request for Rehearing and Stay of the FERC's September 15, 2017, Order. On November 15, the FERC denied the requests for rehearing, stay, and rescission.[143]
    - The NY DEC sought review of the FERC's Orders in the Second Circuit. On March 12, 2018, the 2nd Circuit upheld the FERC's determination that the NY DEC waived its authority to act on Millennium's application for a CWA water quality certification by not acting on the application within one year of receipt. In doing so, the Second Circuit rejected the NY DEC's argument that the one-year statutory deadline begins when a state agency deems the application complete, rather than when the application is received.

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[141] *Millennium Pipeline Co., L.L.C.,* 157 FERC ¶ 61,096 (Nov. 9, 2017).

[142] *Millennium Pipeline Co., L.L.C.,* 160 FERC ¶ 61,065 (Sept. 15, 2017), *reh'g denied*, 161 FERC ¶ 61,186 (Nov. 15, 2017).

[143] *Millennium Pipeline Co., L.L.C.,* 161 FERC ¶ 61,186 (Nov. 15, 2017) ("*November 15 Order*").

    - Millennium sought, and on October 3, 2017, the FERC granted, a one year extension of time to complete construction of the Valley Lateral Project and make it available for service by November 2018.
    - On October 27, 2017, the FERC issued a Notice to Proceed, granting Millennium's request to begin construction of the Valley Lateral.
        - The NY DEC, on October 30, 2017, filed a Request for Stay of the Notice to Proceed. The *November 15 Order* also denied the October 30 request for stay.[144]
    - A related project, the Millennium Eastern System Upgrade (CP16-486) received its certificate of public convenience and necessity on November 28, 2017. On March 19, 2018, the FERC denied a request for stay filed by Delaware Riverkeeper Network filed with its request for rehearing of the certificate order.
    - On April 4, the FERC approved an amendment to the November 9, 2016 certificate of public convenience and necessity authorizing the Valley Lateral Project to reflect an overall increase in the cost of construction of the facilities.[145]

- ***Northern Access Project* (CP15-115)**
    - On Feb. 3, 2017, the FERC issued an order authorizing National Fuel Gas Supply Corporation and Empire Pipeline, Inc. to construct and operate pipeline, compression, and ancillary facilities in McKean County, Pennsylvania, and Allegany, Cattaraugus, Erie, and Niagara Counties, New York (Northern Access Project)
    - In March 2017, Allegheny Defense Project and Sierra Club (collectively Allegheny) filed a request for rehearing of the FERC's order and on August 31, 2017, FERC issued an Order Denying Stay
        - Consistent with its previous authorization, FERC found no evidence of irreparable harm in letting the project go forward.
    - Despite the FERC's Order, the project remains halted pending the outcome of National Fuel's fight with the NY DEC's April denial of a Clean Water Act permit.
        - NY DEC found National Fuel's application for a water quality certification under Section 401 of the Clean Water Act, as well as for stream and wetlands disturbance permits, failed to comply with water regulations aimed at protecting wetlands and wildlife and that the pipeline failed to explore construction alternatives.
        - National Fuel appealed the NY DEC's decision to the 2nd Circuit on the grounds that the denial was improper.[146] Oral argument was held on November 16, 2017. The Court's decision is pending.
- ***PennEast Pipeline Company, LLC* (CP15-558)**
    - On September 24, 2015, PennEast Pipeline Company, LLC (PennEast) filed an application pursuant to section 7(c) of the Natural Gas Act (NGA) requesting authorization to construct and operate a new 116-mile natural gas pipeline from Luzerne County,

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[144] On Oct. 30, 2017, NY DEC also petitioned the United States Court of Appeals for the Second Circuit for a temporary stay of the FERC's Notice to Proceed until the FERC acts on NY DEC's request for rehearing of the Declaratory Order. *In re New York State Department of Environmental Conservation v. FERC*, 2d Cir. No. 17-3503, Petitioner's Emergency Petition for a Writ of Prohibition (Oct. 30, 2017) (Emergency Petition). NY DEC also requested the court to stay the effectiveness of the Notice to Proceed on an interim basis while the court considers the merits of its petition. *Id.* at 34. On Nov. 2, 2017, the court granted an administrative stay pending consideration of the petition by the next available three-judge panel. *In re New York State Dep't of Envtl. Conservation v. FERC*, 2d Cir. No. 17-3503 (Nov. 2, 2017). NY DEC's Emergency Petition is pending at the court.

[145] *Millennium Pipeline Co., L.L.C.*, 163 FERC ¶ 61,009 (Apr. 4, 2018).

[146] *National Fuel Gas Supply Corp. v. NYSDEC et al.*, , 2d Cir. No. 17-1164.

Pennsylvania, to Mercer County, New Jersey, along with three laterals extending off the mainline, a compression station, and appurtenant above ground facilities (PennEast Project).

- PennEast is a joint venture owned by Red Oak Enterprise Holdings, Inc., a subsidiary of AGL Resources Inc.; NJR Pipeline Company, a subsidiary of New Jersey Resources; SJI Midstream, LLC, a subsidiary of South Jersey Industries; UGI PennEast, LLC, a subsidiary of UGI Energy Services, LLC; and Spectra Energy Partners, LP.
- The project is designed to provide up to 1,107,000 Dth/d of firm transportation service.
- Certificates of public convenience and necessity were granted by FERC on January 19, 2018.[147]
  - Rehearings and motions for stay were filed by opponents of the PennEast Project of FERC's order granting authorization of the project. FERC issued a tolling order on these rehearing requests on February 22, 2018.
  - Delaware Riverkeeper Network sought rehearing of FERC's tolling order arguing that the use of tolling orders deprive it of Constitutional due process.
- The New Jersey Attorney General and several conservation groups have filed actions in federal district court in New Jersey seeking to limit PennEast's use of its NGA eminent domain authority.

XIV. State Proceedings & Federal Legislative Proceedings

- **Massachusetts Emissions Allowance Auctions: Stakeholder Input on Auction Design Parameters**

In an action that could have implications for the New England Markets, the Massachusetts (MA) Department of Environmental Protection ("MassDEP") issued on August 11, 2017 final regulations to ensure that MA will meet the 2020 statewide greenhouse gas ("GHG") emissions limits mandated by MA's 2008 Global Warming Solutions Act ("GWSA"). Section 7.74[148] of those regulations reduces carbon dioxide ("CO_2") emissions from MA-based power plants by imposing an annually declining aggregate emissions cap on MA's 21 large fossil fuel-fired generators. Operators of those facilities will have to offset their CO_2 production with allowances (a limited authorization to emit one metric ton of CO_2 in a calendar year). Allowances will be allocated directly in 2018 based on historical generation. Beginning with compliance year 2019, Section 7.74 requires auctioning of the emissions allowances that facilities must use to comply with the regulation. Allowances may be traded between facilities and a limited quantity may be banked from year to year.

On December 15, 2017, MassDEP filed final amendments to correct errors for two facilities in the 2018 allowance allocations. These amendments were published in the Massachusetts register on December 29, 2017. In addition, MassDEP has committed to post on its website compliance forms and an "FAQ" document.

The allowance tracking system will be deployed In the Spring of 2018. Detailed instructions for regulated facilities will be provided at that time. Stakeholder comments on the auction design solicited in the Fall of 2017 will be considered as the MassDEP develops procedures in preparation for allowance auctions that begin in 2019. MassDEP anticipates additional opportunities for stakeholders to participate in the auction design process in 2018, possibly including an opportunity to comment on proposed regulatory amendments. MassDEP is also in the process of soliciting market monitoring services, and will hire an auction administrator in 2018. Questions regarding 310 CMR 7.74 can be directed to Will Space (william.space@state.ma.us; 617-292-5610).

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[147] *PennEast Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018).

[148] Additional information about 310 CMR 7.74 (Reducing CO_2 Emissions from Electricity Generating Facilities) is available at: http://www.mass.gov/eea/agencies/massdep/climate-energy/climate/ghg/electricity-generatoremissions-limits.html.

- **NG Advantage (NY) Permit Challenge (RJI No.: 2017-0799; RJI No.: 2017-0800)**
  Chenango Valley Central School District and various nearby residents Petitioners have initiated proceedings against the Town of Fenton, New York Planning Board and NG Advantage, LLC to halt NG Advantage, LLC's ("NG Advantage") proposed construction of a natural gas compressor facility that would extract gas up to 4000 psi and transport the compressed natural gas to NG Advantage customers. Petitioners are concerned that the project infringes on the rights of those who live near the transfer station. They are specifically concerned about the site's proximity to schools, and the burden it could place on local roads.

  A judicial decision on whether the Town of Fenton followed proper procedures with respect to zoning laws in approving the Project has been held in reserve while Supreme Court Judge Ferris Lebo's reviews oral arguments and submissions. The Project is currently halted pending judgment.

XV. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Base ROE Complaint IV (2016) (18-1077)**
  Underlying FERC Proceedings: EL16-64[149]
  Petitioner: TOs
  On March 15, 2018, the TOs petitioned the DC Circuit Court of Appeals for review of the FERC's *Base ROE Complaint IV Orders*. Also on March 15, the Court ordered the TOs to submit by April 16 its initials materials, including certificates, docketing statement form, procedural motions, and its statement of issues. The Court ordered the FERC to submit by April 16 its entry of appearance and any procedural motions. Dispositive motions and a certified index to the record are due April 30.

- **FCM Resource Retirement Reforms (17-1275)**
  Underlying FERC Proceedings: ER16-551[150]
  Petitioner: Constellation
  As previously reported, Constellation ("Petitioner") petitioned the DC Circuit Court of Appeals on December 28, 2017 for review of the FERC's *FCM Resource Retirement Reforms Orders*. Upon a joint motion of Constellation and the FERC, the following briefing schedule was ordered: Petitioner's Brief to be filed April 17, 2018; Respondent's Brief, July 2, 2018; Petitioner's Reply Brief, July 30, 2018; Deferred Appendix, August 13, 2018; and Final Briefs, August 20, 2018.

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[149] *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 156 FERC ¶ 61,198 (Sep. 20, 2016), *reh'g denied*, 162 FERC ¶ 61,035 (Jan. 18, 2018) ("*Base ROE Complaint IV Orders*").

[150] *ISO New England Inc.,* 155 FERC ¶ 61,029 (Apr. 12, 2016) ("*Resource Retirement Reforms Order*"), *reh'g and clarif. denied*, 161 FERC ¶ 61,115 (Oct. 30, 2017) ("*FCM Resource Retirement Reforms Orders*").

- **Demand Curve Changes (17-1110**)**
  Underlying FERC Proceedings: ER14-1639[151]
  Petitioners: NextEra, NRG, PSEG

NextEra, NRG and PSEG ("Petitioners") petitioned the DC Circuit Court of Appeals for a second time for review of the FERC's Demand Curve orders, which, as previously reported, had been remanded back to the FERC at the FERC's request following the first appeal by Petitioners. Briefing was completed on February 1, 2018 and oral argument scheduled for April 13, 2018. The composition of the argument panel will be Circuit Judge Wilkins, and Senior Circuit Judges Sentelle and Randolph.

- **FCA10 Results (16-1408) and FCA9 Results (16-1068)**
  Underlying FERC Proceedings: ER16-1041[152] **ER15-1137**[153]
  Petitioners: UWUA Local 464 and Robert Clark

UWUA Local 464 and Robert Clark ("Petitioners") filed petitions for review of the FERC's orders on the FCA10 and FCA9 Results Filings, consolidated by the Court on January 31, 2017. All briefing is complete and oral argument was held before Judges Rogers, Millett and Pillard on February 9, 2018. This matter is pending before the Court.

- **NEPGA PER Complaint and FCM Jump Ball and Compliance Proceedings (16-1023/1024)**
  Underlying FERC Proceeding: ER14-1050;[154] **EL14-52;**[155] **EL15-25**[156]
  Petitioner: NEPGA

On January 19, 2018, the Court dismissed for lack of jurisdiction the petition for review in 16-1023 (the appeal of the FCM Jump Ball and Compliance Proceedings) and denied on the merits the petition for review in 16-1024 (the NEPGA PER Complaint appeal). As previously reported, NEPGA filed, on January 19, 2016, a petition for review of the FERC's orders on NEPGA's first PER Complaint. On February 24, 2016, the Court granted NEPGA's motion to consolidate this proceeding with 16-1024. Briefing was completed on November 28, 2016. Oral argument was held October 27, 2017 before Judges Griffith, Dentelle and Randolph. In denying 16-1024 on the merits, the Court found that the underlying orders were not arbitrary and capricious. The Court further stated that "so long as any change is reasonably explained, it is not arbitrary and capricious for an agency to change its mind in light of experience, or in the face of new or additional evidence, or further analysis or other factors indicating that the agency's earlier decision should be altered or abandoned." With respect to 16-1023, the Court found it lacked jurisdiction because petitioner NEPGA had not itself sought rehearing of the FERC order appealed from, which for the Court to have jurisdiction it would have had to do. The court issued its mandate on March 15, 2018. Reporting on this proceeding has concluded.

- **Base ROE Complaints II & III (2012 & 2014) (15-1212)**
  Underlying FERC Proceedings: EL13-33; EL14-86[157]
  Appellants: New England Transmission Owners

As previously reported, the TOs filed a petition for review of the FERC's orders in the 2012 and 2014 ROE complaint proceedings on July 13, 2015. On August 14, 2015, the TOs filed an unopposed motion to hold this case

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[151] 147 FERC ¶ 61,173 (May 30, 2014) (*Demand Curve Order*); 150 FERC ¶ 61,065 (Jan. 30, 2015) (*Demand Curve Clarification Order)*; 155 FERC ¶ 61,023 (Apr. 8, 2016) (*Demand Curve Remand Order*); 158 FERC ¶ 61,138 (Feb. 3, 2017) (*Demand Curve Remand Rehearing Order*).

[152] 155 FERC ¶ 61,273 (June 16, 2016); 157 FERC ¶ 61,060 (Oct. 27, 2016).

[153] 153 FERC ¶ 61,378 (Dec. 30, 2015); 151 FERC ¶ 61,226 (June 18, 2015).

[154] 153 FERC ¶ 61,224 (Nov. 19, 2015); 153 FERC ¶ 61,223 (Nov. 19, 2015); 147 FERC ¶ 61,172 (May 30, 2014).

[155] 153 FERC ¶ 61,222 (Nov. 19, 2015); 150 FERC ¶ 61,053 (Jan. 30, 2015).

[156] 153 FERC ¶ 61,222 (Nov. 19, 2015); 150 FERC ¶ 61,053 (Jan. 30, 2015).

[157] 147 FERC ¶ 61,235 (June 19, 2014); 149 FERC ¶ 61,156 (Nov. 24, 2014); 151 FERC ¶ 61,125 (May 14, 2015).

in abeyance pending final FERC action on the 2012 and 2014 ROE Complaints (*see* Section I above). On August 20, 2015, the Court granted the TOs' motion to hold the case in abeyance, subject to submission of status reports every 90 days. The most recent status report, the tenth such report filed, was filed on February 12, 2018. In that report, the parties again indicated, ultimately, that the proceedings upon which the TOs based their request for abeyance of this appeal remain ongoing. This case continues to be held in abeyance.

- **FCM Pricing Rules Complaints (15-1071**, 16-1042) (consol.)**
  Underlying FERC Proceeding: EL14-7,[158] EL15-23[159]
  Petitioners: NEPGA, Exelon

On February 2, 2018, DC Circuit granted NEPGA's and Exelon's petitions for review of orders accepting the FCM's 7-year price lock-in (EL14-7) and capacity-carry-forward rules (EL15-23).[160] Finding that "the FERC failed to adequately explain why its rationale [for rejecting price lock-in and capacity carry forward rules] in PJM – which seems to foreclose signing off on a Tariff scheme like ISO-NE's – does not apply even more forcefully to the scheme it accepted in the Orders [appealed from]," the DC Circuit granted the Petitions and remanded to FERC for further proceedings in which the FERC, in order to accept the changes filed, must provide some analysis and explanation why it changed course.

Other Federal Court Developments of Interest

- ***California Public Utilities Commission v. FERC* (9th Cir., 16-70481)** (Jan. 8, 2018)

In a decision that could impact how the FERC approaches future orders on ROE filings, the Ninth Circuit Court of Appeals held that the FERC acted arbitrarily and capriciously, and erred, by granting a transmission owner (PG&E) an incentive adder for its participation in an RTO (CAISO) where the participation by the TO was not voluntary. Doing so created a generic incentive adder (for TO participation in an RTO) in contravention of Order 679's requirement of case-by-case review of adders to be granted, which were designed to induce voluntary RTO participation. The Ninth Circuit remanded the matter back to the FERC with instructions to follow the appeals court's reasoning.

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[158] 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

[159] 154 FERC ¶ 61,005 (Jan. 7, 2016); 150 FERC ¶ 61,067 (Jan. 30, 2015).

[160] *New England Power Generators Assoc. v FERC*, 881 F.3d 202 (DC Cir. 2018).

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