NEPOOL PARTICIPANTS COMMITTEE 10/4/19 Meeting
Agenda Item #6

# NEPOOL Participants Committee Report

*October 2019*

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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# Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy market value over the period was $182M, down $139M from August 2019 and down $221M from September 2018
    - September natural gas prices over the period were 2.6% higher than August average values
    - Average RT Hub Locational Marginal Prices ($20.97/MWh) over the period were 11% lower than August averages
      - Avg. DA Hub: $21.77/MWh
    - Average September 2019 natural gas prices and RT Hub LMPs over the period were down 29% and down 49%, respectively, from September 2018 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 99.6% during September, down from 101.3% during August*
    - The minimum value for the month was 95.4% on Saturday, Sep. 7th

Data is through September 25th, unless otherwise indicated.

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

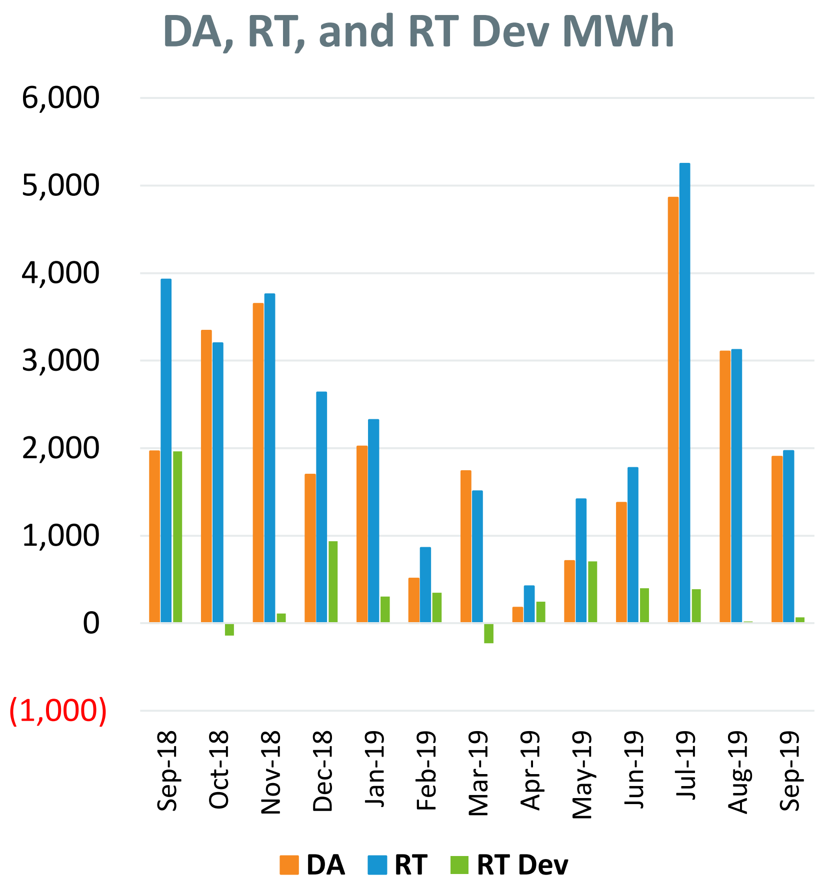
Underlying natural gas data furnished by: ICE Global markets in clear view

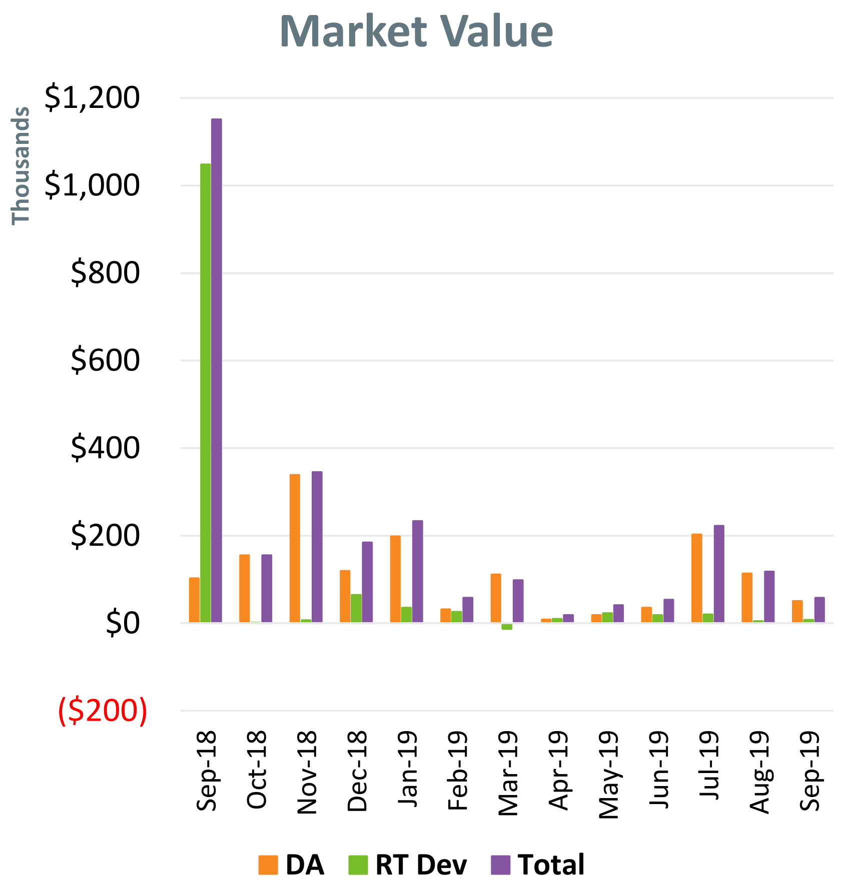
# Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - September NCPC payments totaled $1.6M over the period, up $0.1M from August and down $1.9M from September 2018
    - First Contingency* payments totaled $1.1M, up $23K from August
      - $1M paid to internal resources, down $32K from August
        - » $368K charged to DALO, $479K to RT Deviations, $256K to RTLO
      - $62K paid to resources at external locations, up $55K from August
        - » Charged to RT Deviations
    - Second Contingency payments totaled $479K, up $121K from August
    - Voltage payments totaled $56K, up $56K from August
    - Distribution payments were zero
  - NCPC payments over the period as percent of Energy Market value were 0.9%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $143K; Rapid Response Pricing (RRP) Opportunity Cost - $101K; Posturing - $12K; Generator Performance Auditing (GPA) - $0K;**

# Price Responsive Demand (PRD) Energy Market Activity by Month




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

# Highlights

- Tariff enhancements related to the competitive transmission solicitation process are expected to be filed with FERC by October 11
- FCA 14 qualification activities are nearing completion
  – New Capacity Resource Qualification Determinations were disseminated on September 27
  – FERC filings pertaining to ICR and qualification will be made on November 5
- The final version of RSP19 is under review by the ISO Board

# Forward Capacity Market (FCM) Highlights

- CCP 10 (2019-2020)
  - Late, new resources (regardless of size) are being monitored closely
- CCP 11 (2020-2021)
  - Third and final annual reconfiguration auction to be held March 1-5, 2020 and results to be posted by March 19, 2020
- CCP 12 (2021-2022)
  - Second reconfiguration auction will be August 3-5, 2020 and results to be posted by September 2, 2020
- CCP 13 (2022-2023)
  - Auction results were filed with FERC on February 28 and, on September 25, FERC issued notice that FCA 13 results are effective under operation of law
  - First reconfiguration auction will be June 1-3, 2020 and results to be posted by July 1, 2020

CCP – Capacity Commitment Period
FCA – Forward Capacity Auction

# FCM Highlights, cont.

- CCP 14 (2023-2024)
  - New Capacity Resource Qualification is complete and QDNs were released on September 27
    - Renewable Technology Resource Exemption: approximately 336 MW, and election is due October 1
    - FCM deposit (financial assurance) is due October 28
  - Existing Capacity Resource Qualification is complete
  - This will be the first FCA where nested capacity zones will be modeled
    - Tariff changes were filed with FERC and an order is expected by October 1
    - Capacity Zones to be modeled include: Rest of Pool, Southeastern New England, Northern New England, and Maine (nested zone within Northern New England)
  - ICR & related values with and without Mystic 8/9 have been developed and will be filed with FERC
    - Exelon has until January 20 to decide whether or not to retire the Mystic 8/9 resources
- Both the ICR and Informational FERC filings will be made on November 5

ICR – Installed Capacity Requirement
QDN – Qualification Notification Determination

# FERC Order 1000

- Intraregional Planning
  - Qualified Transmission Project Sponsor (QTPS)
    - 21 companies have achieved QTPS status
    - One company is currently moving through the QTPS application process
  - Based on the results of the Boston Needs Assessment to date, the ISO plans to release its first request for proposal (RFP) for a competitively developed transmission solution in late 2019 or early 2020
  - The ISO anticipates an October Tariff filing by October 11, 2019
  - Draft RFP templates are being updated based on stakeholder feedback and are planned to be reposted for PAC comment in mid-October

# Load Forecast

- The 2020 load forecast process has begun
  - Energy-Efficiency Forecast Working Group WebEx will be held on October 18
  - Load Forecast Committee meeting will be held on November 18
  - Distributed Generation Forecast Working Group meeting will be December 5
- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
  - Discussions are ongoing with industry experts regarding emerging technologies/trends and methods of incorporating these into the forecast

# Highlights

- The lowest 50/50 and 90/10 Fall Operable Capacity Margins are projected for week beginning November 2, 2019.

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

# SYSTEM OPERATIONS

# System Operations

| | | | | |
|---|---|---|---|---|
| **Weather Patterns** | Boston | Temperature: Above Normal (3.3°F)<br>Max: 92°F, Min: 50°F<br>Precipitation: 2.16” – Below Normal<br>Normal: 3.31” | Hartford | Temperature: Above Normal (0.9°F)<br>Max: 92°F, Min: 38°F<br>Precipitation: 1.93” - Below Normal<br>Normal: 3.72” |

| | | | |
|---|---|---|---|
| **Peak Load:** | 18,924 MW | September 23, 2019 | 18:00 (ending) |

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

| Procedure | Declared | Cancelled | Note |
|---|---|---|---|
| NONE | | | |

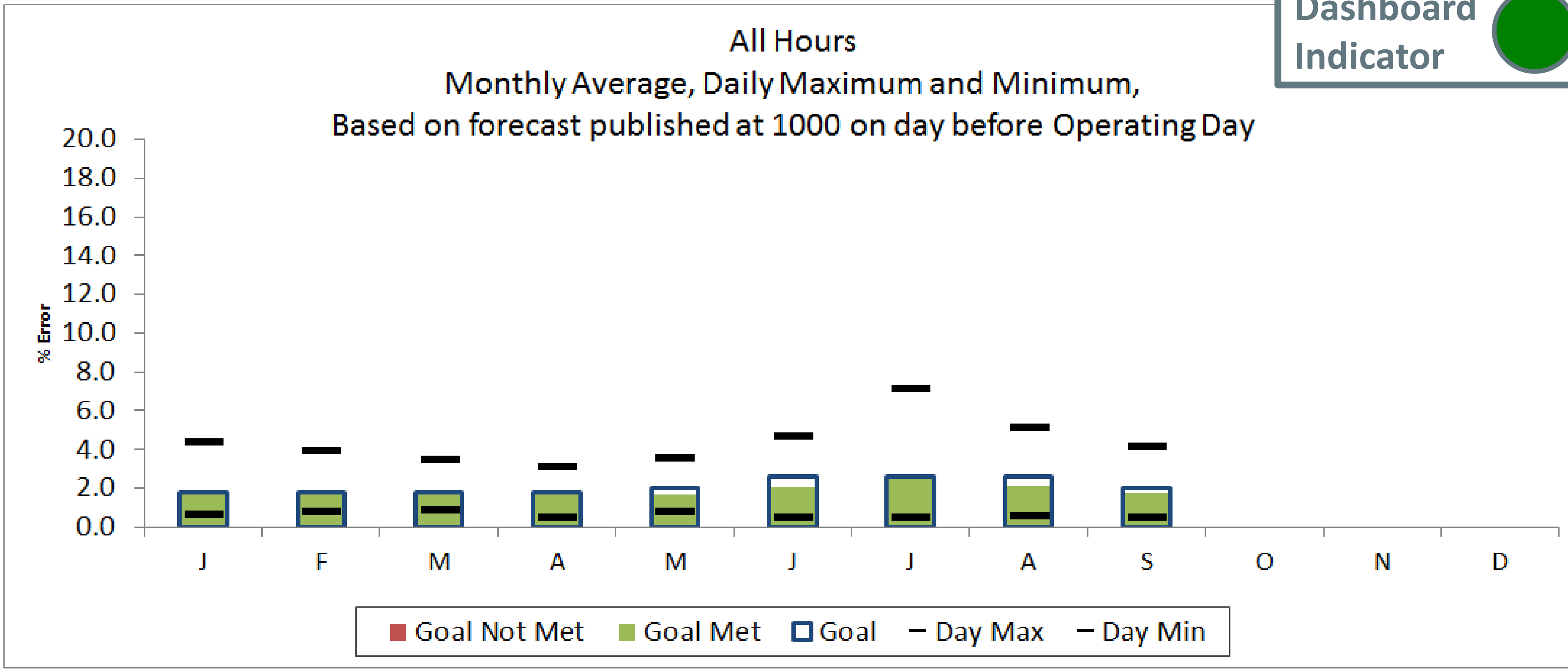
# System Operations

## NPCC Simultaneous Activation of Reserve Events

| Date | Area | MW Lost |
|---|---|---|
| 9/3/2019 | NYISO | 1200 |
| 9/21/2019 | ISO-NE | 668 |
| 9/23/2019 | PJM | 1255 |

# 2019 System Operations - Load Forecast Accuracy

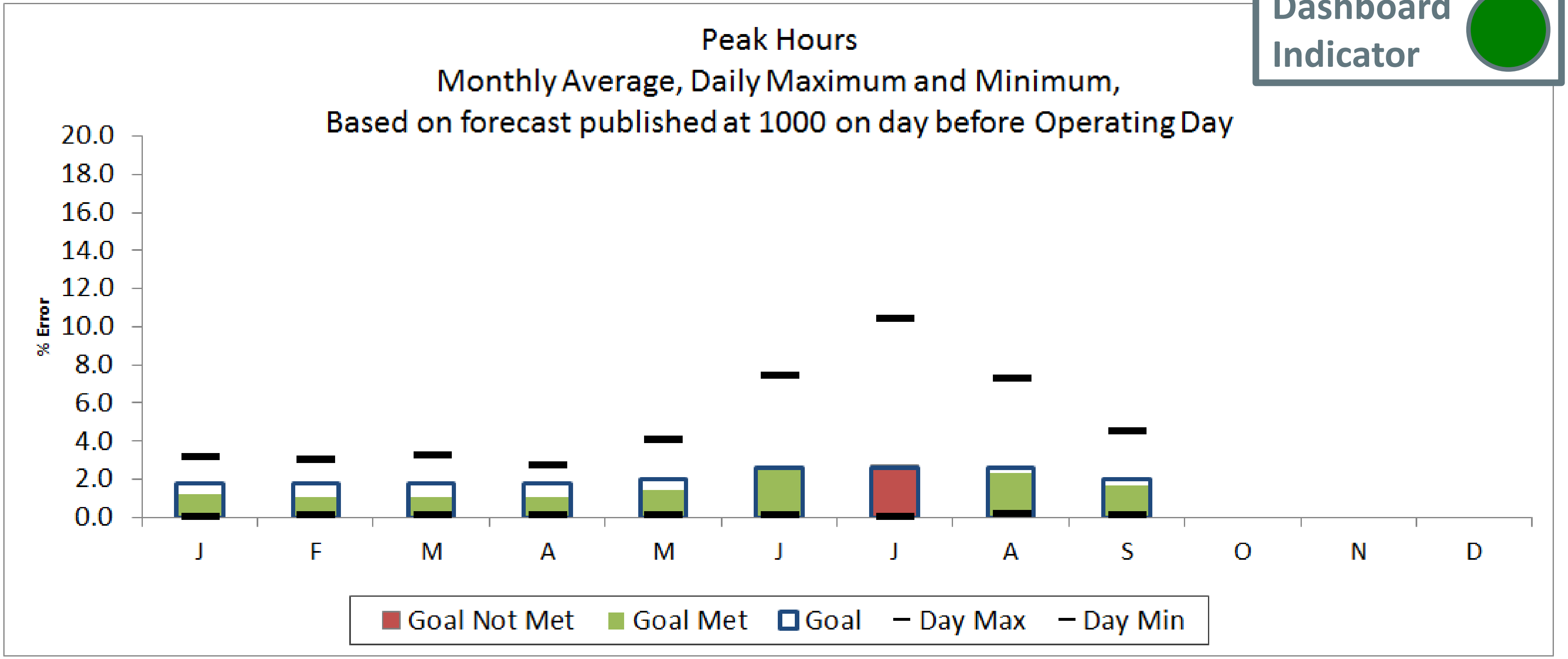
Dashboard Indicator




| Month | J | F | M | A | M | J | J | A | S | O | N | D | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Day Max | 4.36 | 3.87 | 3.47 | 3.11 | 3.53 | 4.68 | 7.14 | 5.10 | 4.11 | | | | 7.14 |
| Day Min | 0.60 | 0.77 | 0.81 | 0.49 | 0.79 | 0.49 | 0.44 | 0.57 | 0.48 | | | | 0.44 |
| MAPE | 1.76 | 1.68 | 1.72 | 1.79 | 1.64 | 2.01 | 2.46 | 2.12 | 1.75 | | | | 1.88 |
| Goal | 1.80 | 1.80 | 1.80 | 1.80 | 2.00 | 2.60 | 2.60 | 2.60 | 2.00 | | | | |

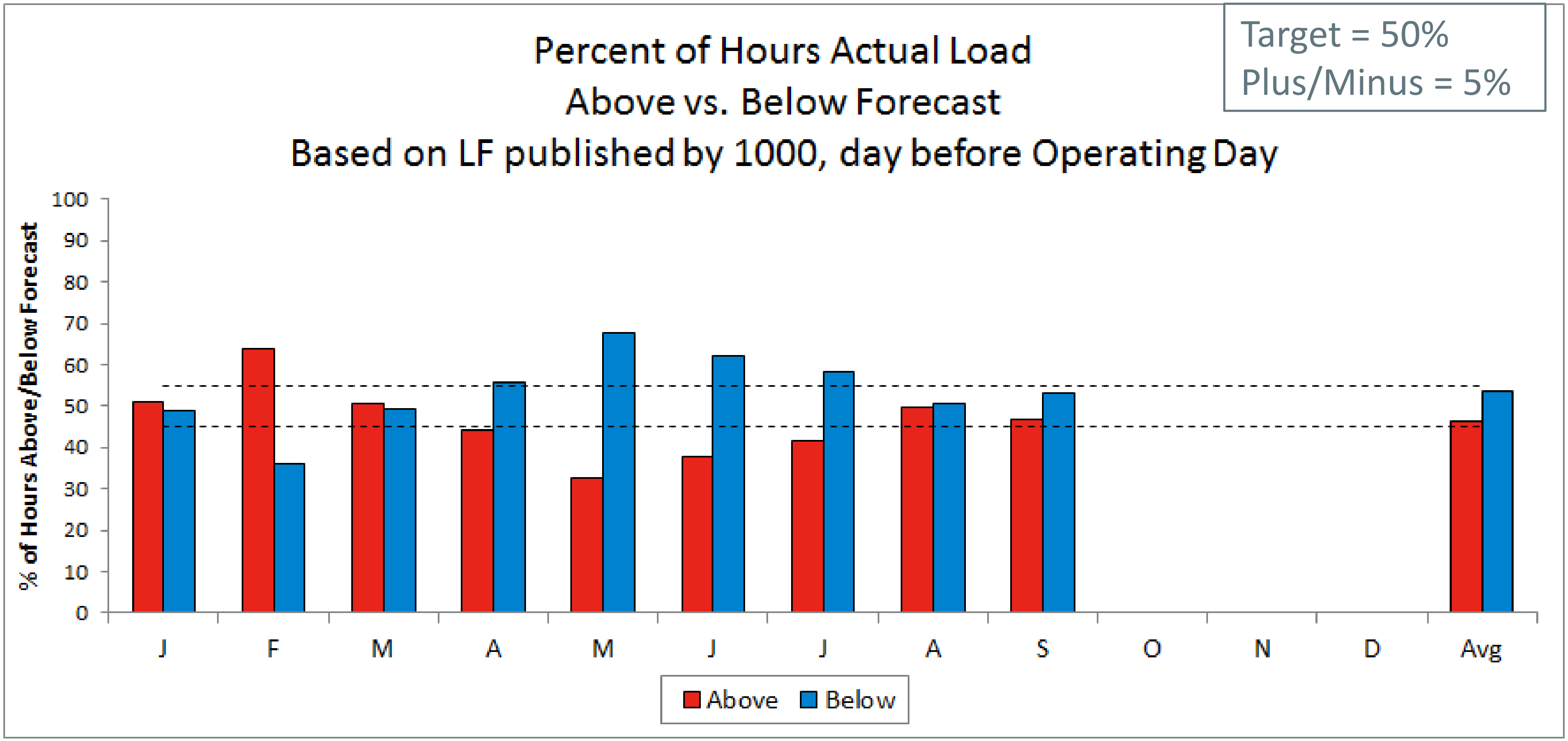
# 2019 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



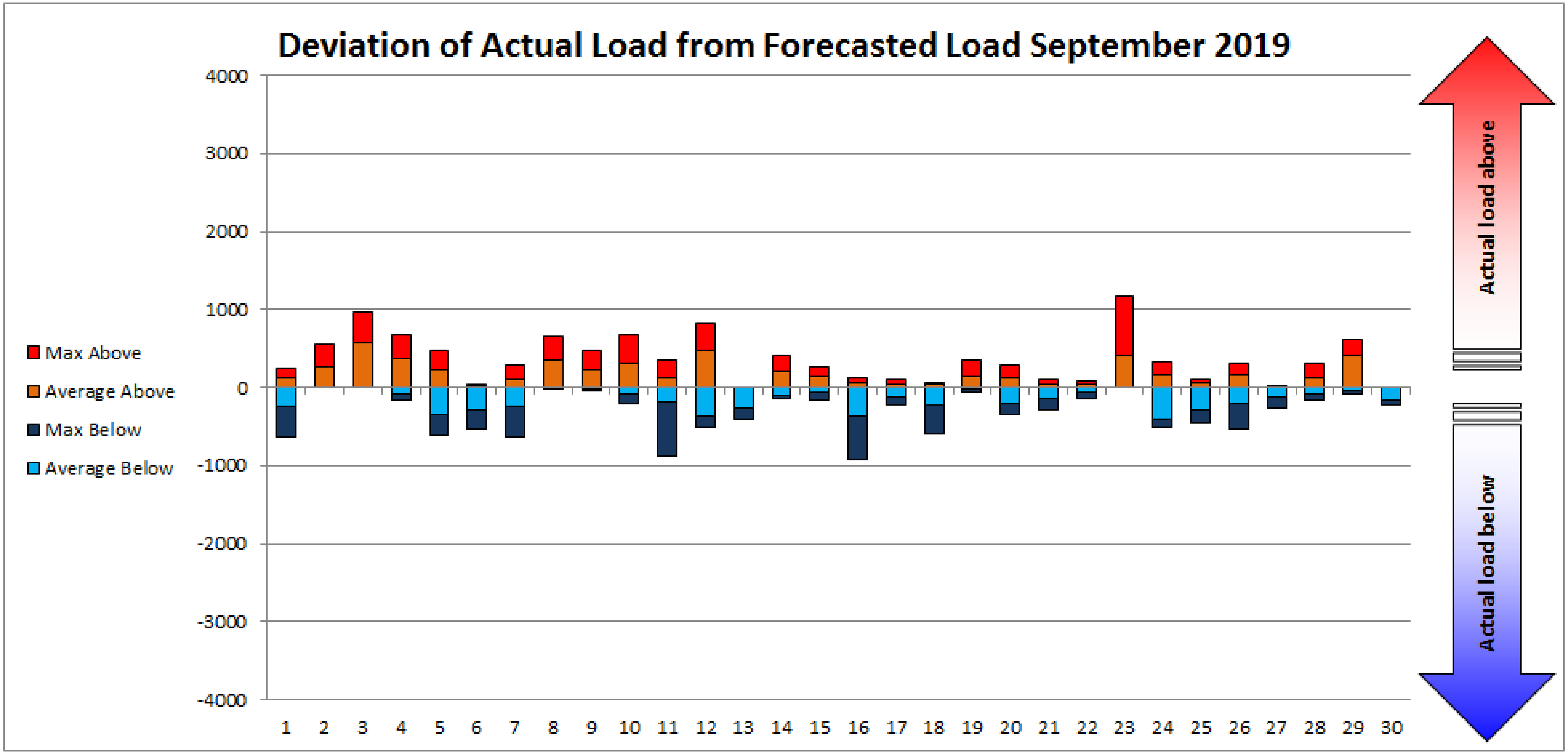

| Month | J | F | M | A | M | J | J | A | S | O | N | D | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Day Max | 3.17 | 3.03 | 3.23 | 2.71 | 4.08 | 7.39 | 10.38 | 7.27 | 4.53 | | | | 10.38 |
| Day Min | 0.02 | 0.06 | 0.06 | 0.12 | 0.07 | 0.07 | 0.01 | 0.16 | 0.07 | | | | 0.01 |
| MAPE | 1.22 | 1.04 | 1.06 | 1.04 | 1.45 | 2.53 | 2.72 | 2.37 | 1.67 | | | | 1.68 |
| Goal | 1.80 | 1.80 | 1.80 | 1.80 | 2.00 | 2.60 | 2.60 | 2.60 | 2.00 | | | | |

# 2019 System Operations - Load Forecast Accuracy cont.

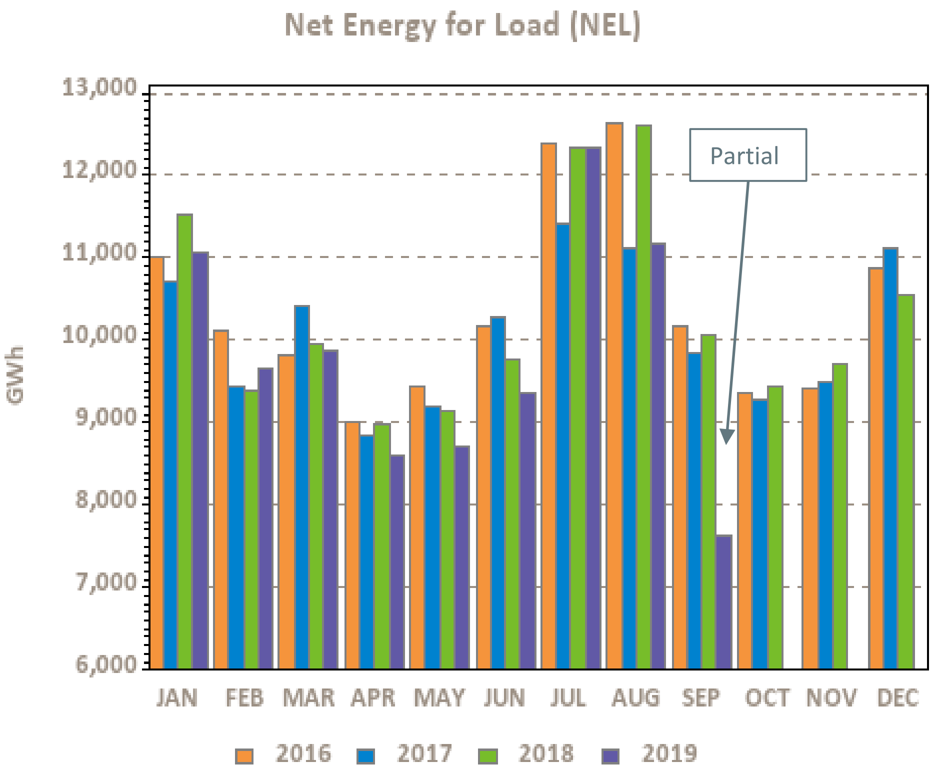



| | J | F | M | A | M | J | J | A | S | O | N | D | Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Above % | 51.1 | 64 | 50.5 | 44.2 | 32.5 | 37.9 | 41.7 | 49.6 | 46.7 | | | | 46 |
| Below % | 48.9 | 36 | 49.5 | 55.8 | 67.5 | 62.1 | 58.3 | 50.4 | 53.3 | | | | 54 |
| Avg Above | 211.7 | 224.2 | 162.1 | 184.1 | 126.1 | 144.9 | 268.3 | 230.9 | 178.8 | | | | 268 |
| Avg Below | -183.0 | -174.3 | -192.4 | -161.7 | -179.6 | -225.1 | -350.1 | -220.1 | -158.3 | | | | -350 |
| Avg All | 30 | 88 | -12 | 1 | -79 | -80 | -108 | 8 | 10 | | | | -17 |

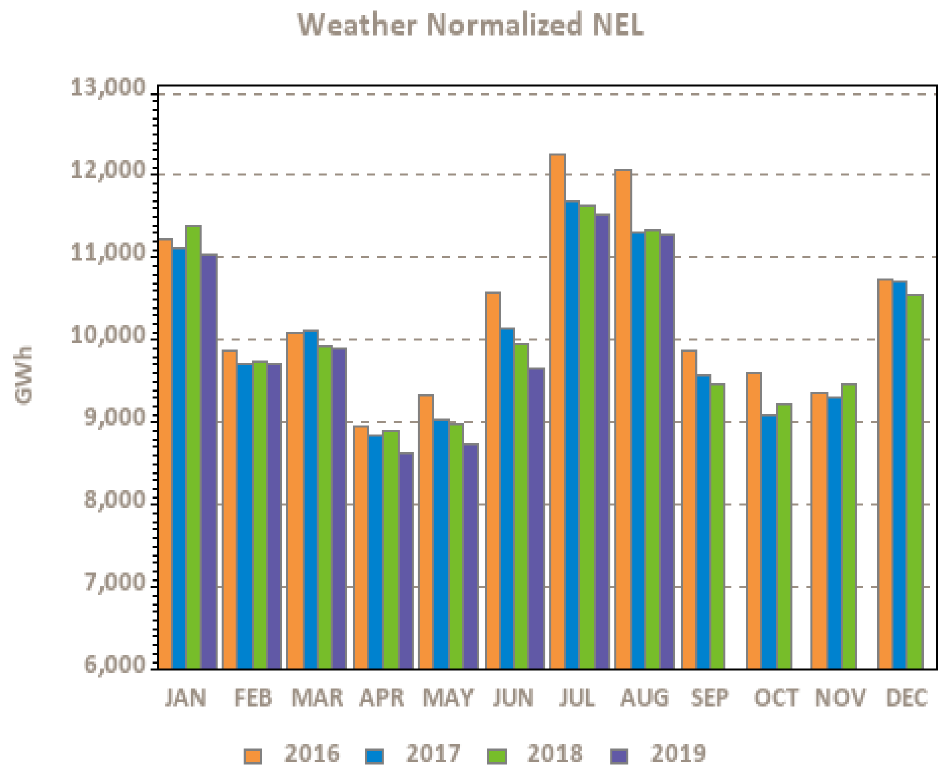
# 2019 System Operations - Load Forecast Accuracy cont.



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



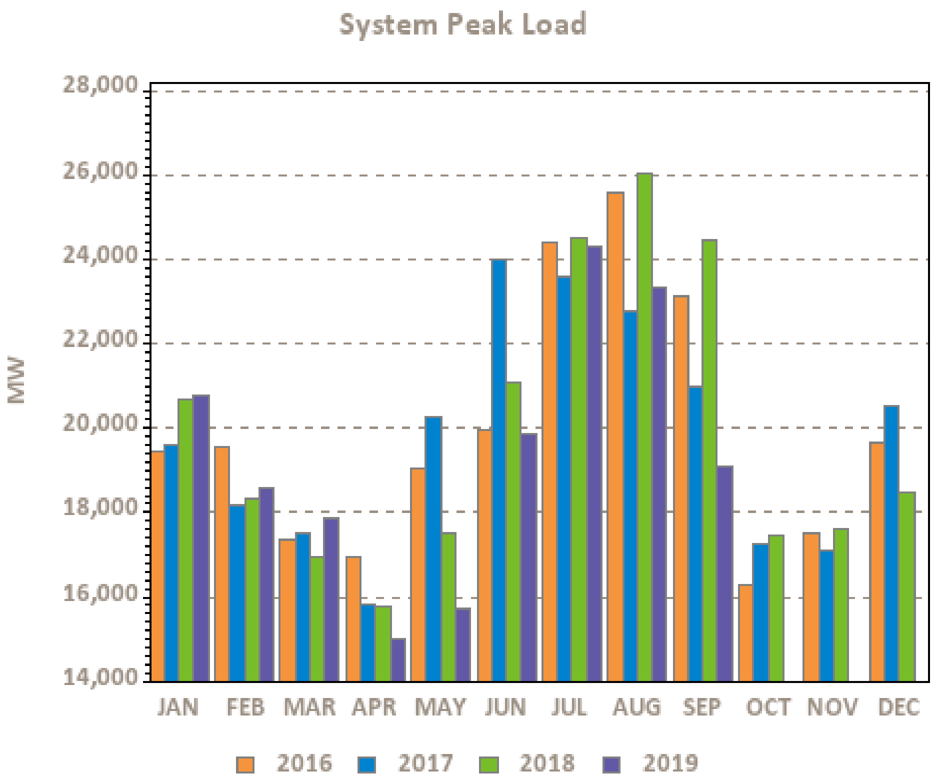

Ann Tot (TWh): 124.4 121.2 123.5 88.5



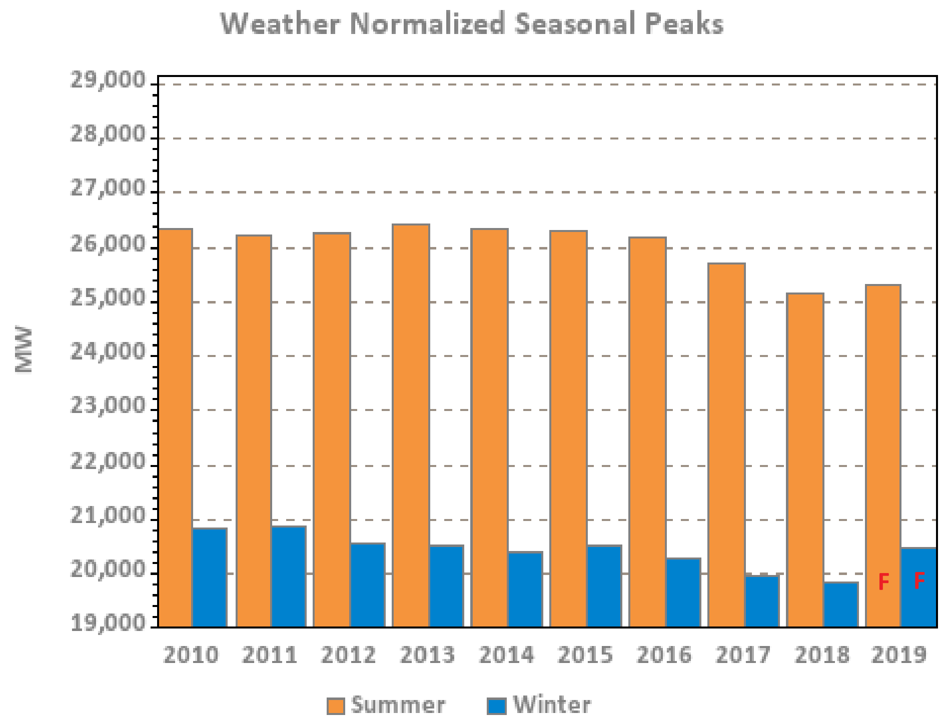

Ann Tot (TWh): 124.0 120.7 120.6 80.5

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

# Monthly Peak Loads and Weather Normalized Seasonal Peak History




Revenue quality metered value

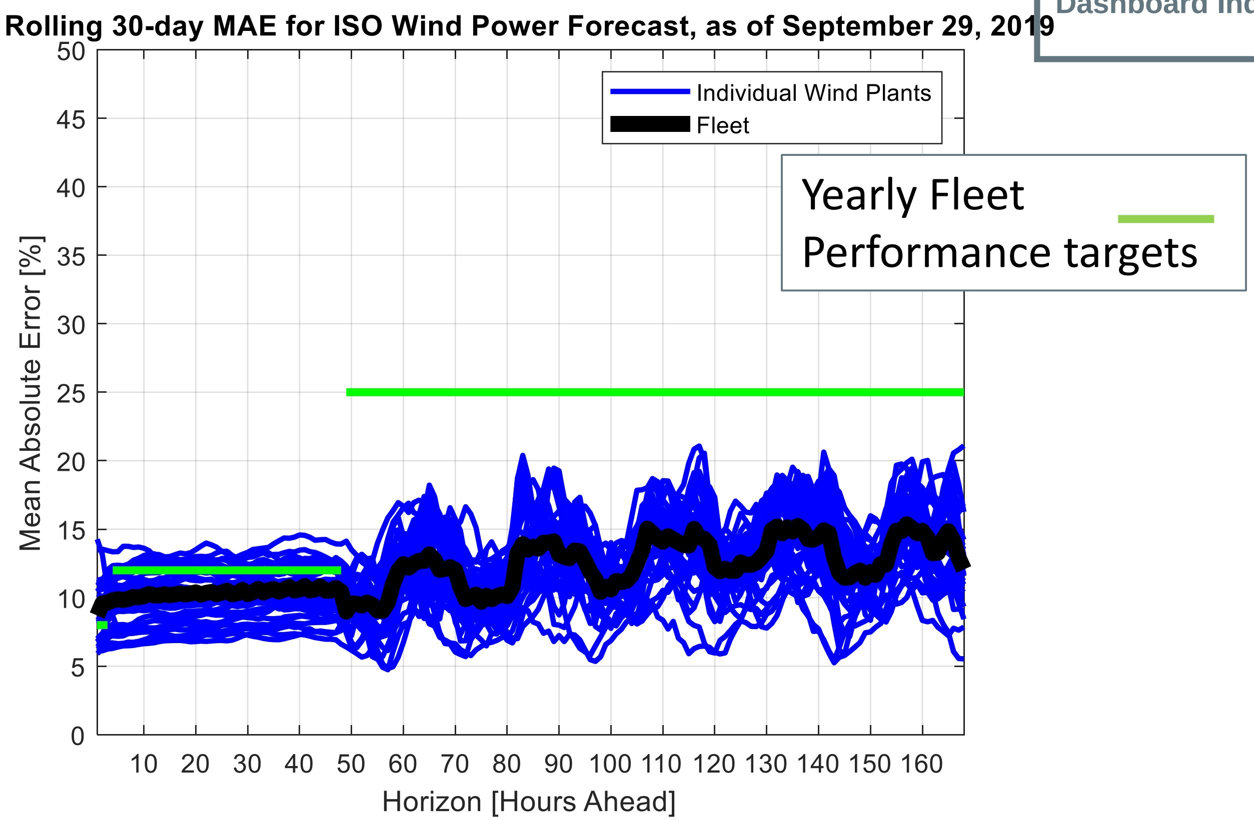



Winter beginning in year displayed

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

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

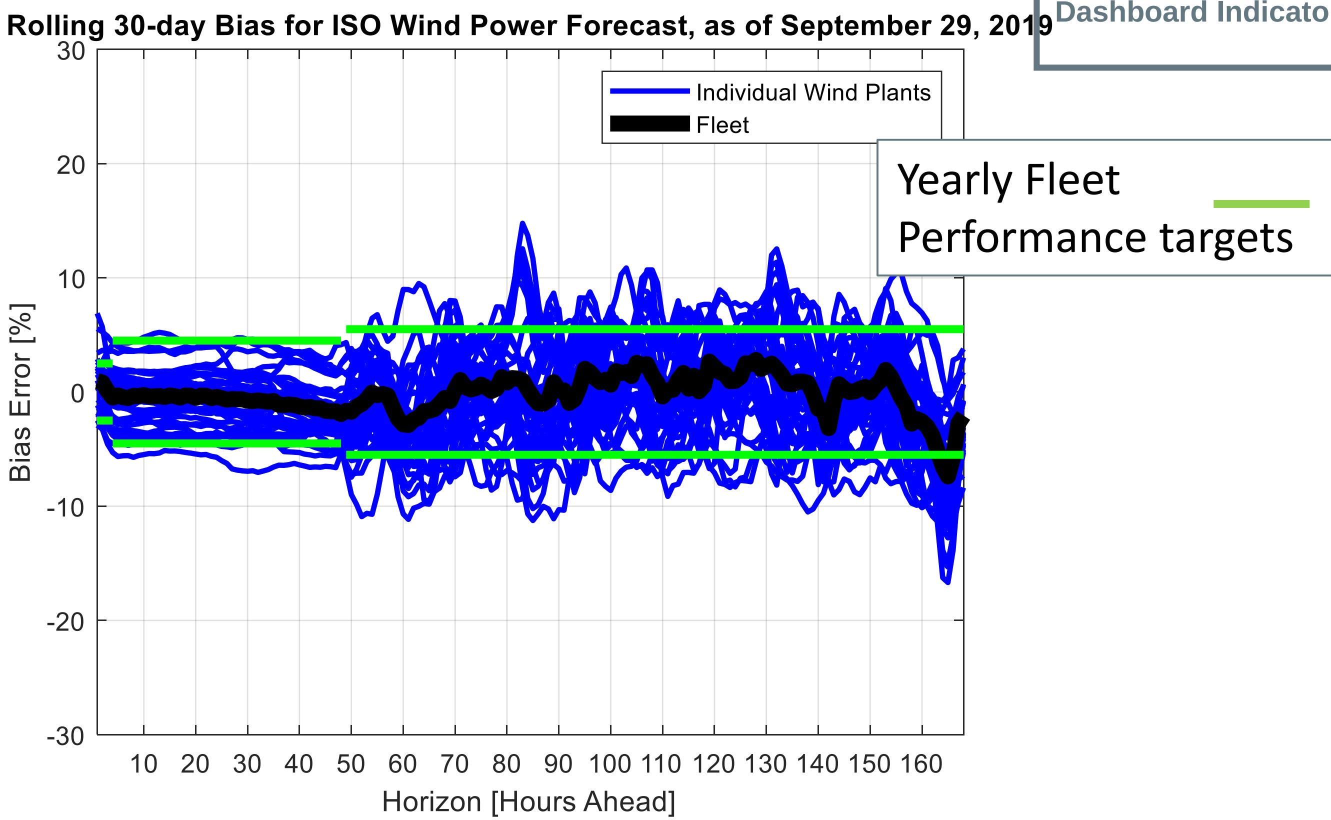
Dashboard Indicator




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

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

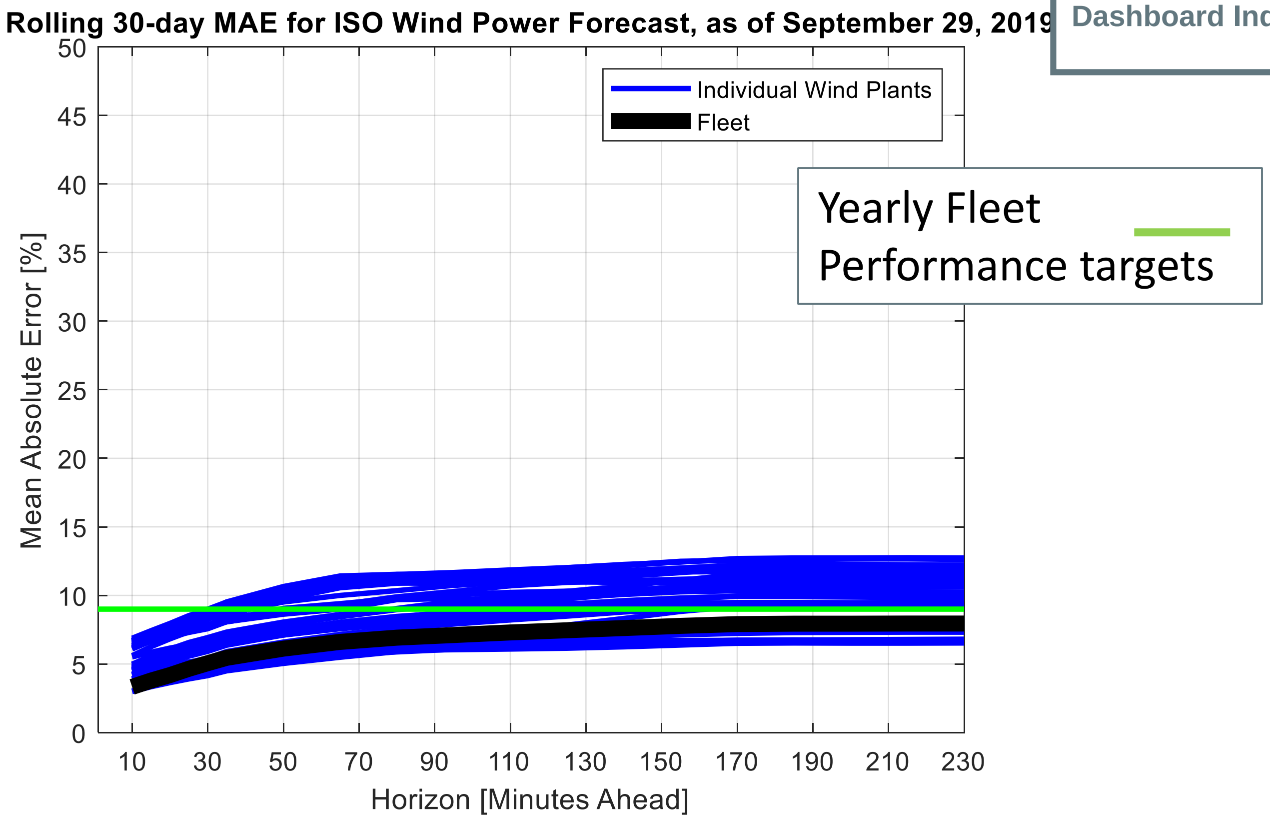
Dashboard Indicator




Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV-GL forecast compares well with industry standards, and, out to 167, hours monthly Bias is within yearly performance targets.

# Wind Power Forecast Error Statistics: Short Term Forecast MAE

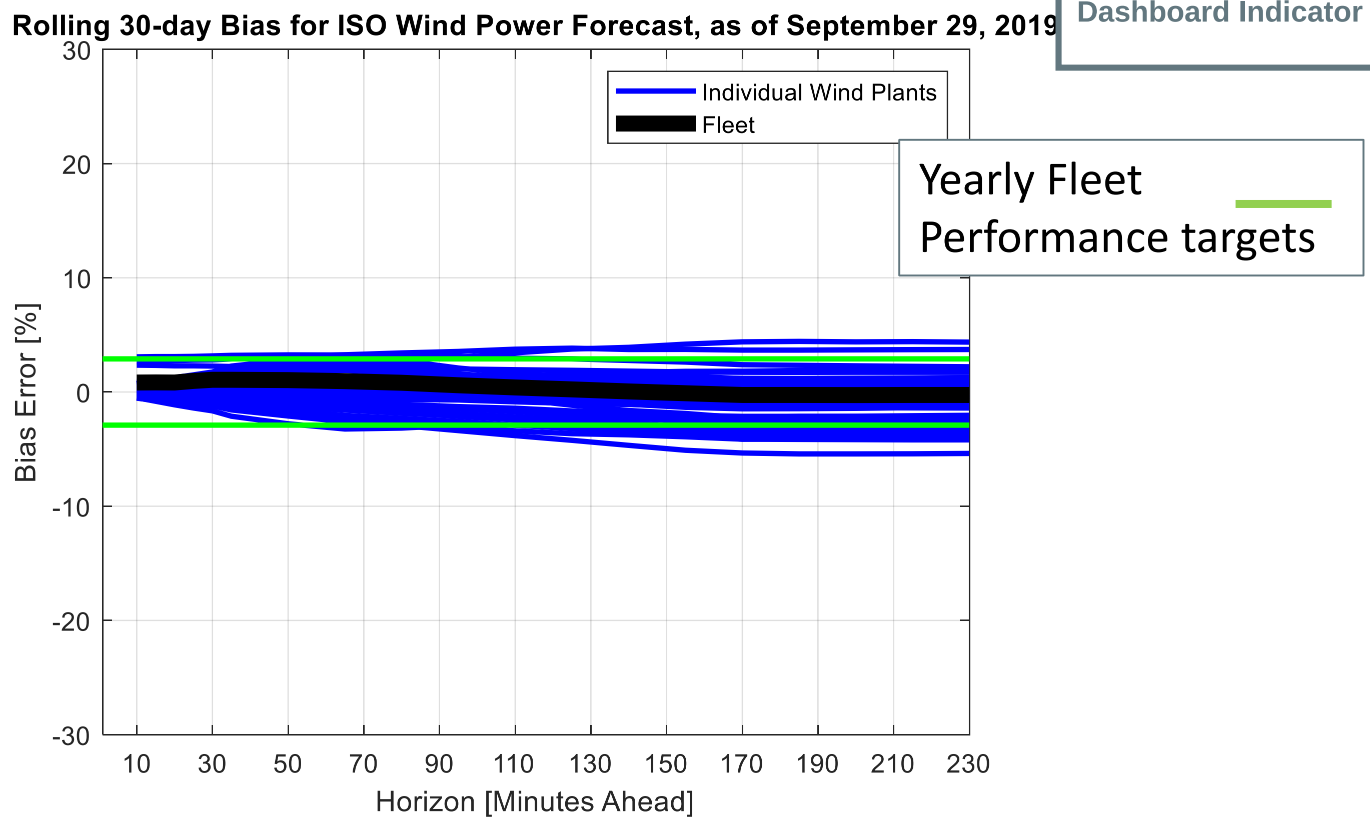
Dashboard Indicator




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

# Wind Power Forecast Error Statistics: Short Term Forecast Bias

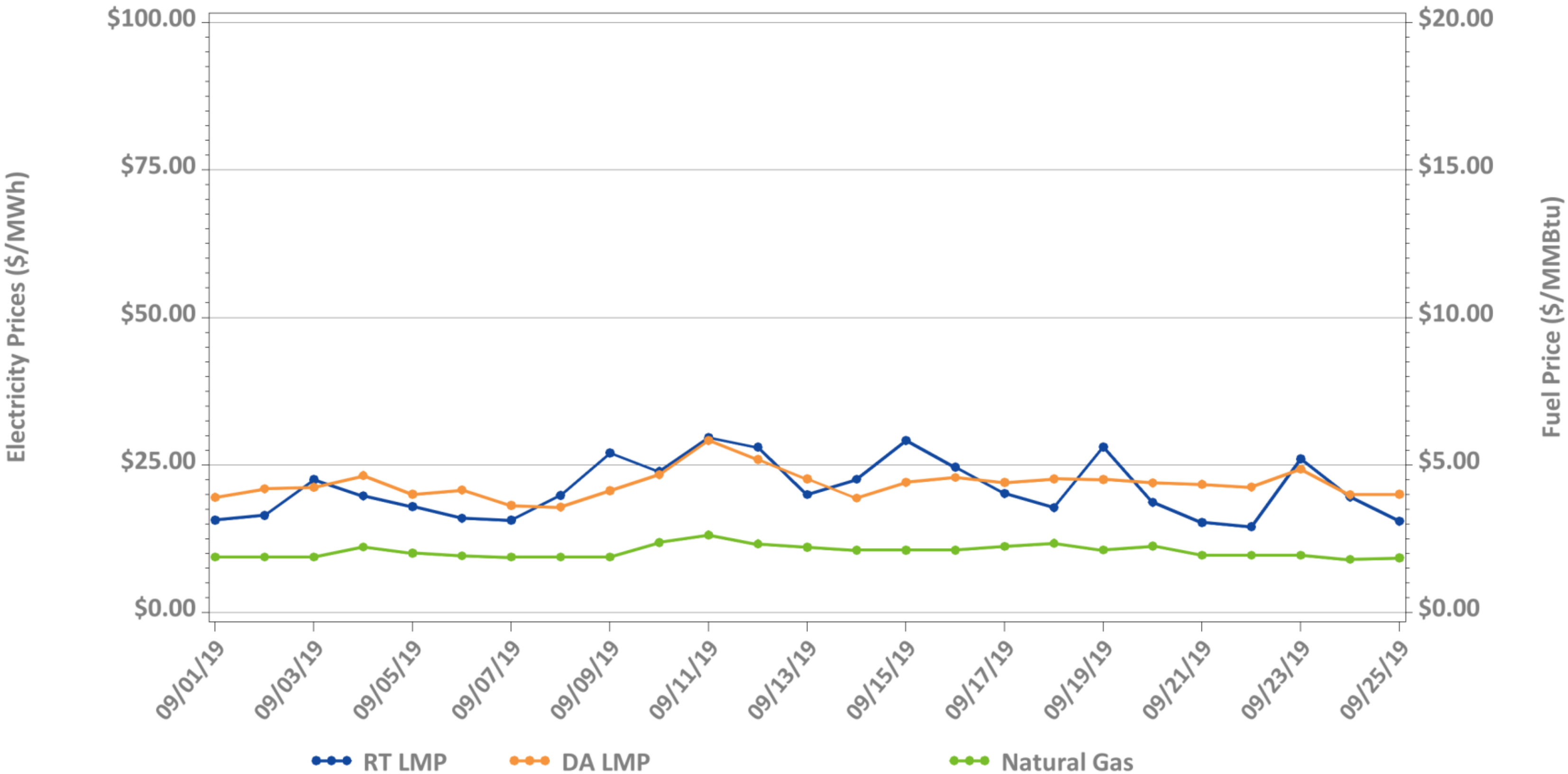
Dashboard Indicator




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: September 1-25, 2019




Underlying natural gas data furnished by:

ICE Global markets in clear view

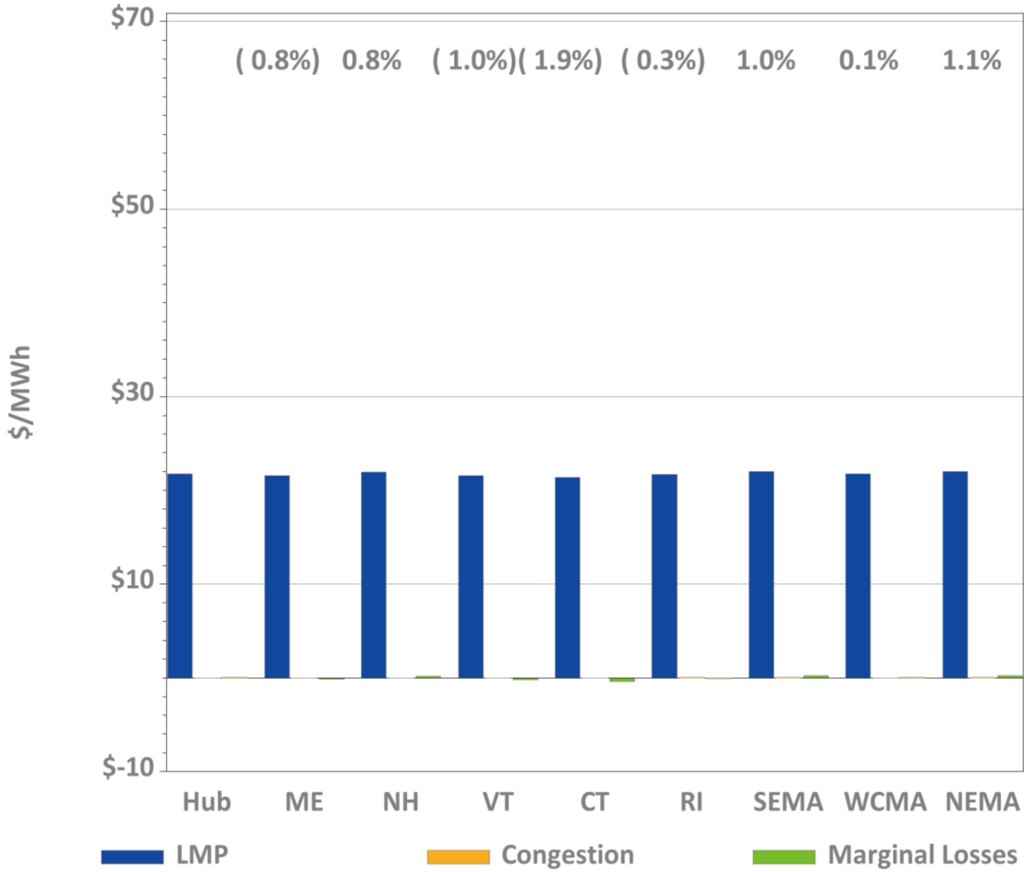
Average price difference over this period (DA-RT): $0.80

Average price difference over this period ABS(DA-RT): $3.36

Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 16%

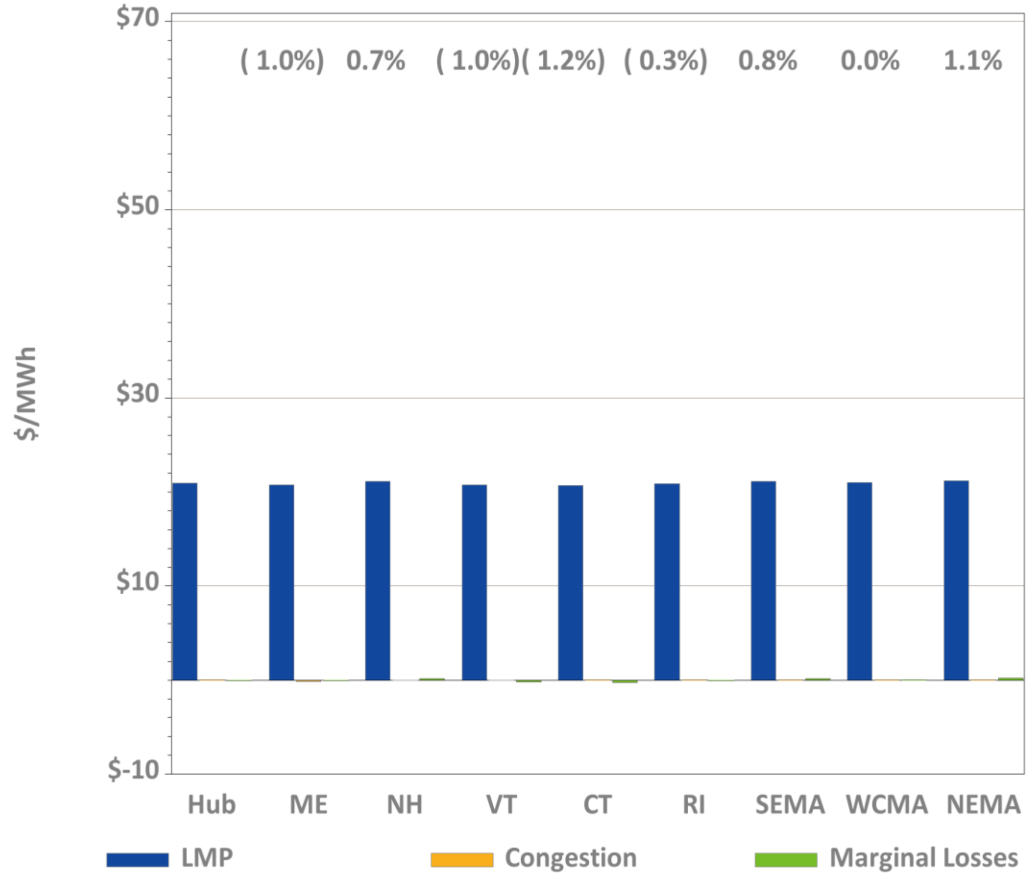
Gas price is average of Massachusetts delivery points

# DA LMPs Average by Zone & Hub, September 2019




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

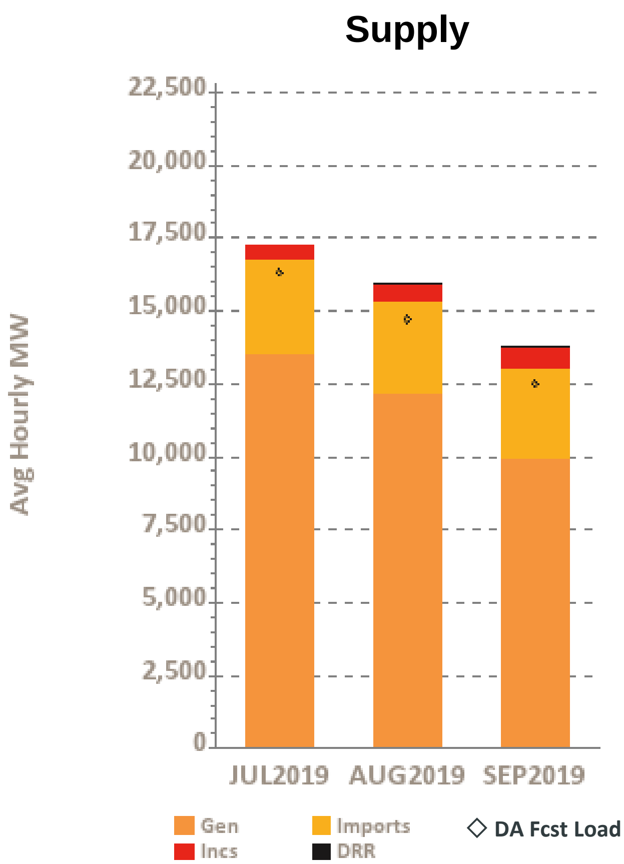
# RT LMPs Average by Zone & Hub, September 2019



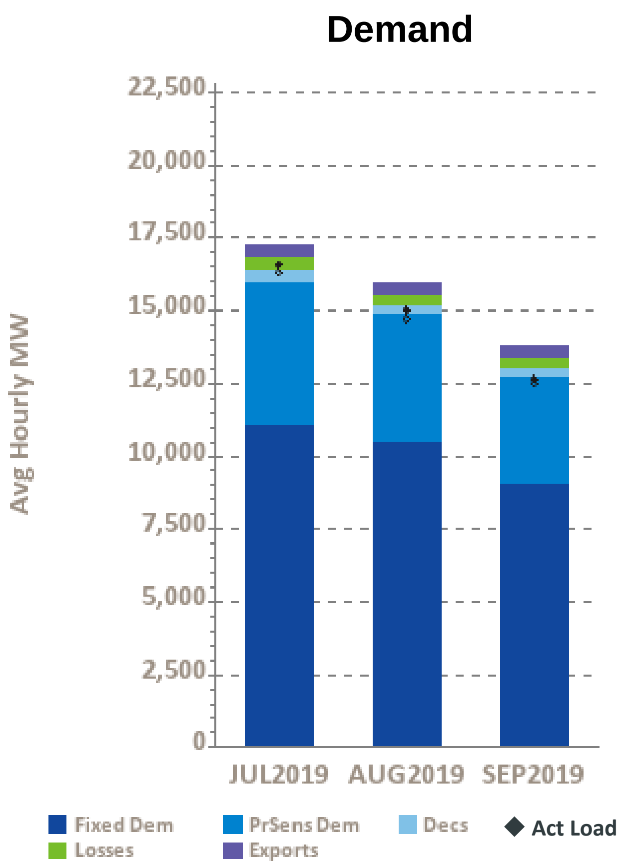
# Definitions

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

# Components of Cleared DA Supply and Demand – Last Three Months

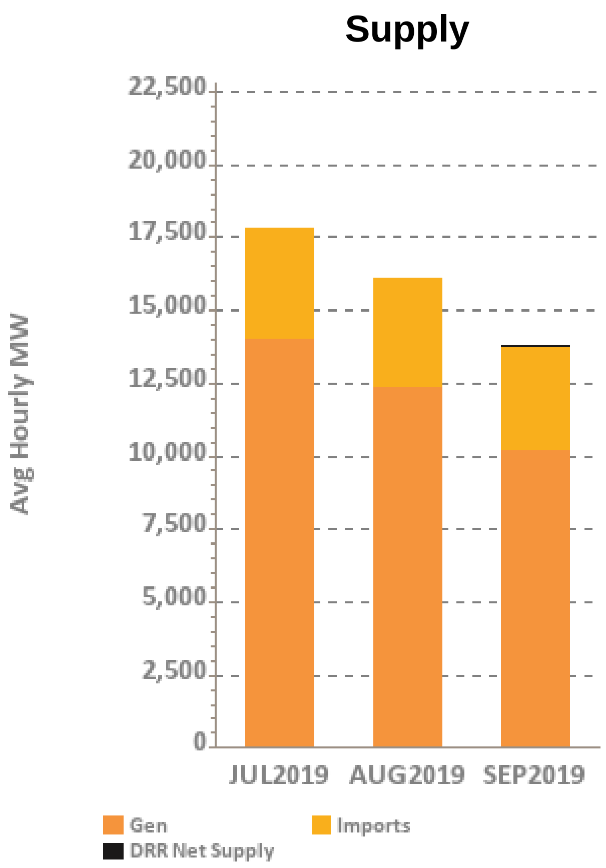


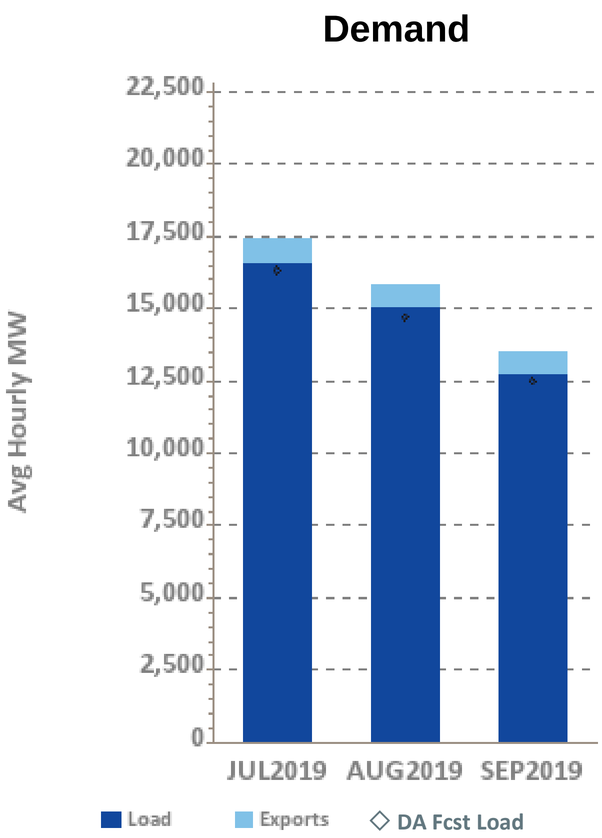

Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load



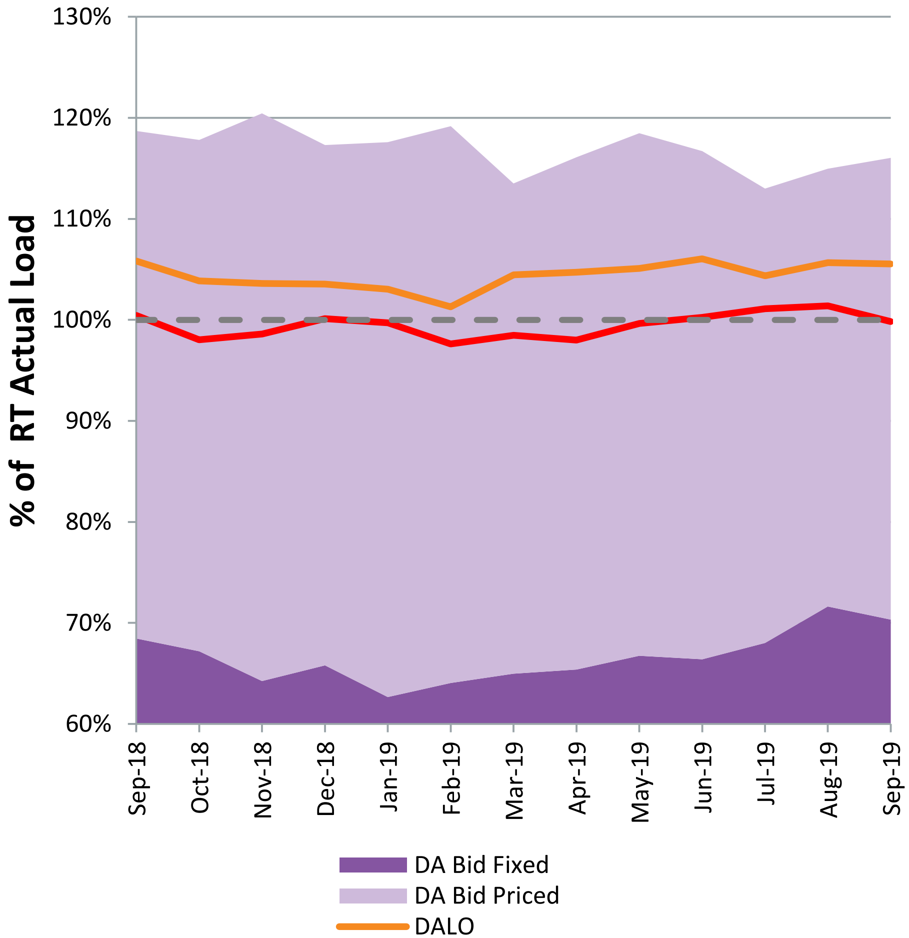

Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

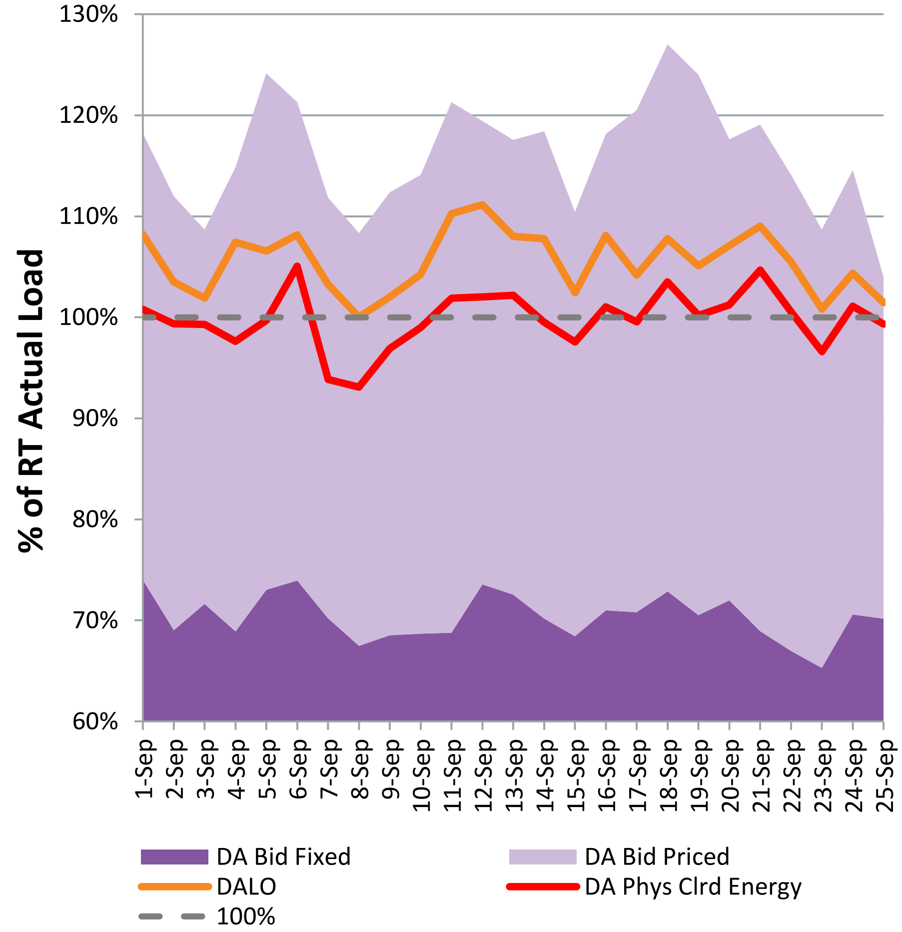
# Components of RT Supply and Demand – Last Three Months



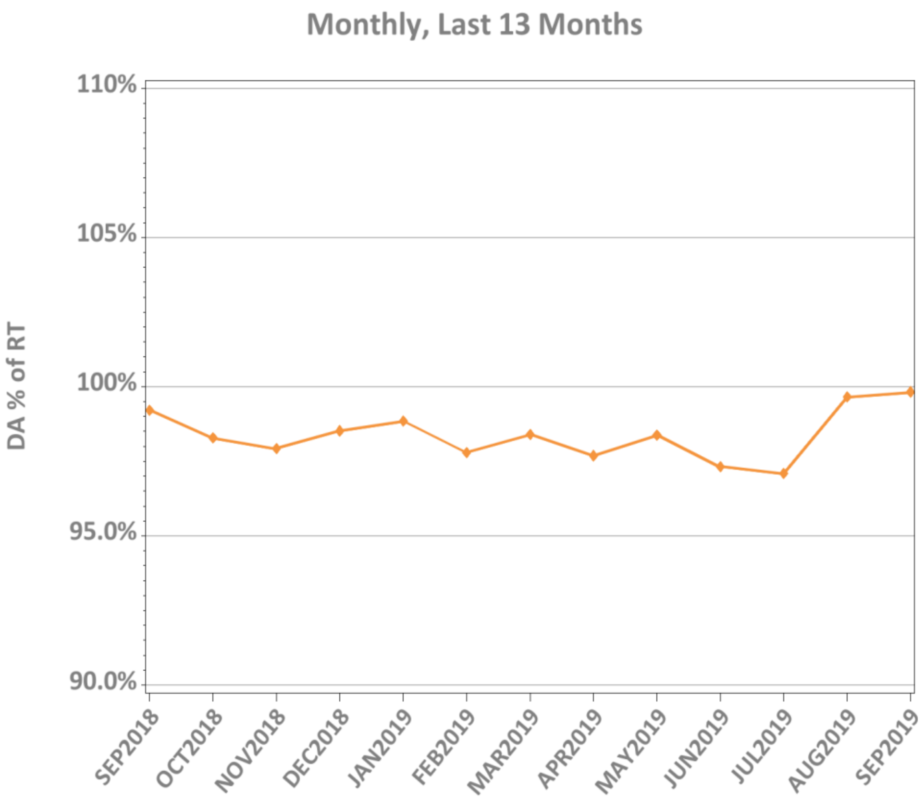
# DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

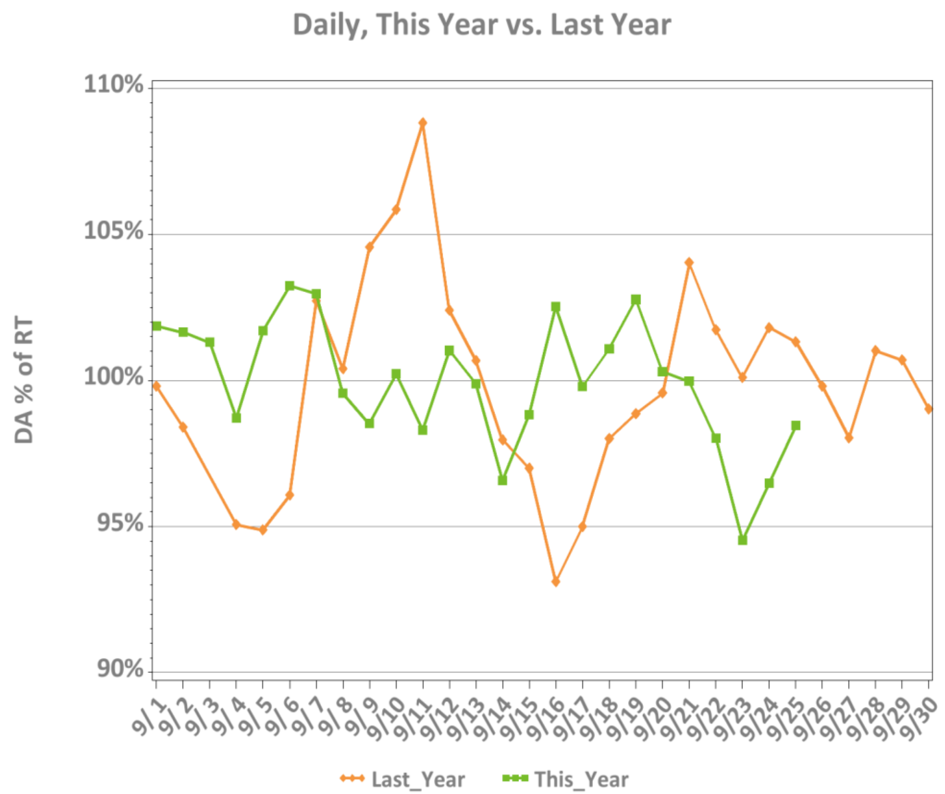



**Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load. DA Bid categories reflect internal load asset bidding behavior (Virtual demand and export bid behavior not reflected).**

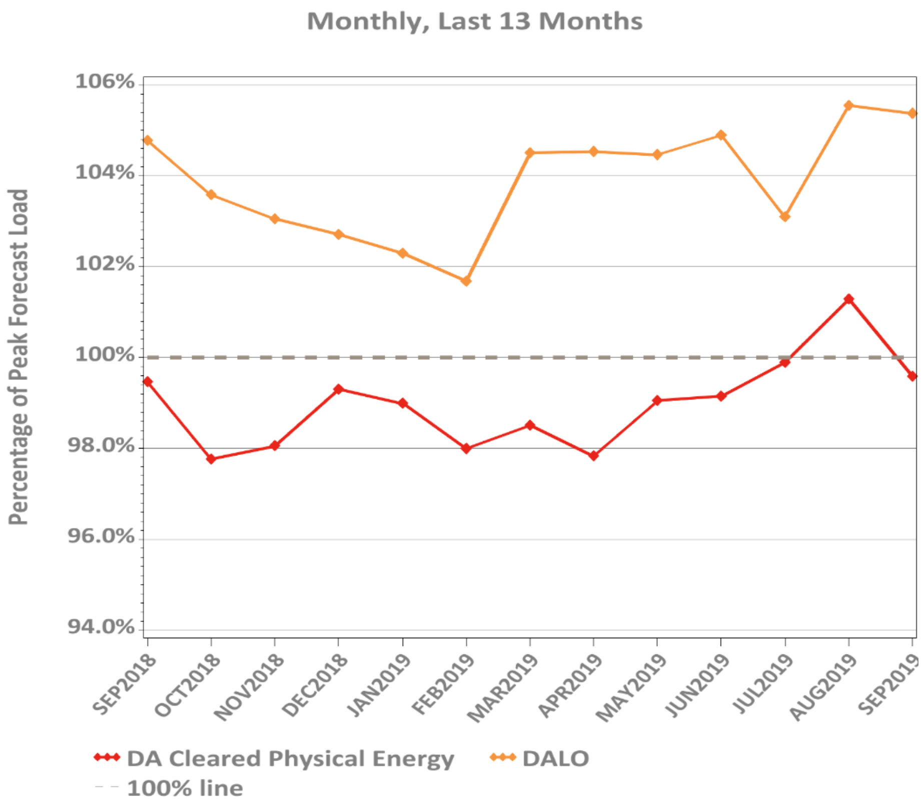
# DA vs. RT Load Obligation: September, This Year vs. Last Year

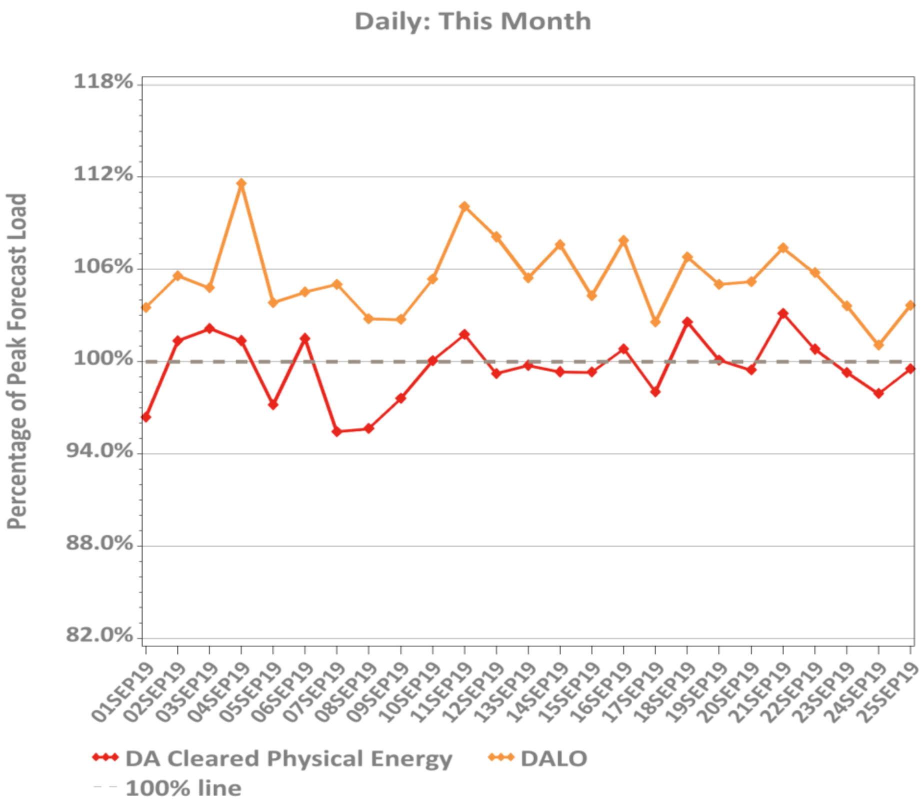



*Hourly average values

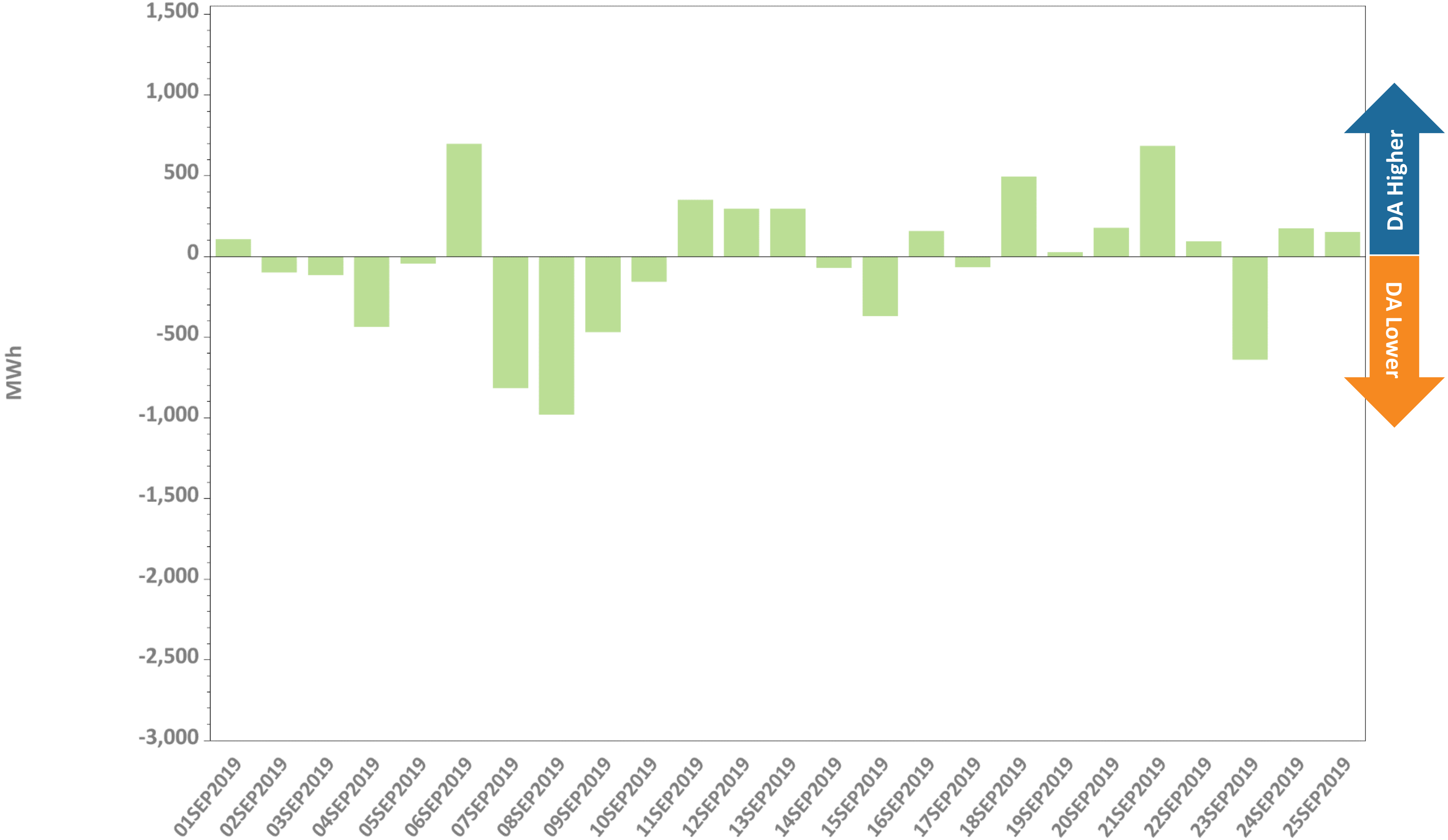
# DA Volumes as % of Forecast in Peak Hour



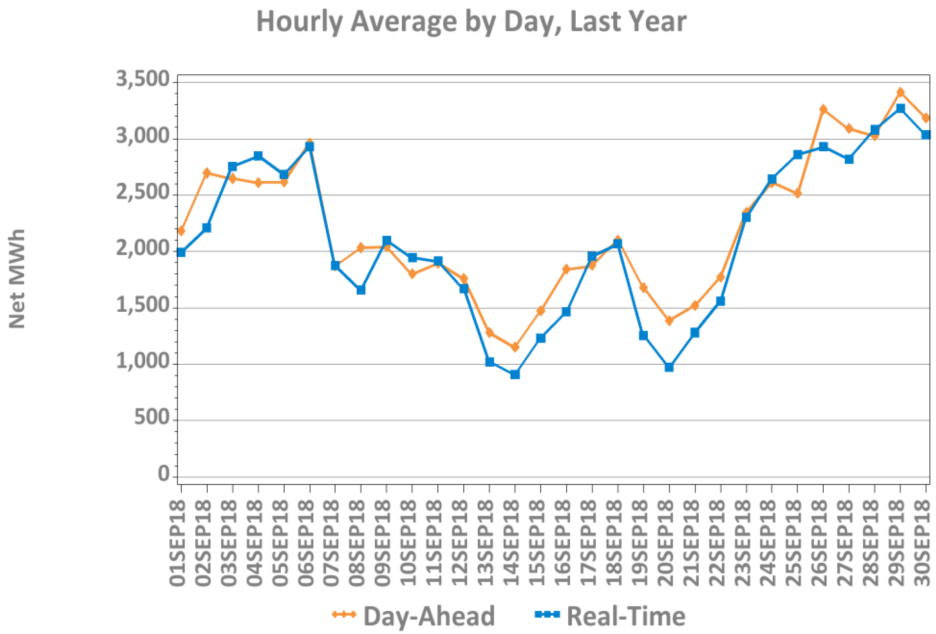

* There were no supplemental commitments required for capacity during the Reserve Adequacy Assessment (RAA) during September.

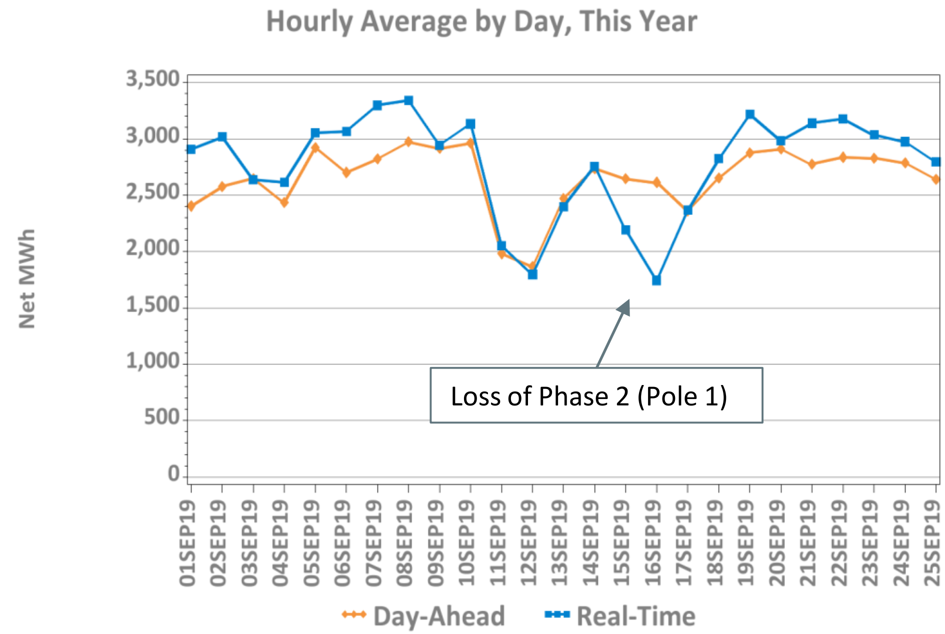
# DA Cleared Physical Energy Difference from RT System Load at Peak Hour*




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

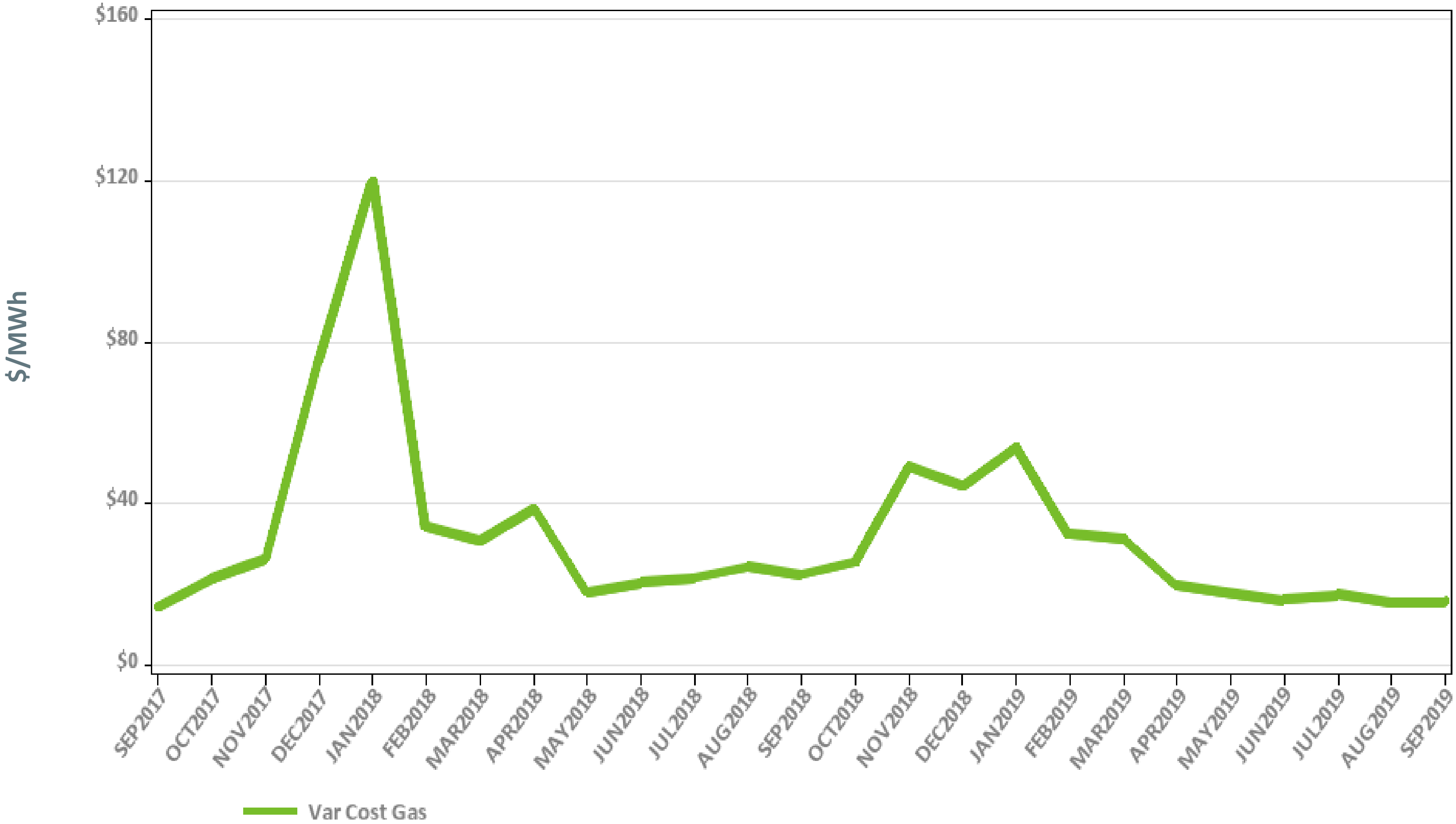
# DA vs. RT Net Interchange
# September 2019 vs. September 2018




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

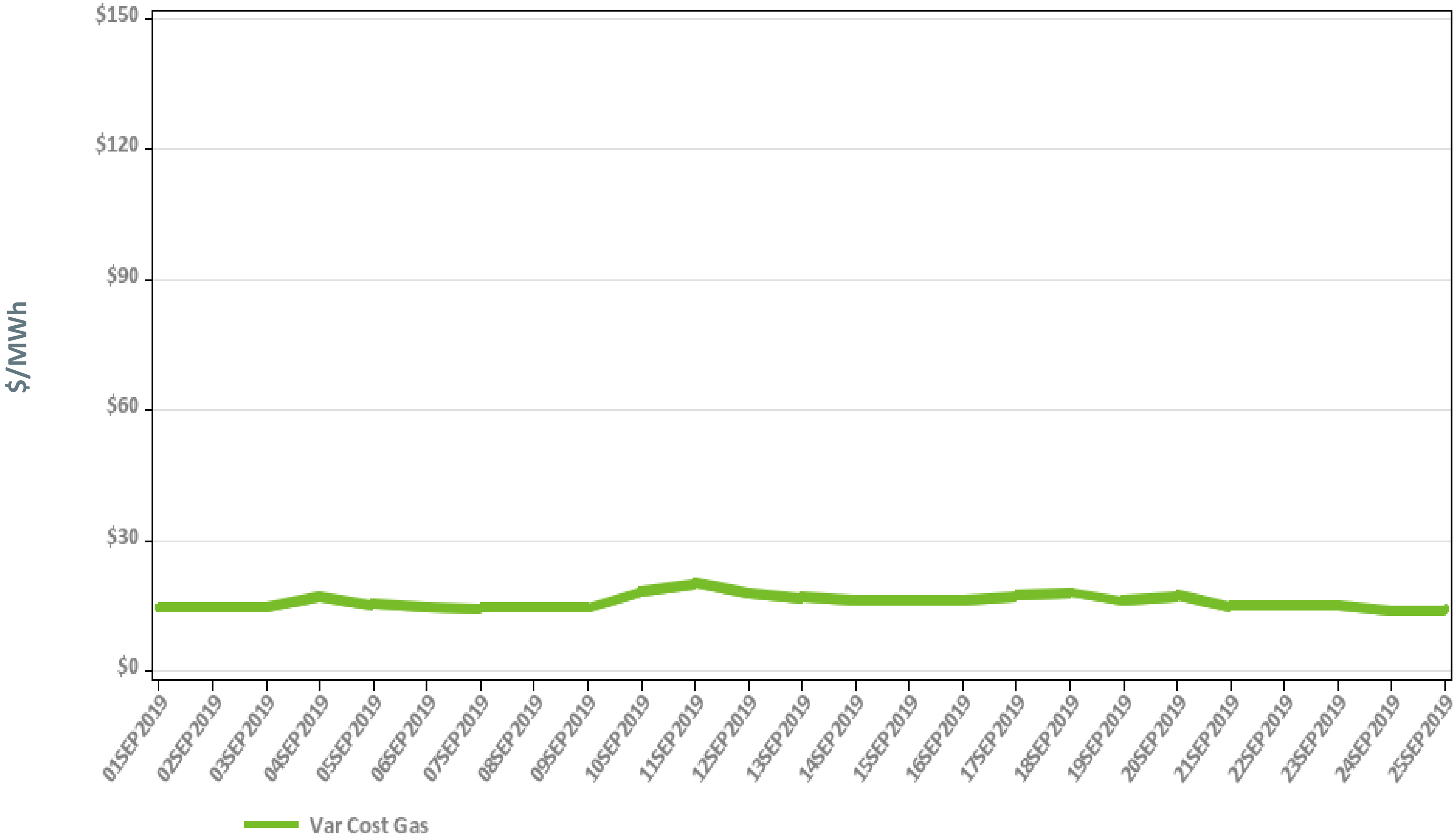
# Variable Production Cost of Natural Gas: Monthly




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

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

# Variable Production Cost of Natural Gas: Daily

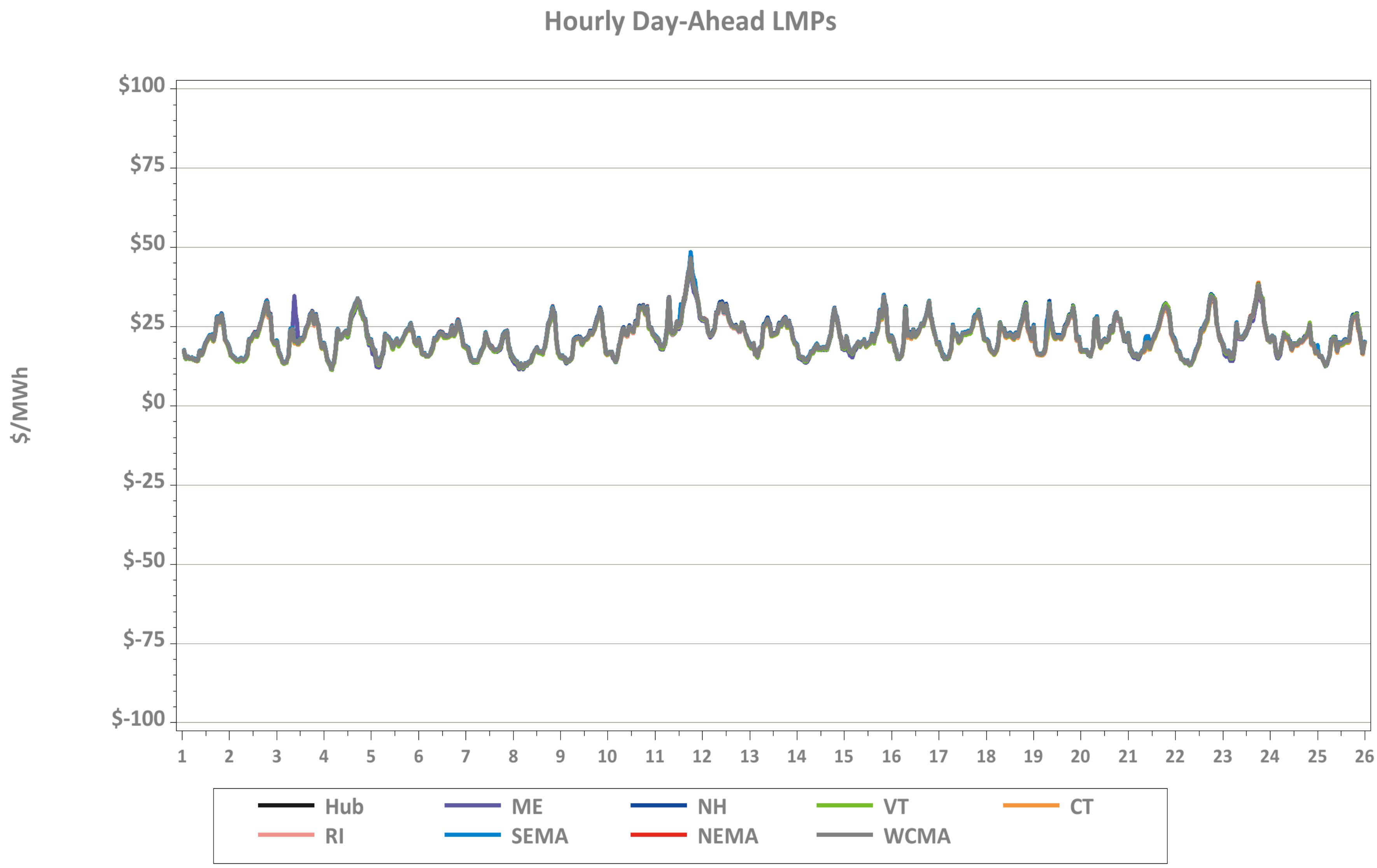



Underlying natural gas data furnished by:

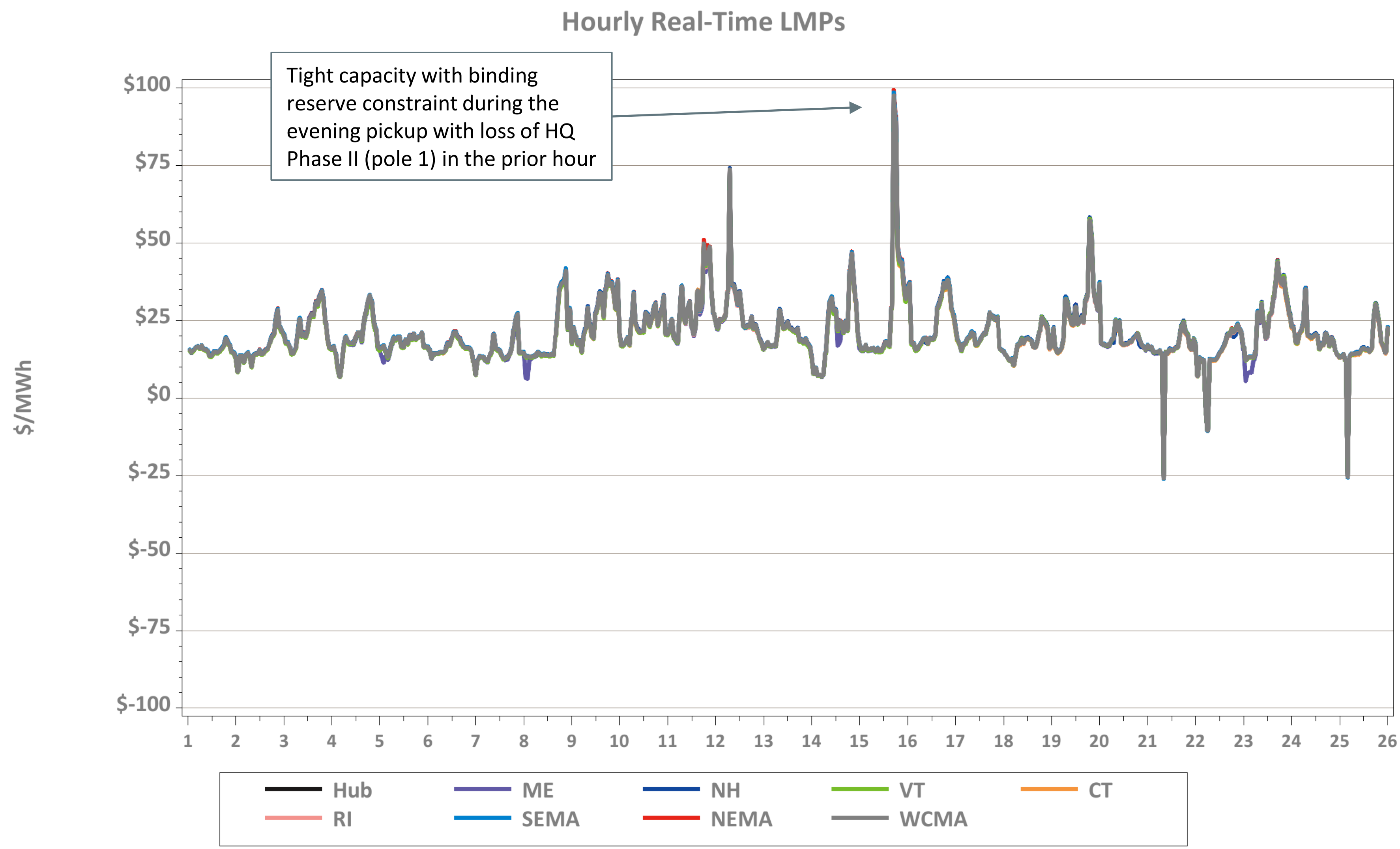
ICE Global markets in clear view

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

# Hourly DA LMPs, September 1-25, 2019

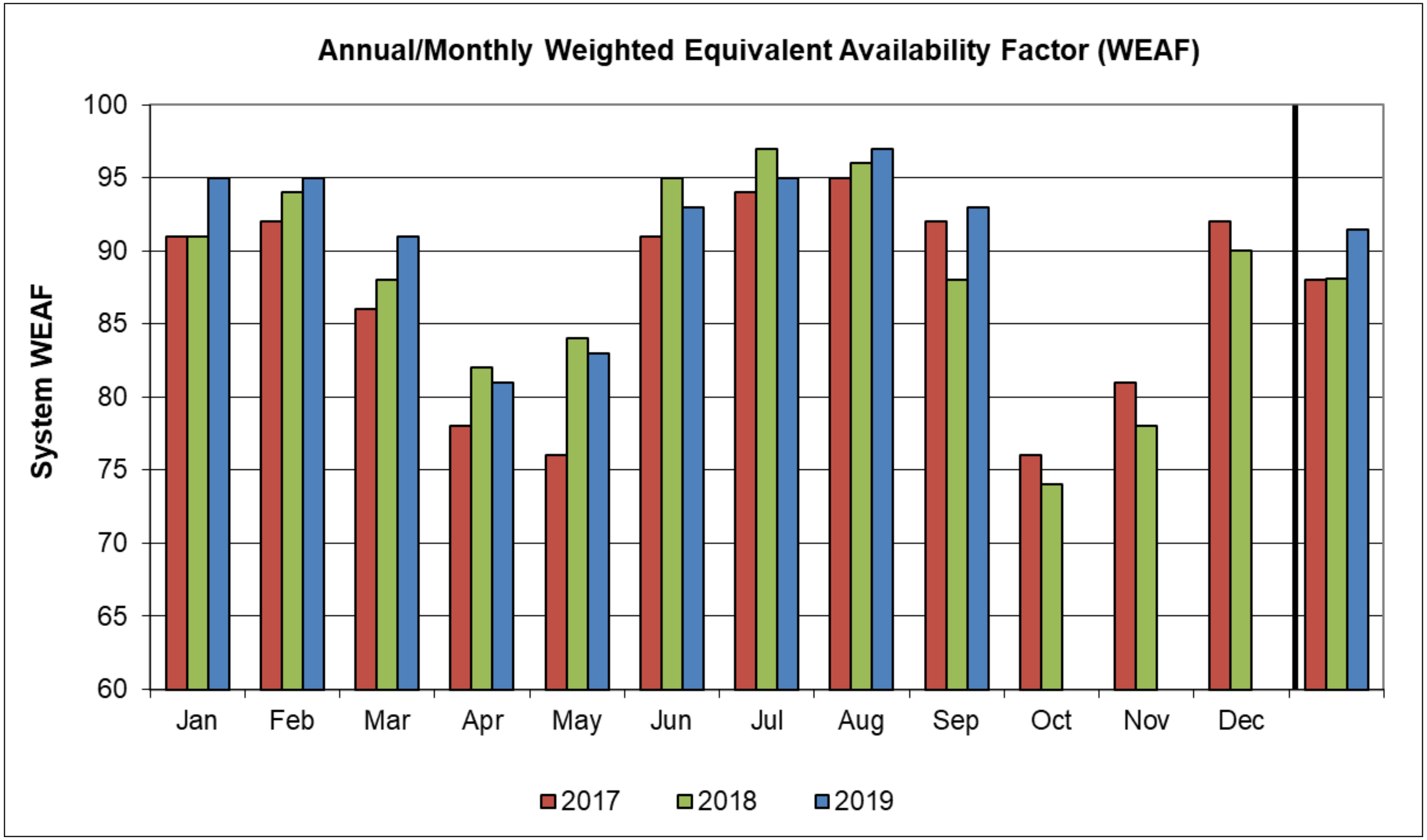


# Hourly RT LMPs, September 1-25, 2019




- No Minimum Generation Emergencies were declared during September.

# System Unit Availability




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

Data as of 9/26/19

# BACK-UP DETAIL

# DEMAND RESPONSE

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

| Load Zone | ADCR* | On Peak | Seasonal Peak | Total |
|---|---|---|---|---|
| ME | 102.6 | 186.1 | 0.0 | 288.7 |
| NH | 28.6 | 107.9 | 0.0 | 136.5 |
| VT | 30.2 | 120.0 | 0.0 | 150.2 |
| CT | 104.8 | 125.9 | 457.9 | 688.7 |
| RI | 20.4 | 230.0 | 0.0 | 250.4 |
| SEMA | 25.4 | 409.7 | 0.0 | 435.1 |
| WCMA | 57.7 | 412.3 | 49.6 | 519.7 |
| NEMA | 49.8 | 667.8 | 0.0 | 717.6 |
| **Total** | **419.6** | **2,259.7** | **507.5** | **3,186.9** |

*** Active Demand Capacity Resources**

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

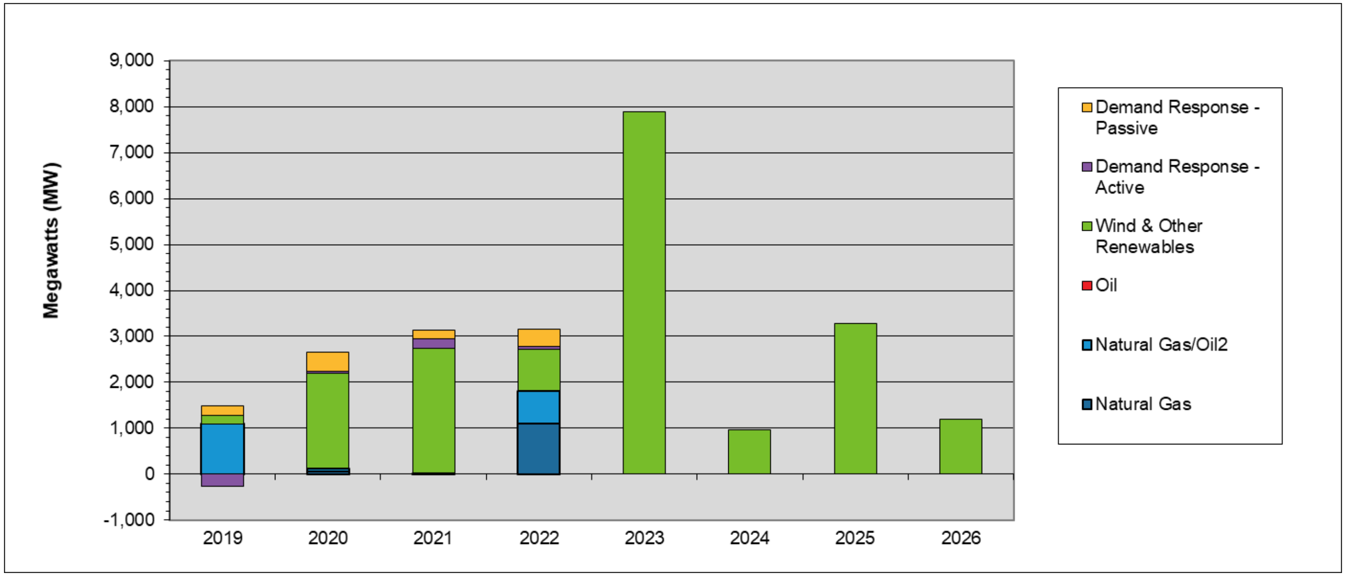
# NEW GENERATION

# New Generation Update
## *Based on Queue as of 9/30/19*

- 2 projects totaling 1,220 MW applied for interconnection study since the last update
- 1 project withdrew, 2 went commercial and net decreases in project capacities resulted in a net increase in new generation projects of 940 MW
- In total, 183 generation projects are currently being tracked by the ISO, totaling approximately 21,140 MW

# Actual and Projected Annual Capacity Additions

## *By Supply Fuel Type and Demand Resource Type*



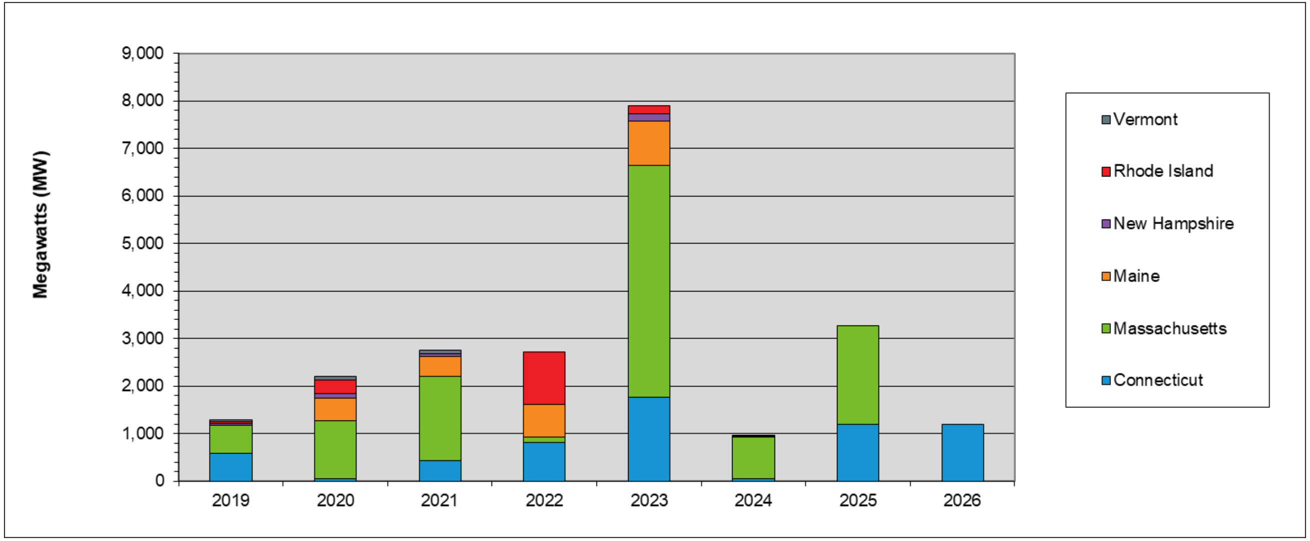

| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | Total MW | % of Total[1] |
|---|---|---|---|---|---|---|---|---|---|---|
| **Demand Response - Passive** | 212 | 422 | 184 | 380 | 0 | 0 | 0 | 0 | 1,199 | 5.1 |
| **Demand Response - Active** | -270 | 42 | 204 | 62 | 0 | 0 | 0 | 0 | 39 | 0.2 |
| **Wind & Other Renewables** | 187 | 2,070 | 2,719 | 898 | 7,901 | 960 | 3,276 | 1,200 | 19,211 | 81.7 |
| **Oil** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 |
| **Natural Gas/Oil[2]** | 1,097 | 76 | 0 | 711 | 0 | 0 | 0 | 0 | 1,884 | 8.0 |
| **Natural Gas** | 0 | 49 | 25 | 1,103 | 0 | 0 | 0 | 0 | 1,177 | 5.0 |
| **Totals** | **1,227** | **2,660** | **3,132** | **3,154** | **7,901** | **960** | **3,276** | **1,200** | **23,510** | **100.0** |

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

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

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

# Actual and Projected Annual Generator Capacity Additions
## *By State*




| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | Total MW | % of Total[1] |
|---|---|---|---|---|---|---|---|---|---|---|
| **Vermont** | 33 | 75 | 70 | 0 | 0 | 0 | 0 | 0 | 178 | 0.8 |
| **Rhode Island** | 50 | 282 | 0 | 1,103 | 356 | 0 | 0 | 0 | 1,791 | 8.5 |
| **New Hampshire** | 28 | 90 | 55 | 5 | 150 | 20 | 0 | 0 | 348 | 1.7 |
| **Maine** | 0 | 481 | 427 | 680 | 931 | 20 | 0 | 0 | 2,539 | 12.0 |
| **Massachusetts** | 592 | 1,212 | 1,770 | 116 | 4,704 | 880 | 2,076 | 0 | 11,350 | 53.9 |
| **Connecticut** | 581 | 55 | 422 | 808 | 1,760 | 40 | 1,200 | 1,200 | 4,866 | 23.1 |
| **Totals** | **1,284** | **2,195** | **2,744** | **2,712** | **7,901** | **960** | **3,276** | **1,200** | **21,072** | **100.0** |

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

# New Generation Projection
## *By Fuel Type*

| Fuel Type | Total | | Green | | Yellow | |
|---|---|---|---|---|---|---|
| | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) |
| Biomass/wood waste | 1 | 37 | 0 | 0 | 1 | 37 |
| Hydro | 2 | 71 | 0 | 0 | 2 | 71 |
| Landfill Gas | 0 | 0 | 0 | 0 | 0 | 0 |
| Natural Gas | 7 | 1,240 | 0 | 0 | 7 | 1,240 |
| Natural Gas/Oil | 6 | 832 | 1 | 45 | 5 | 787 |
| Oil | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar | 120 | 3,176 | 2 | 51 | 118 | 3,125 |
| Wind | 25 | 13,722 | 2 | 33 | 23 | 13,689 |
| Battery storage | 22 | 2,064 | 0 | 0 | 22 | 2,064 |
| Total | 183 | 21,142 | 5 | 129 | 178 | 21,013 |

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

# New Generation Projection

## *By Operating Type*

| Operating Type | Total | | Green | | Yellow | |
|---|---|---|---|---|---|---|
| | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) |
| Baseload | 5 | 130 | 0 | 0 | 5 | 130 |
| Intermediate | 3 | 1,146 | 0 | 0 | 3 | 1,146 |
| Peaker | 150 | 6,144 | 3 | 96 | 147 | 6,048 |
| Wind Turbine | 25 | 13,722 | 2 | 33 | 23 | 13,689 |
| Total | 183 | 21,142 | 5 | 129 | 178 | 21,013 |

- 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*

| Fuel Type | Total | | Baseload | | Intermediate | | Peaker | | Wind Turbine | |
|---|---|---|---|---|---|---|---|---|---|---|
| | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) |
| Biomass/wood waste | 1 | 37 | 1 | 37 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro | 2 | 71 | 1 | 5 | 0 | 0 | 1 | 66 | 0 | 0 |
| Landfill Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Natural Gas | 7 | 1,240 | 3 | 88 | 3 | 1,146 | 1 | 6 | 0 | 0 |
| Natural Gas/Oil | 6 | 832 | 0 | 0 | 0 | 0 | 6 | 832 | 0 | 0 |
| Oil | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar | 120 | 3,176 | 0 | 0 | 0 | 0 | 120 | 3,176 | 0 | 0 |
| Wind | 25 | 13,722 | 0 | 0 | 0 | 0 | 0 | 0 | 25 | 13,722 |
| Battery storage | 22 | 2,064 | 0 | 0 | 0 | 0 | 22 | 2,064 | 0 | 0 |
| Total | 183 | 21,142 | 5 | 130 | 3 | 1,146 | 150 | 6,144 | 25 | 13,722 |

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

# FORWARD CAPACITY MARKET

# Capacity Supply Obligation FCA 10

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

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

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

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

# Capacity Supply Obligation FCA 11

| Resource Type | Resource Type | FCA | ARA 1 | | ARA 2 | | ARA 3 | |
|---|---|---|---|---|---|---|---|---|
| | | *CSO | CSO | Change | CSO | Change | CSO | Change |
| | | MW | MW | MW | MW | MW | MW | MW |
| Demand | *Active Demand* | 419.928 | 441.221 | 21.293 | 594.551 | 153.33 | | |
| | *Passive Demand* | 2,791.02 | 2,835.354 | 44.334 | 2,883.767 | 48.413 | | |
| **Demand Total** | | **3,210.95** | **3,276.575** | **65.625** | **3,478.318** | **201.743** | | |
| Generator | *Non-Intermittent* | 30,494.80 | 30,064.23 | -430.569 | 30,159.891 | 95.661 | | |
| | *Intermittent* | 894.217 | 823.796 | -70.421 | 809.571 | -14.225 | | |
| **Generator Total** | | **31,389.02** | **30,888.03** | **-500.993** | **30,969.462** | **81.432** | | |
| **Import Total** | | **1,235.40** | **1,622.037** | **386.637** | **1,609.844** | **-12.193** | | |
| ****Grand Total** | | **35,835.37** | **35,786.64** | **-48.731** | **36,057.624** | **270.984** | | |
| **Net ICR (NICR)** | | **34,075** | **33,660** | **-415** | **33,520** | **-140** | | |

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

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

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

# Capacity Supply Obligation FCA 12

| Resource Type | Resource Type | | FCA | ARA 1 | | ARA 2 | | ARA 3 | |
|---|---|---|---|---|---|---|---|---|---|
| | | | *CSO | CSO | Change | CSO | Change | CSO | Change |
| | | | MW | MW | MW | MW | MW | MW | MW |
| Demand | *Active Demand* | | 624.445 | 659.137 | 34.692 | | | | |
| | *Passive Demand* | | 2,975.36 | 3,045.073 | 69.713 | | | | |
| **Demand Total** | | | **3,599.81** | **3,704.21** | **104.4** | | | | |
| Generator | | *Non-Intermittent* | 29,130.75 | 29,244.404 | 113.654 | | | | |
| | | *Intermittent* | 880.317 | 806.609 | -73.708 | | | | |
| **Generator Total** | | | **30,011.07** | **30,051.013** | **39.943** | | | | |
| **Import Total** | | | **1,217** | **1,305.487** | **88.487** | | | | |
| ****Grand Total** | | | **34,827.88** | **35,060.710** | **232.83** | | | | |
| **Net ICR (NICR)** | | | **33,725** | **33,550** | **-175** | | | | |

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

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

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

# Capacity Supply Obligation FCA 13

| Resource Type | Resource Type | FCA | ARA 1 | | ARA 2 | | ARA 3 | |
|---|---|---|---|---|---|---|---|---|
| | | *CSO | CSO | Change | CSO | Change | CSO | Change |
| | | MW | MW | MW | MW | MW | MW | MW |
| Demand | *Active Demand* | 685.554 | | | | | | |
| | *Passive Demand* | 3,354.69 | | | | | | |
| **Demand Total** | | **4,040.244** | | | | | | |
| Generator | *Non-Intermittent* | 28,586.498 | | | | | | |
| | *Intermittent* | 1,024.792 | | | | | | |
| **Generator Total** | | **2,9611.29** | | | | | | |
| **Import Total** | | **1,187.69** | | | | | | |
| ****Grand Total** | | **34,839.224** | | | | | | |
| **Net ICR (NICR)** | | **33,750** | | | | | | |

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

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

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

# Active/Passive Demand Response

## *CSO Totals by Commitment Period*

| Commitment Period | Active/ Passive | Existing | New | Grand Total |
|---|---|---|---|---|
| 2010-11 | Active | 1,246.40 | 603.675 | 1,850.07 |
| | Passive | 119.211 | 584.277 | 703.488 |
| | Grand Total | 1365.61 | 1187.952 | 2553.562 |
| 2011-12 | Active | 1,768.39 | 184.99 | 1,953.38 |
| | Passive | 719.98 | 263.25 | 983.23 |
| | Grand Total | 2488.372 | 448.24 | 2936.612 |
| 2012-13 | Active | 1,726.55 | 98.227 | 1,824.78 |
| | Passive | 861.602 | 211.261 | 1,072.86 |
| | Grand Total | 2588.15 | 309.488 | 2897.638 |
| 2013-14 | Active | 1,794.20 | 257.341 | 2,051.54 |
| | Passive | 1,040.11 | 257.793 | 1,297.91 |
| | Grand Total | 2834.308 | 515.134 | 3349.442 |
| 2014-15 | Active | 2,062.20 | 41.945 | 2,104.14 |
| | Passive | 1,264.64 | 221.072 | 1,485.71 |
| | Grand Total | 3326.837 | 263.017 | 3589.854 |
| 2015-16 | Active | 1,935.41 | 66.104 | 2,001.51 |
| | Passive | 1,395.89 | 247.449 | 1,643.33 |
| | Grand Total | 3331.291 | 313.553 | 3644.844 |
| 2016-17 | Active | 1,116.47 | 0.23 | 1,116.70 |
| | Passive | 1,386.56 | 244.775 | 1,631.34 |
| | Grand Total | 2503.028 | 245.005 | 2748.033 |
| 2017-18 | Active | 1,066.59 | 13.486 | 1,080.08 |
| | Passive | 1,619.15 | 341.37 | 1,960.52 |
| | Grand Total | 2685.74 | 354.856 | 3040.596 |
| 2018-19 | Active | 565.866 | 81.394 | 647.26 |
| | Passive | 1,870.55 | 285.602 | 2,156.15 |
| | Grand Total | 2436.415 | 366.996 | 2803.411 |
| 2019-20 | Active | 357.221 | 20.304 | 377.525 |
| | Passive | 2,018.20 | 350.43 | 2,368.63 |
| | Grand Total | 2375.422 | 370.734 | 2746.156 |
| 2020-21 | Active | 334.634 | 85.294 | 419.928 |
| | Passive | 2,236.73 | 554.292 | 2,791.02 |
| | Grand Total | 2571.361 | 639.586 | 3210.947 |
| 2021-22 | Active | 480.941 | 143.504 | 624.445 |
| | Passive | 2,604.79 | 370.568 | 2,975.36 |
| | Grand Total | 3085.734 | 514.072 | 3599.806 |
| 2022-23 | Active | 598.376 | 87.178 | 685.554 |
| | Passive | 2,788.33 | 566.363 | 3,354.69 |
| | Grand Total | 3386.703 | 653.541 | 4040.244 |

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

# What are Daily NCPC Payments?

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

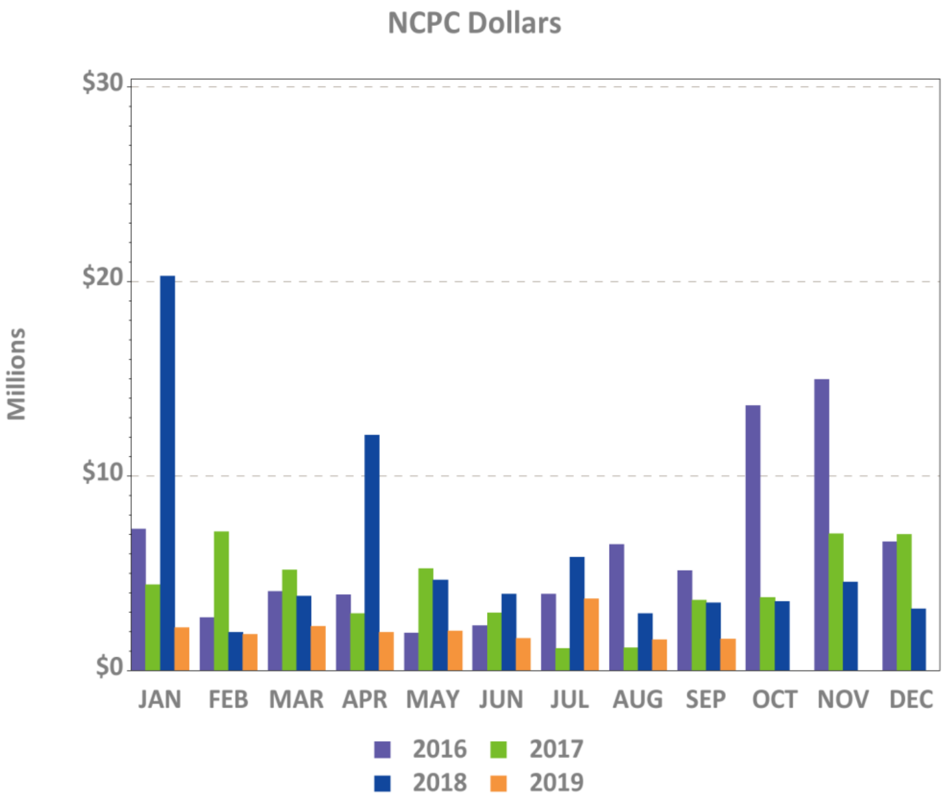
# Definitions

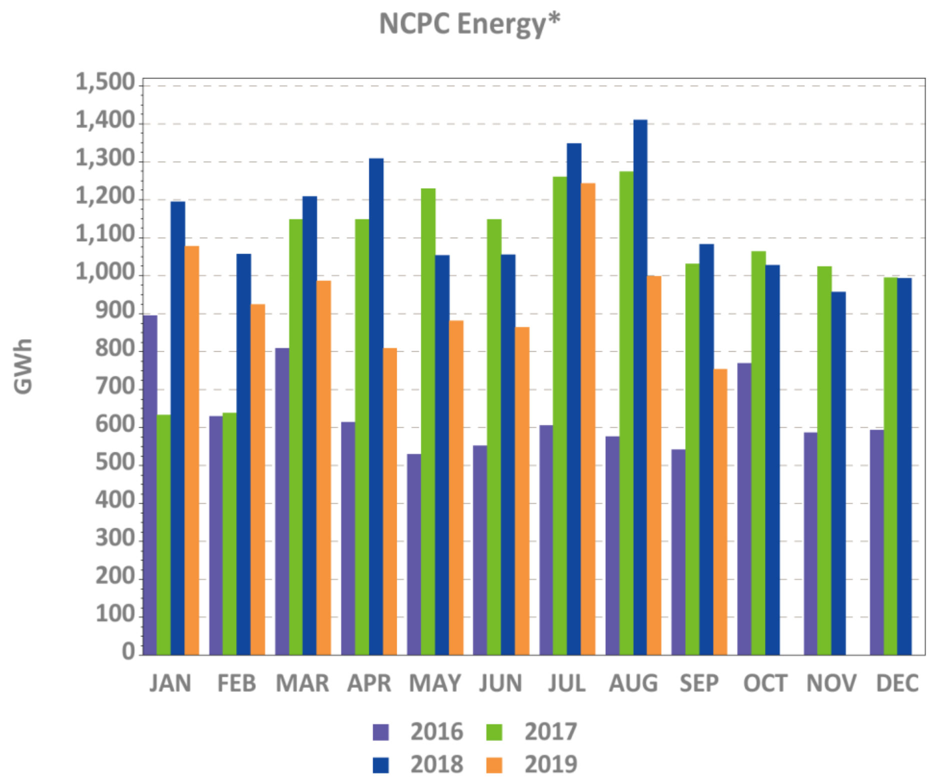
| | |
|---|---|
| 1st Contingency NCPC Payments | Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally |
| 2nd Contingency NCPC Payments | Reliability costs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

# Charge Allocation Key

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

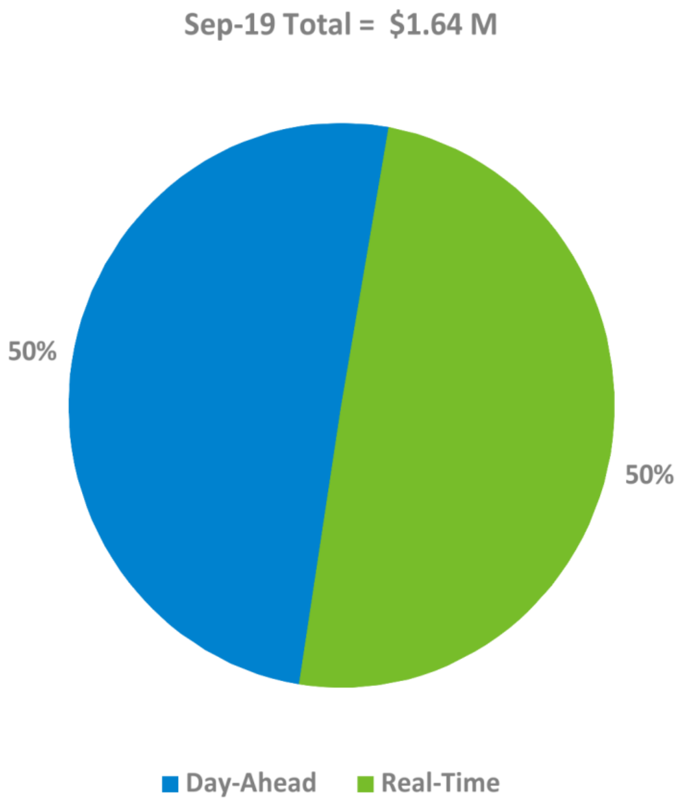
# Year-Over-Year Total NCPC Dollars and Energy

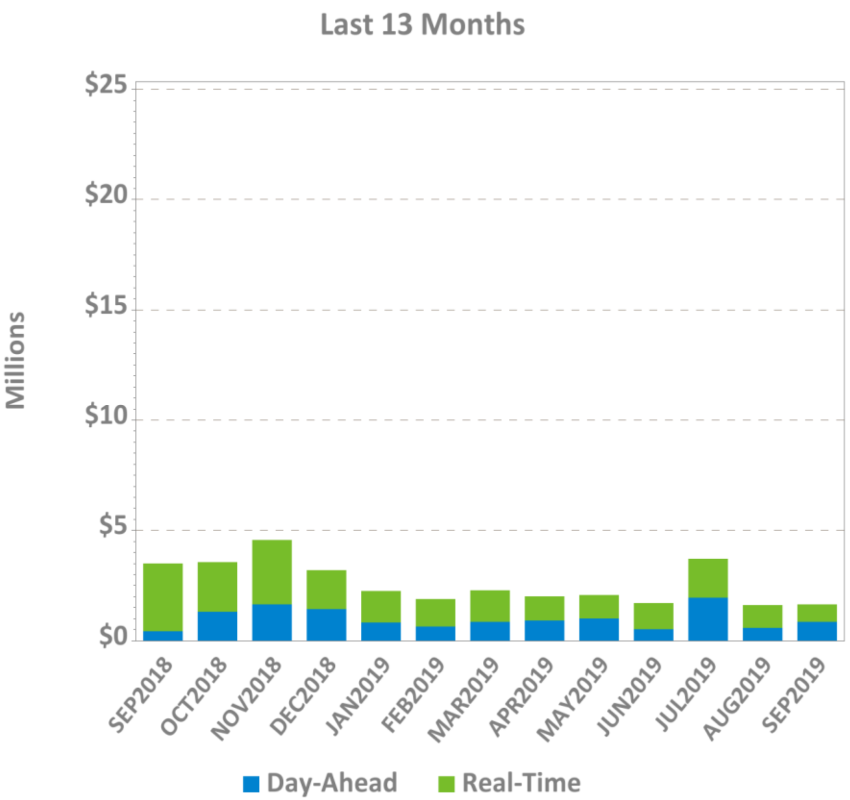


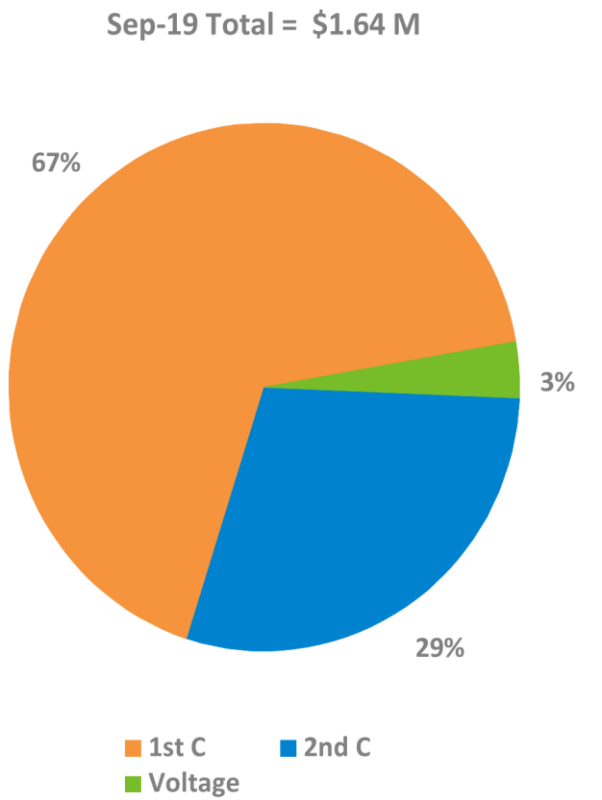

* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

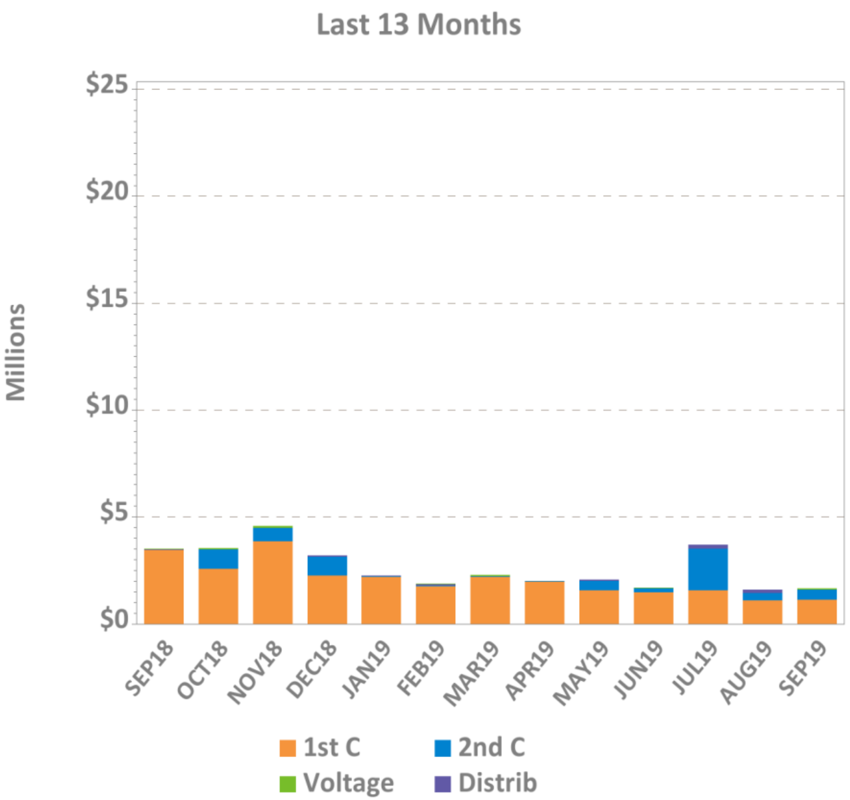
# DA and RT NCPC Charges



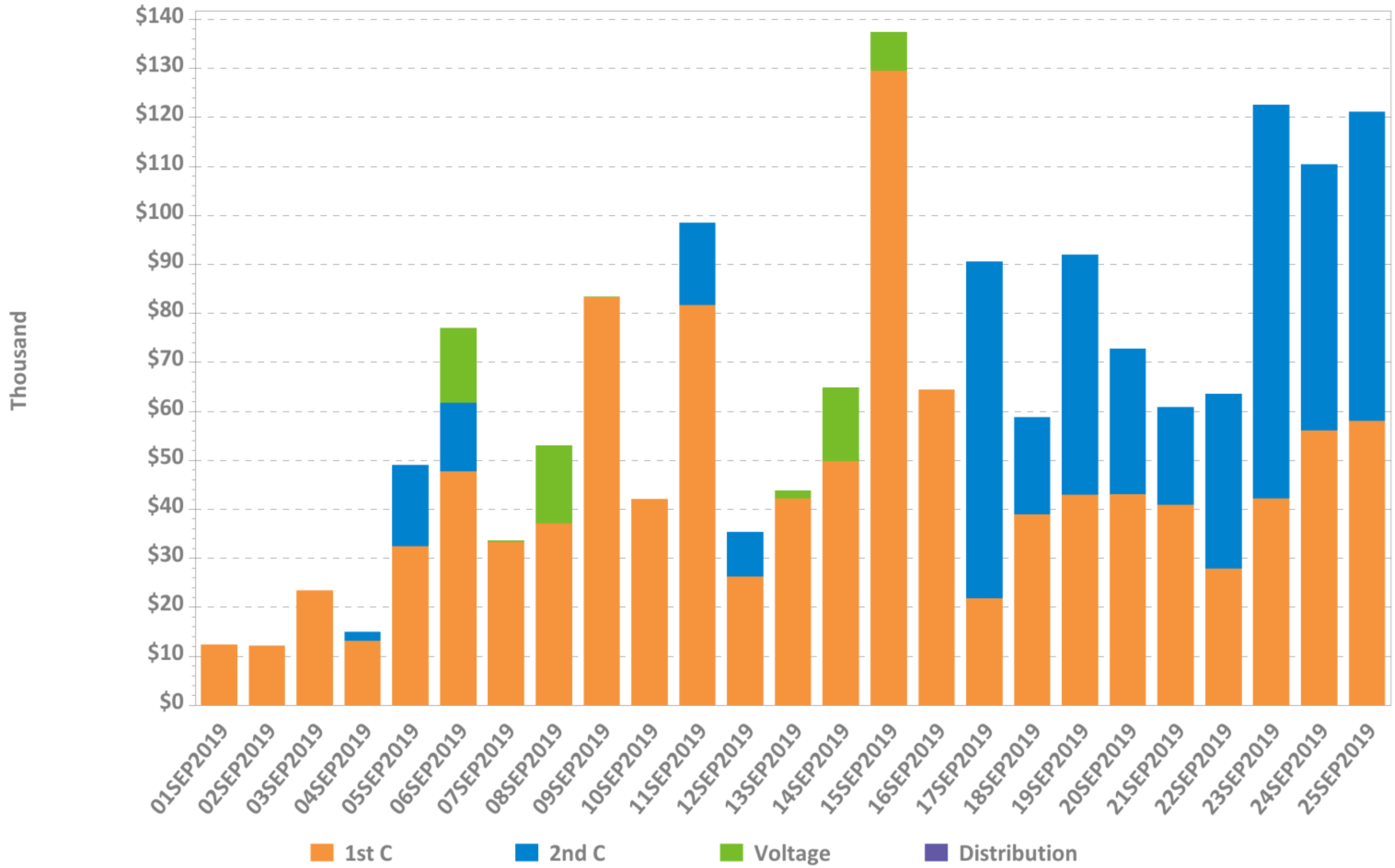
# NCPC Charges by Type



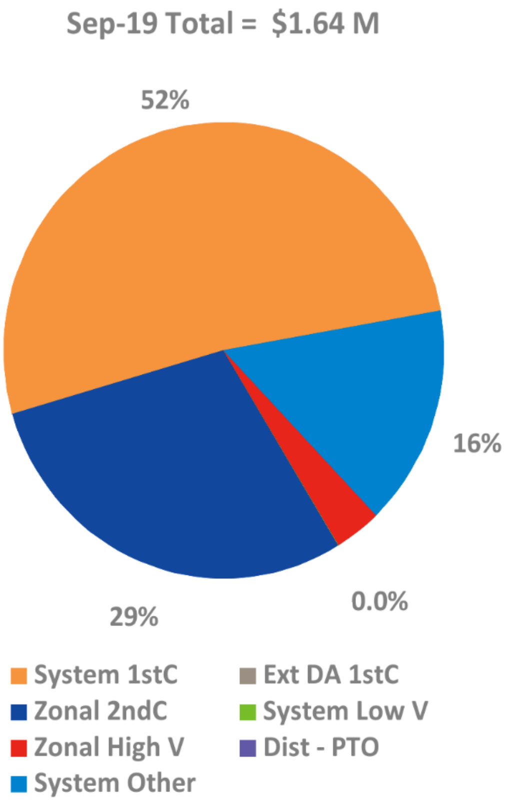



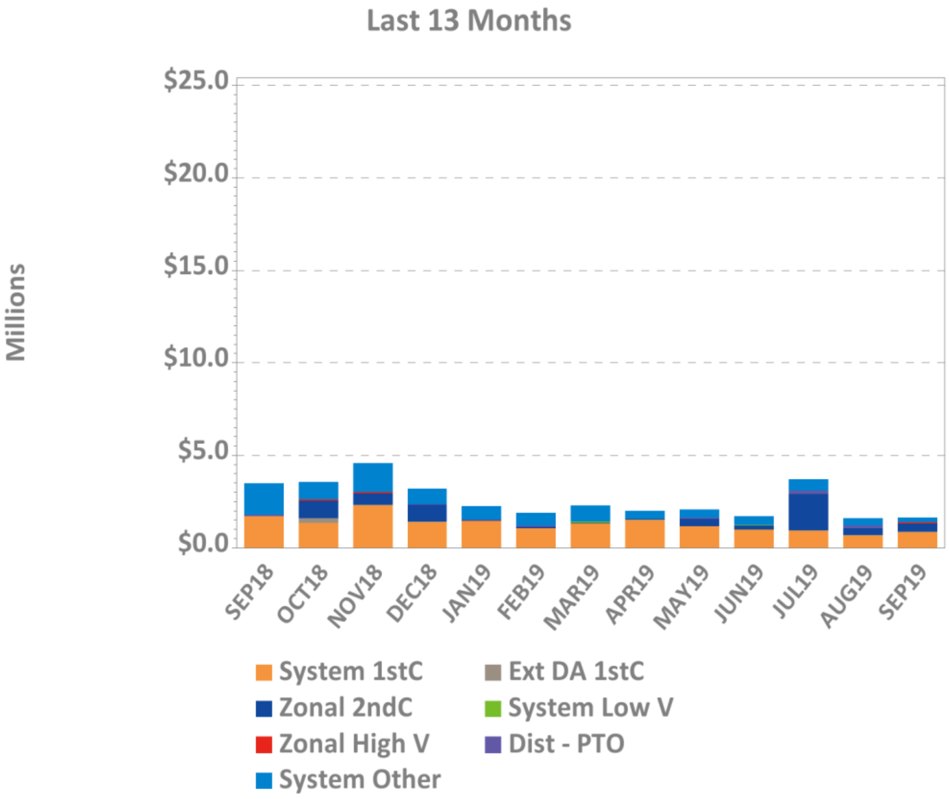

**1st C – First Contingency**
**2nd C – Second Contingency**
**Distrib – Distribution**
**Voltage – Voltage**

# Daily NCPC Charges by Type



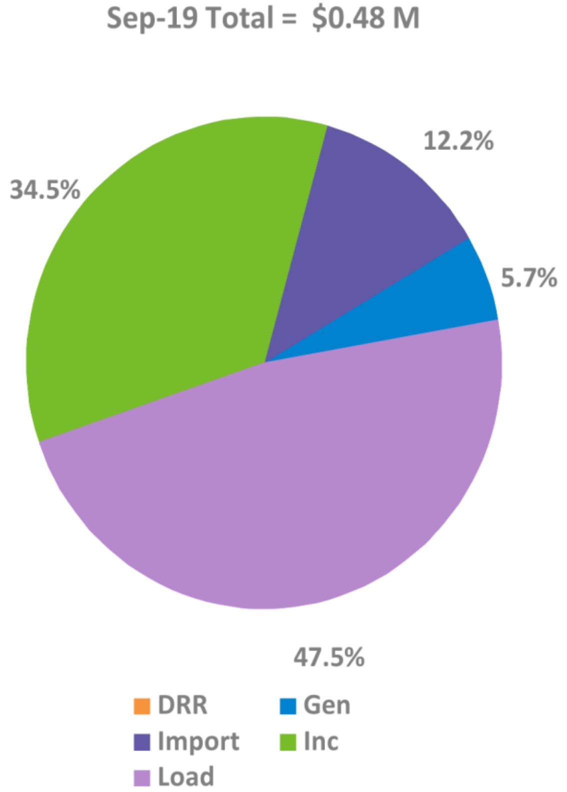
# NCPC Charges by Allocation

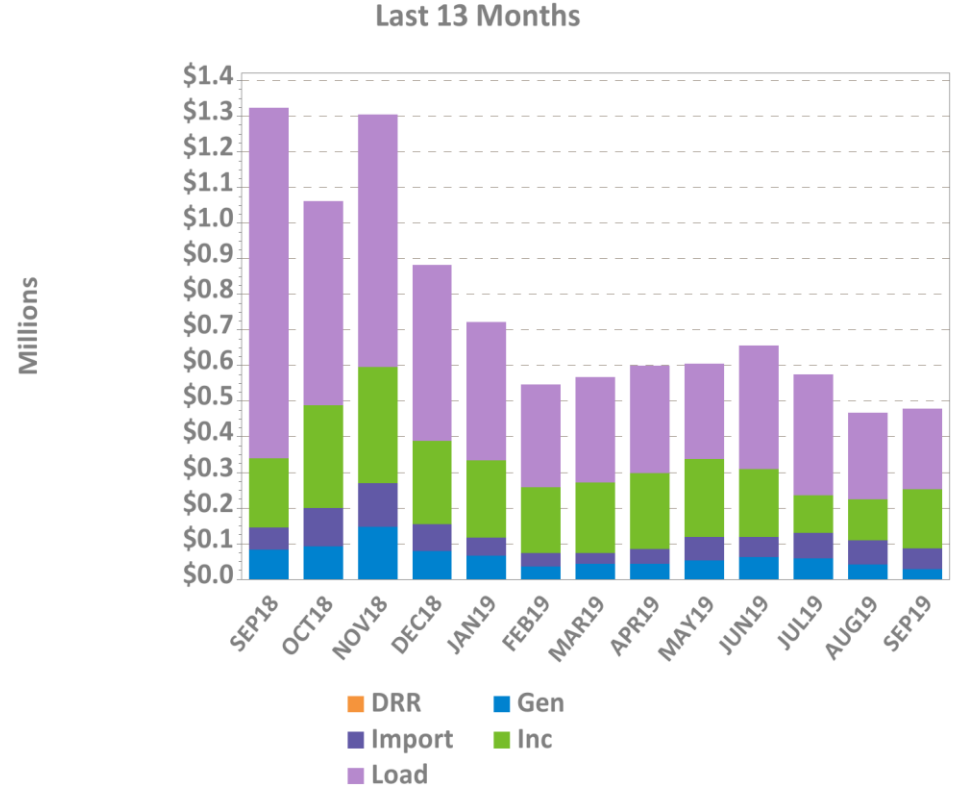



Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

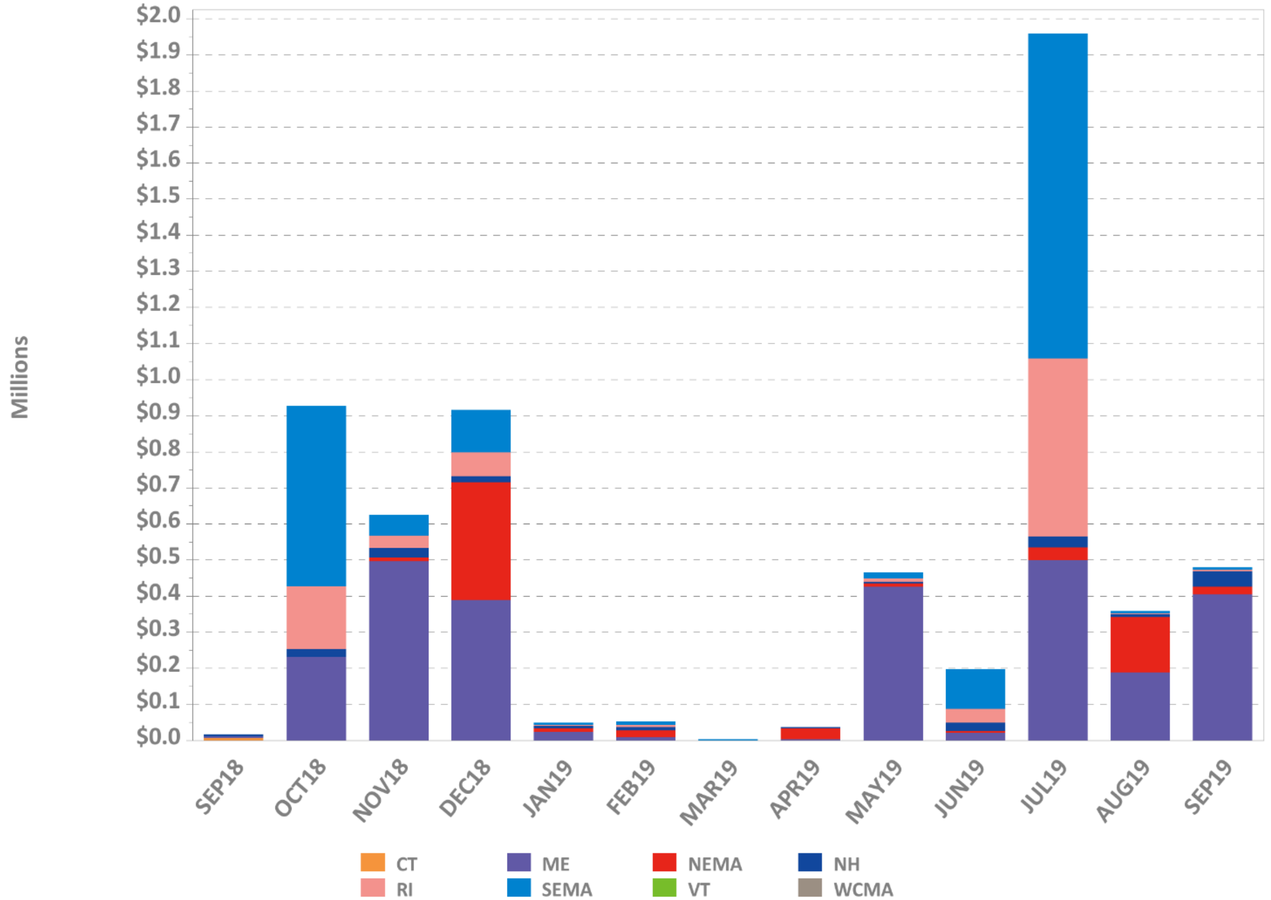
# RT First Contingency Charges by Deviation Type




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

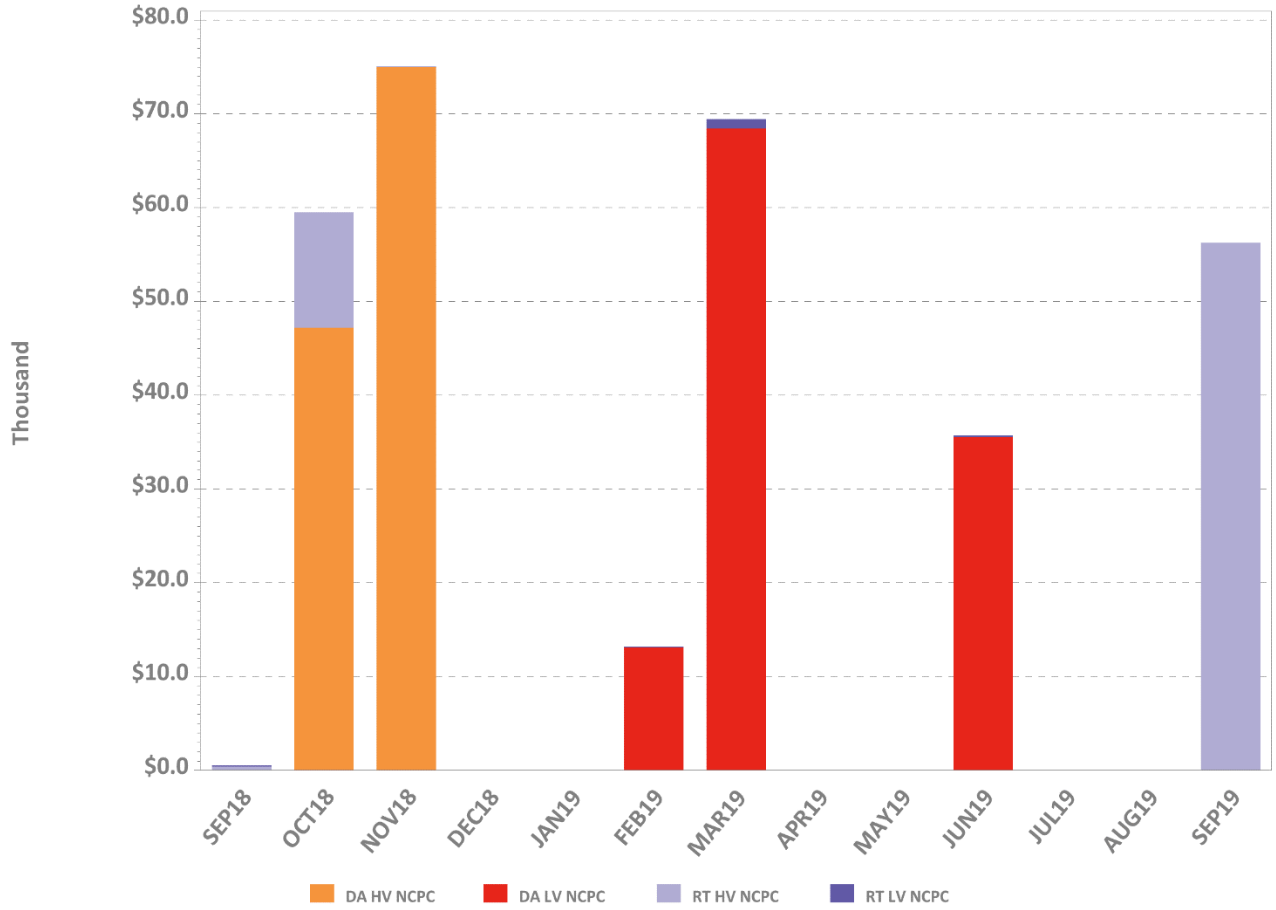
# LSCPR Charges by Reliability Region



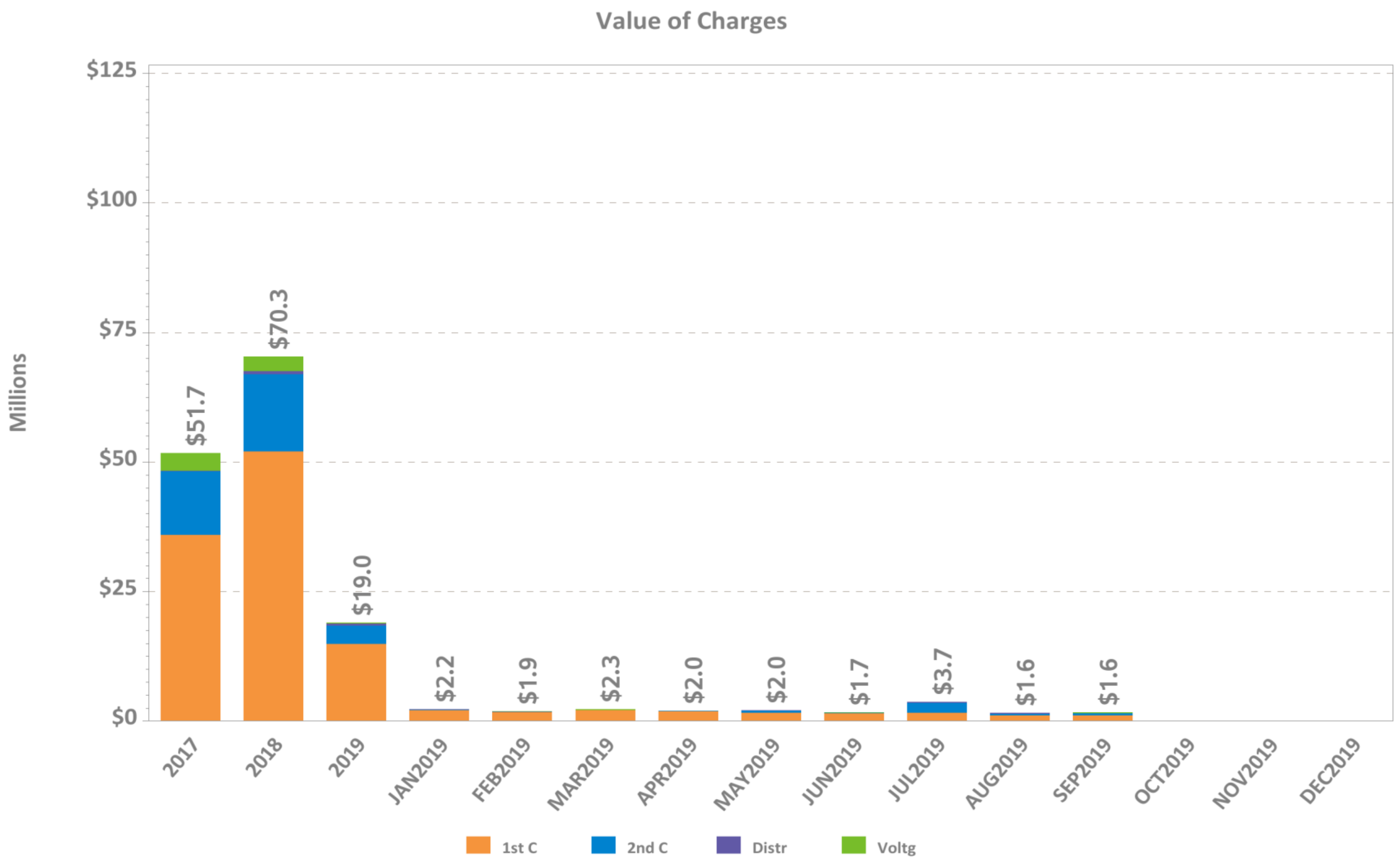

CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

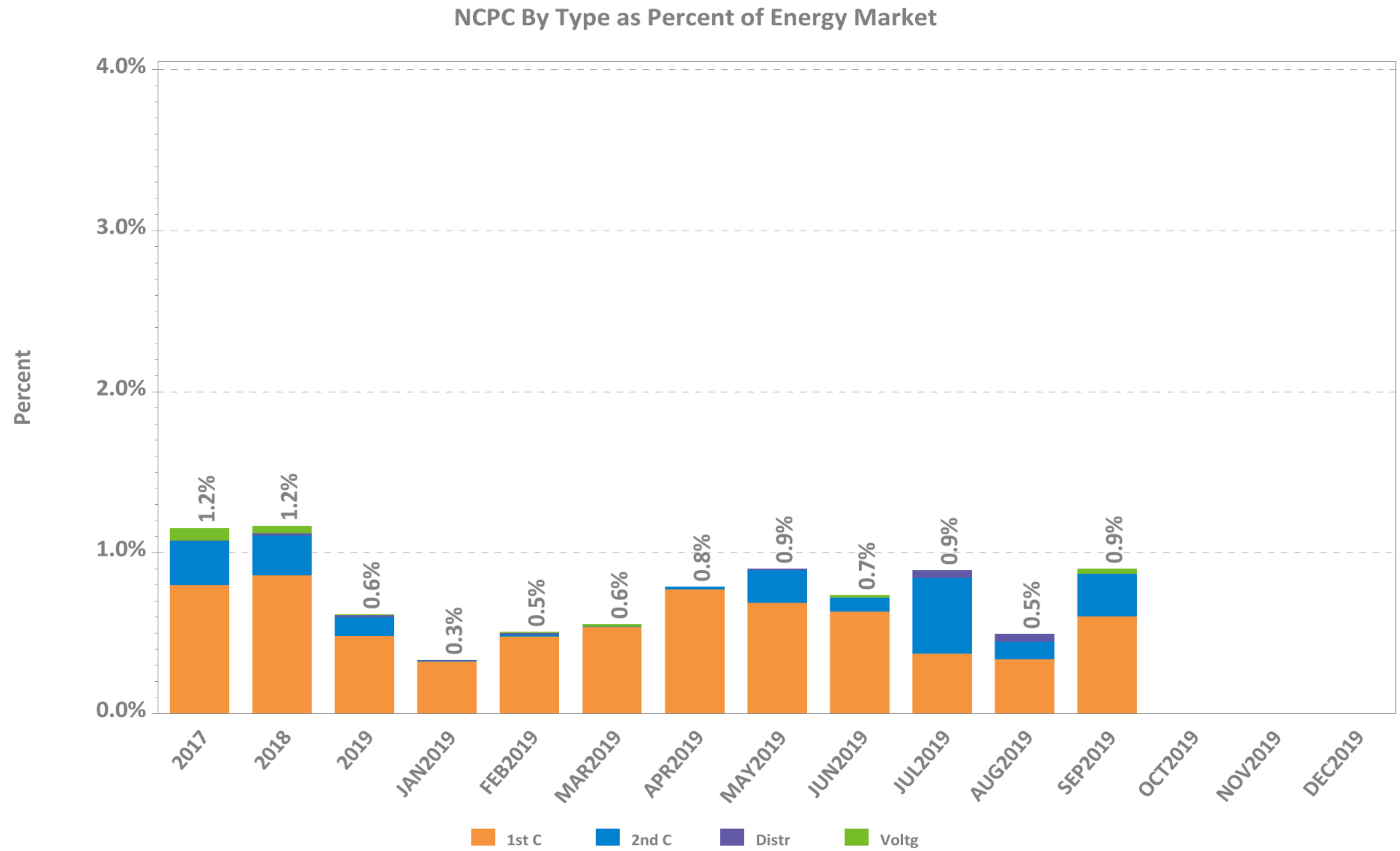
# NCPC Charges for Voltage Support and High Voltage Control



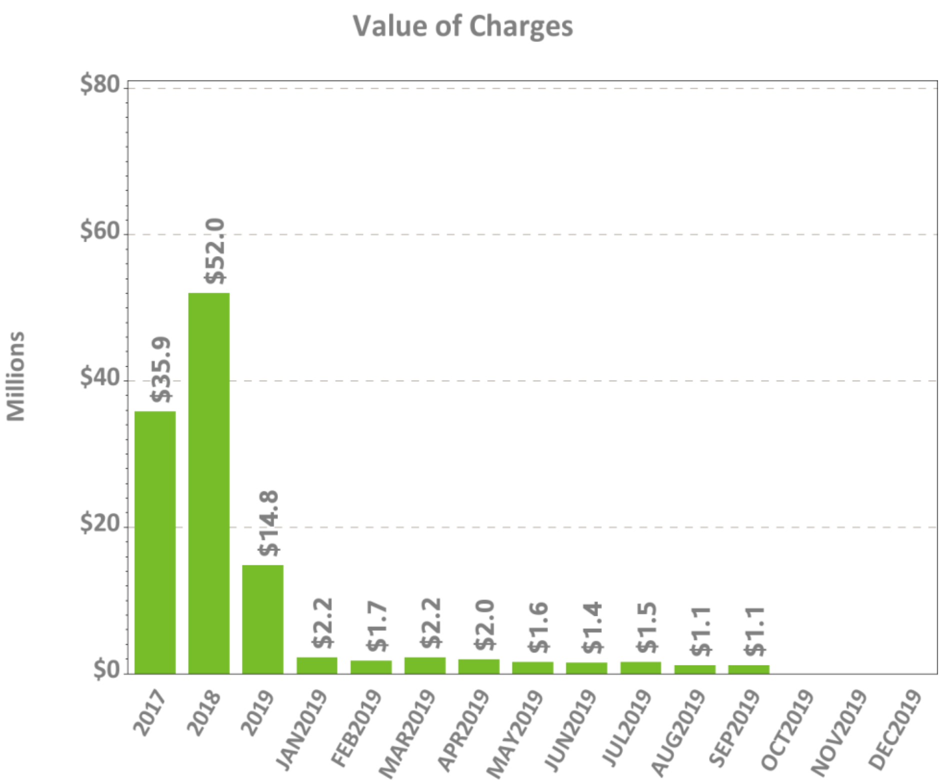
# NCPC Charges by Type

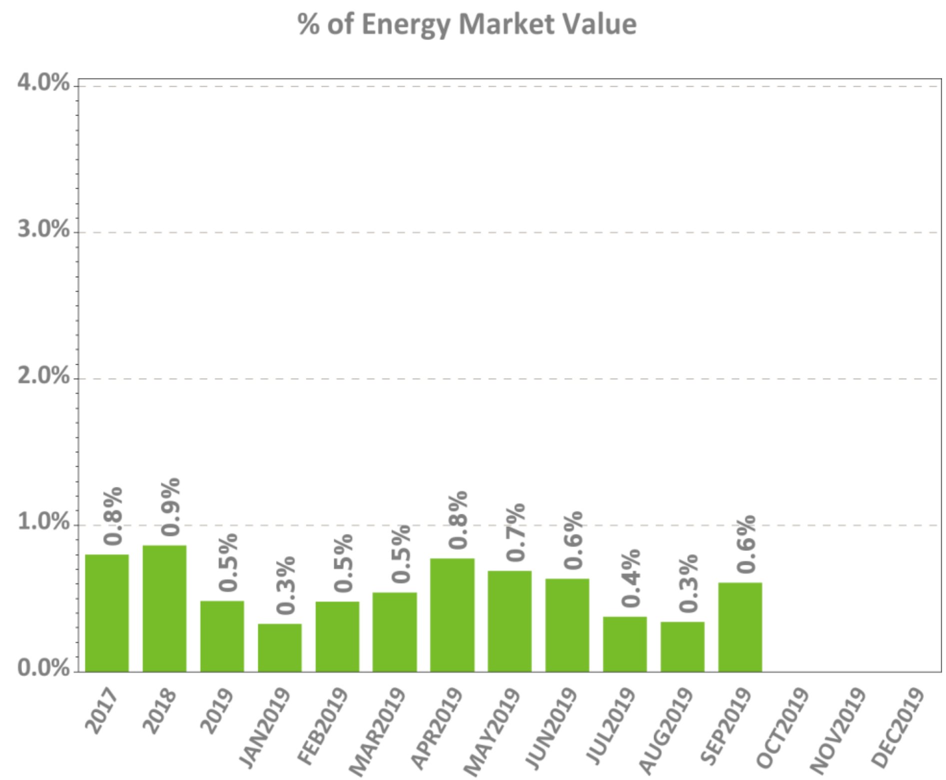


# NCPC Charges as Percent of Energy Market



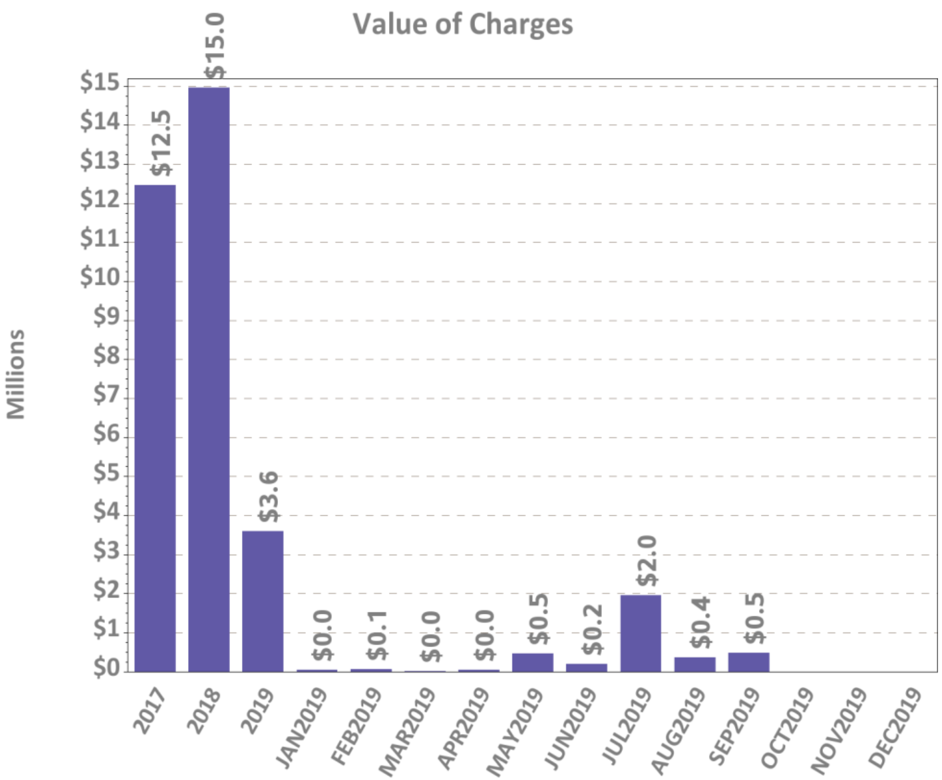
# First Contingency NCPC Charges

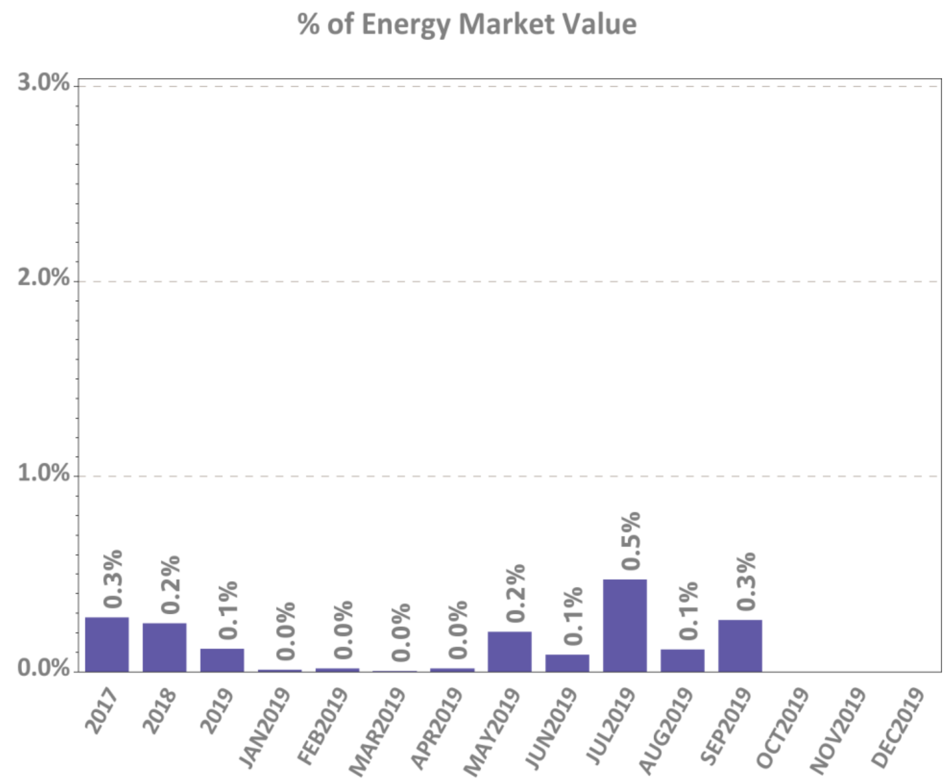



**Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market**

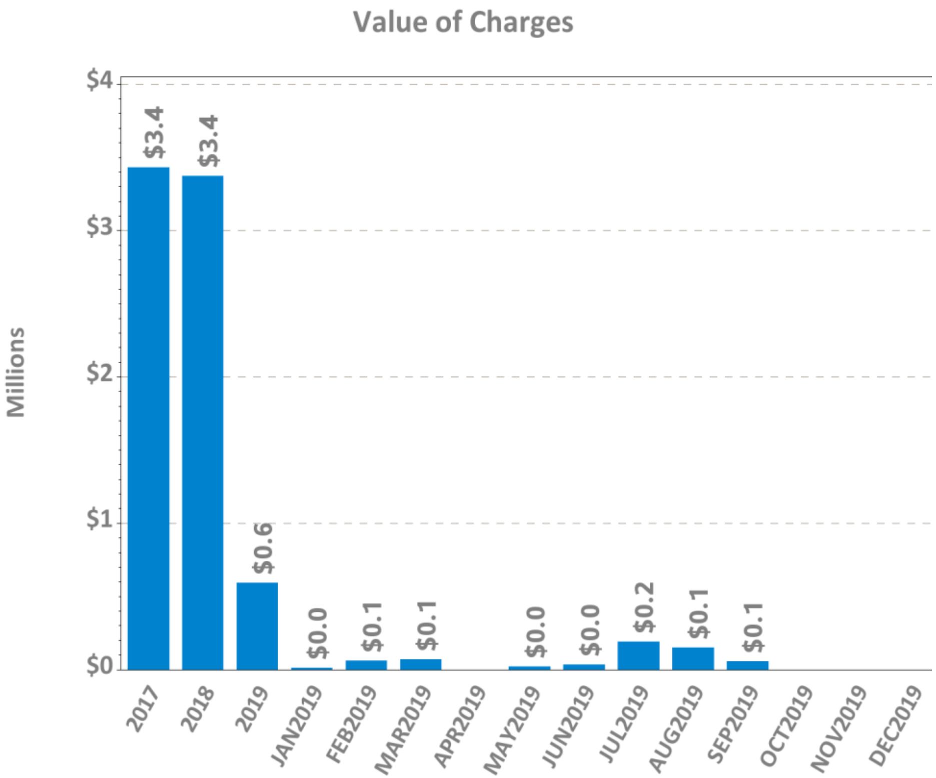
# Second Contingency NCPC Charges

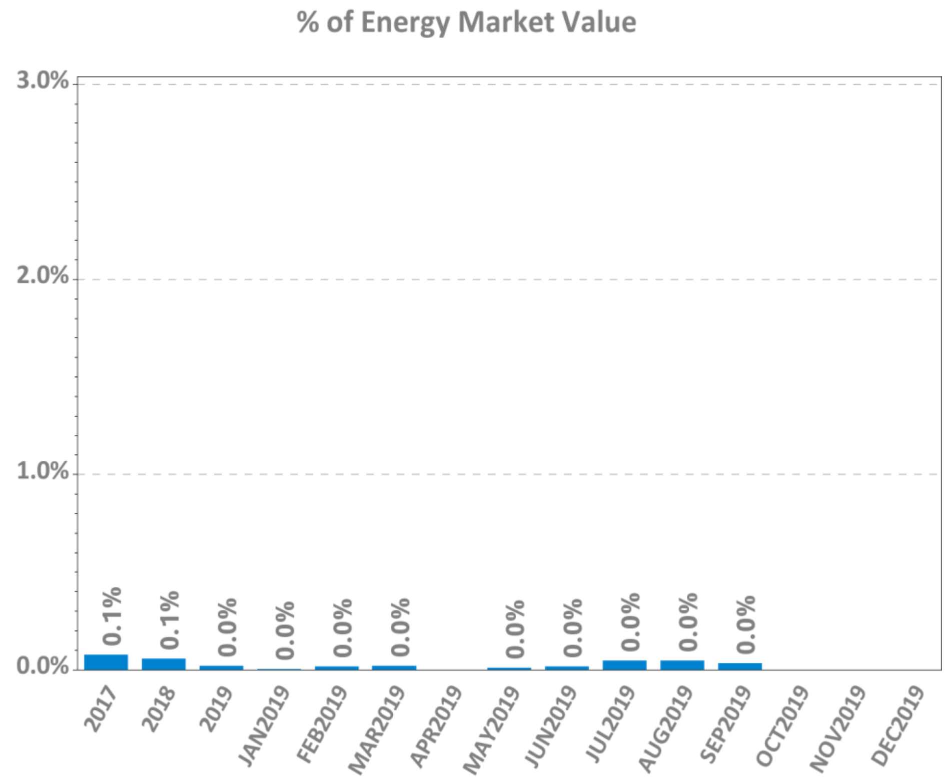



**Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market**

# Voltage and Distribution NCPC Charges




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

# DA vs. RT Pricing

**The following slides outline:**

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

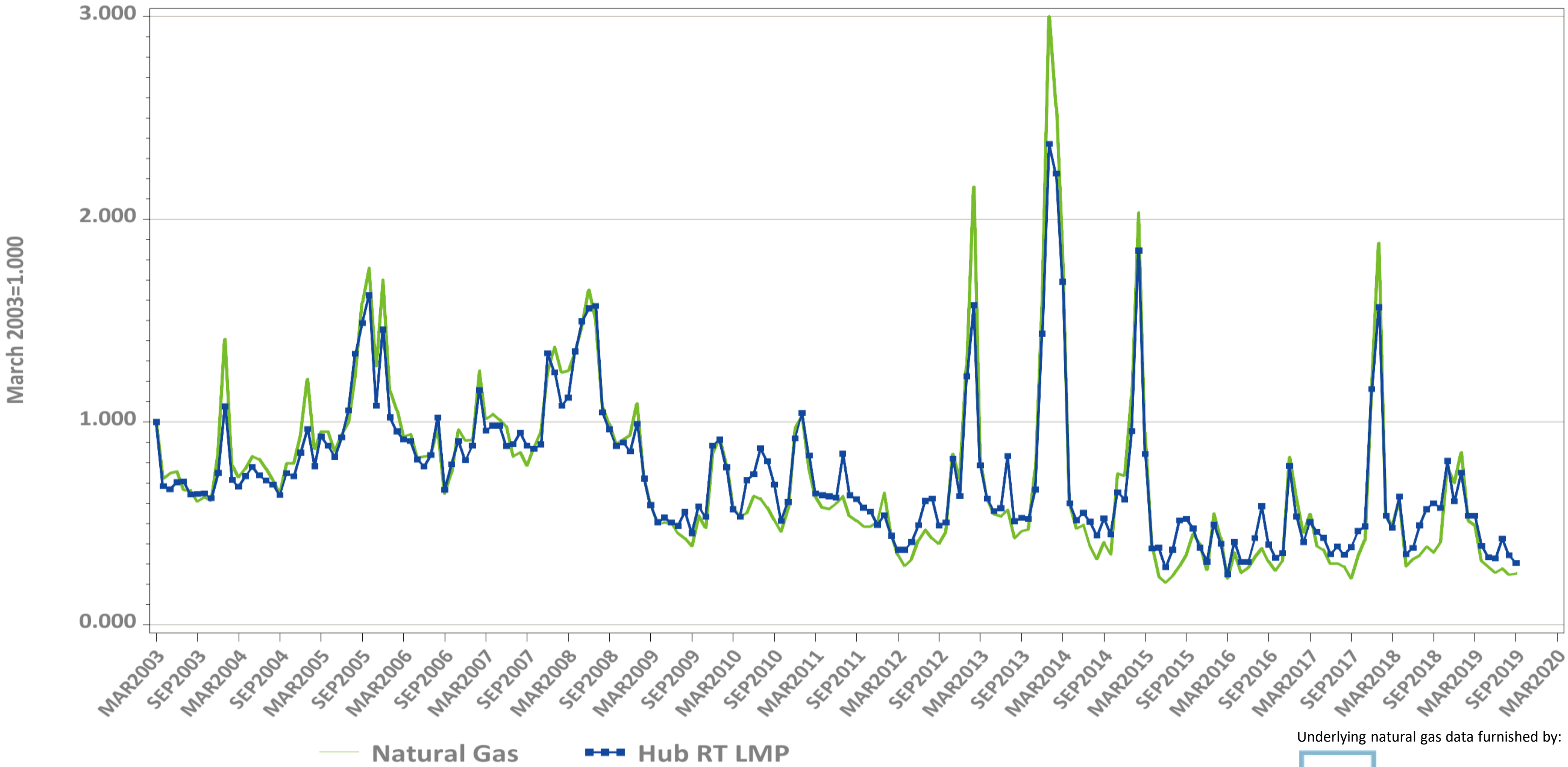
# DA vs. RT LMPs ($/MWh)

Arithmetic Average

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

| September-18 | NEMA | CT | ME | NH | VT | RI | SEMA | WCMA | Hub |
|---|---|---|---|---|---|---|---|---|---|
| Day-Ahead | $34.15 | $33.33 | $33.24 | $34.12 | $33.72 | $34.12 | $35.95 | $33.94 | $33.89 |
| Real-Time | $41.50 | $40.75 | $40.52 | $41.55 | $40.96 | $40.83 | $41.22 | $41.25 | $41.17 |
| RT Delta % | 21.5% | 22.3% | 21.9% | 21.8% | 21.5% | 19.7% | 14.6% | 21.5% | 21.5% |
| September-19 | NEMA | CT | ME | NH | VT | RI | SEMA | WCMA | Hub |
| Day-Ahead | $22.00 | $21.36 | $21.59 | $21.94 | $21.55 | $21.70 | $21.99 | $21.78 | $21.77 |
| Real-Time | $21.20 | $20.72 | $20.76 | $21.11 | $20.75 | $20.90 | $21.13 | $20.98 | $20.97 |
| RT Delta % | -3.6% | -3.0% | -3.9% | -3.8% | -3.7% | -3.7% | -3.9% | -3.7% | -3.7% |
| Annual Diff. | NEMA | CT | ME | NH | VT | RI | SEMA | WCMA | Hub |
| Yr over Yr DA | -35.6% | -35.9% | -35.0% | -35.7% | -36.1% | -36.4% | -38.8% | -35.8% | -35.8% |
| Yr over Yr RT | -48.9% | -49.1% | -48.8% | -49.2% | -49.3% | -48.8% | -48.7% | -49.1% | -49.1% |

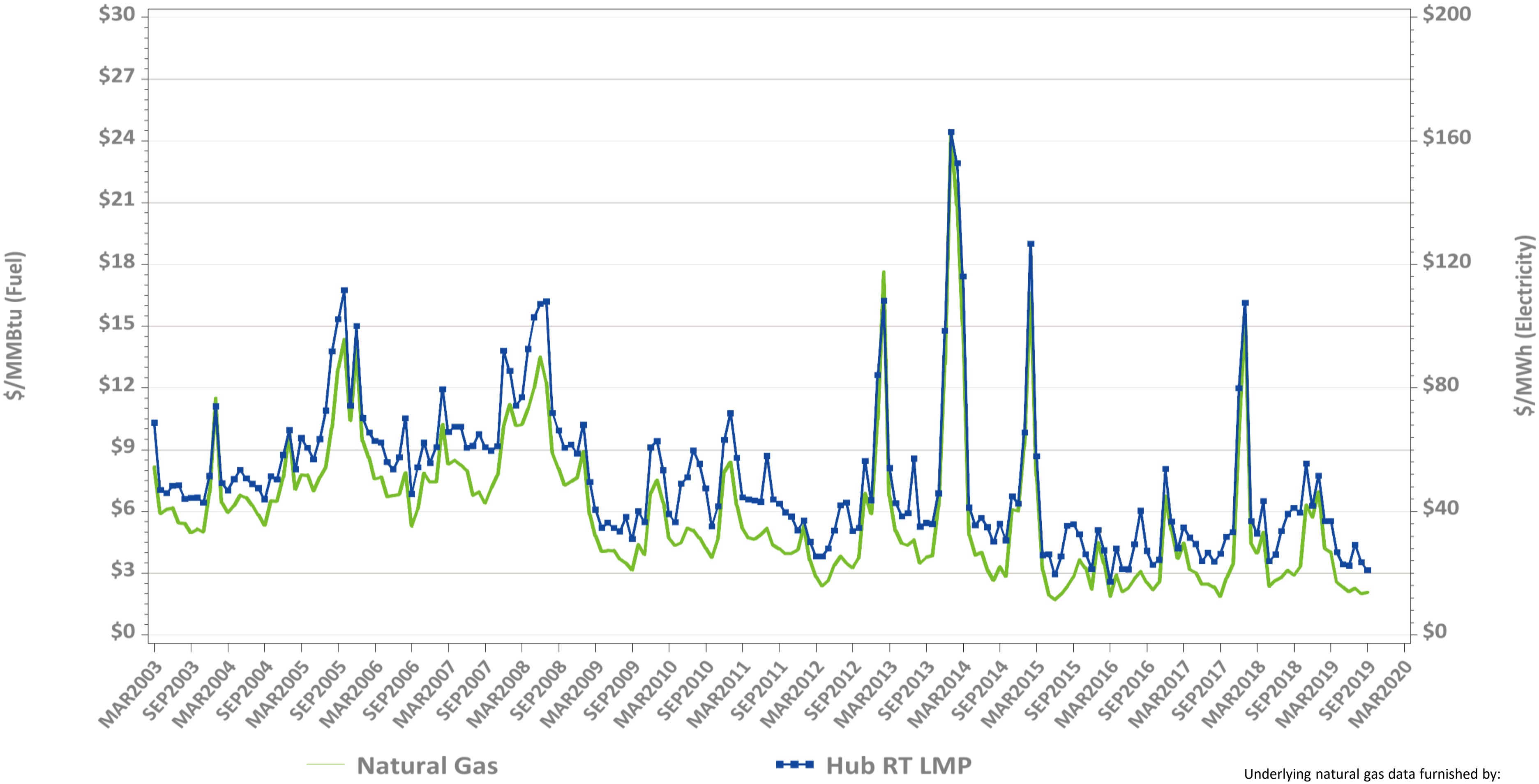
# Monthly Average Fuel Price and RT Hub LMP Indexes




Underlying natural gas data furnished by:

ICE Global markets in clear view

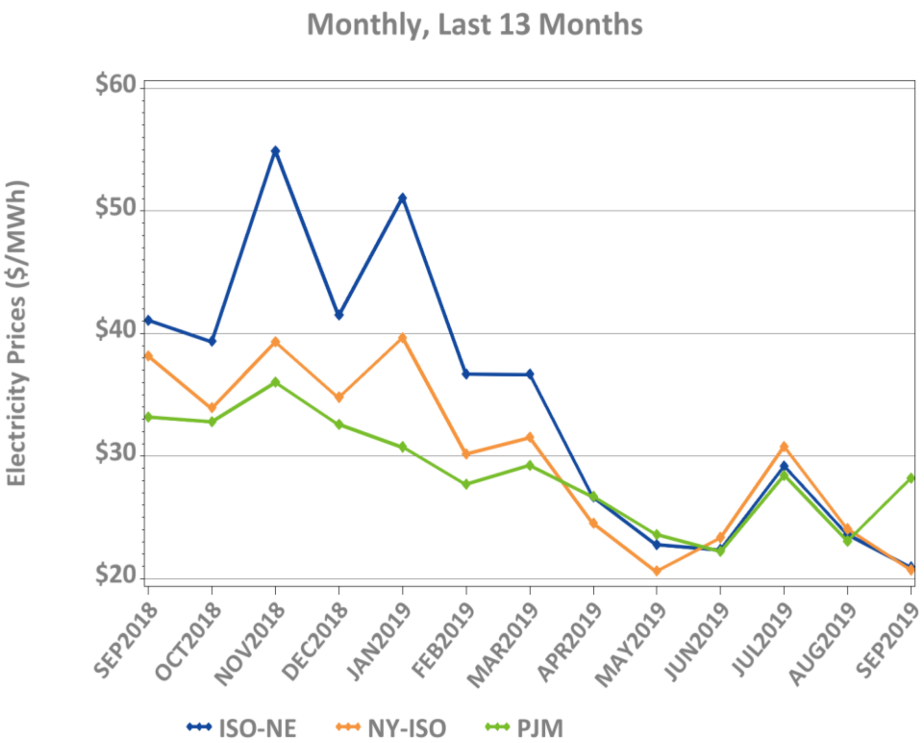
# Monthly Average Fuel Price and RT Hub LMP



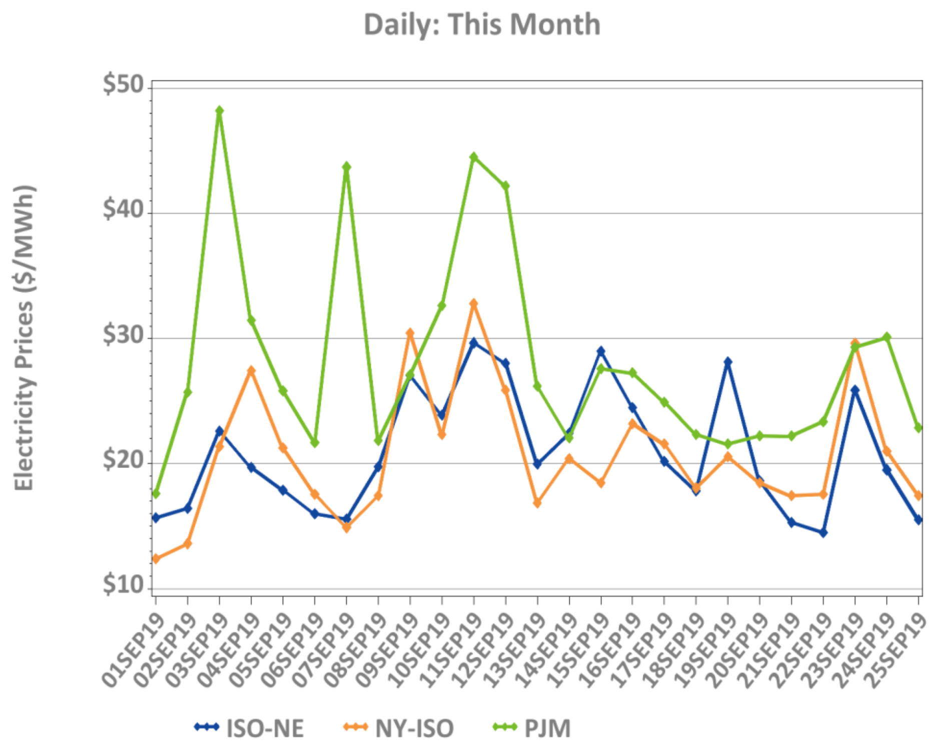

Underlying natural gas data furnished by:

ICE Global markets in clear view

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

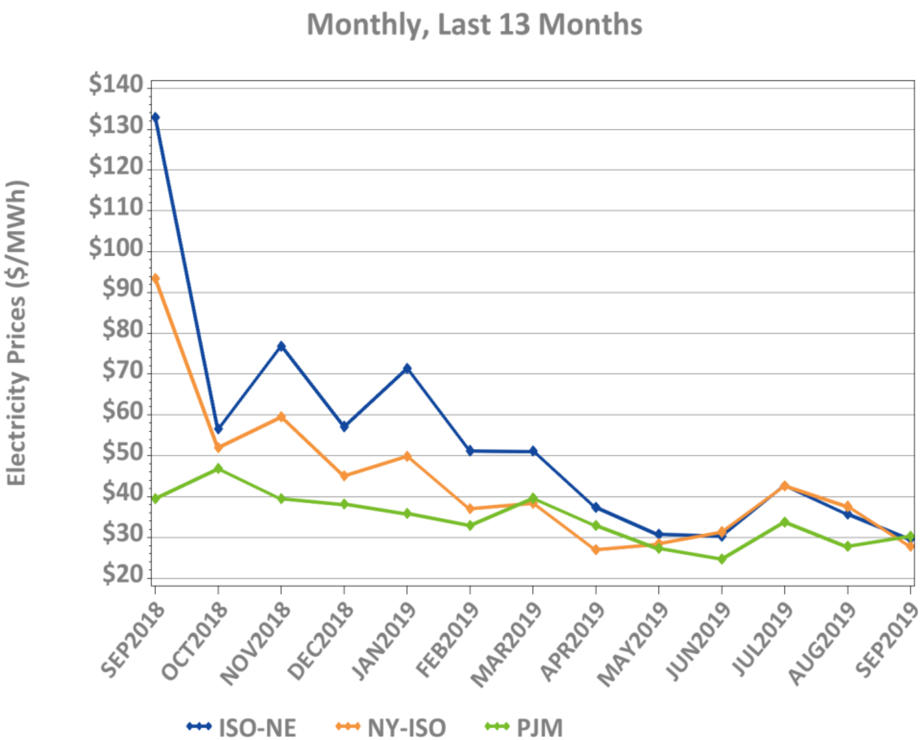


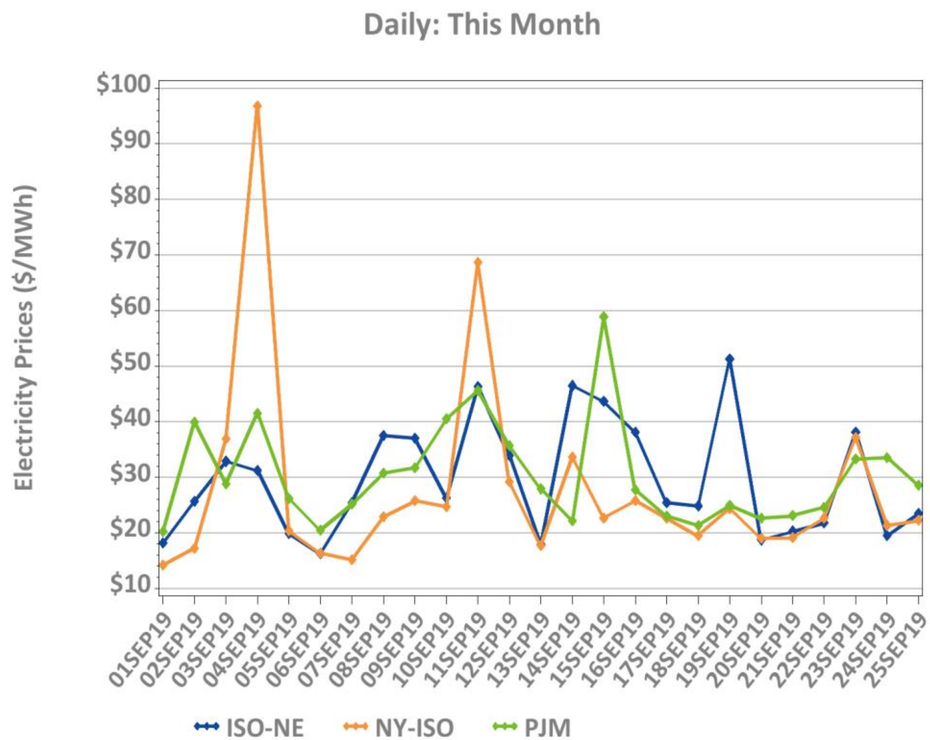

*Note: Hourly average prices are shown.




*Note: Hourly average prices are shown.

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



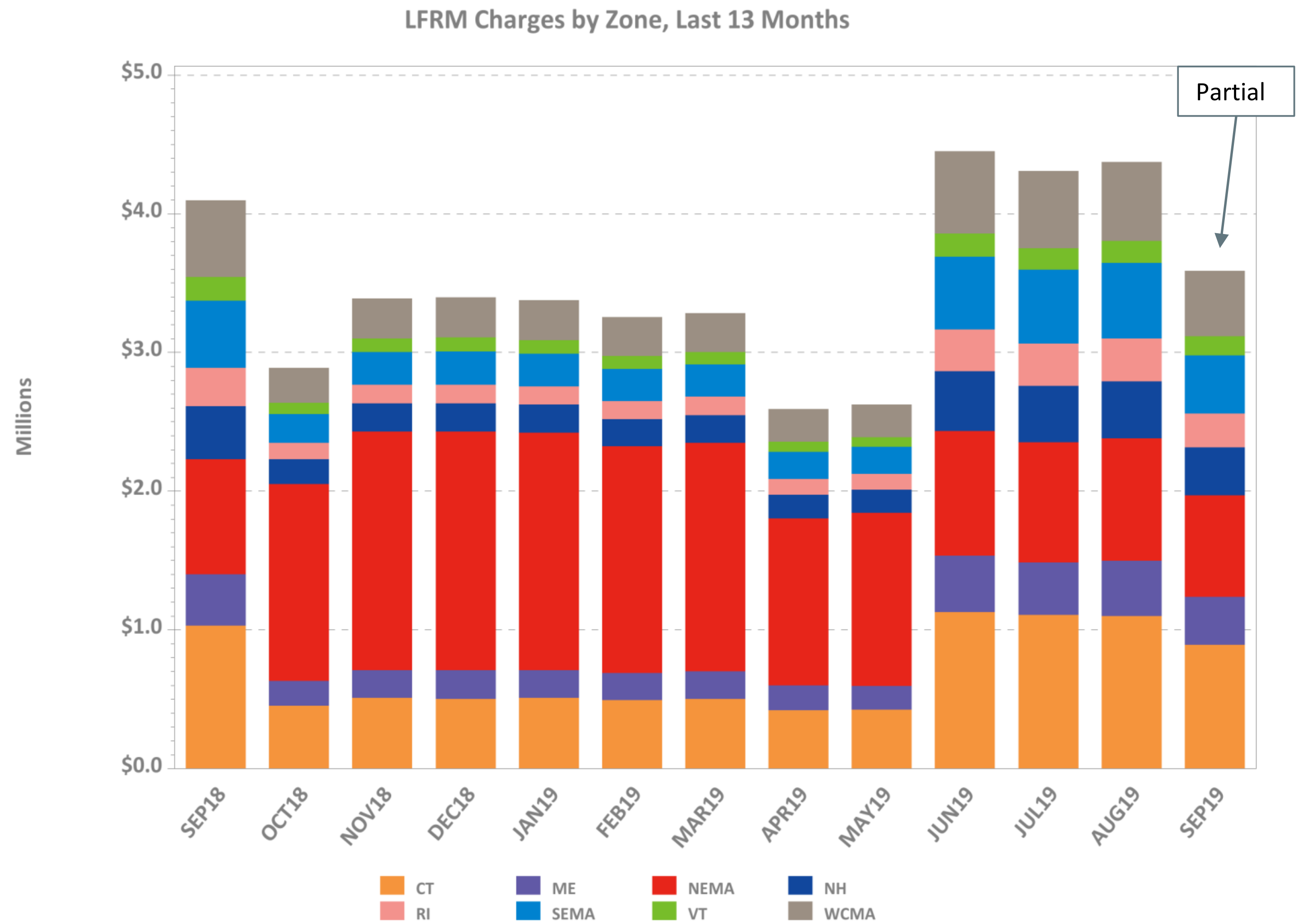

***Forecasted New England daily peak hours reflected**

# Reserve Market Results – September 2019

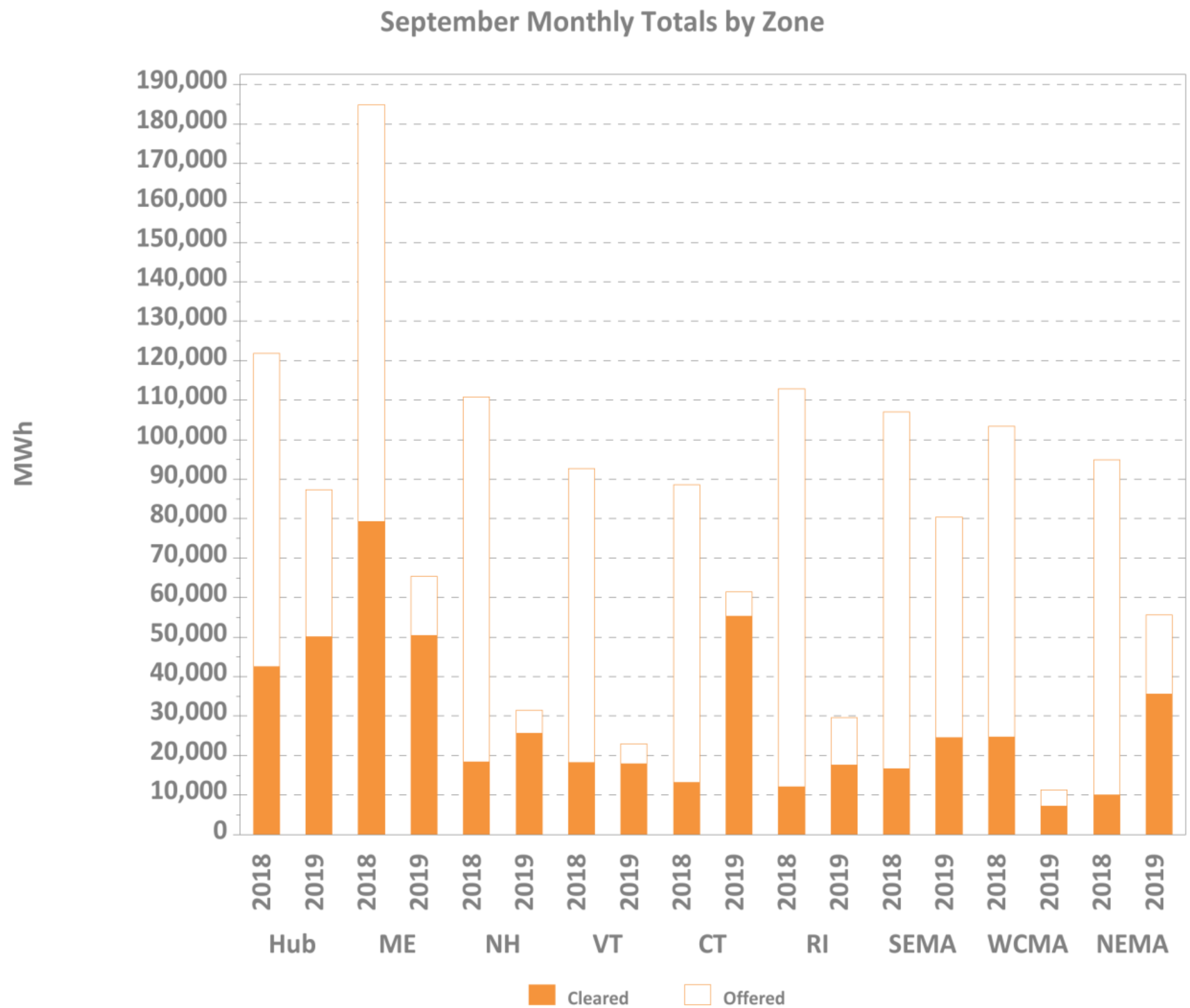
- Maximum potential Forward Reserve Market payments of $3.9M were reduced by credit reductions of $111K, failure-to-reserve penalties of $167K and no failure-to-activate penalties, resulting in a net payout of $3.6M or 93% of maximum
  – Rest of System: $2.68M/2.87M (93%)
  – Southwest Connecticut: $0.3M/0.31M (96%)
  – Connecticut: $0.61M/0.68M (90%)
- $506K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $506K in Real-Time Reserve payments
  – Rest of System: 189 hours, $383K
  – Southwest Connecticut: 189 hours, $50K
  – Connecticut: 189 hours, $53K
  – NEMA: 189 hours, $21K

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

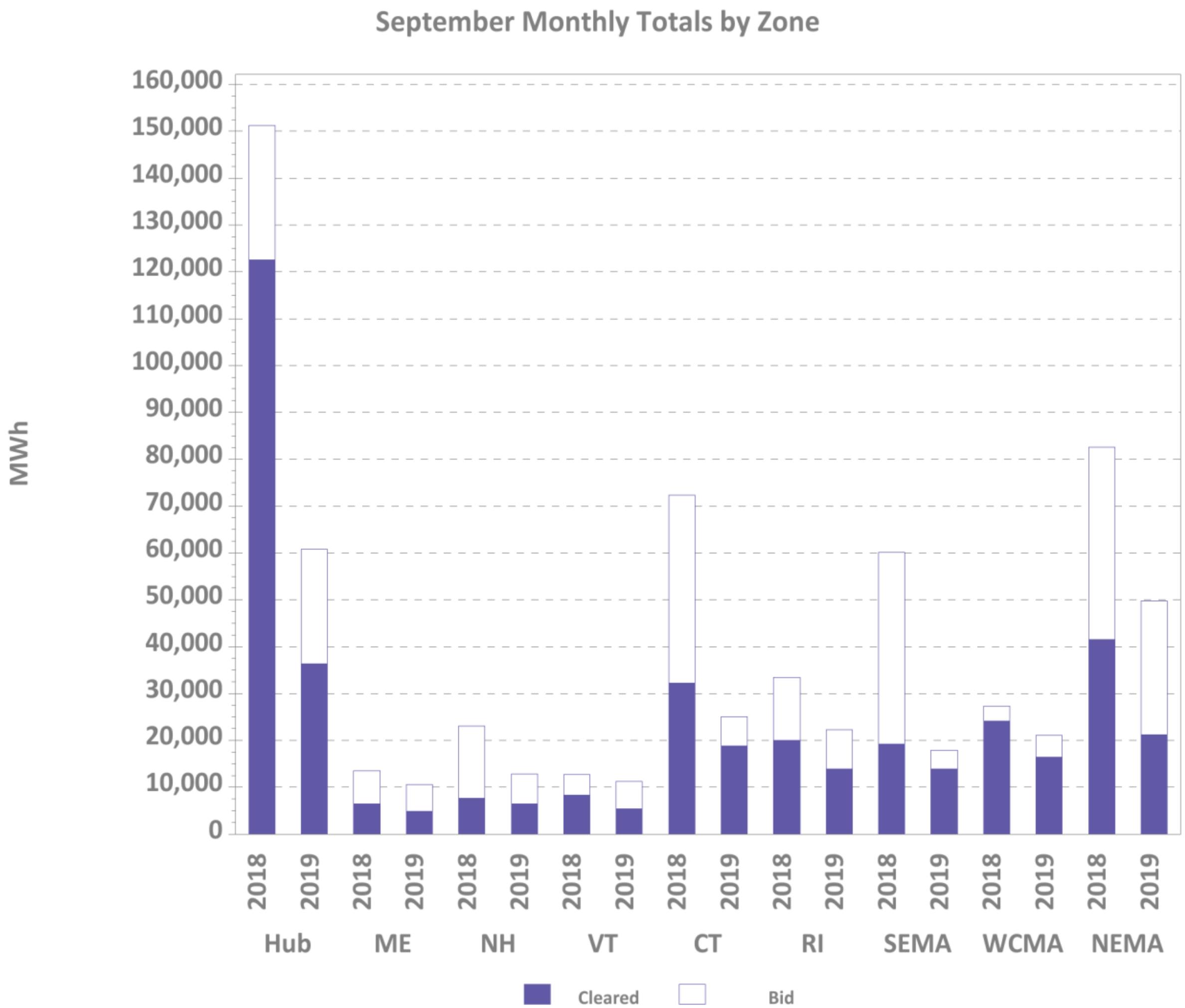
# LFRM Charges to Load by Load Zone ($)



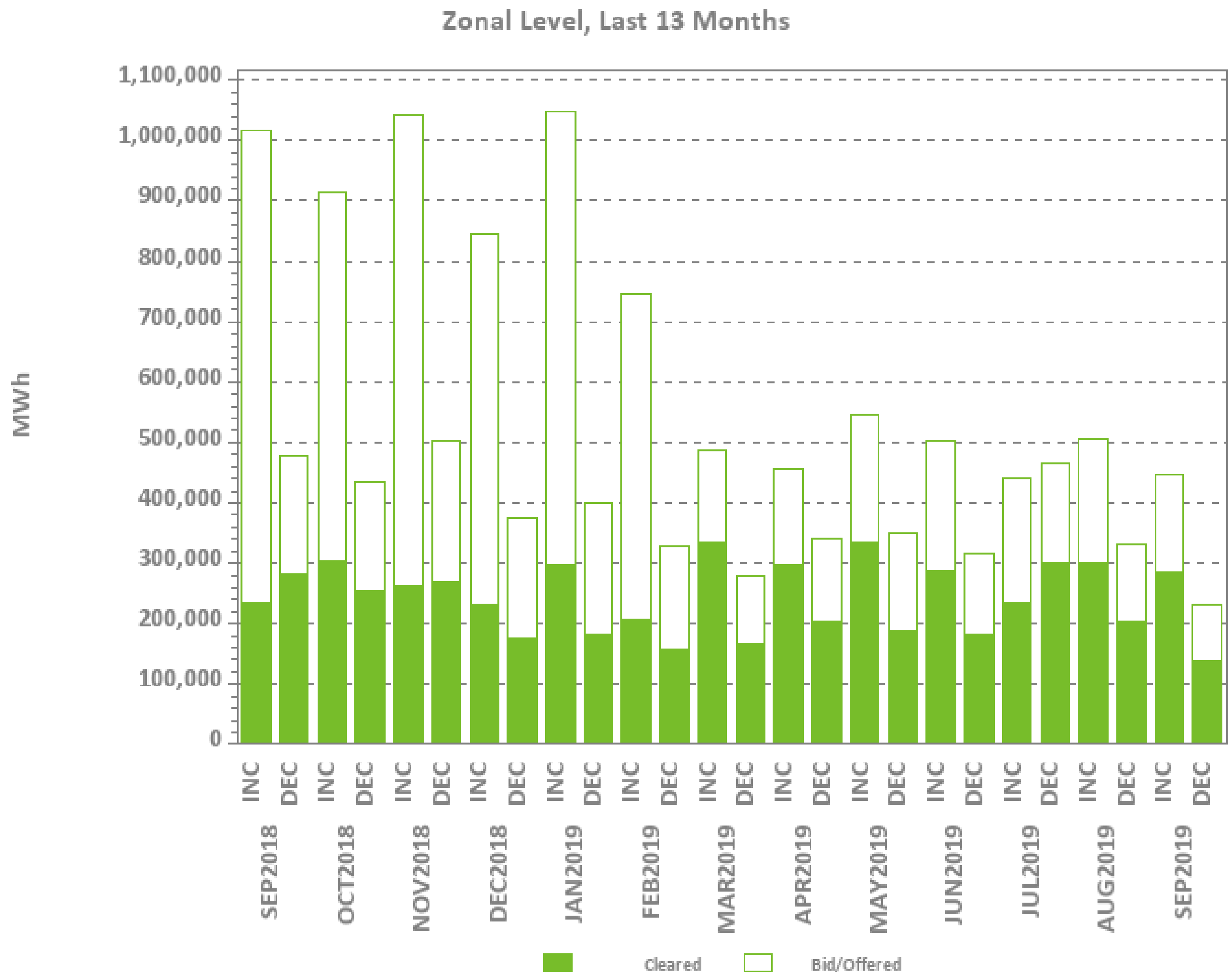
# Zonal Increment Offers and Cleared Amounts



# Zonal Decrement Bids and Cleared Amounts

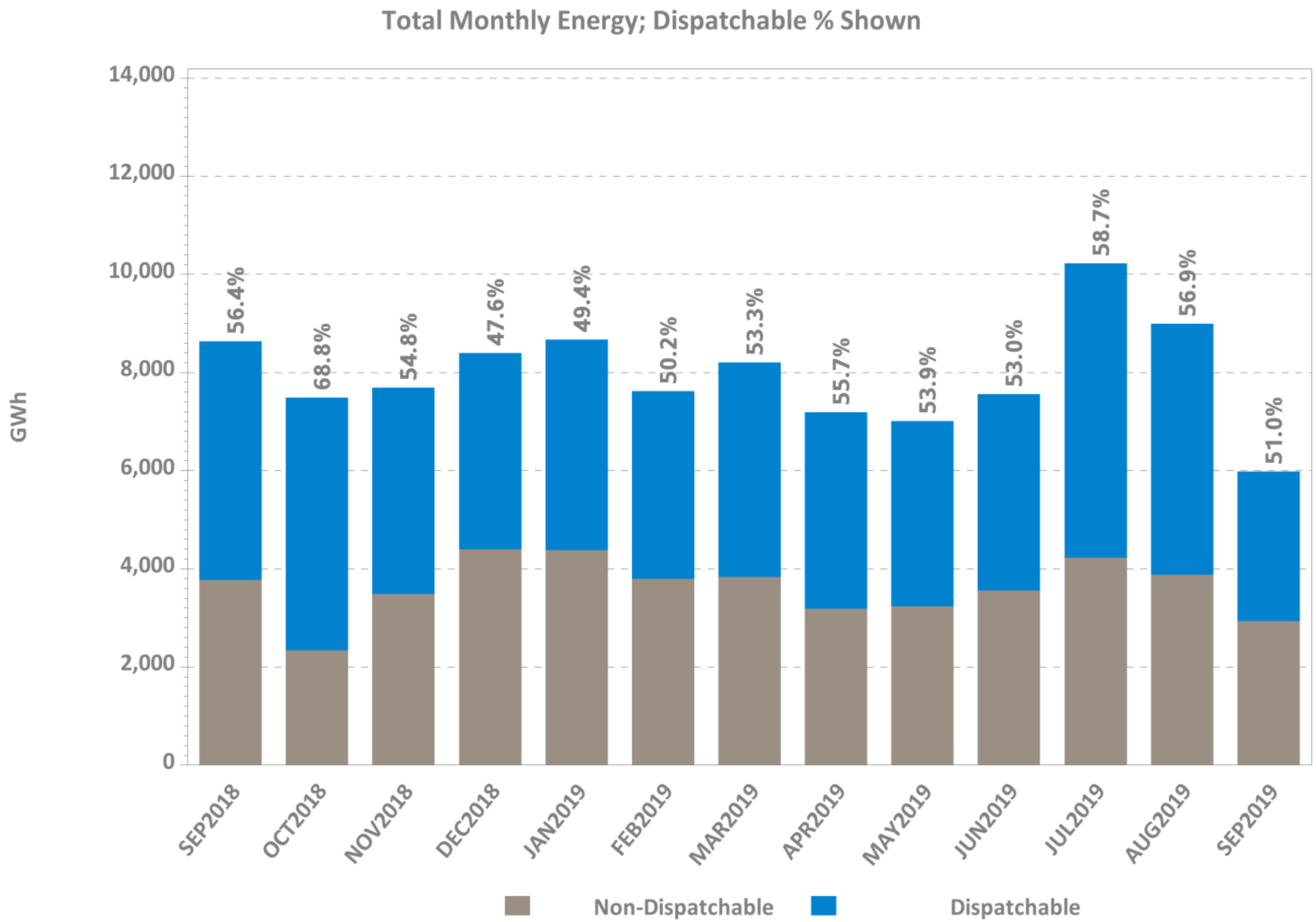


# Total Increment Offers and Decrement Bids




**Data excludes nodal offers and bids**

# Dispatchable vs. Non-Dispatchable Generation




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

# REGIONAL SYSTEM PLAN (RSP)

# 2019 Regional System Plan

- The final version of RSP19 is under ISO Board review, with a decision expected by early November
  - The final draft reflects minor revisions to the Public Meeting version
  - Report will be posted to the ISO-NE website upon ISO Board approval

# Planning Advisory Committee (PAC)

- October 24 PAC Meeting Agenda Topics*
  - NH 2029 Needs Assessment Results
  - Regional System Plan Transmission Projects and Asset Condition October 2019 Update
  - NPCC Directory 1 Project Updates
  - Transmission Owners Local System Plan Presentations

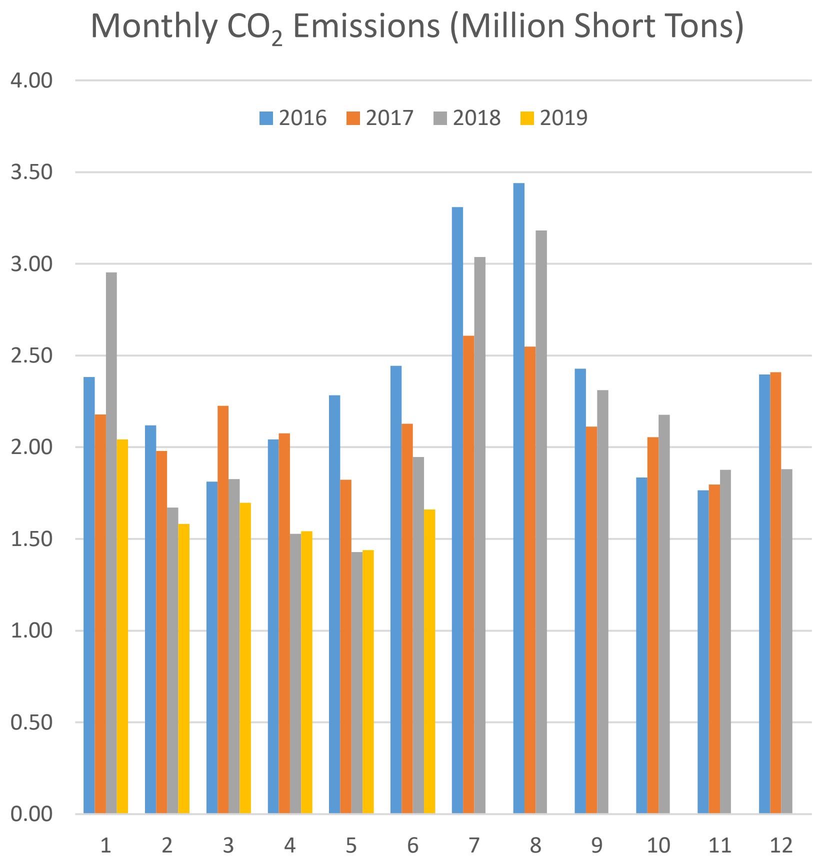
* Agenda topics are subject to change. Visit https://www.iso-ne.com/committees/planning/planning-advisory for the latest PAC agendas.

# Economic Studies

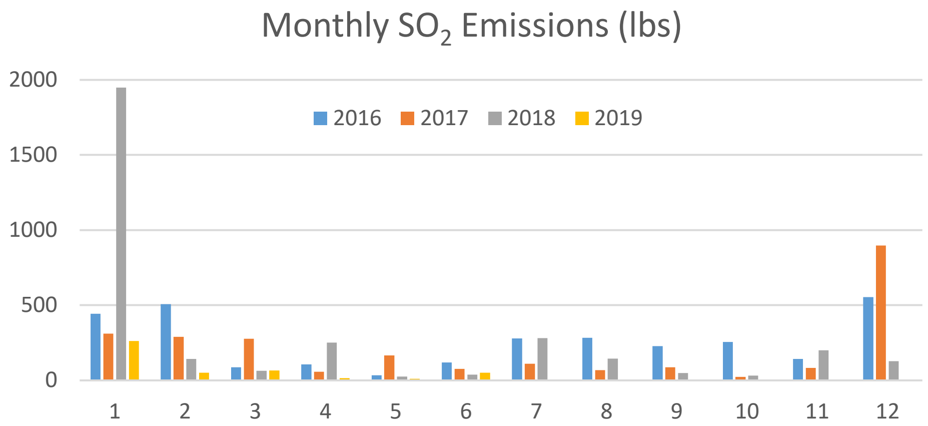
- Three economic study requests were introduced at the April 25 PAC meeting
  - Study requests were submitted by Anbaric, NESCOE, and RENEW Northeast
- Detailed assumptions for each study request were discussed at the August 8 PAC meeting
- The ISO will attempt to complete all analyses for all three requests by Q2 of 2020
  - Preliminary results expected by Q4 of 2019

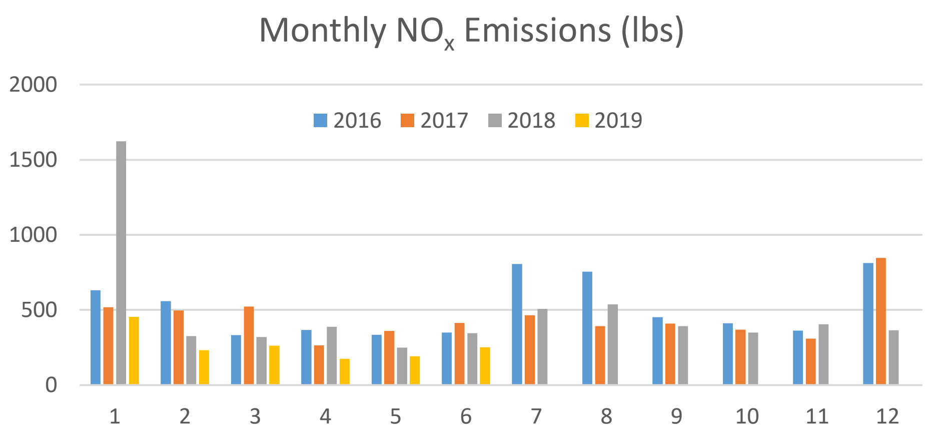
# Environmental Matters – Monthly System Emissions

## Monthly $CO_2$ Emissions Trending Lower in 2019




## Monthly $SO_2$ & NOx Emissions Trending Lower in 2019 (lbs)



# Environmental Matters – MA $CO_2$ Generator Emissions Cap Update (310 CMR 7.74)

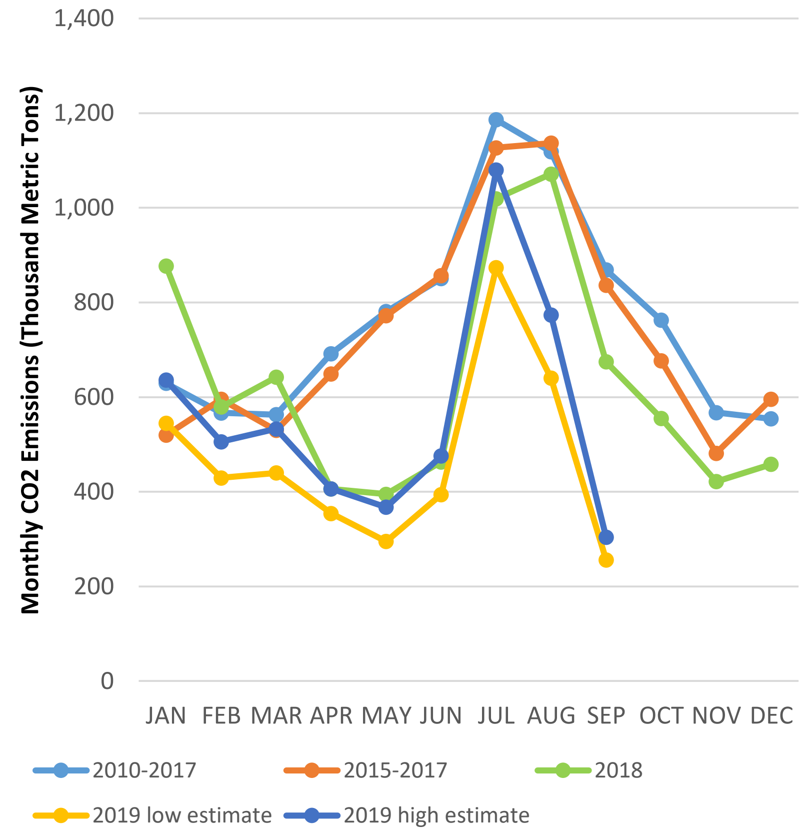
***Massachusetts Global Warming Solutions Act (GWSA)***

## Estimated 2019 Monthly Emissions Trend Lower under GWSA $CO_2$ Cap

- 2019 cap set at 8.73 million metric tons (MMT)
  - 2018 emissions: 7.56 MMT
- Estimated 2019 monthly emissions range (metric tons):
  - Jan 2019: 545,228 – 635,949
  - Feb 2019: 429,523 – 505,696
  - Mar 2019: 345,470 – 473,633
  - Apr 2019: 224,138 – 257,386
  - May 2019: 264,374 – 329,763
  - Jun 2019: 336,584 – 407,926
  - Jul 2019: 616,343 – 747,649
  - Aug 2019: 525,494 – 634,284
  - Sep 2019: 256,214 – 304,322*
  - **YTD 2019: 4.2 MMT – 5.1 MMT**

* September 2019 estimated emissions through 9/22/19

## GWSA Monthly $CO_2$ Emissions (Thousand Metric Tons)




September 2019 estimated emissions through 9/22/19

# RSP Project Stage Descriptions

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

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

# New Hampshire/Vermont 10-Year Upgrades

*Status as of 9/30/19*

*Project Benefit: Addresses Needs in New Hampshire and Vermont*

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

# New Hampshire/Vermont 10-Year Upgrades, cont.

*Status as of 9/30/19*

*Project Benefit: Addresses Needs in New Hampshire and Vermont*

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

# New Hampshire/Vermont 10-Year Upgrades, cont.

*Status as of 9/30/19*

*Project Benefit: Addresses Needs in New Hampshire and Vermont*

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

# Greater Hartford and Central Connecticut (GHCC) Projects*

*Status as of 9/30/19*

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

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

* Replaces the NEEWS Central Connecticut Reliability Project

# Greater Hartford and Central Connecticut Projects, cont.*

*Status as of 9/30/19*

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

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

* Replaces the NEEWS Central Connecticut Reliability Project

# Greater Hartford and Central Connecticut Projects, cont.*

*Status as of 9/30/19*

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

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

* Replaces the NEEWS Central Connecticut Reliability Project

# Greater Hartford and Central Connecticut Projects, cont.*

*Status as of 9/30/19*

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

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

* Replaces the NEEWS Central Connecticut Reliability Project

# Southwest Connecticut (SWCT) Projects

*Status as of 9/30/19*

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

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

# Southwest Connecticut Projects, cont.

*Status as of 9/30/19*

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

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

# Southwest Connecticut Projects, cont.

*Status as of 9/30/19*

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

| Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|
| Relocate the existing 37.8 MVAR capacitor bank from 115 kV B bus to 115 kV A bus at the Plumtree substation | Apr-17 | 4 |
| Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation | May-16 | 4 |
| Terminal equipment upgrade at the Newtown substation (1876) | Dec-15 | 4 |
| Rebuild the 115 kV line from Wilton to Norwalk (1682) and upgrade Wilton substation terminal equipment | Jun-17 | 4 |
| Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1) | Jun-20 | 3 |
| Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3) | Jun-20 | 3 |

# Southwest Connecticut Projects, cont.

*Status as of 9/30/19*

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

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

# Southwest Connecticut Projects, cont.

*Status as of 9/30/19*

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

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

# Greater Boston Projects

## *Status as of 9/30/19*

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

| Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|
| Install new 345 kV line from Scobie to Tewksbury | Dec-17 | 4 |
| Reconductor the Y-151 115 kV line from Dracut Junction to Power Street | Apr-17 | 4 |
| Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury | May-17 | 4 |
| Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury | May-17 | 4 |
| Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood | Dec-15 | 4 |
| Reconductor the F-158S 115 kV line from Maplewood to Everett | Jun-19 | 4 |
| Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn* | May-21 | 3* |
| Refurbish X-24 69 kV line from Millbury to Northboro Road | Dec-15 | 4 |
| Reconductor W-23W 69 kV line from Woodside to Northboro Road | Jun-19 | 4 |

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

# Greater Boston Projects, cont.

*Status as of 9/30/19*

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

| Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|
| Separate X-24 and E-157W DCT | Dec-18 | 4 |
| Separate Q-169 and F-158N DCT | Dec-15 | 4 |
| Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap | May-17 | 4 |
| Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook | May-20 | 3 |
| Install third 115 kV line from West Walpole to Holbrook | May-20 | 3 |
| Install new 345 kV breaker in series with the 104 breaker at Stoughton | May-16 | 4 |
| Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury | Dec-17 | 4 |
| Install a new 115 kV line from Sudbury to Hudson | Dec-20 | 2* |

* Project ISD to be reassessed after MA-EFSB Approval

# Greater Boston Projects, cont.

*Status as of 9/30/19*

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

| Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|
| Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn | Dec-19 | 3 |
| Install a 345 kV breaker in series with breaker 104 at Woburn | May-17 | 4 |
| Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker | Dec-17 | 4 |
| Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations | Aug-16 | 4 |
| Install a new 115 kV 54 MVAR capacitor bank at Newton | Dec-16 | 4 |
| Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury | May-17 | 4 |
| Install a second Mystic 345/115 kV autotransformer and reconfigure the bus | May-19 | 4 |
| Install a 115 kV breaker on the East bus at K Street | Jun-16 | 4 |
| Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards | Jan-20 | 3 |
| Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way | May-20 | 3 |

# Greater Boston Projects, cont.

*Status as of 9/30/19*

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

| Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|
| Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line | Dec-20 | 3 |
| Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station. | May-19 | 4 |
| Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard | Mar-19 | 4 |
| Relocate the Chelsea capacitor bank to the 128-518 termination postion | Dec-16 | 4 |

# Greater Boston Projects, cont.

*Status as of 9/30/19*

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

| Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|
| Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies | Dec-17 | 4 |
| Install a 200 MVAR STATCOM at Coopers Mills | Nov-18 | 4 |
| Install a 115 kV 36.7 MVAR capacitor bank at Hartwell | May-17 | 4 |
| Install a 345 kV 160 MVAR shunt reactor at K Street | Nov-19 | 3 |
| Install a 115 kV breaker in series with the 5 breaker at Framingham | Apr-17 | 4 |
| Install a 115 kV breaker in series with the 29 breaker at K Street | Apr-17 | 4 |

# Pittsfield/Greenfield Projects

*Status as of 9/30/19*

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

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

# Pittsfield/Greenfield Projects, cont.

*Status as of 9/30/19*

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

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

# Pittsfield/Greenfield Projects, cont.

*Status as of 9/30/19*

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

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

# SEMA/RI Reliability Projects

*Status as of 9/30/19*

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

| Project ID | Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|---|
| 1714 | Construct a new 115 kV GIS switching station (Grand Army) which includes remote terminal station work at Brayton Point and Somerset substations, and the looping in of the E-183E, F-184, X3, and W4 lines | Nov-20 | 3 |
| 1742 | Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station | Nov-20 | 3 |
| 1715 | Install upgrades at Brayton Point substation which include a new 115 kV breaker, new 345/115 kV transformer, and upgrades to E183E, F184 station equipment | Jun-20 | 3 |
| 1716 | Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations | Nov-19 | 3 |
| 1717 | Separate the X3/W4 DCT and reconductor the X3 and W4 lines between Somerset and Grand Army substations; reconfigure Y2 and Z1 lines | Nov-19 | 3 |

# SEMA/RI Reliability Projects, cont.

*Status as of 9/30/19*

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

| Project ID | Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|---|
| 1718 | Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line | Nov-20 | 2 |
| 1719 | Install 45.0 MVAR capacitor bank at Berry Street substation | Dec-20 | 2 |
| 1720 | Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations | Nov-21 | 2 |
| 1721 | Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor | Dec-21 | 2 |
| 1722 | Extend the Line 114 from the Dartmouth town line (Eversource- NGRID border) to Bell Rock substation | Dec-21 | 2 |
| 1723 | Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap | Sep-21 | 2 |

# SEMA/RI Reliability Projects, cont.

*Status as of 9/30/19*

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

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

# SEMA/RI Reliability Projects, cont.

*Status as of 9/30/19*

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

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

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

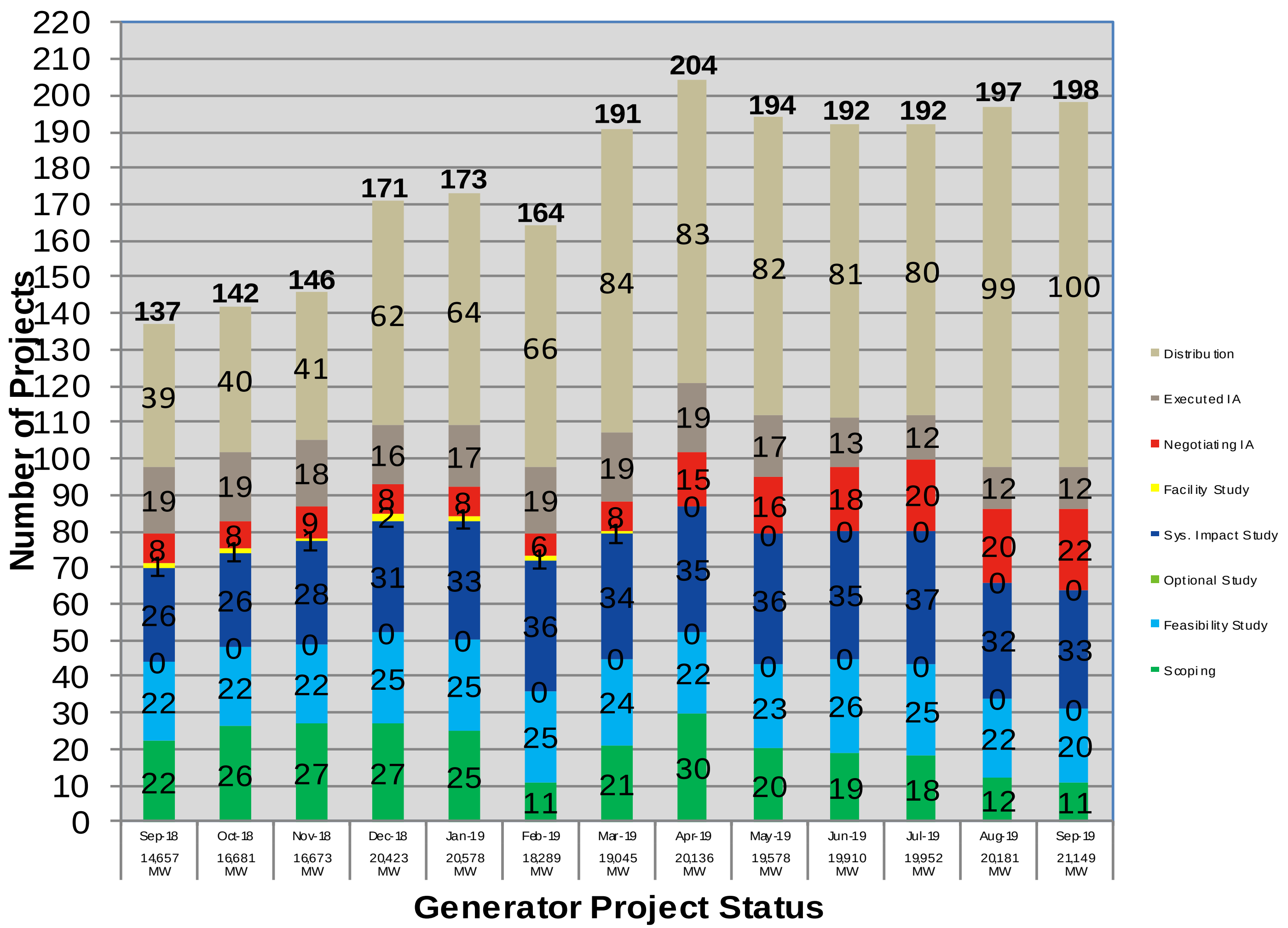
# SEMA/RI Reliability Projects, cont.

*Status as of 9/30/19*

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

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

# Status of Tariff Studies



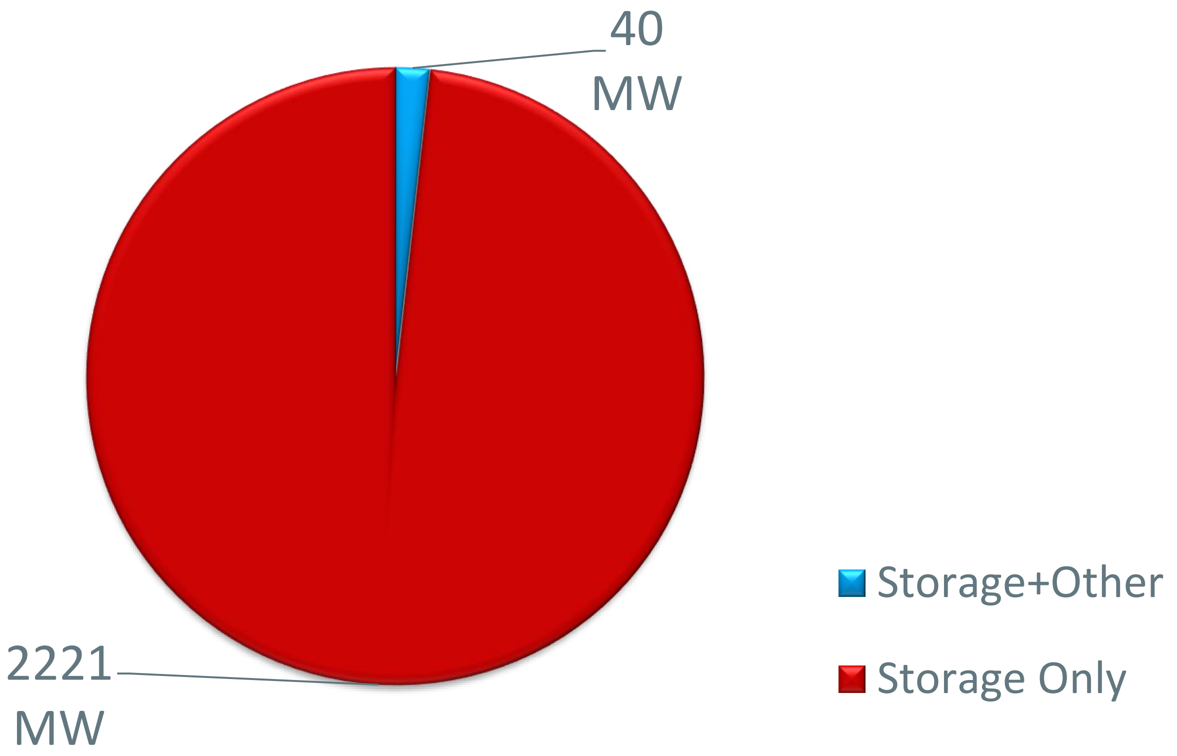

Note: September 2019 based on partial data

As of September 2019, there are 5 ETU's in Scoping, 5 in FS, 3 in SIS, 0 in FAC, 1 Negotiating IA, and 1 with Executed IA

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

# What is in the Queue (as of September 27, 2019)

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



# OPERABLE CAPACITY ANALYSIS

*Fall 2019 Analysis*

# Fall 2019 Operable Capacity Analysis

| 50/50 Load Forecast (Reference) | November - 2019[2] CSO (MW) | November - 2019[2] SCC (MW) |
|---|---|---|
| Operable Capacity MW [1] | 31,344 | 33,309 |
| Active Demand Capacity Resource (+) [5] | 455 | 439 |
| External Node Available Net Capacity, CSO imports minus firm capacity exports (+) | 897 | 917 |
| Non Commercial Capacity (+) | 28 | 28 |
| Non Gas-fired Planned Outage MW (-) | 4,051 | 4,154 |
| Gas Generator Outages MW (-) | 2,890 | 3,182 |
| Allowance for Unplanned Outages (-) [4] | 3,600 | 3,600 |
| Generation at Risk Due to Gas Supply (-) [3] | 0 | 0 |
| Net Capacity (NET OPCAP SUPPLY MW) | 22,183 | 23,757 |
| Peak Load Forecast MW(adjusted for Other Demand Resources) [2] | 16,912 | 16,912 |
| Operating Reserve Requirement MW | 2,305 | 2,305 |
| Operable Capacity Required (NET LOAD OBLIGATION MW) | 19,217 | 19,217 |
| Operable Capacity Margin | 2,966 | 4,540 |

[1] Operable Capacity is based on data as of **September 17, 2019** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **September 17, 2019.**

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

[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.

# Fall 2019 Operable Capacity Analysis

| 90/10 Load Forecast (Extreme) | November - 2019[2] CSO (MW) | November - 2019[2] SCC (MW) |
|---|---|---|
| Operable Capacity MW [1] | 31,344 | 33,309 |
| Active Demand Capacity Resource (+) [5] | 455 | 439 |
| External Node Available Net Capacity, CSO imports minus firm capacity exports (+) | 897 | 917 |
| Non Commercial Capacity (+) | 28 | 28 |
| Non Gas-fired Planned Outage MW (-) | 4,051 | 4,154 |
| Gas Generator Outages MW (-) | 2,890 | 3,182 |
| Allowance for Unplanned Outages (-) [4] | 3,600 | 3,600 |
| Generation at Risk Due to Gas Supply (-) [3] | 0 | 0 |
| Net Capacity (NET OPCAP SUPPLY MW) | 22,183 | 23,757 |
| Peak Load Forecast MW(adjusted for Other Demand Resources) [2] | 17,503 | 17,503 |
| Operating Reserve Requirement MW | 2,305 | 2,305 |
| Operable Capacity Required (NET LOAD OBLIGATION MW) | 19,808 | 19,808 |
| Operable Capacity Margin | 2,375 | 3,949 |

[1]Operable Capacity is based on data as of **September 17, 2019** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **September 17, 2019.**

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

[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.

# Fall 2019 Operable Capacity Analysis

# 50/50 Forecast (Reference)

## ISO-NE OPERABLE CAPACITY ANALYSIS

### October 1, 2019 - 50-50 FORECAST using CSO

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

| STUDY WEEK (Week Beginning, Saturday) | AVAILABLE OPCAP MW | Active Capacity Demand MW | EXTERNAL NODE AVAIL CAPACITY MW | NON COMMERCIAL CAPACITY MW | NON-GAS PLANNED OUTAGES CSO MW | GAS GENERATOR OUTAGES CSO MW | ALLOWANCE FOR UNPLANNED OUTAGES MW | GAS AT RISK MW | NET OPCAP SUPPLY MW | PEAK LOAD FORECAST MW | OPER RESERVE REQUIREMENT MW | NET LOAD OBLIGATION MW | OPCAP MARGIN MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] | [13] |
| 10/5/2019 | 31694 | 389 | 473 | 28 | 5063 | 1540 | 2800 | 0 | 23181 | 15241 | 2305 | 17546 | 5635 |
| 10/12/2019 | 31694 | 389 | 573 | 28 | 3957 | 1512 | 2800 | 0 | 24415 | 16200 | 2305 | 18505 | 5910 |
| 10/19/2019 | 31694 | 389 | 473 | 28 | 3365 | 1741 | 2800 | 0 | 24678 | 16577 | 2305 | 18882 | 5796 |
| 10/26/2019 | 31344 | 455 | 897 | 28 | 3123 | 264 | 3600 | 0 | 25737 | 16792 | 2305 | 19097 | 6640 |
| **11/2/2019** | **31344** | **455** | **897** | **28** | **4051** | **2890** | **3600** | **0** | **22183** | **16912** | **2305** | **19217** | **2966** |
| 11/9/2019 | 31344 | 455 | 897 | 28 | 3793 | 2460 | 3600 | 0 | 22871 | 17269 | 2305 | 19574 | 3297 |
| 11/16/2019 | 31344 | 455 | 897 | 28 | 3205 | 668 | 3600 | 752 | 24499 | 18034 | 2305 | 20339 | 4160 |
| 11/23/2019 | 31344 | 455 | 897 | 28 | 1487 | 668 | 3600 | 1465 | 25504 | 18780 | 2305 | 21085 | 4419 |

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,323 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

# Fall 2019 Operable Capacity Analysis
# 90/10 Forecast (Extreme)

## ISO-NE OPERABLE CAPACITY ANALYSIS

### October 1, 2019 - 90-10 FORECAST using CSO

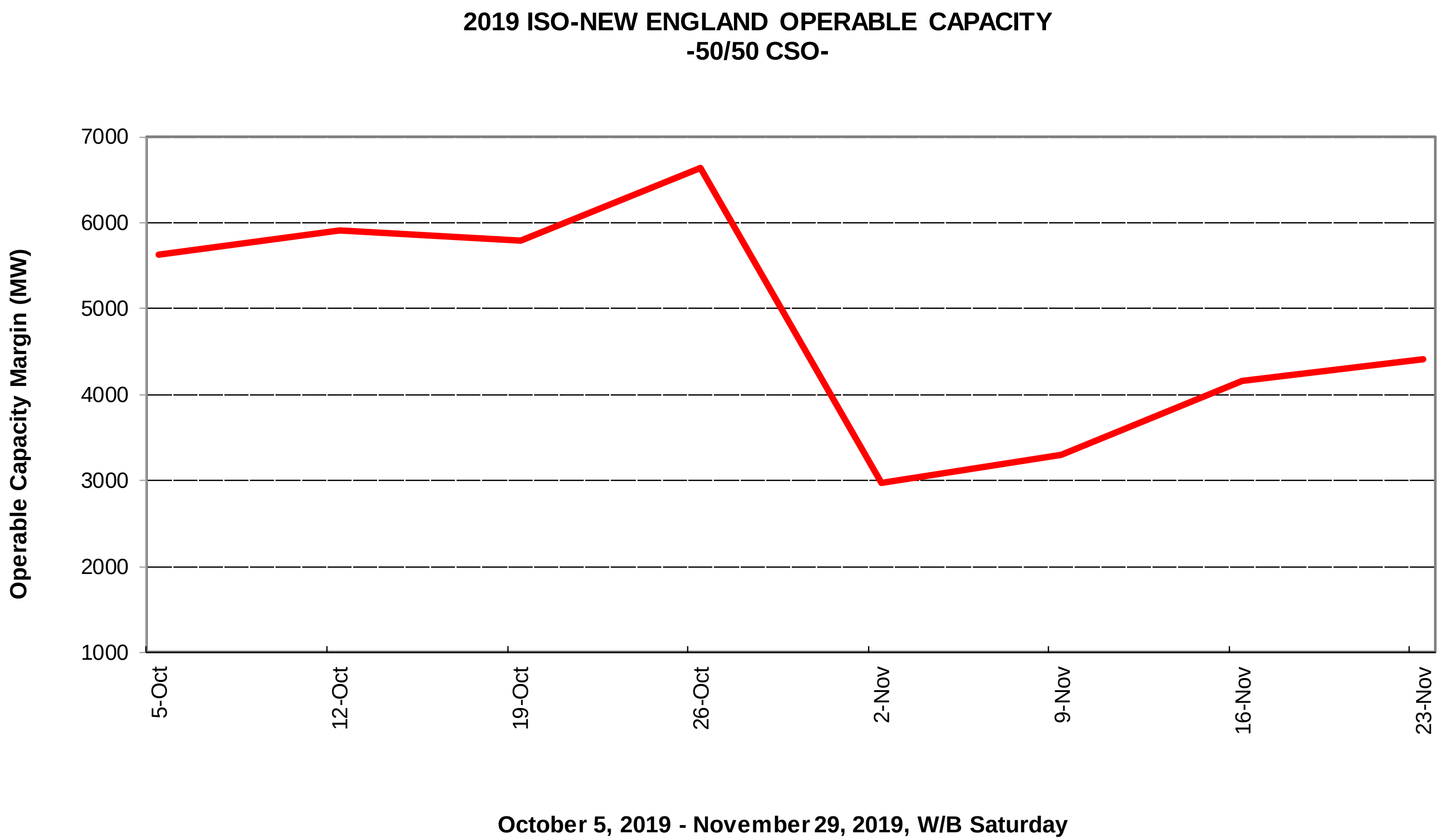
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, August and Mid September

| STUDY WEEK (Week Beginning, Saturday) | AVAILABLE OPCAP MW | Active Capacity Demand MW | EXTERNAL NODE AVAIL CAPACITY MW | NON COMMERCIAL CAPACITY MW | NON-GAS PLANNED OUTAGES CSO MW | GAS GENERATOR OUTAGES CSO MW | ALLOWANCE FOR UNPLANNED OUTAGES MW | GAS AT RISK MW | NET OPCAP SUPPLY MW | PEAK LOAD FORECAST MW | OPER RESERVE REQUIREMENT MW | NET LOAD OBLIGATION MW | OPCAP MARGIN MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] | [13] |
| 10/5/2019 | 31694 | 389 | 473 | 28 | 5063 | 1540 | 2800 | 0 | 23181 | 15783 | 2305 | 18088 | 5093 |
| 10/12/2019 | 31694 | 389 | 573 | 28 | 3957 | 1512 | 2800 | 0 | 24415 | 16770 | 2305 | 19075 | 5340 |
| 10/19/2019 | 31694 | 389 | 473 | 28 | 3365 | 1741 | 2800 | 0 | 24678 | 17159 | 2305 | 19464 | 5214 |
| 10/26/2019 | 31344 | 455 | 897 | 28 | 3123 | 264 | 3600 | 0 | 25737 | 17380 | 2305 | 19685 | 6052 |
| **11/2/2019** | **31344** | **455** | **897** | **28** | **4051** | **2890** | **3600** | **0** | **22183** | **17503** | **2305** | **19808** | **2375** |
| 11/9/2019 | 31344 | 455 | 897 | 28 | 3793 | 2460 | 3600 | 0 | 22871 | 17871 | 2305 | 20176 | 2695 |
| 11/16/2019 | 31344 | 455 | 897 | 28 | 3205 | 668 | 3600 | 910 | 24341 | 18659 | 2305 | 20964 | 3377 |
| 11/23/2019 | 31344 | 455 | 897 | 28 | 1487 | 668 | 3600 | 1702 | 25267 | 19428 | 2305 | 21733 | 3534 |

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 27,212 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

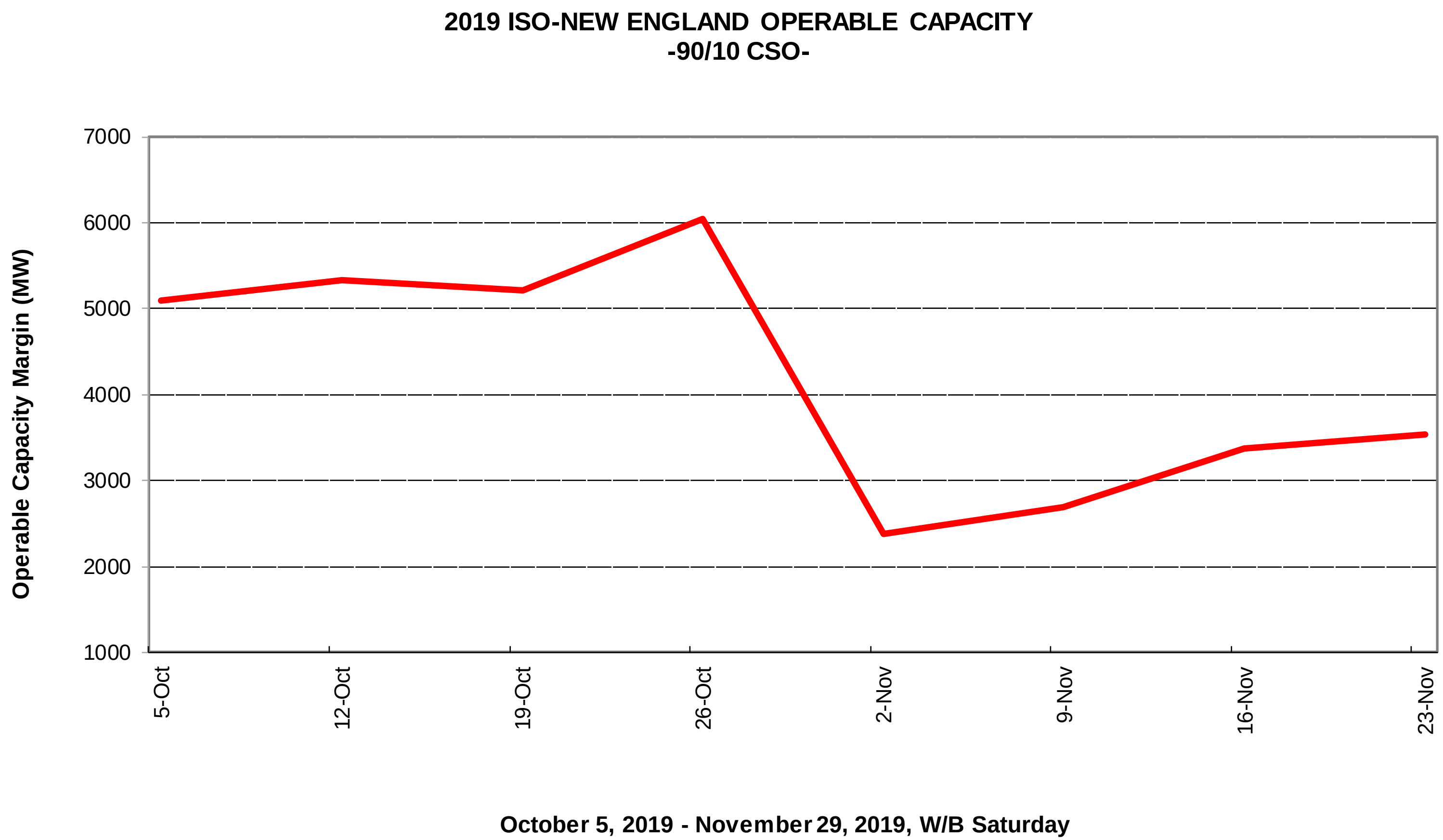
***Highlighted week is based on the week determined by the 50/50 Load Forecast Reference week

# Fall 2019 Operable Capacity Analysis
# 50/50 Forecast (Reference)



# Fall 2019 Operable Capacity Analysis

## 90/10 Forecast (Extreme)



# OPERABLE CAPACITY ANALYSIS

*Preliminary Winter 2019/20 Analysis*

# Preliminary Winter 2019/20 Operable Capacity Analysis

| 50/50 Load Forecast (Reference) | January - 2019[2] CSO (MW) | January - 2019[2] SCC (MW) |
|---|---|---|
| Operable Capacity MW [1] | 31,344 | 33,309 |
| Active Demand Capacity Resource (+) [5] | 458 | 328 |
| External Node Available Net Capacity, CSO imports minus firm capacity exports (+) | 917 | 917 |
| Non Commercial Capacity (+) | 28 | 28 |
| Non Gas-fired Planned Outage MW (-) | 482 | 499 |
| Gas Generator Outages MW (-) | 0 | 0 |
| Allowance for Unplanned Outages (-) [4] | 2,800 | 2,800 |
| Generation at Risk Due to Gas Supply (-) [3] | 4,207 | 4,648 |
| Net Capacity (NET OPCAP SUPPLY MW) | 25,258 | 26,635 |
| Peak Load Forecast MW(adjusted for Other Demand Resources) [2] | 20,476 | 20,476 |
| Operating Reserve Requirement MW | 2,305 | 2,305 |
| Operable Capacity Required (NET LOAD OBLIGATION MW) | 22,781 | 22,781 |
| Operable Capacity Margin | 2,477 | 3,854 |

[1]Operable Capacity is based on data as of **September 17, 2019** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **September 17, 2019.**

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

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

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

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

# Preliminary Winter 2019/20 Operable Capacity Analysis

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|---|---|---|
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| Active Demand Capacity Resource (+) [5] | 458 | 328 |
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| Non Commercial Capacity (+) | 28 | 28 |
| Non Gas-fired Planned Outage MW (-) | 482 | 499 |
| Gas Generator Outages MW (-) | 0 | 0 |
| Allowance for Unplanned Outages (-) [4] | 2,800 | 2,800 |
| Generation at Risk Due to Gas Supply (-) [3] | 4,674 | 5,165 |
| Net Capacity (NET OPCAP SUPPLY MW) | 24,791 | 26,118 |
| Peak Load Forecast MW(adjusted for Other Demand Resources) [2] | 21,173 | 21,173 |
| Operating Reserve Requirement MW | 2,305 | 2,305 |
| Operable Capacity Required (NET LOAD OBLIGATION MW) | 23,478 | 23,478 |
| Operable Capacity Margin | 1,313 | 2,640 |

[1]Operable Capacity is based on data as of **September 17, 2019** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **September 17, 2019.**

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

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

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

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

# Preliminary Winter 2019/20 Operable Capacity Analysis
# 50/50 Forecast (Reference)

## ISO-NE OPERABLE CAPACITY ANALYSIS

### October 1, 2019 - 50-50 FORECAST using CSO

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

| STUDY WEEK (Week Beginning, Saturday) | AVAILABLE OPCAP MW [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] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11/30/2019 | 31344 | 458 | 917 | 28 | 1349 | 333 | 3200 | 2325 | 25540 | 19232 | 2305 | 21537 | 4003 |
| 12/7/2019 | 31344 | 458 | 917 | 28 | 1329 | 333 | 3200 | 2786 | 25099 | 19532 | 2305 | 21837 | 3262 |
| 12/14/2019 | 31344 | 458 | 917 | 28 | 875 | 0 | 3200 | 3301 | 25371 | 19543 | 2305 | 21848 | 3523 |
| 12/21/2019 | 31344 | 458 | 917 | 28 | 330 | 0 | 3200 | 3621 | 25596 | 19608 | 2305 | 21913 | 3683 |
| 12/28/2019 | 31344 | 458 | 917 | 28 | 330 | 0 | 3200 | 3967 | 25250 | 19993 | 2305 | 22298 | 2952 |
| 1/4/2020 | 31344 | 458 | 917 | 28 | 329 | 279 | 2800 | 3806 | 25533 | 20476 | 2305 | 22781 | 2752 |
| **1/11/2020** | **31344** | **458** | **917** | **28** | **482** | **0** | **2800** | **4207** | **25258** | **20476** | **2305** | **22781** | **2477** |
| 1/18/2020 | 31344 | 458 | 917 | 28 | 482 | 0 | 2800 | 4014 | 25451 | 20476 | 2305 | 22781 | 2670 |
| 1/25/2020 | 31344 | 458 | 917 | 28 | 482 | 0 | 2800 | 3737 | 25728 | 20245 | 2305 | 22550 | 3178 |
| 2/1/2020 | 31344 | 458 | 917 | 28 | 545 | 0 | 3100 | 3737 | 25365 | 19967 | 2305 | 22272 | 3093 |
| 2/8/2020 | 31344 | 458 | 917 | 28 | 545 | 0 | 3100 | 3322 | 25780 | 19937 | 2305 | 22242 | 3538 |
| 2/15/2020 | 31344 | 458 | 917 | 28 | 500 | 0 | 3100 | 3045 | 26102 | 19664 | 2305 | 21969 | 4133 |
| 2/22/2020 | 31344 | 458 | 917 | 28 | 405 | 0 | 3100 | 2492 | 26750 | 18636 | 2305 | 20941 | 5809 |
| 2/29/2020 | 31344 | 458 | 917 | 28 | 1188 | 267 | 2200 | 1809 | 27283 | 18273 | 2305 | 20578 | 6705 |
| 3/7/2020 | 31344 | 458 | 917 | 28 | 1219 | 279 | 2200 | 1659 | 27390 | 18069 | 2305 | 20374 | 7016 |
| 3/14/2020 | 31344 | 458 | 917 | 28 | 1219 | 647 | 2200 | 737 | 27944 | 17690 | 2305 | 19995 | 7949 |
| 3/21/2020 | 31344 | 458 | 917 | 28 | 1835 | 650 | 2200 | 319 | 27743 | 17102 | 2305 | 19407 | 8336 |

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,323 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

# Preliminary Winter 2019/20 Operable Capacity Analysis

## 90/10 Forecast (Extreme)

### ISO-NE OPERABLE CAPACITY ANALYSIS

October 1, 2019 - 90-10 FORECAST using CSO

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

| STUDY WEEK (Week Beginning, Saturday) | AVAILABLE OPCAP MW | Active Capacity Demand MW | EXTERNAL NODE AVAIL CAPACITY MW | NON COMMERCIAL CAPACITY MW | NON-GAS PLANNED OUTAGES CSO MW | GAS GENERATOR OUTAGES CSO MW | ALLOWANCE FOR UNPLANNED OUTAGES MW | GAS AT RISK MW | NET OPCAP SUPPLY MW | PEAK LOAD FORECAST MW | OPER RESERVE REQUIREMENT MW | NET LOAD OBLIGATION MW | OPCAP MARGIN MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] | [13] |
| 11/30/2019 | 31344 | 458 | 917 | 28 | 1349 | 333 | 3200 | 2620 | 25245 | 19886 | 2305 | 22191 | 3054 |
| 12/7/2019 | 31344 | 458 | 917 | 28 | 1329 | 333 | 3200 | 3132 | 24753 | 20194 | 2305 | 22499 | 2254 |
| 12/14/2019 | 31344 | 458 | 917 | 28 | 875 | 0 | 3200 | 3668 | 25004 | 20206 | 2305 | 22511 | 2493 |
| 12/21/2019 | 31344 | 458 | 917 | 28 | 330 | 0 | 3200 | 4023 | 25194 | 20273 | 2305 | 22578 | 2616 |
| 12/28/2019 | 31344 | 458 | 917 | 28 | 330 | 0 | 3200 | 4408 | 24809 | 20674 | 2305 | 22979 | 1830 |
| 1/4/2020 | 31344 | 458 | 917 | 28 | 329 | 279 | 2800 | 4260 | 25079 | 21173 | 2305 | 23478 | 1601 |
| **1/11/2020** | **31344** | **458** | **917** | **28** | **482** | **0** | **2800** | **4674** | **24791** | **21173** | **2305** | **23478** | **1313** |
| 1/18/2020 | 31344 | 458 | 917 | 28 | 482 | 0 | 2800 | 4460 | 25005 | 21173 | 2305 | 23478 | 1527 |
| 1/25/2020 | 31344 | 458 | 917 | 28 | 482 | 0 | 2800 | 4153 | 25312 | 20934 | 2305 | 23239 | 2073 |
| 2/1/2020 | 31344 | 458 | 917 | 28 | 545 | 0 | 3100 | 4153 | 24949 | 20648 | 2305 | 22953 | 1996 |
| 2/8/2020 | 31344 | 458 | 917 | 28 | 545 | 0 | 3100 | 3691 | 25411 | 20617 | 2305 | 22922 | 2489 |
| 2/15/2020 | 31344 | 458 | 917 | 28 | 500 | 0 | 3100 | 3384 | 25763 | 20336 | 2305 | 22641 | 3122 |
| 2/22/2020 | 31344 | 458 | 917 | 28 | 405 | 0 | 3100 | 2768 | 26474 | 19277 | 2305 | 21582 | 4892 |
| 2/29/2020 | 31344 | 458 | 917 | 28 | 1188 | 267 | 2200 | 2040 | 27052 | 18903 | 2305 | 21208 | 5844 |
| 3/7/2020 | 31344 | 458 | 917 | 28 | 1219 | 279 | 2200 | 1874 | 27175 | 18693 | 2305 | 20998 | 6177 |
| 3/14/2020 | 31344 | 458 | 917 | 28 | 1219 | 647 | 2200 | 891 | 27790 | 18302 | 2305 | 20607 | 7183 |
| 3/21/2020 | 31344 | 458 | 917 | 28 | 1835 | 650 | 2200 | 427 | 27635 | 17697 | 2305 | 20002 | 7633 |

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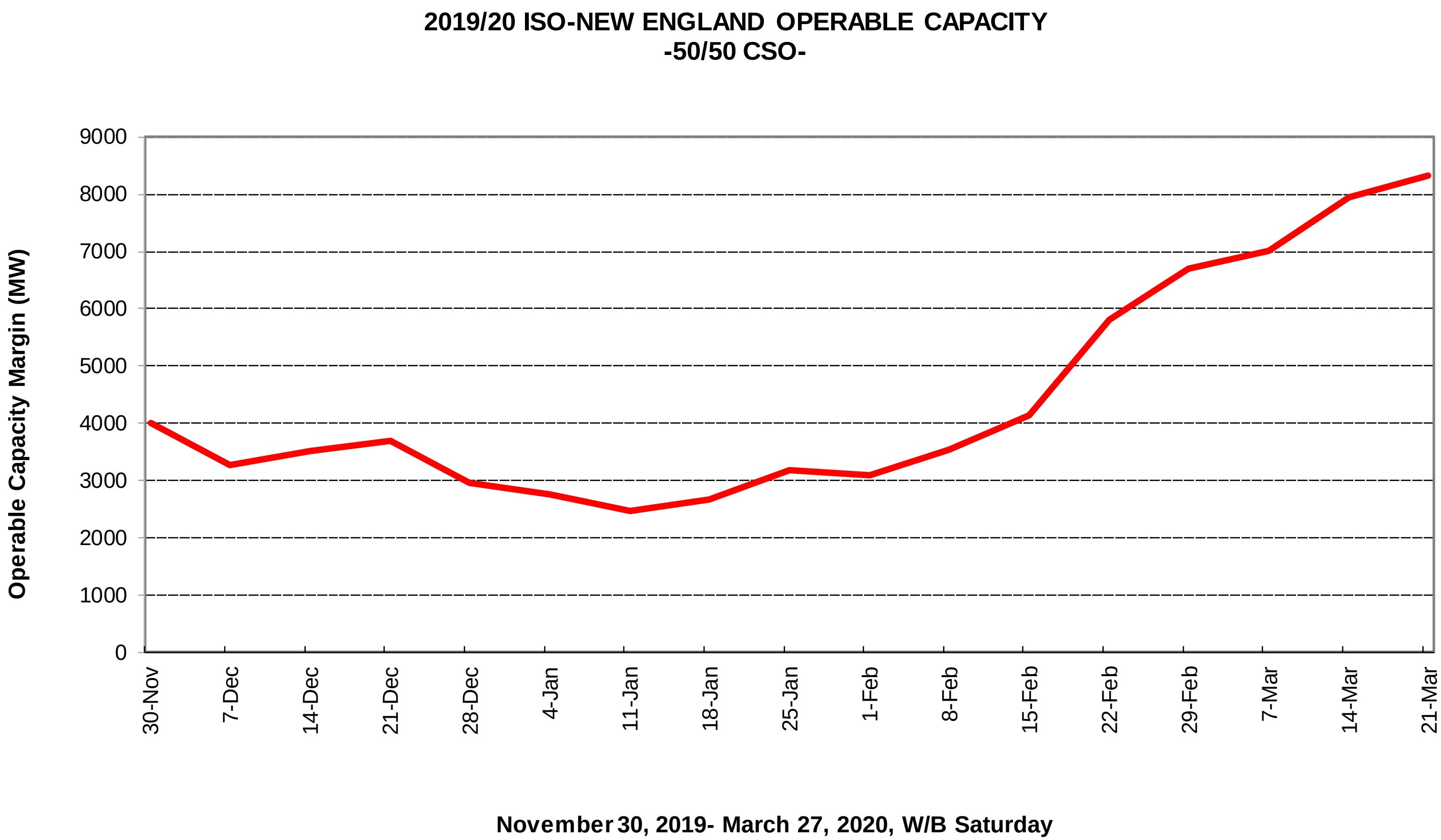
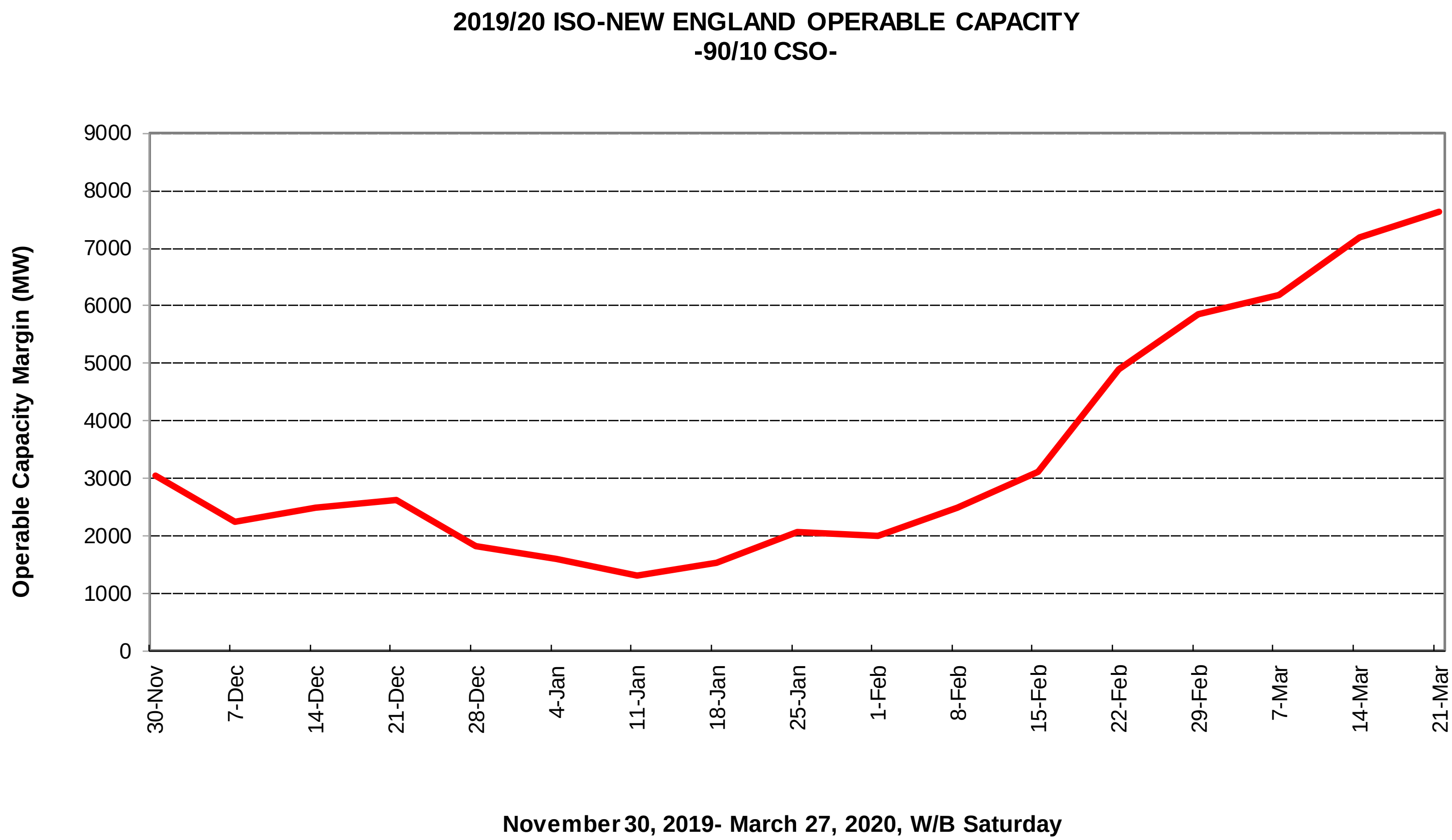
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

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

# Preliminary Winter 2019/20 Operable Capacity Analysis
## 50/50 Forecast (Reference)



# Preliminary Winter 2019/20 Operable Capacity Analysis
# 90/10 Forecast (Extreme)



# OPERABLE CAPACITY ANALYSIS

*Appendix*

# Possible Relief Under OP4: Appendix A

| OP 4 Action Number | Page 1 of 2<br>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.<br>Begin to allow the depletion of 30-minute reserve. | 0 [1]<br><br>600 |
| 2 | Declare Energy Emergency Alert (EEA) Level 1[4] | 0 |
| 3 | Voluntary Load Curtailment of Market Participants' facilities. | 40 [2] |
| 4 | Implement Power Watch | 0 |
| 5 | Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency | 1,000 |
| 6 | Voltage Reduction requiring > 10 minutes | 125 [3] |

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

# Possible Relief Under OP4: Appendix A

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

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