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Representative Future Locational Reserve Needs for Current Reserve Zones

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Objectives

- To develop future representative operating reserve needs for current reserve zones
  - Greater Southwest Connecticut (SWCT)
  - Greater Connecticut (CT)
  - NEMA/Boston
- Study Period
  - 2018 - 2022 (both summer and winter seasons)
    - Actual requirements are reported for 2018
- Major Study Assumptions
  - Historical data of the last two years
  - 2018-2027 Forecast Report of Capacity, Energy, Loads, and Transmission (2018 CELT) and Forward Capacity Market (FCM) results used for future loads; behind-the-meter photovoltaic (BTM PV) forecast; passive demand resources; and resource additions and retirements
  - Transmission limits consistent with those assumed for Installed Capacity Requirement related simulations conducted in 2018

BACKGROUND

Operating Reserve Requirements

- Real-time operating reserve capacity must be available to respond to system contingencies. Typical contingencies considered are
  - Loss of a supply source, such as a generator
  - Loss of a transmission element, such as a 345 kV transmission line
  - In certain circumstance, loss of multiple elements, such as two lines, a line and a generator, or several generators in a station that are vulnerable to a common-mode failure
- Types of operating reserve
  - Ten Minute non-Spin Reserve (TMNSR)
    - Nonsynchronized reserve that is fully available in 10 minutes from the time first requested
  - Ten-Minute Spin Reserve (TMSR)
    - Synchronized reserve that is fully available in 10 minutes from the time first requested
  - Thirty-Minute Operating Reserve (TMOR)
    - The sum of synchronized reserve and nonsynchronized reserve capability that is fully available within thirty minutes from the time first requested, excluding the capability assigned to meet ten-minute reserve requirements

Operating Reserve Requirements, *cont.*

- Reliability standards, criteria, and procedures require the New England power system be planned and operated to protect and recover from specific types of network contingencies
  - NERC Standard BAL-002-0 Disturbance Control Performance
    - http://www.nerc.com/files/BAL-002-0.pdf
  - NPCC Regional Reliability Reference Directory #5, Reserve
    - https://www.npcc.org/Standards/Directories/Directory_5-Full%20Member%20Approved%20clean%20-GJD%2020150330.pdf
  - ISO New England Operating Procedure No. 8, Operating Reserve and Regulation
    - http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op8/op8_rto_final.pdf
  - ISO New England Operating Procedure No. 19, Transmission Operations
    - http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op19/op19_rto_final.pdf
- Useful reference on operating reserve requirements
  - ISO New England Operating Reserves White Paper
    - http://www.iso-ne.com/pubs/whtpprs/operating_reserves_white_paper.pdf

System-wide Operating Reserve Requirements

- Typical system-wide operating reserve requirements
  - System real-time reserves to account for historical non-performance
    - Total 10-minute Reserve = 1st Contingency x 120%
      - Typically, TMNSR = 50% x Total 10-minute Reserve
      - Typically, TMSR = 50% x Total 10-minute Reserve
    - TMOR = 50% x 2nd Contingency
  - Increase TMNSR in the Forward Reserve Market to account for (a) any historical under-performance of Resources dispatched in response to a system contingency, and (b) the likelihood that more than one half of the forecasted first contingency supply loss will be satisfied using TMNSR
    - TMNSR = 1st Contingency x 120%
      x bias of the historical delivery ratio of TMNSR to TMSR
  - System-wide replacement reserve
    - 180 MW during winter period
    - 160 MW during summer period

Subregional Reserve Requirements/Locational Forward Reserve Market

- Reliability standards, criteria, and procedures also require operating reserve to be distributed to ensure that the ISO can fully use it for any probable contingency without exceeding transmission system limitations
  - Certain amount of reserve is required within specific New England subregions to meet the local 2nd contingency
  - Depending on system conditions (the configuration of the interface, the largest generator on-line, loads, and the total resources on-line in the area), the local 2nd contingency will be either a line or a generator(s)
- Locational Forward Reserve Market (LFRM)
  - Requirements reflect the amount of 30-minute reserves required to meet the local 2nd contingency under normal operating conditions, while accounting for reserves imported across the interfaces into constrained locations (External Reserve Support or ERS)
  - The requirements for the LFRM are currently derived from an analysis of historical data
    - A rolling, two-year historical data of daily peak hour operational requirements for each Reserve Zone for like periods (summer or winter)
    - The requirements are modified, as required, to reflect changes in the configuration of the transmission system or addition/retirement of major generating resources

Future Locational Reserve Needs Projection

- Future reserve needs for the Reserve Zones are evaluated through probabilistic simulations that generate a series of possible system conditions for the future
- System historical data (with adjustments made to reflect future system conditions), is used to develop the probability distribution for the system variables and correlations
- Variables considered in simulations
  - Transmission Import Capability
    - Reflects assumed system condition/topology changes
  - Largest generation contingency
  - Local online generation
    - Adjustments made to reflect assumed major additions and retirements/deactivations
  - Load
    - Load scaled up/down to forecast values
    - Passive demand resources and BTM PV reflected
- Some operational constraints and interdependency may not be fully modeled in the simulation of the future system

SUMMARY OF STUDY RESULTS AND OBSERVATIONS

Summary of Representative Future Requirements

Area/Improvement	Market Period[a]	Range of Fast-Start Resources Offered into the Past Five Forward Reserve Auctions (MW)[b]	Representative Future Locational Forward Reserve Market Requirements (MW)	
			Summer (Jun to Sep)[c]	Winter (Oct to May)[c]
Greater Southwest Connecticut[d,g]	2018	Max: 346 Min: 188 Avg: 227	21[e]	To-be-updated
Reflecting impact of CPV-Towantic	2019		0 (50 – 300, w/o Towantic)	0
Reflecting impact of Bridgeport Harbor 5	2020		0	0
	2021		0	0
Reflecting impact of retirement of Bridgeport 3 and SWCT upgrades	2022		0	0
Greater Connecticut [f,g]	2018	Max: 1,188 Min: 613 Avg: 960 (h)	0[e]	To-be-updated
Reflecting impact of CPV-Towantic	2019		0	0
Reflecting impact of Bridgeport Harbor 5	2020		0	0
Reflecting impact of Greater Hartford/Central Connecticut upgrades	2021		0	0
Reflecting impact of retirement of Bridgeport Harbor 3	2022		0	0
NEMA/BOSTON[g,i]	2018	Max: 318 Min: 0 Avg: 148	44[e]	To-be-updated
Reflecting impact of Footprint	2019		0 – 50 (250 –700 w/o Footprint)	0 (250 –400 w/o Footprint)
Reflecting impact of Greater Boston Upgrades	2020		0	0
	2021		0	0
	2022		0	0

Footnotes for Table in Previous page

(a) The market period is from June 1 through May 31 of the following year.

(b) These values are the range of the megawatts of resources offered into the past forward-reserve auctions. A summary of the forward-reserve offers for the past auctions is available at http://www.iso-ne.com/markets-operations/markets/reserves.

(c) “Summer” means June through September and “winter” means October through May of a Capacity Commitment Period (CPC); (e.g., the 2018 winter values are for October 2018 through May 2019 of 2018-2019 CCP). The representative values show a range to reflect uncertainties associated with the future system conditions.

(d) The assumed N−1 and N−1−1 transmission import limits into Greater Southwest Connecticut are 2,500 MW and 1,750 MW, respectively. These limits increase to 2,800 MW and 1,900 MW in 2021 with the SWCT upgrades.

(e) These values are actual locational forward-reserve requirements. The projections of the requirements for future years are based on assumed contingencies.

(f) For Greater Connecticut, the assumed import limits reflect an N−1 value of 2,950 MW and an N−1−1 value of 1,750 MW. With the Greater Hartford/Central Connecticut Upgrades assumed in service in 2020, the N-1 and N-1-1 import limits will increase to 3,400 MW and 2,200 MW, respectively.

(g) In some circumstances when transmission contingencies are more severe than generation contingencies, shedding some nonconsequential load (i.e. load shed that is not the direct result of the contingency) may be acceptable.

(h) These values include resources in Greater Southwest Connecticut.

(i) The assumed N−1 and N−1−1 values reflecting transmission import limits into BOSTON are 4,850 MW and 4,175 MW, respectively. These limits will increase to 5,700 MW and 4,600 MW, respectively, after the Greater Boston Upgrades assumed in service by June 2019.

Results Summary and Observations

- Greater Southwest Connecticut
  - The in-service of CPV-Towantic is expected to help reduce local reserve needs to a minimum level for the summer 2019
  - With the assumed addition of Bridgeport Harbor 5, and the SWCT transmission upgrades, Forward Reserve Requirements are expected to be zero for the remainder of the study period
- Greater Connecticut
  - The in-service of CPV-Towantic, the assumed addition of Bridgeport Harbor 5 generations, and the Greater Hartford/Central Connecticut Upgrades are projected to eliminate local reserve needs during the study period
- NEMA/BOSTON
  - Reserve needs are expected to be in the range of 250 – 700 MW for summer and 250 – 400 MW for the winter for 2019 without considering the impacts of Footprint generation
  - In-service of Footprint generation and Greater Boston Upgrades are expected to help eliminate the local reserve needs for the study period

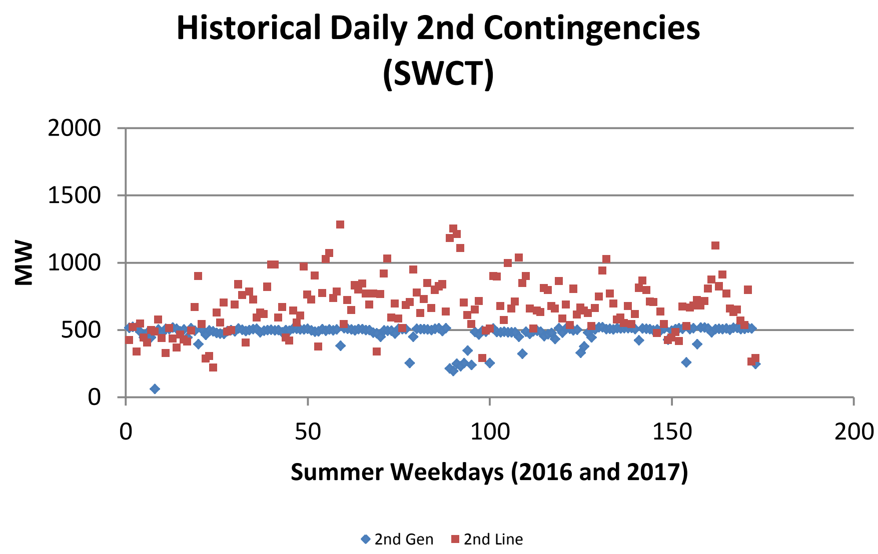
APPENDIX

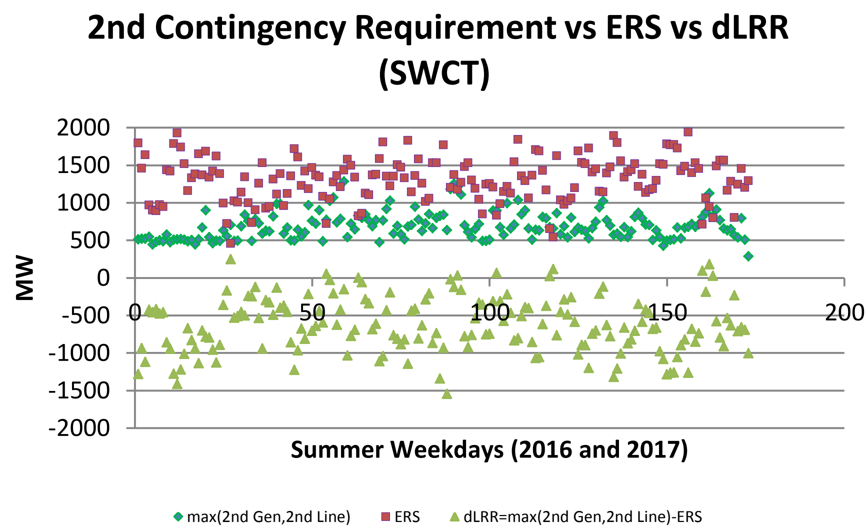
DEVELOPMENT OF REPRESENTATIVE FUTURE LOCATIONAL RESERVE REQUIREMENTS

- Greater Southwest Connecticut (SWCT)

Historical Data
- Summer

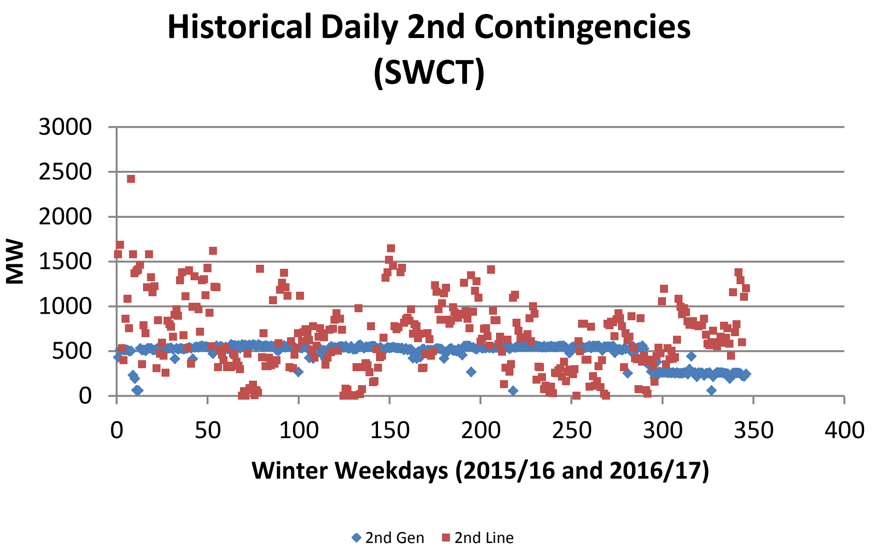
- 2^{nd} Gen was relatively constant
- 2^{nd} Line was volatile, and the magnitude can be much higher than 2^{nd} Gen
- 2^{nd} contingency requirement set by 2^{nd} Gen for about 20% of the time during the last two summers
- Certain amount of reserve was required for the zone for less than 10% of the time during the last two summers

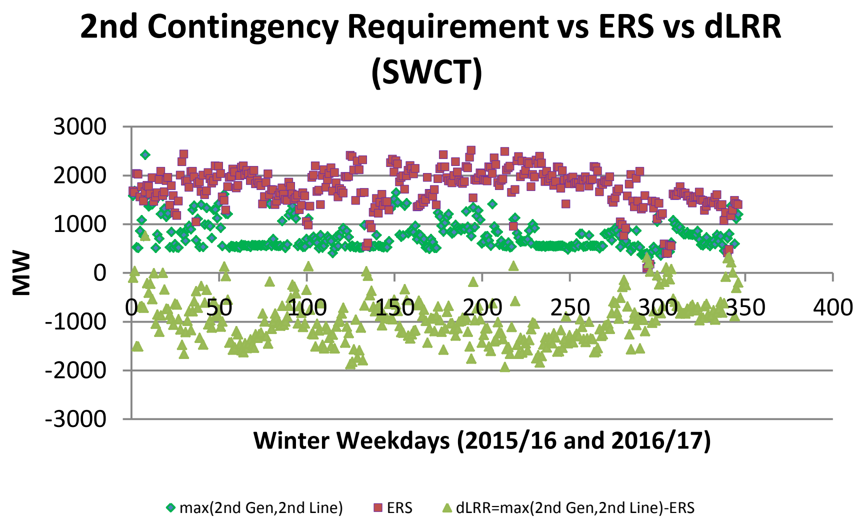




Historical Data - Winter

- 2nd Gen was relatively constant
- 2nd Line was volatile, and the magnitude can be much higher than 2nd Gen
- 2nd contingency requirement set by a line for about 65% of the time
- Certain amount of reserve was required for the zone for less than 5% of the time during the last two winters





Study Assumptions for SWCT - Resources

- Assumed Second Generation Contingency
  - Loss of Milford 1 & 2 (520 MW)
  - Loss of CPV-Towantic (725 MW) in 2018
- No major resource retirements in last two summers
- Future resource retirements assumed
  - Bridgeport Harbor 3 in 2021
    - Affects the reserve requirement calculation for 2022 and beyond
- Major resource additions
  - CPV-Towantic (725 MW) by June 2018
    - Affects the reserve requirement calculation for 2019 and beyond
  - Bridgeport Harbor 5 (484 MW) by June 2019
    - Affects the reserve requirement calculation for 2020 and beyond

Study Assumptions for SWCT - Transmission

- Typical planning interface limits
  - $Limit_{N-1}$: 2,500 MW
  - $Limit_{N-2,Gen}$: 2,500 MW
  - $Limit_{N-2, Line}$: 1,750 MW
- Assumed transmission upgrades
  - Southwest Connecticut Upgrades by June 2021
    - $Limit_{N-1}$: 2,800 MW
    - $Limit_{N-2,Gen}$: 2,800 MW
    - $Limit_{N-2, Line}$: 1,900 MW
    - Affect the reserve requirement calculation for 2022
- 30ACT (Non-generation based 30 minute actions)
  - 10% of post 2nd contingency native area load shed for line-line condition (not to exceed 500 MW)

Study Assumptions for SWCT - Load

- Based on the 2018 CELT forecast
  - Values shown in the table are the sum of Reginal System Plan (RSP) subareas of SWCT and NOR
  - https://www.iso-ne.com/static-assets/documents/2018/05/forecast_data_2018.xlsx

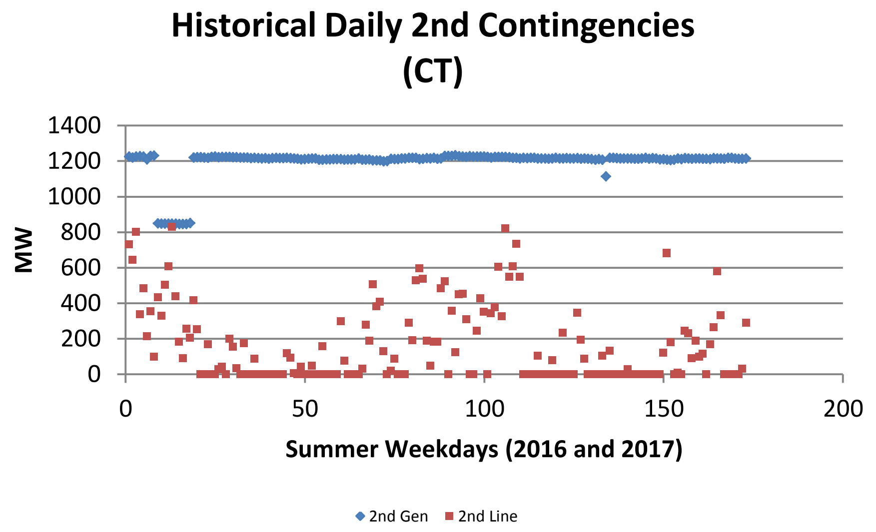
Year	50/50 Forecast (MW)		90/10 Forecast (MW)		Passive DR (MW)		BTM PV (MW)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2018	3,740	2,867	4,062	2,954	288	258	61	0
2019	3,760	2,874	4,082	2,962	309	278	72	0
2020	3,776	2,878	4,102	2,965	331	299	82	0
2021	3,796	2,886	4,123	2,973	359	324	91	0

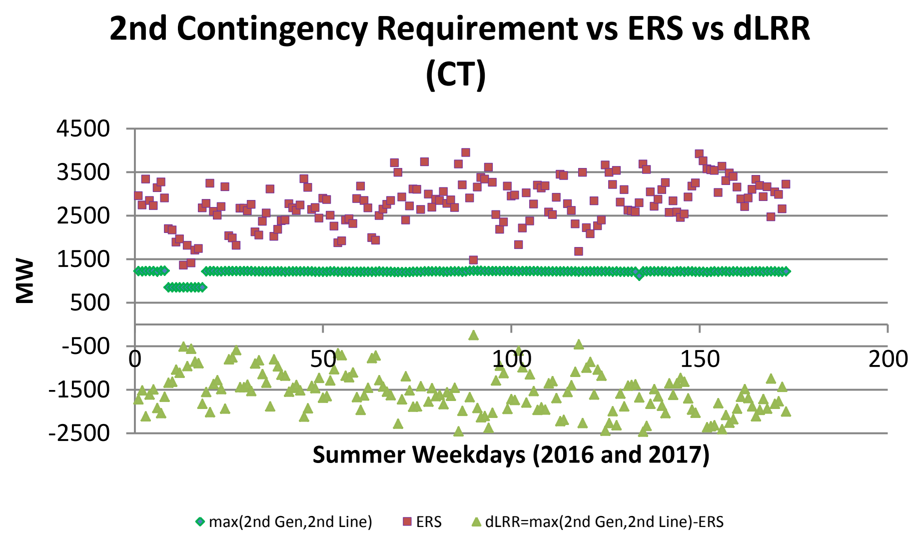
DEVELOPMENT OF REPRESENTATIVE FUTURE LOCATIONAL RESERVE REQUIREMENTS

- Greater Connecticut (CT)

Historical Data
- Summer

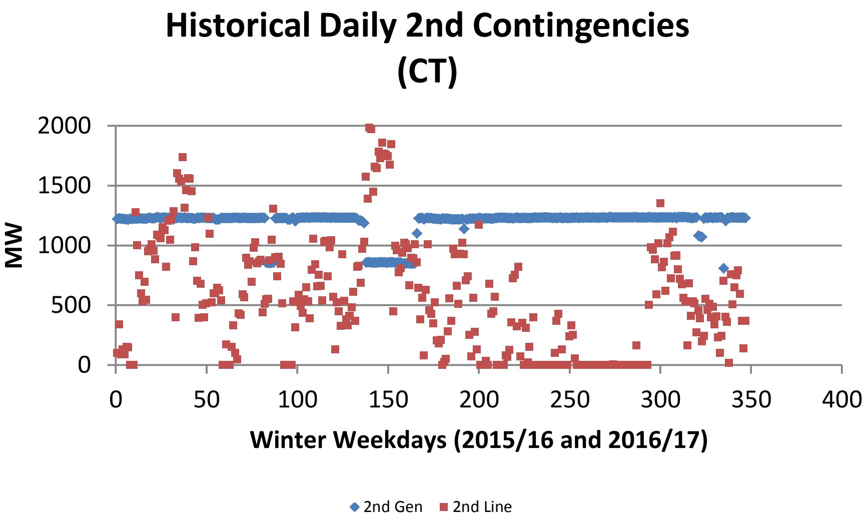
- 2^{nd} Gen was relatively constant
- 2^{nd} contingency requirement set by 2^{nd} Gen all the time
- No local reserve was required for the zone during the last two summers

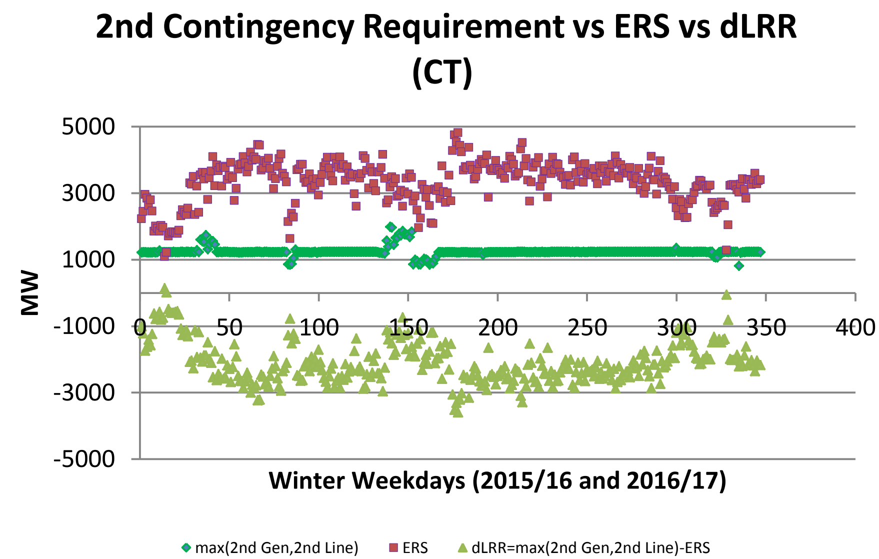




Historical Data
- Winter

- 2nd Gen was relatively constant
- 2nd Line was volatile, and the magnitude can be higher than 2nd Gen
- 2nd contingency requirement set by a generator for about ~90% of time
- Certain amount of reserve was required for the zone for less than 1% of the time during the last two winters





Study Assumptions for CT - Resources

- Typical Second Generation Contingency
  - Loss of Millstone 3 (1,230 MW)
- No major resource retirements in last two summers
- Future resource retirements assumed
  - Bridgeport Harbor 3 in 2021
    - Affects the reserve requirement calculation for 2022 and beyond
- Major resource additions
  - CPV-Towantic (725 MW) by June 2018
    - Affects the reserve requirement calculation for 2019 and beyond
  - Bridgeport Harbor 5 (484 MW) by June 2019
    - Affects the reserve requirement calculation for 2020 and beyond

Study Assumptions for CT - Transmission

- Typical planning interface limits
  - $Limit_{N-1}$: 2,950 MW
  - $Limit_{N-2,Gen}$: 2,950 MW
  - $Limit_{N-2,\ Line}$: 1,750 MW
- Assumed transmission upgrades
  - Greater Hartford/Central Connecticut Upgrades by June 2020
    - $Limit_{N-1}$: 3,400 MW
    - $Limit_{N-2,Gen}$: 3,400 MW
    - $Limit_{N-2,\ Line}$: 2,200 MW
    - Affect the reserve requirement calculation for 2021
- 30ACT (Non-generation based 30 minute actions)
  - 10% of post 2nd contingency native area load shed for line-line condition (not to exceed 500 MW)

Study Assumptions for CT - Load

- Based on the 2018 CELT forecast
  - Values shown in the table are sum of RSP subareas of CT, SWCT and NOR
  - https://www.iso-ne.com/static-assets/documents/2018/05/forecast_data_2018.xlsx

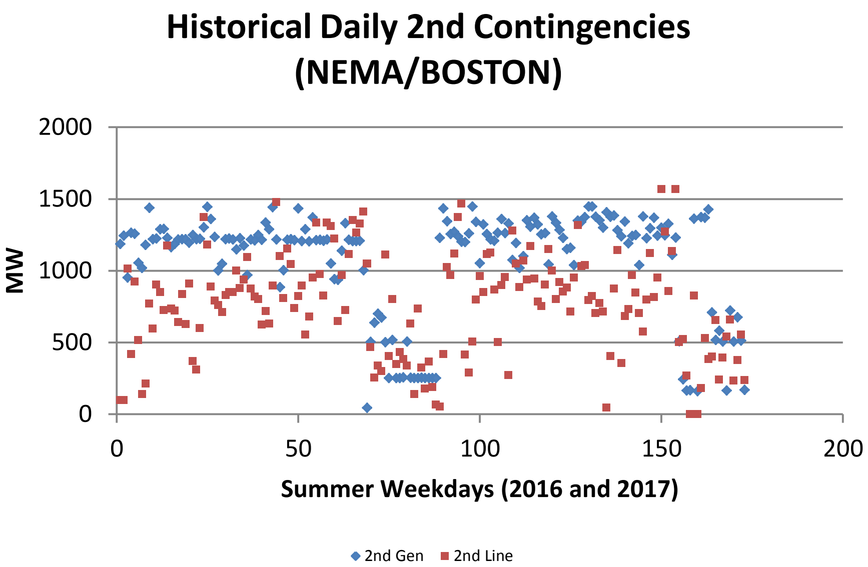
Year	50/50 Forecast (MW)		90/10 Forecast (MW)		Passive DR (MW)		BTM PV (MW)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2018	7,306	5,598	7,936	5,768	563	505	152	0
2019	7,341	5,610	7,974	5,781	604	543	179	0
2020	7,368	5,614	8,005	5,785	647	583	204	0
2021	7,404	5,627	8,044	5,798	701	631	226	0

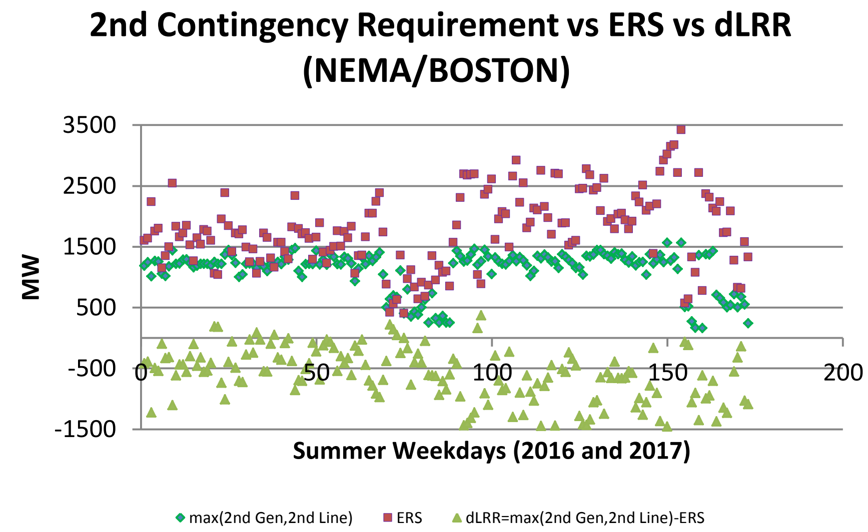
DEVELOPMENT OF REPRESENTATIVE FUTURE LOCATIONAL RESERVE REQUIREMENTS

- NEMA/BOSTON

Historical Data
- Summer

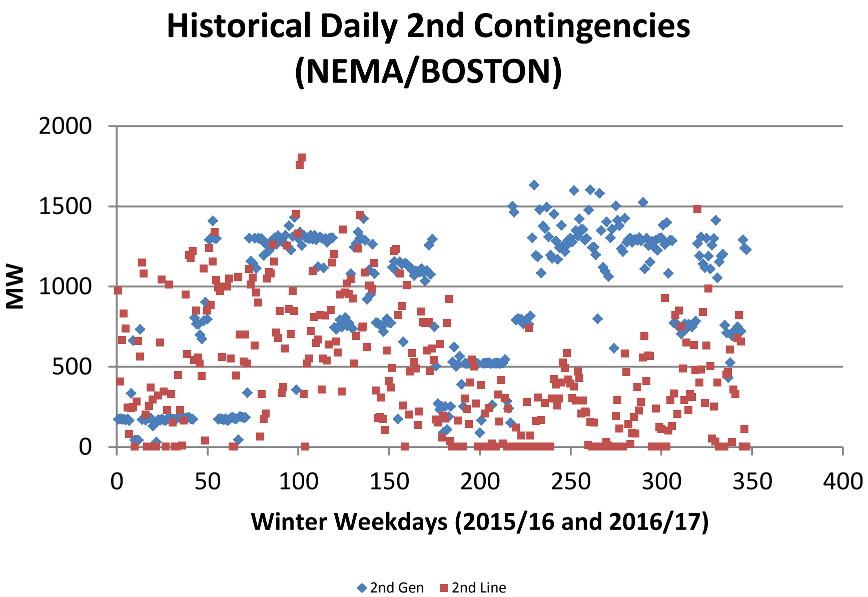
- 2nd Gen were relatively constant; 2nd Line were volatile
- 2nd contingency requirement set by a generator for about 80% of time during the last two summers
- Certain amount of reserve was required for the zone for about 6% of the time during the last two summers

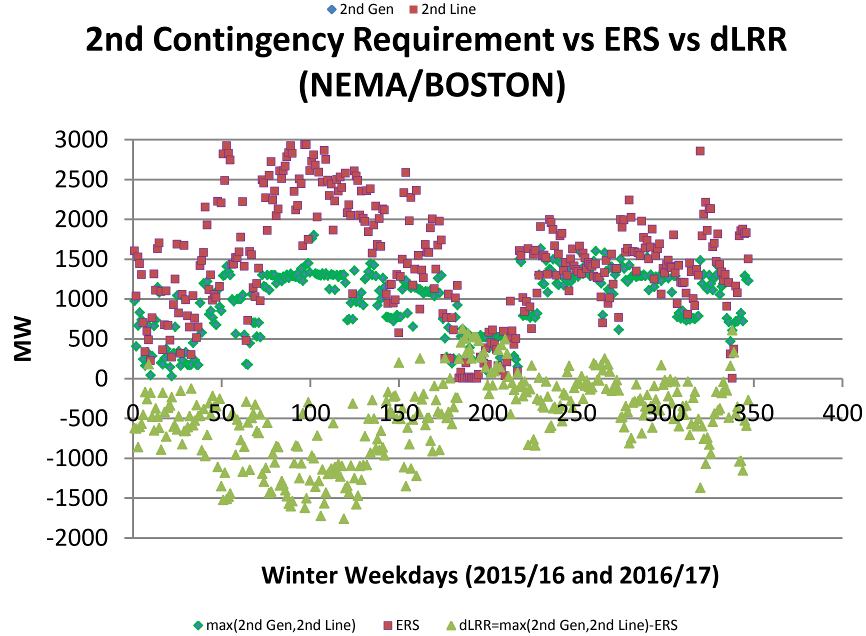




Historical Data - Winter

- Both 2nd Gen 2nd Line were volatile
- 2nd contingency requirement set by a generator for about 80% of time during the last two winters
- Certain amount of reserve was required for the zone for about 15% of the time during the last two winters





Study Assumptions for NEMA/BOSTON - Resources

- Typical Second Generation Contingency
  - Loss of Mystic 8 and 9 (1,400 MW)
- No major resource retirements in last two summers
- No major future resource retirements assumed
- Assumed major resource addition
  - Footprint (674 MW) in 2018
    - Affects the reserve requirement calculation for 2019 and beyond

Study Assumptions for NEMA/BOSTON - Transmission

- Typical planning interface limits
  - $Limit_{N-1}$: 4,850 MW
  - $Limit_{N-2,Gen}$: 4,850 MW
  - $Limit_{N-2, Line}$: 4,175 MW
- Assumed transmission upgrades
  - Greater Boston Upgrades by June 2019
    - $Limit_{N-1}$: 5,700 MW
    - $Limit_{N-2,Gen}$: 5,700 MW
    - $Limit_{N-2, Line}$: 4,600 MW
    - Affect the reserve requirement calculation for 2020 and beyond
- 30ACT (Non-generation based 30 minute actions)
  - 400 MW of post 2nd contingency native area load shed for line-line condition

Study Assumptions for NEMA/BOSTON - Load

- Based on the 2018 CELT forecast
  - https://www.iso-ne.com/static-assets/documents/2018/05/forecast_data_2018.xlsx

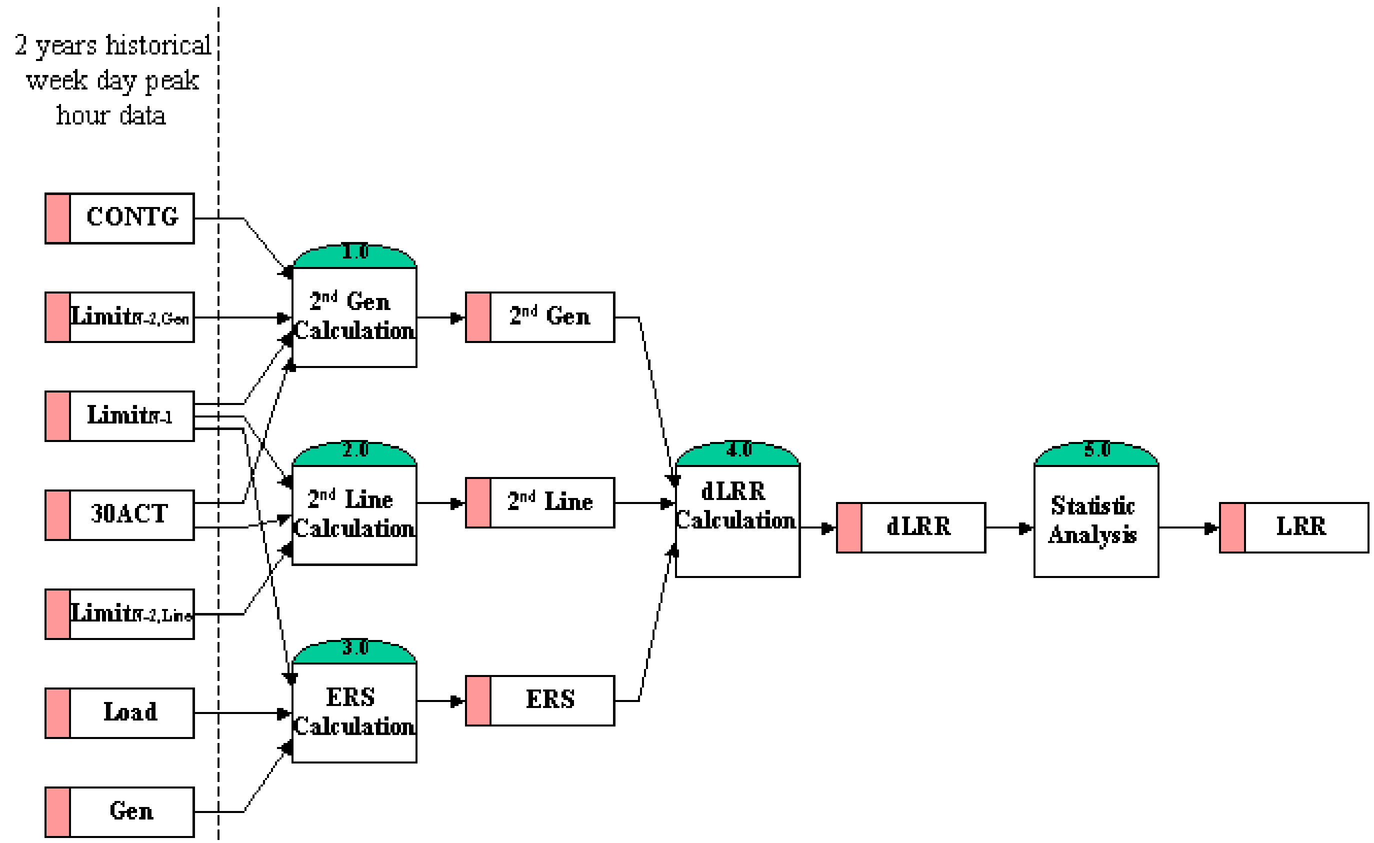
Year	50/50 Forecast (MW)		90/10 Forecast (MW)		Passive DR (MW)		BTM PV (MW)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2018	6,327	4,885	6,837	5,033	674	684	57	0
2019	6,388	4,921	6,904	5,069	783	741	65	0
2020	6,441	4,945	6,964	5,093	885	839	70	0
2021	6,500	4,979	7,030	5,127	980	930	74	0

CALCULATION METHODOLOGY OF LOCATIONAL FORWARD RESERVE MARKET REQUIREMENTS

Calculation of LFRM Requirements

- Requirements calculated through a statistic analysis based on the actual historical operational data
- For the peak hour of each weekday and for each Reserve Zone, the daily Locational Reserve Requirement (dLRR) is calculated
  - dLRR is the amount of 30-minute contingency response, given the available transfer capability on the interface, that must be physically located within the import-constrained area to ensure recovery from the loss of the 2nd contingency
  - A calculated value based on several data elements of the system
- These daily peak hour operating requirements are aggregated into a frequency distribution. The MW value of the 95th percentile of the distribution establishes the LFRM requirement for each Reserve Zone

Data Flow Diagram



Note:

Process 1.0 : 2^{nd} Gen = $Limit_{N-1}$ - $Limit_{N-2,Gen}$ + CONTG - 30ACT

Process 2.0: 2^{nd} Line = $Limit_{N-1}$ - $Limit_{N-2,Line}$ –30ACT

Process 3.0: ERS = $Limit_{N-1}$ –(Load – Gen)

Process 4.0: dLRR = Max(2^{nd} Gen, 2^{nd} Line) – ERS

Process 5.0: set LRR to be 95^{th} percentile rank level

Calculation Formulas

1.0 The Second Generation Contingency

$2^{nd}\ \text{Gen} = \text{Limit}_{N\text{-}1} - \text{Limit}_{N\text{-}2,\ Gen} + \text{CONTG} - \text{30ACT}$

2.0 The Second Line Contingency

$2^{nd}\ \text{Line} = \text{Limit}_{N\text{-}1} - \text{Limit}_{N\text{-}2,\ Line} - \text{30ACT}$

3.0 The External Reserve Support (ERS)

$\text{ERS} = \text{Limit}_{N\text{-}1} - (\text{LOAD} - \text{GEN})$

4.0 The daily Locational Reserve Requirement

$\text{dLRR} = \text{MAX}(2^{nd}\ \text{Gen},\ 2^{nd}\ \text{Line}) - \text{ERS}$

Where,

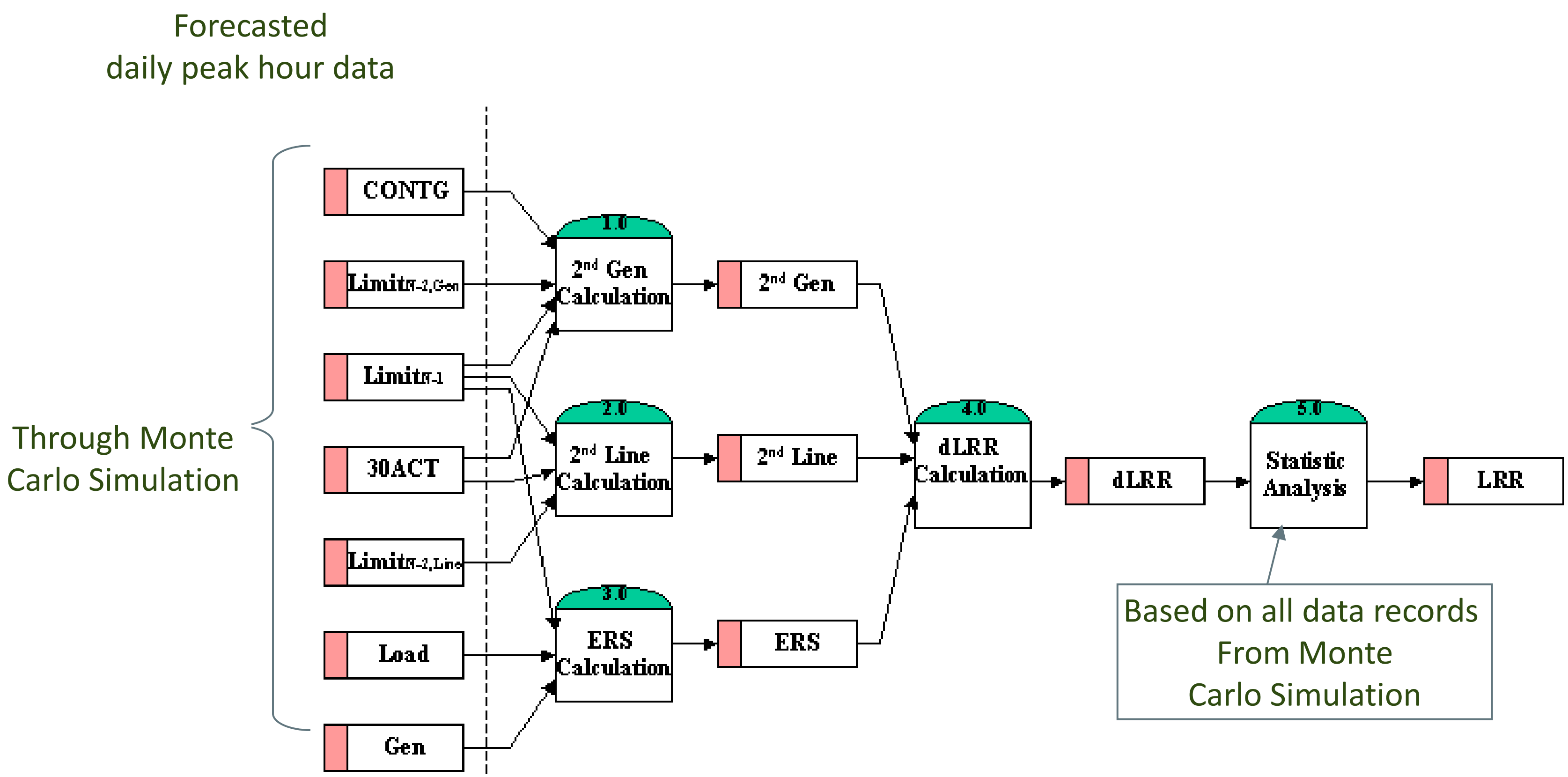
- LOAD = Forecast daily peak load
- GEN = Minimum capacity commitments required for 1st contingency coverage from day ahead
- CONTG = Second generation contingency
- $\text{Limit}_{N\text{-}1}$ = First contingency interface limit
- $\text{Limit}_{N\text{-}2,\ Gen}$ = Second generation contingency interface limit
- $\text{Limit}_{N\text{-}2,\ Line}$ = Second line contingency interface limit
- 30ACT = Non-generation based 30 minute actions, e.g., certain OP4 actions, load swap, transmission owner authorized load shedding

ISO New England manual for Forward Reserve and Real-Time Reserve (Manual M-36) contains all the details for the calculation:

https://www.iso-ne.com/static-assets/documents/2017/03/m36_forward-reserve_rev21_20170301.pdf

METHODOLOGY OF PROJECTING FUTURE REPRESENTATIVE LFRM REQUIREMENTS

Locational Reserve Requirements Forecast Data Flow Diagram



Note:

Process 1.0 : 2^{nd} Gen = $Limit_{N-1}$ - $Limit_{N-2,Gen}$ + CONTG - 30ACT
Process 2.0: 2^{nd} Line = $Limit_{N-1}$ - $Limit_{N-2,Line}$ –30ACT
Process 3.0: ERS = $Limit_{N-1}$ –(Load – Gen)
Process 4.0: dLRR = Max(2^{nd} Gen, 2^{nd} Line) – ERS
Process 5.0: set LRR to be 95^{th} percentile rank level

Simulation Procedure to Generate dLRR data

- After input variables randomly sampled
  - Process 1.0
    - 2nd Gen = Limit_{N-1} - $\text{Limit}_{N-2,Gen}$ + CONTG – 30ACT
  - Process 2.0
    - 2nd Line = Limit_{N-1} - $\text{Limit}_{N-2,Line}$ – 30ACT
  - Process 3.0
    - ERS = Limit_{N-1} – (Load – Gen)
  - Process 4.0
    - dLRR = Max(2nd Gen, 2nd Line) – ERS
- After completion of simulation (thousands of iterations)
  - Process 5.0
    - Form frequency distribution of dLRR, and set LRR to 95th percentile of the distribution

Software Used for Simulation

- Crystal Ball (Professional Edition)
  - Crystal Ball is an Excel based risk analysis, simulation and optimization software marketed by Decisioneering (a division of Oracle/Hyperion)
    - An add-in module to Microsoft Excel to provide an easy way to perform forecast simulations
    - Uses Monte Carlo simulation to generate a wide range of possible optimized outcomes in terms of the range of forecast outputs and their probabilities based on the input assumptions
  - http://www.oracle.com/crystalball/index.html

Questions

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