

Demand Resource Operable Capacity Analysis – Assumptions for 2013/14 (FCA 4)

Assumptions

- The analysis uses assumptions based upon
 - Purchasing the required amount of Installed Capacity Requirement (ICR) for the for the System Wide study
 - A set of Transmission Security Analysis values developed by System Planning for the Load Zone studies

Total Resources

- New England Analysis
 - **1. Total Capacity:** The capacity value is the Representative Future Net ICR of 32,411 MW for 2013/14 calculated for use in the 2009 Regional System Plan and other planning studies
- Load Zone Analysis
 - **1. Minimum Capacity Requirement from TSA:** This capacity value is the minimum amount of resources that are necessary according to a Transmission Security Analysis (TSA) performed for each Load Zone
 - Maine Load Zone uses the Maximum Capacity Limits

Total Resources (cont.)

- Load Zone Generation
 - Amount of generation that is accounted for in each load zone for the purpose of the DR Op Cap analysis
 - Maximum adequacy requirement: Maximum Capacity Limit (MCL)
 - This value was used for Maine in the analysis due to export constraints
 - Minimum Generation Requirement from TSA
 - Amount of generation that is required in an area in order to secure the system for N-1-1 conditions
 - Was determined for each zone based on a TSA and consistently with PP-10 criteria
- The Load Zone Results do not represent a simultaneous feasibility between load zones. Each Load Zone analysis is completed independently of the other

Import Capacity

- New England Analysis
 - **2. Net of Non-ICAP Purchases & Sales:** value assumed is the average of the 2007 - 2009 ICAP Transaction Summary monthly average for HQ Phase I/II used as a proxy for import capacity. The monthly average is assumed for all hours.
- Load Zone Analysis
 - **2. Import Capability (N-1) (See Next Slide)**

Import Capability (cont.)

- Import Capability for Load Zone Analysis
 - For zones that closely reflect electric boundaries defined in the Regional System Plan (RSP), RSP import limits were used
 - Connecticut and Northeast Massachusetts
 - For zones that do not closely reflect electric boundaries defined in the RSP, import limits were determined for the purpose of the DR Op Cap analysis only
 - Maine, New-Hampshire, Vermont, Rhode-Island, Southeast Massachusetts and Western and Central Massachusetts
 - These import limits were strictly based on thermal, N-1 constraints
 - All elements at 115kV and above were monitored
 - All single-element contingencies and multiple-element contingencies as described in OP-19 Section II.A.2 were considered
 - These import limits were determined using SIEMENS/PTI/MUST
 - MW from remote generation outside the zone were transferred to all generation inside the zone
 - Resulted in one standard number for each zone
 - No detailed sensitivities were performed to assess the range of all potential import limits
 - Studies represent all lines in conditions

Demand Resources

- New England & Load Zone Analyses
 - **3. Total Demand Resources:** Three scenarios are used: Low DR, Intermediate DR and High DR clearing and are developed as
 - Low – 100% of DR capacity which cleared FCA 3 (2012/13 CCP)
 - Intermediate – Low DR scenario plus 10% additional resources
 - 10% values is based on the difference between the Low scenario and total of 100% of the Existing DR capacity and 50% of the New Capacity Qualified for FCA3
 - High – Low DR scenario plus 20% additional resources
 - 20% value is based on the difference between the Low scenario and total of 100% of the Existing DR capacity and 100% of the New Capacity Qualified for FCA3
 - The Total Demand Resources are the Cleared/Qualified capacity values which are the Demand Reduction Value * Transmission & Distribution Gross-up (8%)

Demand Resources

- New England & Load Zone Analyses
 - **3. Total Demand Resources continued:**
 - Real-Time Emergency Generator DR are limited to the 600 MW amount that will be purchased to meet the ICR and Load Zones are prorated to sum to the New England value

Total Demand Resources Scenarios

-Demand Reduction Value (MW)

Low Scenario	Active DR (excl. RTEG)	Passive DR	RTEG	Total
CONNECTICUT	252.6	337.9	188.4	778.9
NEMASSBOST	222.9	192.6	122.4	537.9
SEMASS	138.6	107.0	67.1	312.7
WCMASS	123.7	106.8	82.3	312.8
VERMONT	30.7	69.7	7.4	107.8
RHODEISLAND	45.8	65.2	74.0	185.0
MAINE	253.4	55.6	31.0	340.0
NEWHAMPSHIRE	38.4	58.6	11.0	108.0
TOTAL	1106.1	993.4	583.6	2683.1

Intermediate Scenario	Active DR (excl. RTEG)	Passive DR	RTEG	Total
CONNECTICUT	277.9	371.7	207.2	856.8
NEMASSBOST	245.2	211.9	134.6	591.7
SEMASS	152.5	117.7	73.8	344.0
WCMASS	136.1	117.5	90.5	344.1
VERMONT	33.8	76.7	8.1	118.6
RHODEISLAND	50.4	71.7	81.4	203.5
MAINE	278.7	61.2	34.1	374.0
NEWHAMPSHIRE	42.2	64.5	12.1	118.8
TOTAL	1216.7	1092.7	642.0	2951.4

High Scenario	Active DR (excl. RTEG)	Passive DR	RTEG	Total
CONNECTICUT	303.1	405.5	226.1	934.7
NEMASSBOST	267.5	231.1	146.9	645.5
SEMASS	166.3	128.4	80.5	375.2
WCMASS	148.4	128.2	98.8	375.4
VERMONT	36.8	83.6	8.9	129.4
RHODEISLAND	55.0	78.2	88.8	222.0
MAINE	304.1	66.7	37.2	408.0
NEWHAMPSHIRE	46.1	70.3	13.2	129.6
TOTAL	1327.3	1192.1	700.3	3219.7

Total Capacity Without Demand Resources

- New England Analysis
 - **4. Total Capacity Without Demand Resources** : Total Capacity + Net of Non-ICAP Purchases & Sales – Total Demand Resources [1+2-3]
- Load Zone Analysis
 - **4. Total Capacity Without Demand Resources** : Minimum Capacity Requirement from TSA (or MCL for ME) + Import Capability (N-1) – Total Demand Resources [1+2-3]

Assumed Generation Maintenance & Assumed Unplanned Outages

- New England Analysis
 - **5. Assumed Generation Maintenance:** monthly average of the weekly values from the 2007 - 2009 Annual Maintenance Schedules (AMS)
 - **6. Assumed Unplanned Generation Outages:** monthly average of the weekly Allowance for Unplanned Outages from the 2007 - 2009 AMS Operable Capacity Analysis
- Load Zone Analysis
 - **5. Assumed Generation Maintenance:** prorated New England value based on the Capacity Requirement from TSA (or ME MCL)/New England Qualified Capacity
 - **6. Assumed Unplanned Generation Outages:** prorated New England value based on Capacity Requirement from TSA (or ME MCL)/New England capacity

Hourly Forecasted 50-50 Peak Load

- New England & Load Zone Analyses
 - **8. Forecasted 50-50 Peak Load:** (Monthly peak shown in table)
 - The summer & winter peak loads are from the 2009 CELT 50-50 Forecast for 2013/2014
 - An hourly profile is produced based on the 2002 load shapes for New England and for each of the Load Zones
 - 2002 was chosen because the summer period had several days in the range of the summer peak (represents typical summer weather)
 - Resulting 2013/14 monthly peaks may be different than the 2009 CELT forecast of monthly peaks because they were developed using the 2002 load shape

Generating Resources Available to Meet Load & OR

- **New England & Load Zone Analysis**
 - **7. Gen Resources Available to Meet Load & OR** = Total Capacity Without Demand Resources – Assumed Generation Maintenance – Assumed Unplanned Generation Outages [4-5-6]

Hourly Forecasted 90-10 Peak Load for August 2013

- New England & Load Zone Analyses
 - **8. Forecasted 90-10 Peak Load:** (Monthly peak shown in table)
 - The summer 2009 CELT 90-10 Load Forecast for August 2013 was used to create an hourly load profile and a 90-10 Operable Capacity analysis was performed with all other assumptions remaining the same

Operating Reserve Requirement

- New England Analysis
 - **9. Operating Reserve Requirement:** assumed to be 1 times the largest contingency and $\frac{1}{2}$ times the second largest contingency. The value is assumed to be 2000 MW for this analysis
- Load Zone Analysis
 - **9. Operating Reserve Requirement:** assumed to be the largest contingency in the Load Zone
 - Consistent with the Transmission Security Analysis assumptions

Passive Resources

- New England & Load Zone Analyses
 - **10. Passive Demand Resources:** These energy efficiency type of resources are assumed as already in-service and therefore subtracted from the Load Forecast for each hour
 - A monthly ratio was developed by the ISO Demand Resource group which assumes a lower reduction value for Passive Resources in shoulder months
 - Equals DRV of Passive DR * T&D Gross-up
 - **11. Peak Load & OR – Passive DR:** = Forecasted Peak Load + Operating Reserves – Passive DR [8+9-10]

Surplus/Deficiency Before Calling Active DR

- New England & Load Zone Analyses
 - **12. Surplus/Deficiency Before Calling DR:** assumed to be the amount of MW need before calling Active DR and/or OP 4 (if needed)
 - Calculated from
 - Gen Resources Available to Meet Load & OR (Line 7) – Peak Load + OR – Passive Resources (Line 11)
 - Negative value shows need for Active Demand Resources

Description of DR Op Cap Results

- All MW of DR is the DRV with the 8% T&D Gross-up
- **13. Maximum MW of Non-RTEG Active DR Available:** MW of Critical Peak and Real-Time DR available for each scenario
- **14. Maximum MW of Non-RTEG Active DR Needed:** MW of Critical Peak and Real-Time DR that would be called in any month with a need for DR as show in line 12
- **15. Maximum MW of RTEG Active DR Available:** MW of RTEG available for each DR scenario
- **16. Maximum MW of RTEG Active DR Needed:** MW of RTEG that would be required once the entire supply of non-RTEG is called in any hour with a need for DR as show in line 12 (not limited to 600 MW)
- **17. Additional MW of OP 4:** remaining deficiency, if any, once all Active DR have been called
- **18. Average MW Amount of DR Need:** monthly average of any hours when DR is needed

Description of DR Op Cap Results (cont.)

- **19. # of Hours Load + OR – Passive DR above Available Resources:** Sum of the number of hours each month when at least 1 MW of DR would be needed
- **20. Corresponding # of Days:** Sum of the days for each month when at least 1 hour of DR is needed
- **21. Maximum # of Consecutive Days:** Maximum number of consecutive days when DR would be needed per month

Description of DR Op Cap Results (cont.)

- **22. Number of Calls per MW of Non-RTEG Active DR:** Calculated as the peak of each day's DR need divided by the total MW of non-RTEG Active DR. For example, if there is 1000 MW of DR need and 500 MW of available non-RTEG Active DR, then on that day, the non-RTEG Active DR would be called 1.0 times
- **23. Number of Calls per MW of RTEG:** Once all MW of non-RTEG Active DR is called, if there is still any remaining need, this value is calculated as the peak hour of remaining need divided by the total MW of RTEG



Questions?