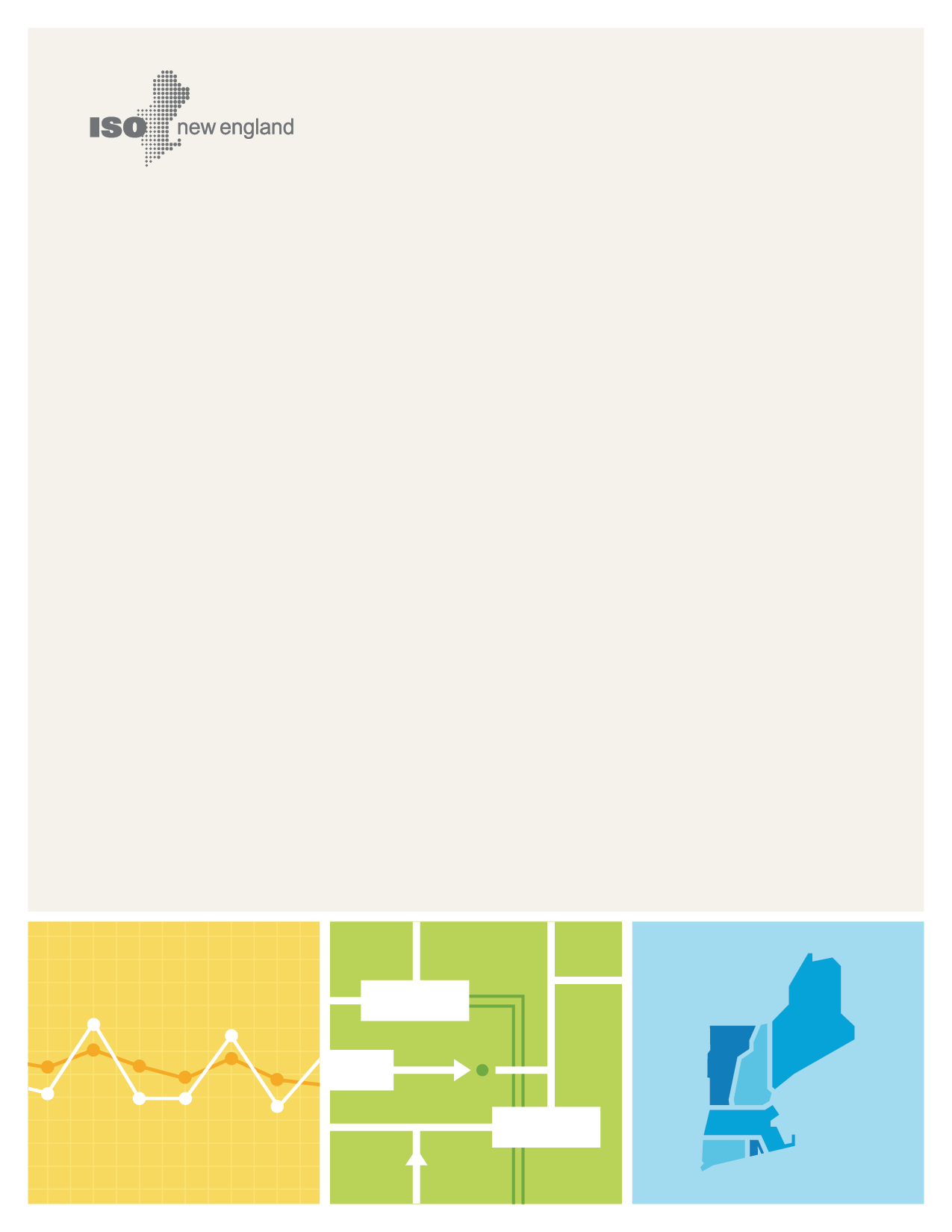
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**Transmission Planning Technical Guide**

**Appendix J:**

**Load Modeling Guide**

**DRAFT**

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System Planning**

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# Introduction

## Objective

This documentation is intended to help identify the methodology, equations, and processes that are used when modeling load, demand resources, and solar photovoltaics in the ISO New England (ISO) network model to ensure consistency across all New England planning studies.

# Sources of Load Modeling Data

Data for load modeling comes from multiple sources. Detailed descriptions of the sources are listed in the following sub-sections.

## Capacity, Energy, Loads, and Transmission Report

The ISO New England Capacity, Energy, Loads, and Transmission Report (CELT Report) is an ISO document that is published annually in May on the ISO website[[1]](#footnote-1). Along with each annual report, a corresponding detailed forecast data spreadsheet is posted[[2]](#footnote-2). This spreadsheet contains the 1 to 10 year gross load forecasts for New England as a whole and each of the six individual states. These forecasts are also provided at multiple expected weather values. The two weather values commonly used in New England studies are the 50/50 and 90/10 gross load levels. The 50/50 gross load level is a gross peak demand level with a 50% chance of being exceeded because of weather conditions. The 90/10 gross load level is an extreme weather level and is the gross peak demand level with a 10% chance of being exceeded because of weather conditions.

The CELT report also provides historical percentages of each operating company’s share of the state’s total load. Also included in the CELT report are energy efficiency (EE) and solar photovoltaic (PV) forecasts[[3]](#footnote-5). This data is separated from the base gross load and will be modeled as another form of demand response (DR) for EE or behind-the-meter (BTM) generation for a portion of the PV.

## Forward Capacity Auction Results

Beginning June 1, 2018, the annual Forward Capacity Auction (FCA) clears Demand Capacity Resources (DCR) for a capacity commitment period (CCP). There are three specific categories of DCR, On-Peak Demand Resources and Seasonal Peak Demand Resources, commonly referred to as passive DCR, and Active Demand Capacity Resources, commonly referred to as ADCR. Shortly after an auction has been completed, the results will be tabulated on an Excel spreadsheet and published on the ISO website[[4]](#footnote-6). This spreadsheet is used as an input to the amount of DCR modeled in the base case. Examples of data used from FCA results are shown in Section 5.

## Transmission Owner Load Distributions

As part of the annual Multiregional Modeling Working Group (MMWG) network model library creation process, New England Transmission Owners (TO) provide load distribution data for the substations in their service territory by providing a representative amount of load at each substation based on their internal load forecasts. This data describes the proportion of their total load forecast that will be split among their substations and designate which loads are scalable and non-scalable. The TO will also provide the load distribution for three load levels/seasons: Summer, Winter, and Light Load, and for two forecast years: 1 year out and 10 years out. These 6 data points will capture how load shifts during different times of the year and will also show varying load growth rates across the system.

# Types of Load

There are several types of load on the power grid and they are each treated differently when it comes to modeling in the network model. This section will describe each in detail.

## Scaling CELT Load

This is the most common type of load in the network model. This load represents the residential, commercial, and most industrial load on the system and is part of the CELT report forecast total. As the total system load level goes up and down, this load follows that trend and is scaled in the network model to match the overall load for an area. In the ISO network model, scaling CELT load is contained in zones that end in 5, 6, or 7.

## Non-Scaling CELT Load

This type of load is typically used to model large industrial load and load from electric commuter trains. This load is part of the CELT report forecast total. This load does not change value consistent with total system load level for a given season. In the ISO network model, non-scaling CELT load is contained in zones that end in 8.

## Generator Station Service Load

This type of load is the amount of power consumed by a generating station for their operation. This load is not contained in the CELT report forecast total. This is because the CELT forecast utilizes historical net output of a generating plant typically metered at the high side of the generator step-up (GSU) transformer. Since modeling generators at their gross output rather than at their net output can have a significant impact on transient stability studies, the ISO network model will model the maximum capability of a generator at its gross output (net PMax plus the station service load) with the station service load typically being modeled at the same bus as the machine. The net effect on the high side of the GSU will still be the net output of the unit, which corresponds to the generation output utilized in developing the CELT report. In the ISO network model, generator station service load is contained in zones that end in 9.

## Manufacturing Load

This type of load is used to model the behind-the-meter (BTM) load at a manufacturing facility that also has generation that is behind-the-meter. For transient stability reasons, it is important to model both the generator and load at these facilities and not the net output at the high side of the interconnection transformer. This type of load is not contained in the CELT report forecast total since the CELT reports the net output of a manufacturing facility and the behind-the-meter generation. In the ISO network model, manufacturing load is contained in zones 50-55, one zone for each of the six New England states.

## Demand Capacity Resources

This type of load is a negative amount used to reduce the gross load. In the past, the load in network models was scaled down by a certain amount to account for DCR. This made it very hard to know what the original load level was and how much of each type of DCR was modeled. To fix this dilemma, DCR is discretely modeled as negative loads in the ISO network model. This is done for two reasons. First, if DCR is modeled separately from the regular gross load, it can be assigned separate zones/owners in the network model for documentation of how much DCR is modeled in the case. It also allows the study to leave the gross load unchanged in the case to verify the gross load level in the study compared to the CELT report. In the ISO network model, passive DCR is contained in zones 20-27, owner 90, and a load ID of ‘P’ and ADCR is contained in zones 30-48, owner 91, and a load ID of ‘A’. Note: Starting with the 2018 CELT report, passive DCR will no longer be modeled separately in transmission planning studies from forecasted energy efficiency. It will be modeled as a single negative load based on the 10 year energy efficiency forecast described in Section 3.6.

## Forecasted Energy Efficiency

In the CELT report, energy efficiency (EE) is forecasted for the 10 year planning horizon. Forecasted EE is intended to model future passive DCR for the 10 year forecast period. Qualification values from the third Annual Reconfiguration Auction #3 (ARA 3) for the Capacity Commitment Period (CCP) that starts June 1 are the starting point for the forecast (i.e. Qualification values for ARA 3 for CCP #9 starting June 1, 2018 will be used for the 2018 CELT forecast). An additional negative load will be modeled to represent the forecasted EE. In the ISO network model, forecasted EE is contained in zones 20-27, owner 92, and a load ID of ‘EE’.

## Solar Photovoltaic Generation

In the CELT report, solar photovoltaic (PV) generation is forecasted for the 10 year planning horizon. Solar PV is intended to model existing and future installations based on current state programs and goals. The PV forecast consists of three PV resource types:

* PV as a resource in the FCM
* Non-FCM Energy Only Resource
* Behind the Meter (BTM) PV

For transmission planning studies, all three resource types are included in the ISO models.

Solar PV is modeled in three different categories based on size of the facility. Facilities greater than or equal to 5 MW will be modeled as generators. Facilities less than 5 MW will be modeled as two types of negative loads.

In the ISO network model, solar PV facilities greater than or equal to 5 MW (Category 1) are generators assigned owner 24. Facilities less than 5 MW and greater than or equal to 1 MW (Category 2) are negative loads contained in zones 30-48, owner 94, and load ID of ‘PV’. Facilities less than 1 MW (Category 3) are aggregated together as negative loads contained in zones 30-48, owner 94, and load ID of ‘PD’ (PD stands for Photovoltaic Distribution). Section 6 describes the breakdown in more detail.

# CELT Load Scaling Methodology

The load scaling process has been streamlined into a computer-coded process. It takes the data inputs from the engineer and creates a file to add to a network model with all loads scaled and adjusted according to an established process. This creates a consistent method for load scaling and ensures that for the same input conditions, the load will be modeled consistently between multiple planning studies. The following section describes this scaling process in a detailed step-by-step process. An example of scaling the load for the state of Maine will be used in each section to demonstrate the concepts.

Note: All numbers in the following sections are purely examples and may not represent actual data.

## CELT Forecast

The CELT forecast is used as the basis for all load scaling. The ISO CELT load forecast is a composite number of the six individual state load forecasts. The sum of the state forecasts can be as much as 15 MW different from the ISO composite forecast due to round-off error. Load scaling for a state in the network model starts with the CELT state forecasts.

Example: For a Summer Peak study, the state of Maine has a 90/10 forecast of 2,500 MW (gross load + distribution and transmission losses). All loads in the network model represented in the CELT forecast for the state of Maine will use 2,500 MW (minus transmission losses) as the basis for scaling.

## Accounting for Transmission Losses

The CELT forecast value assumes 8% total losses on the system during peak demand. This 8% is split between transmission and distribution losses. A power flow program calculates losses on the network model so the load model needs to take this into account so losses are not double counted. Load in the ISO network model is typically modeled at the low side of the distribution transformer. The distribution network is not modeled. This means all of the losses from the customer meter to the distribution station need to be accounted for in the load model.

Transmission losses can change depending on the generation dispatch in the network model. In order to establish a baseline system load to represent, a fixed transmission loss percentage is used. This fixed percentage removes the iterative process that previously took place where, after changing a generation dispatch, the load would be re-scaled to match the CELT forecast. Looking at typical dispatches from previous studies, transmission losses in New England are usually around 2.5% of the total load & losses. To avoid double counting these losses, the CELT state gross load forecast is reduced by the transmission losses to account for the losses being calculated by the power flow program.

Example: If the Maine forecast being used is 2,500 MW (gross load + distribution and transmission losses) from Step 4.1, the gross load modeled in Maine is then scaled to 2,442.13 MW.

The intent is when this amount of load is modeled in the power flow program, the program will calculate about 57.87 MW of transmission losses making the total gross load & losses for Maine equal to the CELT forecast of 2,500 MW.

## Split State Load Forecast by Company

In the CELT report, each state load forecast is comprised of one or more operating companies (OpCo). Each OpCo represents a metering domain used by the ISO Settlements Department. Examples of metering domains are: CMP (Central Maine Power; part of Avangrid), BECO-NEMA (Boston Electric Company; part of Eversource), WMECO (Western MA Electric Company; part of Eversource), etc. For the complete list of operating companies and their share of the state historical load, see the CELT forecast data Excel spreadsheet posted on the ISO website[[5]](#footnote-7) (Tab 11 in the spreadsheet). Once the total state load is determined in Step 4.2, the forecast is then split by company to determine how much load each company will be scaled to in the network model.

Example: The state of Maine from Step 4.2 will be scaled to 2,442.13 MW. Let’s say that Maine is split into two companies, ABC and DEF. Company ABC has 85% of the historical Maine load and Company DEF has 15% of the state load. This means that Company ABC load will be scaled to 2,075.81 MW and Company DEF will be scaled to 366.32 MW.

## Scale Load within Each Company

Now that each CELT state forecast is adjusted for losses and split by OpCo, the last step is to scale network load assigned to the company to the desired value. Each load record in the network model is assigned an owner. Each owner is assigned to an OpCo in the CELT forecast. Each group of owners is scaled to the desired OpCo load value. For a list of owner assignments in the ISO network model, see Section 8.4. This data is updated periodically when updates are made to the network model.

Example: OpCo ABC has 2 owners, owners 123 and 456. Owner 123 provides a load distribution of 1,500 MW of scaling CELT load, 100 MW of non-scaling CELT load, and 0 MW of manufacturing load. Owner 456 provided a load distribution of 500 MW of scaling CELT load, 20 MW of non-scaling CELT load, and 50 MW of manufacturing load. Table 4‑1 demonstrates how the load is modeled before and after scaling. As described in Step 4.3, the total OpCo ABC CELT load should equal 2,075.81 MW.

Table ‑  
OpCo ABC Load Scaling Example

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Load Type | Load Distribution Provided  by Owners (MW) | | Load Modeled after Scaling  to CELT Forecast (MW) | |
| **Owner 123** | **Owner 456** | **Owner 123** | **Owner 456** |
| Scaling CELT Load | 1,500.00 | 500.00 | **1,466.86** | **488.95** |
| Non-Scaling CELT Load | 100.00 | 20.00 | 100.00 | 20.00 |
| Manufacturing Load | 0.00 | 50.00 | 0.00 | 50.00 |

## Split Owner Scalable Load by Substation

Once the total amount of scaling load is calculated by owner, the load distributions provided by the TOs assigned to that owner are then proportionally scaled to match the overall owner total. These are the load values that are then modeled in the power flow case.

Example: Owner 456 is assigned 488.95 MW of Scaling CELT load from the example in Step 4.4. If the TO has only 5 substation loads assigned to that owner, as shown in Table 4‑2, the scaled substation loads are shown below.

Table ‑  
Owner 456 Substation Load Scaling Example

|  |  |  |
| --- | --- | --- |
| Substation | TO Provided  Load Forecast  Distribution (MW) | Load Modeled  After scaling to  CELT Forecast (MW) |
| East | 100.00 | 97.79 |
| North | 125.00 | 122.24 |
| Central | 75.00 | 73.34 |
| West | 50.00 | 48.89 |
| South | 150.00 | 146.69 |
| TOTAL | **500.00** | **488.95** |

# Demand Resources Methodology

Shortly after each FCA has been completed, the results will be tabulated on an Excel spreadsheet and published on the ISO website[[6]](#footnote-8). Within this spreadsheet, details on the ADCR that cleared the auction are listed. Using the information in the spreadsheet, the amount of ADCR that cleared the FCA is aggregated by dispatch zone and used for modeling in the power flow case. For long term studies, the amount of ADCR that is desired is the Existing Qualified Capacity (QC) for the next FCA. Starting with the 2018 CELT forecast, the passive DCR will no longer be modeled separately and a single energy efficiency forecast aggregated by load zone will be used for transmission planning studies. The example of scaling the load for the state of Maine will continue to be used in each section to demonstrate the concepts.

## Aggregate FCA ADCR Results

Existing QC for new ADCR, which has cleared the auction and received a Capacity Supply Obligation (CSO), is not available immediately following an FCA. As an alternative, the CSO of resources that cleared the auction is assumed to be the QC for the next FCA. Existing ADCR will use the QC from the recently completed FCA

This value may change slightly when the QC is established for the next FCA, but is assumed to be a close approximation given the timeframe needed to update the data after an auction. For example, the results of FCA 12 are shown in Table 5‑1 for ADCR.



Table ‑  
ADCR Aggregate – FCA Results Example

| Dispatch Zone | New – Cleared | | Existing – Qualified | | Total QC | |
| --- | --- | --- | --- | --- | --- | --- |
| SUM CSO | WIN CSO | SUM QC | WIN QC | SUM QC | WIN QC |
| Bangor Hydro | 0.000 | 0.000 | 2.430 | 2.652 | **2.430** | **2.652** |
| Boston | 4.754 | 4.754 | 51.921 | 51.921 | **56.675** | **56.675** |
| Central MA | 7.113 | 7.113 | 23.713 | 22.129 | **30.826** | **29.242** |
| Eastern CT | 11.968 | 11.968 | 28.997 | 29.554 | **40.965** | **41.522** |
| Lower SEMA | 3.535 | 3.535 | 7.463 | 7.240 | **10.998** | **10.775** |
| Maine | 0.000 | 0.000 | 120.497 | 141.173 | **120.497** | **141.173** |
| New Hampshire | 15.815 | 15.815 | 15.609 | 14.890 | **31.424** | **30.705** |
| North Shore | 2.160 | 2.160 | 18.688 | 18.688 | **20.848** | **20.848** |
| Northern CT | 20.27 | 20.27 | 25.773 | 25.432 | **46.043** | **45.702** |
| Northwest Vermont | 7.323 | 7.323 | 30.898 | 35.202 | **38.221** | **42.525** |
| Norwalk - Stamford | 0.088 | 0.088 | 3.186 | 3.186 | **3.274** | **3.274** |
| Portland Maine | 0.853 | 0.853 | 15.755 | 12.753 | **16.608** | **13.606** |
| Rhode Island | 8.446 | 8.446 | 40.023 | 36.523 | **48.469** | **44.969** |
| Seacoast | 9.300 | 9.300 | 1.600 | 1.599 | **10.900** | **10.899** |
| SEMA | 3.240 | 3.240 | 38.219 | 36.567 | **41.459** | **39.807** |
| Springfield MA | 12.587 | 12.587 | 15.576 | 14.409 | **28.163** | **26.996** |
| Vermont | 11.262 | 11.262 | 3.181 | 4.483 | **14.443** | **15.745** |
| Western CT | 17.619 | 17.619 | 33.886 | 32.965 | **51.505** | **50.584** |
| Western MA | 7.171 | 7.171 | 31.740 | 30.836 | **38.911** | **38.007** |
| NE Total | **143.504** | **143.504** | **509.155** | **522.202** | **652.659** | **665.706** |

## Calculate ADCR DRV by Dispatch Zone

The next step is to sum the new and existing values of ADCR for each dispatch zone. Demand Capacity Resource amounts in the FCA have the losses gross-up of 8% applied to make them equivalent to other capacity resources on the system. To model the actual load reduction at the customer meter, known as the demand reduction value (DRV), this 8% gross-up needs to be removed.

The values in the last two columns shown in the example below, illustrate the DRV amounts that would be stored in the BCDB for use in the power flow model. Table 5‑2 shows the gross-up removed from each ADCR dispatch zone.



Table ‑  
ADCR Calculation by Dispatch Zone Example

| Dispatch Zone | SUM QC  (MW) | WIN QC  (MW) | Losses  Gross-Up | SUM DRV  (MW) | WIN DRV  (MW) |
| --- | --- | --- | --- | --- | --- |
| Bangor Hydro | 2.43 | 2.65 | 8% | **2.25** | **2.46** |
| Boston | 56.68 | 56.68 | 8% | **52.48** | **52.48** |
| Central MA | 30.83 | 29.24 | 8% | **28.54** | **27.08** |
| Eastern CT | 40.97 | 41.52 | 8% | **37.93** | **38.45** |
| Lower SEMA | 11.00 | 10.78 | 8% | **10.18** | **9.98** |
| Maine | 120.50 | 141.17 | 8% | **111.57** | **130.72** |
| New Hampshire | 31.42 | 30.71 | 8% | **29.10** | **28.43** |
| North Shore | 20.85 | 20.85 | 8% | **19.30** | **19.30** |
| Northern CT | 46.04 | 45.70 | 8% | **42.63** | **42.32** |
| Northwest Vermont | 38.22 | 42.53 | 8% | **35.39** | **39.38** |
| Norwalk - Stamford | 3.27 | 3.27 | 8% | **3.03** | **3.03** |
| Portland Maine | 16.61 | 13.61 | 8% | **15.38** | **12.60** |
| Rhode Island | 48.47 | 44.97 | 8% | **44.88** | **41.64** |
| Seacoast | 10.90 | 10.90 | 8% | **10.09** | **10.09** |
| SEMA | 41.46 | 39.81 | 8% | **38.39** | **36.86** |
| Springfield MA | 28.16 | 27.00 | 8% | **26.08** | **25.00** |
| Vermont | 14.44 | 15.75 | 8% | **13.37** | **14.58** |
| Western CT | 51.51 | 50.58 | 8% | **47.69** | **46.84** |
| Western MA | 38.91 | 38.01 | 8% | **36.03** | **35.19** |
| NE Total | **652.66** | **665.71** |  | **604.31** | **616.39** |

## Calculate Forecasted EE Values from CELT Forecast

Within the CELT report detailed forecast data, a data column in the load forecast contains the Summer passive demand resources (passive DR). This value in the CELT report represents the cumulative passive DR for an area for the specified forecast year using the Qualification values from the third Annual Reconfiguration Auction (ARA 3) as the starting point for the forecast. By taking the difference of year N and N+1 the incremental amount of forecasted EE can be determined. Using the 2018 CELT report as an example, Table 5‑3 represents the cumulative forecasted EE modeled in the CELT report.

Table ‑  
Cumulative Forecasted EE from 2018 CELT Forecast by Load Zone Example

|  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Load Zone | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
| MAINE | 175.89 | 197.15 | 217.16 | 235.77 | 252.89 | 268.45 | 282.43 | 294.86 | 305.79 | 315.30 |
| NEW HAMP | 108.82 | 124.44 | 139.20 | 152.85 | 165.60 | 177.38 | 188.13 | 197.80 | 206.42 | 213.99 |
| VERMONT | 114.31 | 128.53 | 141.99 | 154.73 | 166.59 | 177.52 | 187.49 | 196.72 | 204.95 | 212.13 |
| NEMASSBOST | 680.53 | 790.73 | 894.46 | 990.95 | 1079.67 | 1160.33 | 1232.83 | 1297.28 | 1353.93 | 1403.20 |
| SEMASS | 388.68 | 451.63 | 510.87 | 565.98 | 616.65 | 662.72 | 704.13 | 740.94 | 773.30 | 801.44 |
| WCMASS | 415.88 | 483.23 | 546.62 | 605.59 | 659.81 | 709.10 | 753.41 | 792.79 | 827.41 | 857.52 |
| RHODE ISLAND | 244.77 | 278.30 | 310.57 | 341.03 | 369.20 | 394.94 | 418.22 | 439.04 | 457.46 | 473.58 |
| CONNECTICUT | 569.72 | 611.62 | 655.36 | 710.27 | 761.32 | 808.20 | 850.73 | 888.85 | 922.62 | 952.20 |
| NE Total | **2698.59** | **3065.63** | **3416.22** | **3757.16** | **4071.72** | **4358.63** | **4617.36** | **4848.29** | **5051.89** | **5229.35** |

Since these load values represent load and 8% total losses, the losses need to be removed to represent the forecasted EE DRV. The values shown in Table 5‑4 represent the cumulative forecasted EE DRV annual amounts that would be stored in the BCDB for use in the power flow model.

Table ‑  
Cumulative Forecasted EE DRV Calculation by Load Zone Example

|  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Load Zone | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
| MAINE | 162.86 | 182.54 | 201.07 | 218.30 | 234.15 | 248.56 | 261.51 | 273.02 | 283.14 | 291.94 |
| NEW HAMP | 100.76 | 115.22 | 128.89 | 141.52 | 153.33 | 164.24 | 174.19 | 183.15 | 191.13 | 198.14 |
| VERMONT | 105.84 | 119.01 | 131.47 | 143.27 | 154.25 | 164.37 | 173.60 | 182.15 | 189.76 | 196.41 |
| NEMASSBOST | 630.12 | 732.16 | 828.20 | 917.54 | 999.70 | 1074.38 | 1141.51 | 1201.18 | 1253.64 | 1299.26 |
| SEMASS | 359.89 | 418.17 | 473.03 | 524.05 | 570.98 | 613.63 | 651.97 | 686.06 | 716.02 | 742.07 |
| WCMASS | 385.08 | 447.44 | 506.13 | 560.73 | 610.93 | 656.57 | 697.60 | 734.06 | 766.12 | 794.00 |
| RHODE ISLAND | 226.64 | 257.69 | 287.57 | 315.77 | 341.85 | 365.69 | 387.24 | 406.52 | 423.58 | 438.50 |
| CONNECTICUT | 527.52 | 566.32 | 606.81 | 657.66 | 704.92 | 748.33 | 787.71 | 823.01 | 854.28 | 881.66 |
| NE Total | **2498.69** | **2838.55** | **3163.17** | **3478.85** | **3770.11** | **4035.77** | **4275.34** | **4489.16** | **4677.67** | **4841.99** |

## Accounting for Distribution Losses & DR Availability

After demand resources are adjusted to their DRV amounts, they no longer include transmission and distribution losses. For the power flow model, the DRV needs to apply a distribution losses gross-up factor to account for losses saved by addition of the facilities. In addition to adjusting the amount for losses, the total amount also needs to be reduced based on the assumed availability of the type of DRV during the peak. Separate availability factors are applied to passive DR (passive DCR and forecasted EE) and ADCR. See Section 7 of the Transmission Planning Technical Guide Appendix C – Demand Resources Modeling Guide of for more details on the determination of the availability factor.

Example: Assuming a ADCR DRV amount of 18.96 MW for Dispatch Zone B (to be used in the following examples for Owner 456), after accounting for distribution losses savings of 5.5%, and an availability factor of 75%, the total modeled ADCR in Dispatch Zone B is 15.00 MW.

## Split DR Zone Totals by Substation

Now that the total amount of DRV is known for each zone (load or dispatch zone), it is divided up on the substation level using the TO load distributions.

Example: Using the Owner 456 substations listed in Step 4.5, assume that the Load Zone A is made up of the 5 substations and that those stations are further split into Dispatch Zone B (East, North, and Central) and Dispatch Zone C (South and West). After taking the DRV and increasing by 5.5% to account for distribution losses, Load Zone A contains 60 MW of forecasted EE DR. Dispatch Zone B contains 15 MW of ADCR DRV and Dispatch Zone C contains 10 MW of ADCR DRV.

Table ‑  
Owner 456 Substation DR Scaling Example

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Substation | Load Zone | Disp Zone | TO Provided  Load Forecast S/S  Distribution (MW) | CELT Load (MW) | ADCR  DRV (MW) | Forecasted EE  DRV (MW) | Net Load  (MW) |
| East | A | B | 100.00 | 97.79 | -5.00 | -12.00 | 80.79 |
| North | A | B | 125.00 | 122.24 | -6.25 | -15.00 | 100.99 |
| Central | A | B | 75.00 | 73.34 | -3.75 | -9.00 | 60.59 |
| Total Dispatch Zone B Modeled | | | | | **-15.00** |  |  |
| West | A | C | 50.00 | 48.89 | -2.50 | -6.00 | 40.39 |
| South | A | C | 150.00 | 146.69 | -7.50 | -18.00 | 121.19 |
| Total Dispatch Zone C Modeled | | | | | **-10.00** |  |  |
| Total Load Zone A DR Modeled | | | | |  | **-60.00** |  |
| Total Load | | | | **488.95** | **-25.00** | **-60.00** | **403.95** |

An example of how demand resources at the South Substation would be modeled in the power flow case is shown in Figure 5‑1 and Table 5‑6.

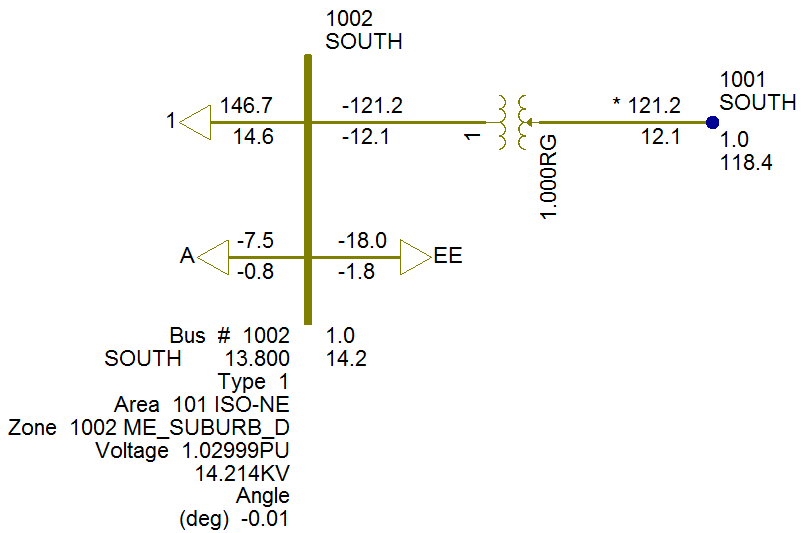
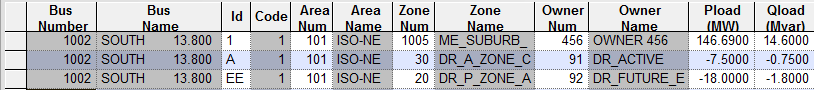


Figure ‑: South Street Substation One-Line Diagram w/ DR

Table ‑  
South Substation Load Records Example w/ DR



# Solar Photovoltaic Methodology

## Annual PV Forecast

Every year the ISO publishes a solar PV forecast[[7]](#footnote-9) in Section 3.1.1 of the CELT report for the 10 year planning horizon. This forecast provides the peak MWAC[[8]](#footnote-10) amounts[[9]](#footnote-11) of three types of solar PV (FCM, Non-FCM, and BTM) by state. Since solar PV is continually installed throughout the year, the amount installed as of June 1st of each year is assumed available for the Summer Peak Load for Transmission Planning[[10]](#footnote-12).

Example: If the forecasted PV in Maine in 2025 is 450 MW and in 2026 is 470 MW, and 30% of the yearly installed capacity is in service by June 1st, the network model would contain 456 MW of installed PV for the Summer of 2026 before gross-up for losses.

## Calculate Total PV by Dispatch Zone

The PV forecast is generated at the state level. In the ISO network model, solar PV is modeled on a dispatch zone basis similar to ADCR. The annual PV forecast will provide an updated breakdown of the dispatch zones within each state.

Example: For a study, dispatch zone C load is 40% of the Maine state load so dispatch zone C will contain 40% of the Maine solar PV. Based on the 456 MW from Step 6.1, the total solar PV modeled in dispatch zone A is 182.4 MW.

## Modeling Distributed PV in the Dispatch Zone

As described in Section 2.3.10 of the Transmission Planning Technical Guide, there are up to three categories of solar PV within each dispatch zone. Category 1 facilities (5 MW or greater) are modeled as discrete generators at the nearest substation location in the network model. Category 2 facilities (greater than or equal to 1 MW and less than 5 MW) are modeled as discrete negative loads at the nearest substation location in the network model. The rest of the solar PV, classified as Category 3 (less than 1 MW), is typically behind-the-meter (BTM) facilities and they are modeled as aggregate negative loads spread across the dispatch zone proportionally to the load at the substation. The amount of distributed solar PV to model is determined by subtracting all Category 1 and 2 facilities nameplate MW from the total solar PV nameplate MW for the dispatch zone.

Example: Continuing with the example from Step 6.3, dispatch zone C has 182.4 MW of nameplate solar PV. Of that, there are two facilities in Category 1, 5.5 MW and 10 MW, and a total of 30.5 MW of solar PV in Category 2. Based on those values, the total distributed BTM solar PV in dispatch zone C is 136.4 MW.

## Accounting for Distribution Losses & PV Availability

The PV forecast is a nameplate value and does not include transmission and distribution losses. Similar to the DRV associated with DCR, Category 2 and 3 solar PV needs to apply a distribution losses gross-up factor to account for losses saved by addition of the facilities. In addition to increasing the amount for losses, the total amount also needs to be reduced based on the assumed availability of solar PV during the peak. This availability factor is applied to all categories of solar PV. See Section 2.3.10.3 of the Transmission Planning Technical Guide for more details on the determination of the availability factor.

Example: Using the nameplate amount of 136.4 MW of Category 3 BTM PV from Step 6.3, after accounting for distribution losses savings of 5.5%, and an availability factor of 26%, the total modeled BTM PV in dispatch zone A is 37.41 MW.

## Modeling of PV in Power Flow Case

The final step in the process is to model all three categories of solar PV in the network model. All Category 1 and 2 facilities are modeled discretely as generators and negative loads respectively at their point of interconnection. For the Category 3 distributed BTM PV, the negative loads are scaled proportionally to the substation loads within the dispatch zone, similar to ADCR.

Example: Using the total 37.41 MW of Category 3 solar PV from Step 6.4, a total dispatch zone C load of 1000 MW, and a 146.69 MW load at the South Substation, the total BTM PV modeled at the South Substation would be -5.49 MW.

In addition, the 5.5 MW nameplate Category 1 facility and 3.25 MW nameplate of Category 2 facilities are located at the South Substation. An example of how solar PV combined with the demand resources from Step 5.5 at the South Substation would be modeled in the power flow case is shown in Figure 6‑1 and Table 6‑1.

### Modeling PV Power Factor

As described in Section 2.3.10.6 of the Technical Guide, solar PV is modeled with the same power factor of the load so it does not affect the net power factor of the load. If no load is present at the bus, then a 1.0 unity power factor will be assumed.

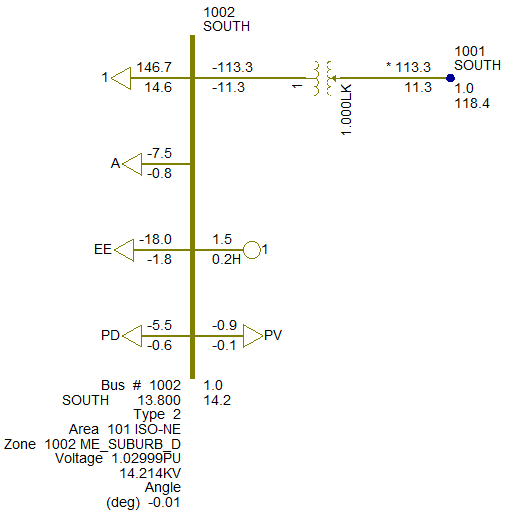
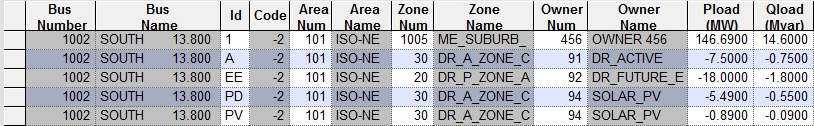


Figure ‑: South Street Substation One-Line Diagram w/ DR & PV

Table ‑  
South Substation Load Records Example w/ DR & PV



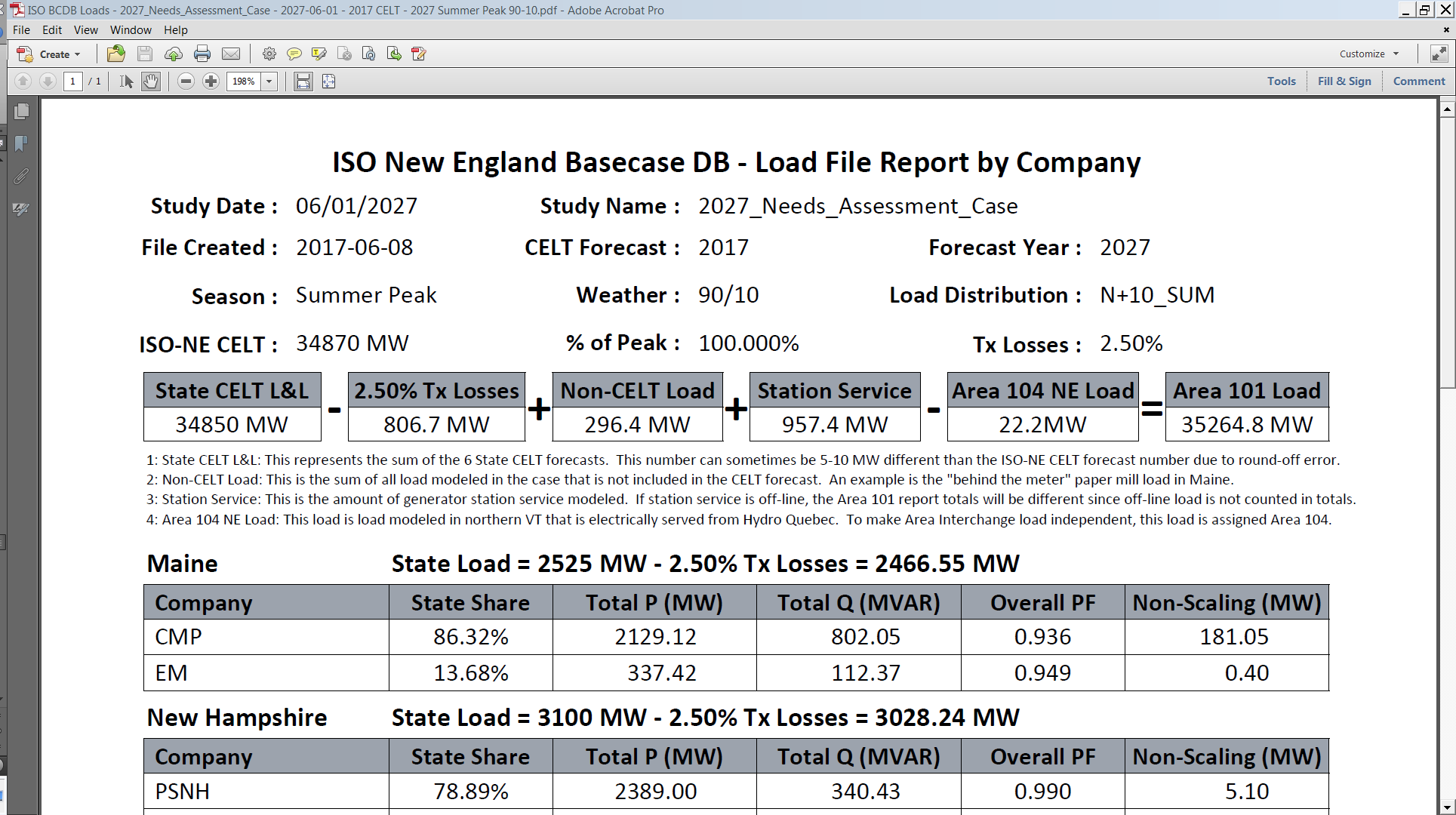
# Basecase Database Summary Reports

Each network model created for a study should be accompanied with reports describing how the load, demand resources, and solar PV were modeled. This section breaks down the reports and gives a detailed description of each section.

## Load Summary Report

### Input Assumptions

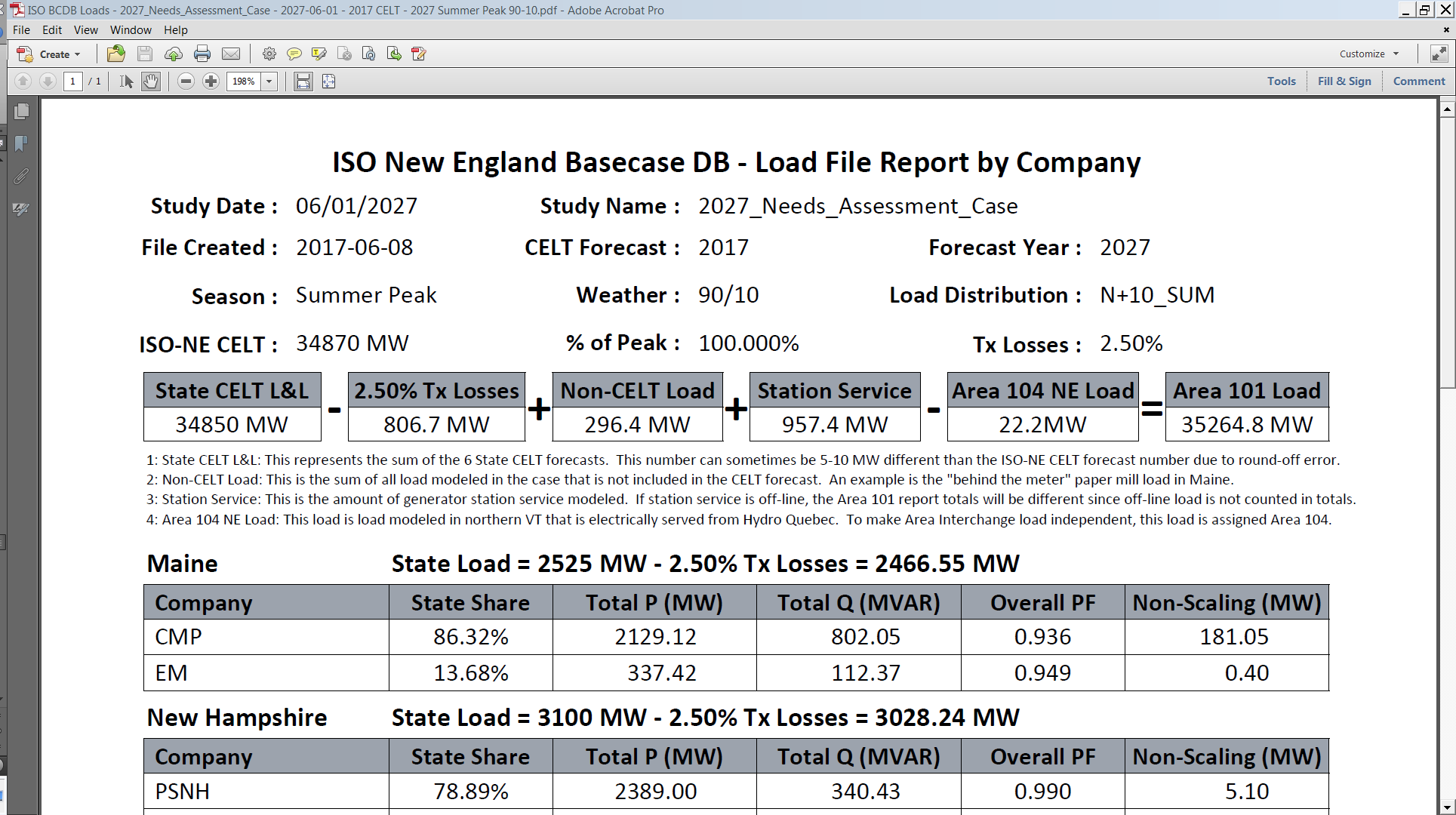
This section describes the input assumptions used when scaling the load for the network model.



1. **File Created** – Date the load scaling file was created from the BCDB.
2. **CELT Forecast** – Vintage of the CELT forecast used for the load scaling file.
3. **Forecast Year** – Forecast year the load is supposed to model.
4. **Season** – Time of year during the forecast year: Summer Peak, Winter Peak, Spring Peak, Shoulder Peak, Fall Peak, Light Load, Min Load, or Custom Load Level
5. **Weather** – Two weather levels can be used, 90/10 extreme weather and 50/50 expected weather.
6. **Load Distribution** – Can be one of six transmission owner provided load distributions. These load distributions provide data as to how a company’s load is divided amongst its substations. This data is used to reflect load shifts between 3 different periods – Summer, Winter, Light Load and 2 time frames – Near-term 1 year out and long-term 10 years out.
7. **ISO-NE CELT** – Total ISO Load forecast for a given year, season, and weather. This is a sum of the 6 state gross load forecasts in the CELT. It can be different from the individual sum of all state forecasts by 5-10 MW due to rounding.
8. **% of Peak** – For load levels less than the 90/10 or 50/50 peaks, it describes the percentage of 50/50 Summer Peak load used.
9. **Tx Losses** – Lists the amount of losses assumed to be calculated by the power flow program. See Section 4.2 for a more detailed description.

### Area 101 (ISO-NE) Scaling Equation

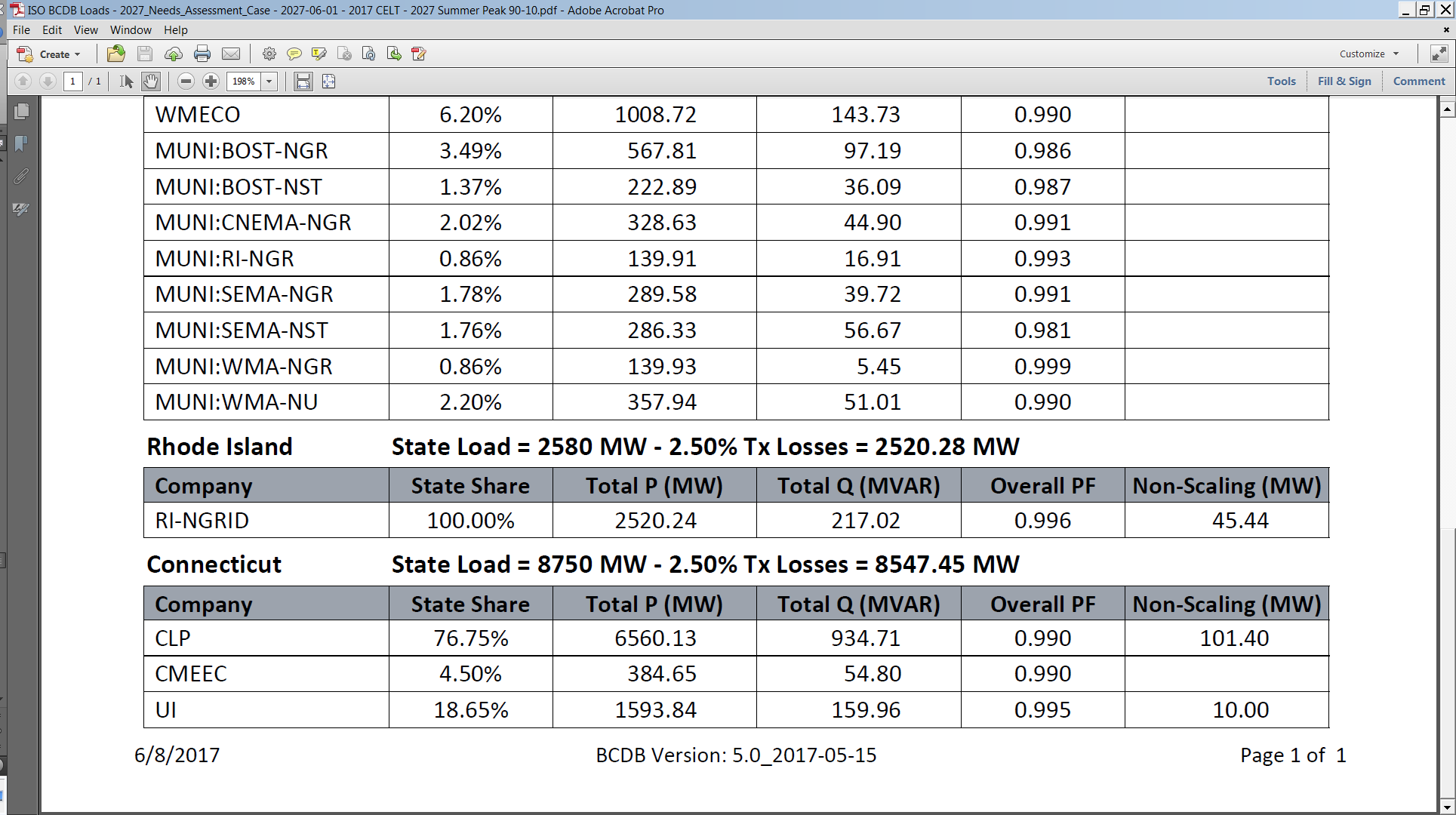
This equation gives an overall calculation of how to match the CELT load forecast value with the amount of load modeled in Area 101 of the network model.



1. **State CELT L&L** – This represents the sum of the six state CELT gross load forecasts. This number can sometimes be 5-10 MW different from the ISO CELT forecast number due to round-off error.
2. **Tx Losses** – Shows how much the forecast was reduced for transmission losses that are calculated by the power flow program. See Section 4.2 for a more detailed description.
3. **Non-CELT (Manufacturing) Load** – This is the sum of all load modeled in the case that is not included in the CELT forecast. An example is the “behind-the-meter” paper mill load in Maine. See Section 2 for a more detailed description of manufacturing load.
4. **Station Service** – This is the amount of generator station service modeled. If station service is off-line, the Area 101 report totals will be different since off-line load is not counted in totals.
5. **Area 104 NE Load** – This is load modeled in northern VT that is electrically served from Hydro Quebec. To make Area Interchange load independent, this load is assigned Area 104.
6. **Area 101 Load** – After all these factors are applied to the original CELT forecast, this should be the amount of gross load contained in Area 101 of the network model.

### State Breakdown of Load Scaling – By Company

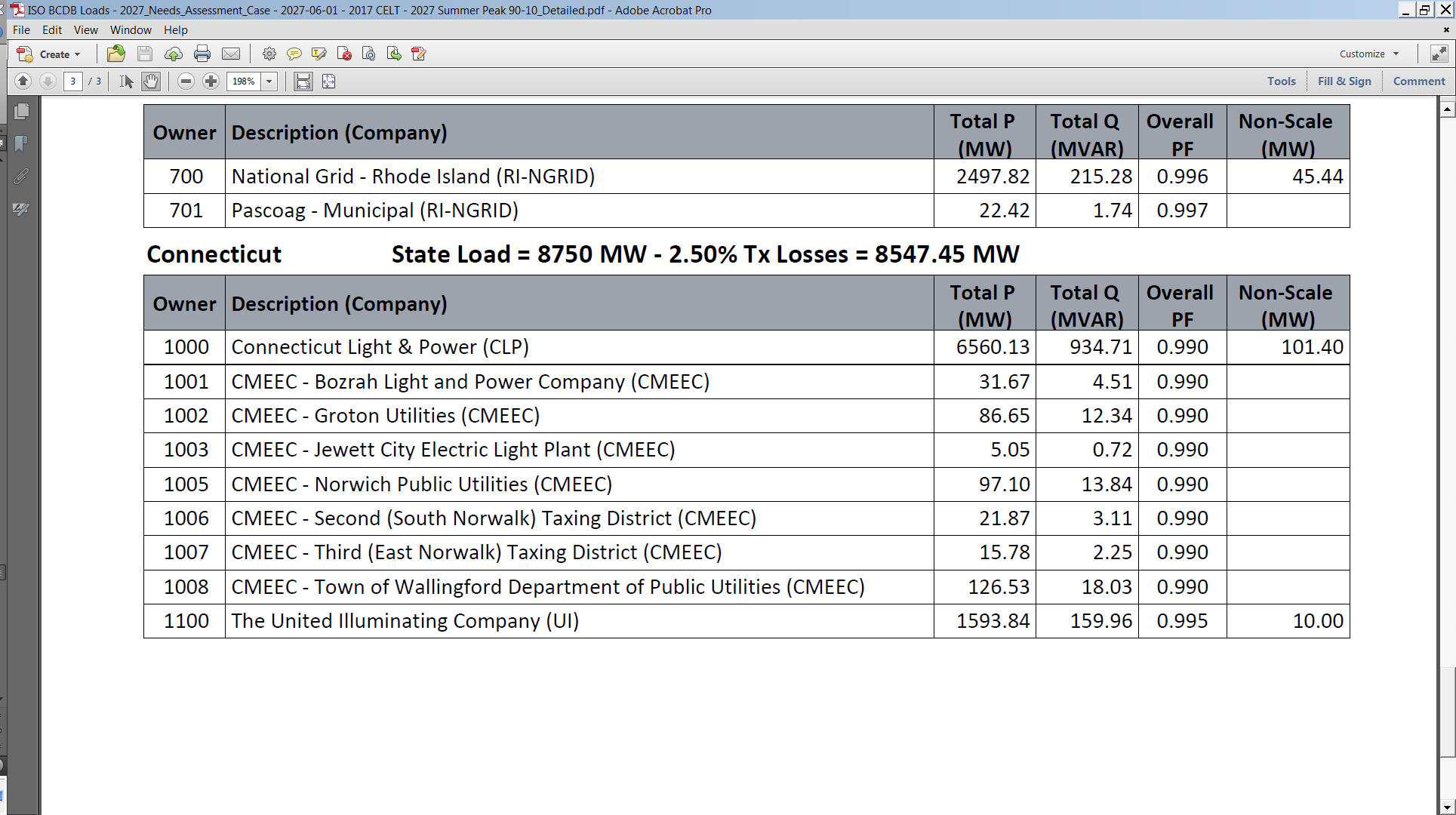
This section of the report describes how the state gross load forecast was broken down amongst the companies within that state.



1. **State** – Lists the CELT gross load forecast for the state and what the load will be scaled to after transmission losses are removed. See Section 4.2 for a more detailed description.
2. **Company** – This describes each company that is metered in the CELT report for the state.
3. **State Share** – This lists the percentage of the state forecast that each company will be scaled. See Section 4.3 for a more detailed description.
4. **Total P (MW)** – This lists the amount of MW gross load for the company in the network model. It will equal the state gross load minus transmission losses times the company’s state share.
5. **Total Q (MVAR)** – This lists the amount of MVAr gross load for the company in the network model. These values are provided in the Transmission Owner load distribution data and the values are scaled proportionally to the MW gross load to maintain the same power factor.
6. **Overall PF** – This is a calculation of the aggregate power factor for the company in the network model. This value is just an overall average power factor for the Company. Each individual substation may have different power factors depending on the data supplied by the TO.
7. **Non-Scaling (MW)** – This lists how much of the total MW gross load for the company is non-scaling CELT load (described in Section 3.2).

### State Breakdown of Load Scaling – By Owner

This section of the report describes how the state load forecast was broken down amongst the owners within that state.

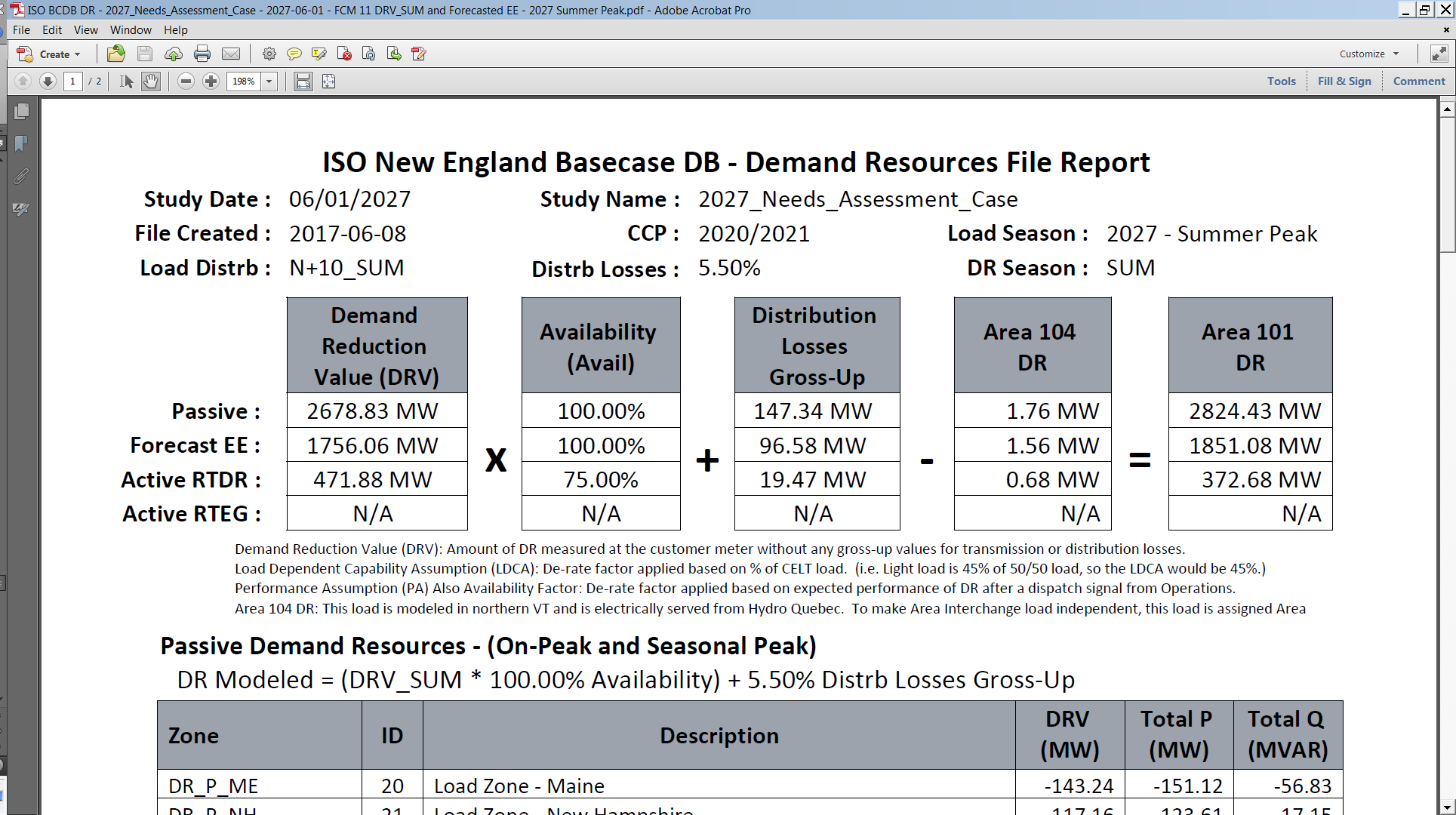


1. **State** – Lists the CELT gross load forecast for the state and what the load will be scaled to after transmission losses are removed. See Section 4.2 for a more detailed description.
2. **Owner** – Gives the owner number assigned to this load in the network model.
3. **Description (Company)** – A text description of the owner and it also lists the company that this owner is represented in the CELT report for the state.
4. **Total P (MW)** – This lists the amount of MW gross load for the owner in the network model. This value will match the report in the power flow model for the total load assigned to this owner.
5. **Total Q (MVAR)** – This lists the amount of MVAR gross load for the owner in the network model. These values are provided in the Transmission Owner load distribution data and the values are scaled proportionally to the MW load to maintain the same power factor.
6. **Overall PF** – This is a calculation of the aggregate power factor for the owner in the network model.
7. **Non-Scaling (MW)** – This lists how much of the total MW load for the owner is non-scaling CELT gross load (described in Section 3.2).

## Demand Resources Report

### Input Assumptions

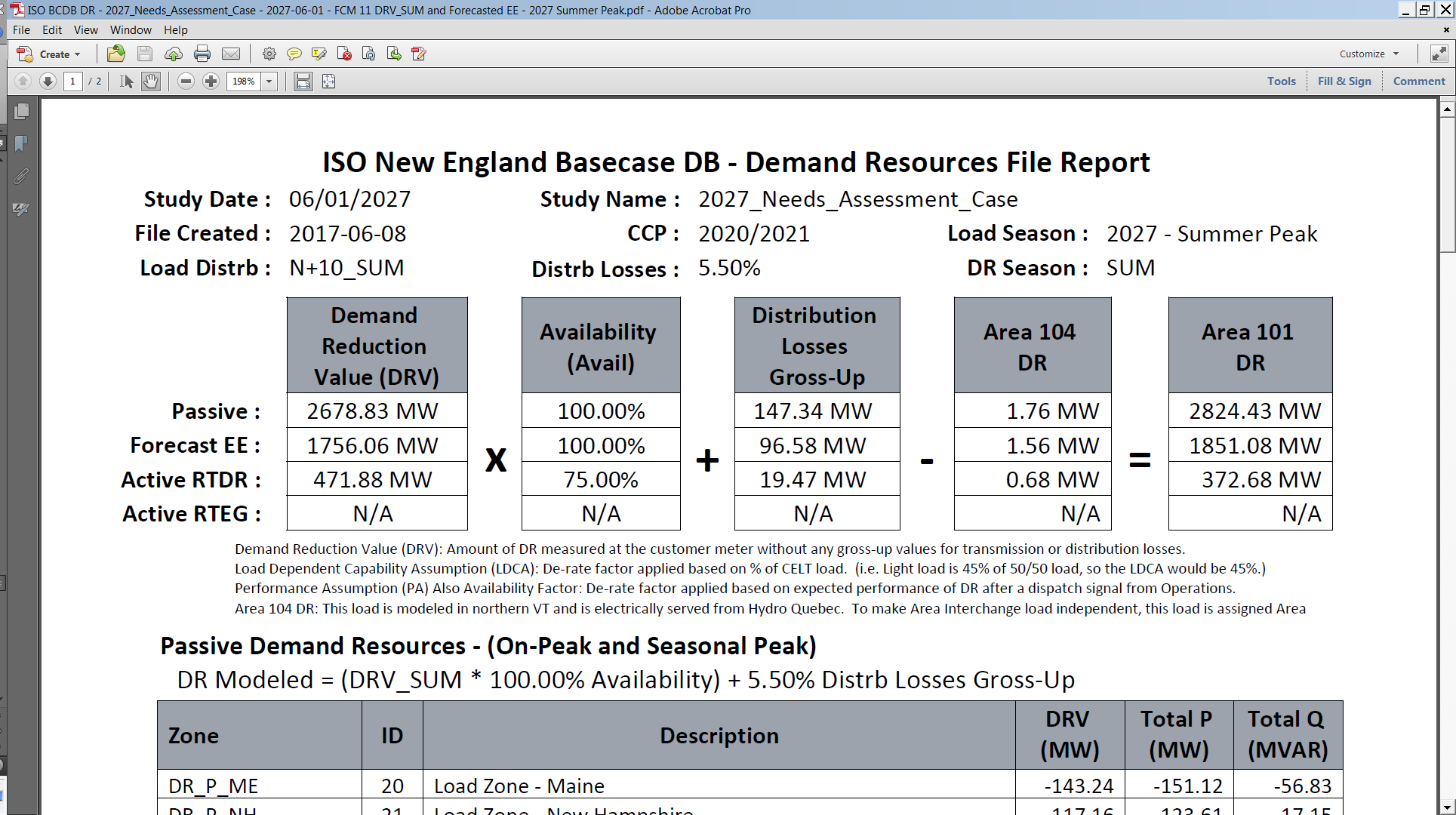
This section describes the input assumptions used when scaling the DR for the network model.



1. **File Created** – Date the DR file was created from the BCDB.
2. **CCP** – Capacity Commitment Period used for DCR amounts. For example: CCP 2020/2021 represents the DCR cleared in Forward Capacity Auction (FCA) 11.
3. **Load Season** – Which CELT forecast year and time of year during that year. Used to determine de-rate factors applied to DCR described in the next section. Examples: Summer Peak, Winter Peak, Spring Peak, Shoulder Peak, Fall Peak, Light Load, Min Load, or Custom Load Level
4. **Load Distribution** – Can be one of six transmission owner provided load distributions. These load distributions provide data as to how a company’s load is divided amongst its substations. This data is used to reflect load shifts between 3 different periods – Summer, Winter, Light Load and 2 time frames – Near-term 1 year out and long-term 10 years out.
5. **Distrib Losses** – Lists the amount of losses assumed to be from the customer meter where the DRV is calculated to where the DR is modeled in the power flow. This value is described more in the next section. Typically, the Transmission Losses (2.5% in this example) in the load file plus the Distribution Losses (5.5% in this example) in the DCR file should sum up to 8% to match the CELT total losses assumption.
6. **DR Season** – Either Summer or Winter. Depending on the Load Season, will determine which DR capacity value to use. Winter DR is applied to winter peak and Summer DR is applied to all other seasons.

### Area 101 (ISO-NE) DR Scaling Equation

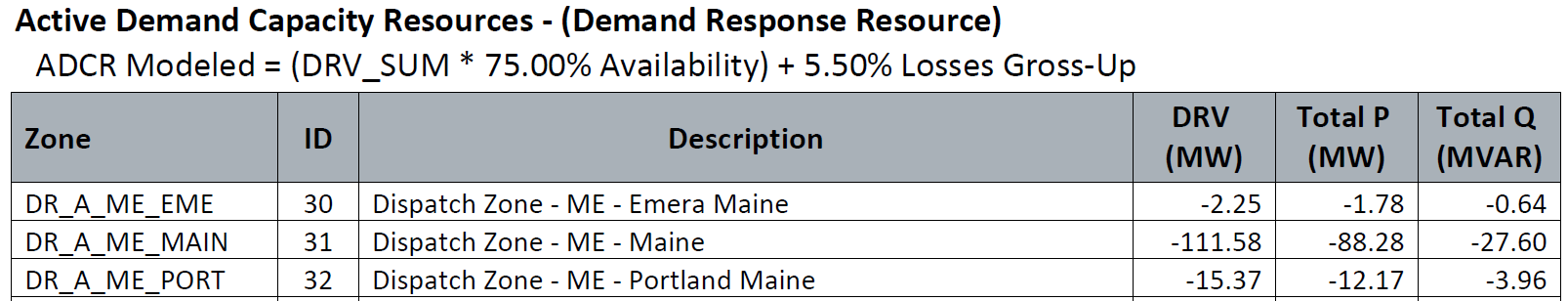
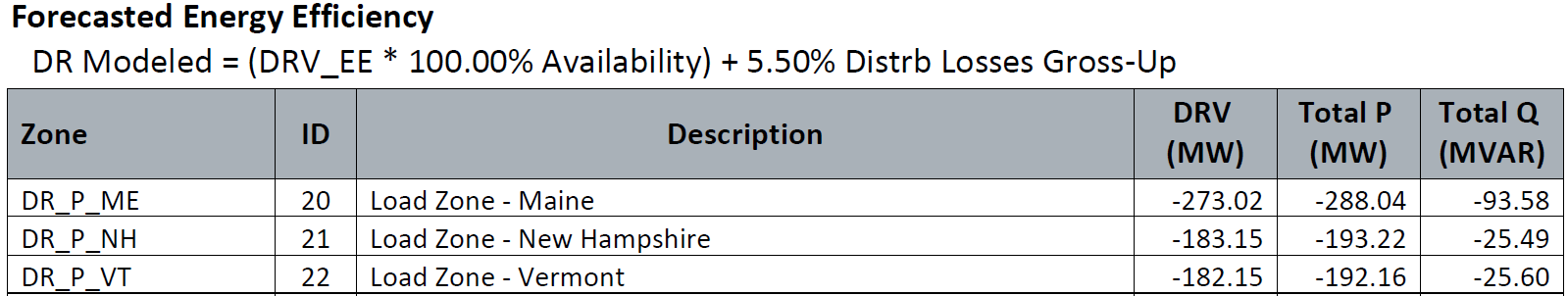
This equation gives an overall calculation of how to match the DR values from the FCA and forecasted EE with the amount of DCR modeled in Area 101 of the network model.



1. **Demand Reduction Value (DRV)** – MW value of DCR measured at the customer meter without any gross-up values for transmission or distribution losses.
2. **Availability (Avail)** – De-rate factor applied based on expected performance of DR after a dispatch signal from Operations.
3. **Distribution Losses Gross-Up** – This is the amount of losses that are added to the DRV. Since DR is modeled at the low-side of the distribution transformer the net effect of the DRV at the customer meter plus the amount losses reduced on the distribution network is modeled. This percentage is typically based on 8% minus the amount of transmission losses assumed in the CELT gross load. For this example we assumed 2.5% transmission losses, therefore 5.5% distribution losses are used.
4. **Area 104 DR** – This load is modeled in northern VT and is electrically served from Hydro Quebec. To make Area Interchange load independent, this DR is assigned Area 104.
5. **Area 101 DR** – After all these factors are applied to the original DRV from the FCA, this should be the amount of DR contained in Area 101 of the network model.

### Breakdown of DR Modeled by Zone

This section describes the amount of DR modeled in the power flow case.

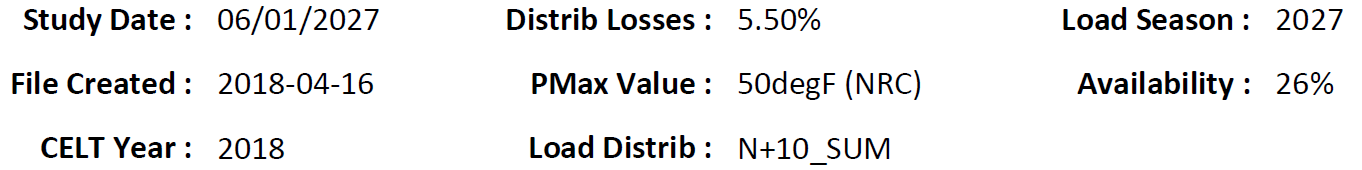


1. **Demand Resources Type (Heading row one)** – The report details the breakdown of major types of DR: Active Demand Capacity Resources (ADCR) and Forecasted Energy Efficiency (forecasted EE). Forecasted EE consists of passive DR that is forecasted to come into the market due to state sponsored programs for the 10 year planning horizon. Common forms of this DR are energy efficiency programs such as lighting and HVAC improvements. ADCR consists of Demand Response Resources (DRR). Common forms of this DR are demand side management programs such as curtailing HVAC and industrial operations during times of need.
2. **DR Modeled (Heading row two)** – This equation shows how the values from the input assumptions are applied to arrive at the amount of DR physically modeled in the power flow case.
3. **Zone** – Text description of the zone the DR is modeled. For passive DCR it is modeled by Load Zone and for ADCR it is modeled by Dispatch Zone.
4. **ID** – Numerical ID of zone in power flow model.
5. **Description** – Detailed description of load/dispatch zone area represented.
6. **DRV (MW)** – Amount of DCR cleared in CCP for that load/dispatch zone or total amount of forecasted EE for the year under study. This value is the amount of DR at the customer meter without any gross-up or de-rate factors. For ADCR it is cleared in the auction by load zone, and then broken down into dispatch zones proportional to the amount of CELT load in each dispatch zone. For an example of how the DRV is calculated see Section 5.
7. **Total P (MW)** – Amount of real power DR modeled in the power flow case in each zone. This value is derived from the base DRV with the gross-up and de-rate factors applied.
8. **Total Q (MVAr)** – Amount of reactive power DR modeled in the power flow case. The power factor of DR is matched to the power factor of the load modeled at each bus.

## Solar Photovoltaic Resources Report

### Input Assumptions

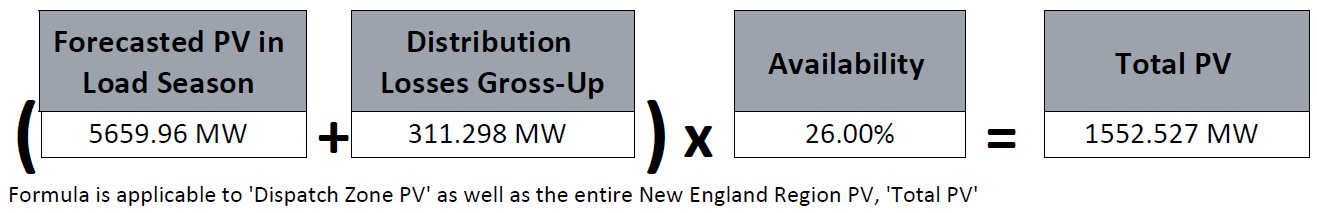
This section describes the input assumptions used when scaling the load for the network model.



1. **Study Date** – Forecast date the solar PV is supposed to model.
2. **Distribution Losses** – Lists the amount of losses assumed on the distribution system. See Section 4.2 for a more detailed description.
3. **Load Season** – Forecast year the solar PV is supposed to model.
4. **File Created** – Date the solar PV file was created from the BCDB.
5. **Maximum Power Value** – The maximum power value used for solar PV generators.
6. **Availability** – The percentage of output of forecasted solar PV that is assumed in the model.
7. **Load Distribution** – Can be one of six transmission owner provided load distributions. These load distributions provide data as to how a company’s load is divided amongst its substations. This data is used to reflect load shifts between 3 different periods – Summer, Winter, Light Load and 2 time frames – Near-term 1 year out and long-term 10 years out.

### Area 101 (ISO-NE) Solar PV Scaling Equation

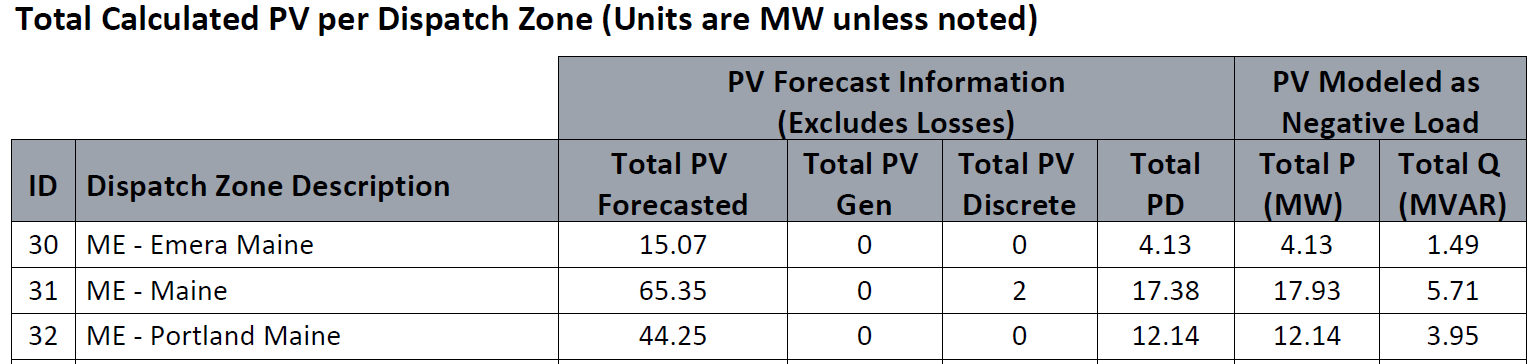
This equation gives an overall calculation of how to match the CELT solar PV forecast value with the amount of solar PV modeled in Area 101 of the network model.



1. **Forecasted PV in Load Season** – Based on the study date, the expected amount of nameplate solar PV installed.
2. **Distribution Losses Gross-Up** – The amount of losses expected to be saved by the installation of solar PV is added to the nameplate to approximate the effect of the solar PV at the low-side of the distribution transformer.
3. **Availability** – The percentage of output of forecasted solar PV that is assumed in the model.
4. **Total PV** – The amount of solar PV modeled in Area 101 of the network model.

### Breakdown of Solar PV Modeled by Dispatch Zone

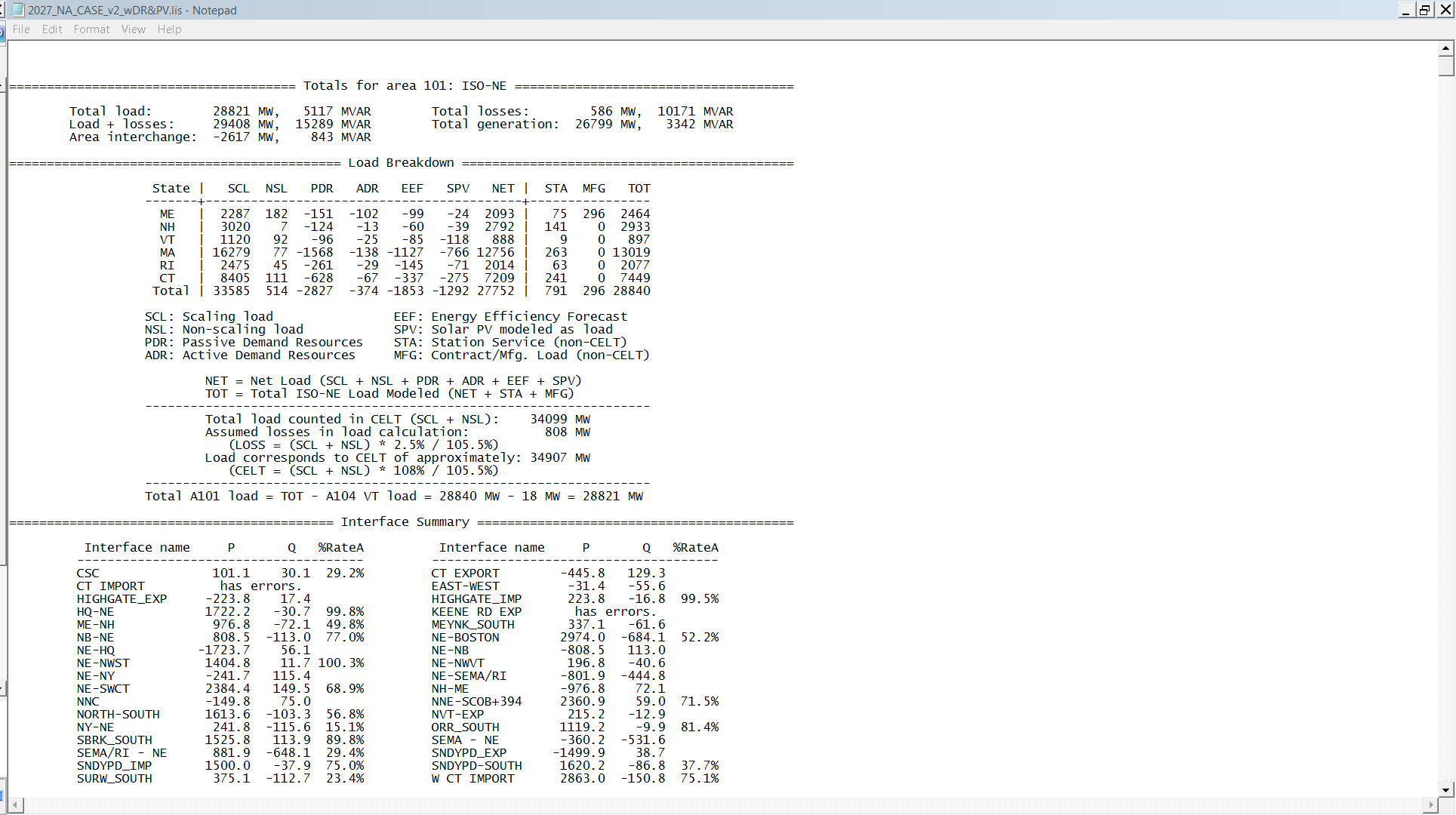
This section describes the amount of solar PV modeled in the power flow case by Dispatch Zone.



1. **ID** – Numerical ID of zone in power flow model.
2. **Dispatch Zone Description** – Text description of the Dispatch Zone the solar PV is modeled.
3. **PV Forecast Information (Excludes Losses)** –The next four columns summarize the solar PV values from the CELT forecast.
   1. **Total PV Forecasted** – The total nameplate MWAC amount of solar PV forecasted for the Dispatch Zone.
   2. **Total PV Gen** – The total nameplate MWAC amount of Category 1 solar PV facilities in the Dispatch Zone. These facilities are modeled as generators in the network model and not included in the negative load models for solar PV.
   3. **Total PV Discrete** – The total nameplate MWAC amount of Category 2 solar PV facilities in the Dispatch Zone. These facilities are modled as discrete negative loads in the network model and not included in the distributed solar PV aggregate negative load.
   4. **Total PD** – The total expected MWAC amount (nameplate times availability factor) of Category 3 solar PV facilities in the Dispatch Zone. These facilities are the remaining behind-the-meter solar PV modeled as an aggregate negative load proportional to the customer load at each substation. Total PD is calculated as:
4. **PV Modeled as Negative Load** – The next two columns total the amount of Category 2 and 3 modeled in the Dispatch Zone.
   1. **Total P (MW)** – Amount of real power solar PV modeled in the power flow case in each Dispatch Zone as a negative load. This value is derived from the nameplate MWAC amount of Category 2 and 3 solar PV with the gross-up and availability factors applied. Total P is calculated as:
   2. **Total Q (MVAr)** – Amount of reactive power solar PV modeled in the power flow case in each Dispatch Zone as a negative load. The power factor of solar PV is matched to the power factor of the load modeled at each bus.

## Python Case Summary Report

In many studies, a case summary script is used to display key characteristics of a power flow base case. The ISO base case summary python script includes a state-by-state breakdown of load, demand resources, and solar PV, including scaling, non-scaling, station service, and non-CELT manufacturing load. A sample of this table is provided below (numbers for illustrative purposes only).



The columns in the load summary each correspond to one of the types of load described in Section 3 of this document, as follows:

1. **SCL** –Scaling CELT Gross Load (See Section 3.1)
2. **NSL** – Non-Scaling CELT Gross Load (See Section 3.2)
3. **PDR** – Passive Demand Capacity Resources (if modeled discretely from forecasted EE) (See Section 3.5)
4. **ADR** – Active Demand Capacity Resources (See Section 3.5)
5. **EEF** – Forecasted Energy Efficiency (See Section 3.6)
6. **SPV** – Solar Photovoltaic (PV) generation (represents Category 2 and 3 only, Category 1 units are modeled as generators and not included in this total) (See Section 3.7)
7. **NET** – The net power delivered to customers included in the CELT forecast, equal to the sum of scaling and non-scaling load, less passive DCR, ADCR, forecasted EE, and solar PV.
8. **STA** – Generator Station Service Load (See Section 3.3)
9. **MFG** – Manufacturing Load not included in CELT forecast (See Section 3.4)

As with many load reports, totals may appear incorrect in the last decimal place due to rounding errors. Also, please note that the sum of scaling and non-scaling load typically does not equal the ISO New England-wide CELT forecast. This is due to the treatment of transmission system losses, which are included in the total load quoted in the CELT forecast and discussed in Section 4.2 and explicit modeling of load and generation, which is captured as net in the CELT forecast. The base case summary script does not include transmission system losses, but simply quotes the sum of all loads modeled in the base case in each state listed.

# ISO-NE Number Range Assignments

## Area Number Assignments

The area number assignments for NPCC Control Areas are shown in Table 8‑1.

Table ‑  
NPCC Area Number Assignments

| Long Name | Number | PSSE Name | Description |
| --- | --- | --- | --- |
| ISO New England | 101 | ISO-NE | New England (ME, NH, VT, MA, RI, CT) |
| New York ISO | 102 | NYISO | New York State |
| Independent Electricity System Operator | 103 | IESO | Eastern Canadian Province – Ontario |
| TransÉnergie | 104 | TE | Eastern Canadian Province – Québec |
| New Brunswick System Operator | 105 | NB | Eastern Canadian Province – New Brunswick |
| Nova Scotia Power | 106 | NS | Canadian Maritime Provinces |
| Cornwall | 107 | CORNWALL | Area bordering IESO, HQ, and NYISO |

## Bus Number Assignments

The bus number assignments for the ISO New England Control Area are shown in Table 8‑2.

Table ‑  
ISO-NE Bus Number Assignments

| State | Range | Subranges | |
| --- | --- | --- | --- |
| ME | 100,000 - 103,999 | Avangrid (CMP):  Emera Maine (MPS):  Emera Maine (BHE):  Non-regulated TOs: | 100,000 – 102,499  102,500 – 102,999  103,000 – 103,699  103,700 – 103,999 |
| NH | 104,000 - 106,999 | Eversource (PSNH):  National Grid:  Non-regulated TOs: | 104,000 – 105,999  106,000 – 106,699  106,700 – 106,999 |
| VT | 107,000 - 109,999 | VELCO:  National Grid:  Non-regulated TOs: | 107,000 – 109,499  109,500 – 109,699  109,700 – 109,999 |
| MA | 110,000 - 116,999 | Eversource (NSTAR):  National Grid:  Eversource (WMECO):  Non-regulated TOs: | 110,000 – 112,999  113,000 – 115,999  116,000 – 116,699  116,700 – 116,999 |
| RI | 117,000 - 118,999 | National Grid:  Non-regulated TOs: | 117,000 – 118,699  118,700 – 118,999 |
| CT | 119,000 - 124,999 | Eversource (CL&P):  Avangrid (UI):  Non-regulated TOs: | 119,000 – 122,999  123,000 – 124,699  124,700 – 124,999 |

## Zone Number Assignments

The zone number assignments for ISO New England Control Area are shown in Table 8‑3.

Table ‑  
ISO-NE Zone Number Assignments

| State/Type | Range | Subranges/Description |
| --- | --- | --- |
| Non-NPCC | 1 - 9 | RFC (2), SERC (3), FRCC (4), SPP (5), MRO (6), ERCOT (7), WECC (8) |
| NPCC – Non-ISONE | 10 - 19 | NYISO (12), IESO (13), TE (14), NBSO (15), NSP (16), Cornwall (17) |
| Load Zones | 20 - 29 | Used by passive DCR and Forecasted EE |
| Dispatch Zones | 30 - 49 | Used by ADCR and Solar PV |
| Manufacturing Load | 50 - 55 | By 6 NE states (Non-Scaling load not included in CELT) |
| Future New England Use | 56 - 59 |  |
| OP-17 Zones | 60 - 93 | Used for Load Power Factors per OP-17 definitions |
| Future New England Use | 94 - 97 |  |
| Unknown | 98 | Unknown Zone - TO BE ASSIGNED |
| New England TO Border Buses | 99 |  |
| ME | 100 - 399 | Avangrid (CMP): 100-299 Emera Maine (MPS): 300-349 Emera Maine (BHE):350-399 |
| NH | 400 - 699 | National Grid: 400-499 Eversource (PSNH): 500-699 |
| VT | 700 - 999 | VELCO: 700-899 National Grid: 900-998 |
| MA | 1000 - 1399 | Eversource (NSTAR): 1000-1099 National Grid: 1100-1299 Eversource (WMECO): 1300-1399 |
| RI | 1400 - 1599 | National Grid: 1400-1599 |
| CT | 1600 - 1899 | Eversource (CL&P): 1600-1799 Avangrid (UI): 1800-1899 |
| RSP Subareas | 1901 - 1915 | 13 RSP Zones plus one for border buses and one for external |
| Future New England Use | 1916 - 1999 |  |

### Name and Numbering Convention

Zone numbers (100-1899) will end with a digit corresponding to:

* **0:** transmission, PTF
* **1:** transmission, non-PTF
* **2:** distribution
* **3:** generation, transmission-connected
* **4:** generation, distribution-connected
* **5:** load, local growth rate 1 (Load ID: 1)
* **6:** load, local growth rate 2 (only if necessary, Load ID: 2)
* **7:** load, local growth rate 3 (only if necessary, Load ID: 3)
* **8:** load, special/non-scaling (excluding station service)
  + Special/Non-scaling Load ID: SX where "X" is 1 through 9
* **9:** load, station service
  + Station Load ID: XA=continuous, XB=online only where "X" is the final digit of the unit id

Zone names (100-1899) will have the format of "XX\_YYYYYYY\_Z" where:

* **XX:** two letter state abbreviation
* **YYYYYYY:** seven character region description
* **Z:** P-transmission,PTF; N-transmission,non-PTF; D-distribution; G-generation; L-normal load; R-response load; S-special/non-scaling/station load

## Owner Number Assignments

The owner number assignments for ISO New England Control Area are shown in Table 8‑4.

Table ‑  
ISO-NE Owner Number Assignments

| Service Territory Owner/Type | Range | Description |
| --- | --- | --- |
| Non-ISONE | 1 - 9 | NPCC (1), RFC (2), SERC (3), FRCC (4), SPP (5),  MRO (6), ERCOT (7), WECC (8) |
| Generators (nuclear) | 10 |  |
| Generators (coal) | 11 |  |
| Generators (gas, thermal) | 12 |  |
| Generators (gas, combined-cycle) | 13 |  |
| Generators (gas, simple-cycle) | 14 |  |
| Generators (gas, fuel cell) | 15 |  |
| Generators (oil) | 16 |  |
| Generators (hydro, run-river) | 17 |  |
| Generators (hydro, ponded) | 18 |  |
| Generators (hydro, pumped) | 19 |  |
| Generators (biomass) | 20 |  |
| Generators (wind) | 21 |  |
| Generators (diesel/jet fuel) | 22 |  |
| Generators (solar, thermal) | 23 |  |
| Generators (solar, PV) | 24 | Category 1 (≥ 5 MW) |
| Generators (tidal/wave) | 25 |  |
| Generators (geothermal) | 26 |  |
| Generators (static var comp) | 27 |  |
| Generators (HVDC) | 28 |  |
| Generators (Distribution) | 29 |  |
| Generators (Dynamic VAR Device) | 30 |  |
| Generators (Battery Storage) | 31 |  |
| Future Generator Types | 32 - 79 |  |
| Load - Motor | 80 |  |
| Load - Manufacturing | 81 | Non-Scaling load not included in CELT forecast |
| Future New England Use | 82 - 89 |  |
| Demand Response – ADCR | 90 |  |
| Demand Response – Passive DCR | 91 | Starting w/ 2018 CELT no longer used in transmission planning studies |
| Demand Response – Forecasted EE | 92 |  |
| Demand Response - RTEG | 93 | RETIRED – NO LONGER USED |
| Solar Photovoltaic (PV) | 94 | Category 2 (< 5 MW and ≥ 1 MW) and Category 3 (< 1 MW BTM) PV |
| Future New England Use | 95 - 97 |  |
| Unknown | 98 | Unknown Owner – TO BE ASSIGNED |
| New England TO Border Buses | 99 |  |
| Avangrid (CMP) | 100 - 199 | Includes Emera Maine (BHE and MPS) as assigned by Avangrid (CMP) |
| VELCO | 200 - 399 | Includes VT municipals as assigned by VELCO |
| Eversource (NSTAR) | 400 - 499 | Includes MA municipals as assigned by Eversource (NSTAR) |
| National Grid | 500 - 799 | Includes MA, RI, NH municipals as assigned by NGrid |
| Eversource (PSNH, WMECO, CL&P) | 800 - 1099 | Includes CT, MA, NH municipals as assigned by Eversource |
| Avangrid (UI) | 1100 - 1199 | Includes CT municipals as assigned by Avangrid (UI) |

### Name and Numbering Convention

Owner names (100-1999) will have the format of "XX\_YYYYYYYYY" where:

* **XX:** two letter state abbreviation
* **YYYYYYYYY:** nine character company description

# Revision History

|  |  |  |
| --- | --- | --- |
| Rev No. | Date | Reason |
| 2.0 | TBD | * Converted document to new ISO report template * Updated document to conform with ISO style guide * Added equations to explain all steps in methodologies * Added descriptions for Solar PV modeling as Section 6 and reporting as Section 7.3 * Included Area-Bus-Zone-Owner Assignments as Section 8 * Updated to reflect changes to terminology with Price Responsive Demand (PRD) * Updated to reflect change in use of energy efficiency forecast for entire 10 year planning horizon for transmission planning studies |
| 1.0 | 01/14/2016 | * Latest revision of Appendix J of Technical Guide |

1. <https://www.iso-ne.com/system-planning/system-plans-studies/celt> [↑](#footnote-ref-1)
2. <https://www.iso-ne.com/system-planning/system-forecasting/load-forecast> [↑](#footnote-ref-2)
3. The generic terms demand resource (DR) and passive demand resource (passive DR) are used in this document and may include forecasted EE and PV [↑](#footnote-ref-5)
4. <https://www.iso-ne.com/markets-operations/markets/forward-capacity-market> [↑](#footnote-ref-6)
5. <https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/> [↑](#footnote-ref-7)
6. <https://www.iso-ne.com/markets-operations/markets/forward-capacity-market> [↑](#footnote-ref-8)
7. <https://www.iso-ne.com/system-planning/system-plans-studies/celt> [↑](#footnote-ref-9)
8. For the remainder of this section, it is assumed all solar PV amounts are in AC amounts and DC equivalent values are not listed. [↑](#footnote-ref-10)
9. The Solar PV amounts listed in the CELT report do not included transmission and distribution losses. [↑](#footnote-ref-11)
10. Note: The behind-the-meter PV reduction in the CELT and PV forecast use July 1st as an installed date based on the typical peak month of the year. Transmission Planning only accounts for installations through June 1st to account for the start of the summer season. [↑](#footnote-ref-12)