Public Utility Commission of Texas

Texas Technical Reference Manual

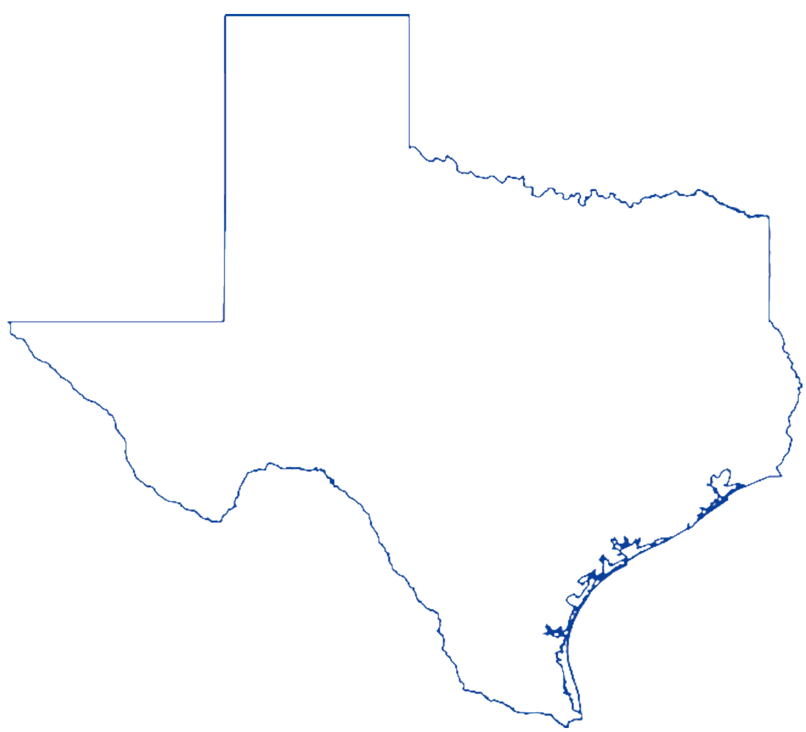
Version 9.0

Volume 1: Overview and User Guide

Program Year 2022

Last Revision Date:

November 2021



Public Utility Commission of Texas

Texas Technical Reference Manual

Version 9.0

Volume 1: Overview and User Guide

Program Year 2022

Last Revision Date:

November 2021

Table of Contents

Appendices

List of Figures

List of Tables

Acknowledgments

The Technical Reference Manual is maintained by the Public Utility Commission of Texas' independent Evaluation, Measurement, and Verification (EM&V) team led by Tetra Tech. This version of the Texas Technical Reference Manual (TRM) was primarily developed from program documentation and measure savings calculators used by the Texas Electric Utilities and their Energy Efficiency Services Providers (EESPs) to support their energy efficiency efforts, and original source material from petitions filed with the Public Utility Commission of Texas by the utilities, their consultants and EESPs such as Frontier Energy (TXu 1-904-705), ICF, CLEAResult, and Nexant. Portions of the Technical Reference Manual are copyrighted 2001-2017 by the Electric Utility Marketing Managers of Texas (EUMMOT), while other portions are copyrighted 2001-2018 by Frontier Energy. Certain technical content and updates were added by the EM&V team to provide further explanation and direction, as well as a consistent structure and level of information.

TRM Technical Support

Technical support and questions can be emailed to the EM&V project manager (lark.lee@tetratech.com) and PUCT staff (therese.harris@puc.texas.gov).

1. TRM PURPOSE AND SCOPE

The purpose of the statewide Technical Reference Manual (TRM) is to provide a single common reference document to estimate energy and peak demand savings resulting from the installation of energy efficiency measures promoted by utility-administered programs in Texas. This document is a compilation of deemed savings values approved by the Public Utility Commission of Texas (PUCT) for use in estimating savings for energy efficiency measures. The TRM is updated annually through a collaborative process between the Electric Utilities Marketing Managers of Texas (EUMMOT) and the PUCT's third-party Evaluation, Measurement, and Verification (EM&V) contractor. The data and methodologies in this document are to be used by program planners, administrators, implementers, and evaluators for forecasting, reporting, and evaluating energy and demand savings from energy efficiency measures installed in Texas. The scope of the TRM is to measure savings; therefore, utilities' program manuals should be consulted for health and safety considerations related to the implementation of measures (e.g., residential air sealing measures).

The development and maintenance of the TRM are addressed in 16 Texas Administrative Code (TAC) § 25.181, relating to Energy Efficiency Goal (Project No. 39674). The TRM includes measures that use a deemed savings approach and standardized M&V protocols to determine or verify energy and demand savings for specific measures or programs ((16 TAC § 25.181(q)(6)(A)).

1.1 DEEMED SAVINGS DISCUSSION

Deemed savings refers to an approach for estimating average or typical savings for efficiency measures installed in relatively homogenous markets with well-known building characteristics and usage schedules. Previous market research and building simulation tools have been used to develop estimates of "average" or deemed energy or peak savings per measure as a function of building type, capacity, weather, building schedules, and other input variables. Using this approach, program savings can be estimated by multiplying the number of measures installed by the deemed or estimated savings per measure based on previous research on the average operating schedules, baseline efficiencies, and thermal characteristics of buildings in a given market.

The deemed savings approach provides reasonably accurate estimates of savings in mass markets where building operating conditions, system characteristics, and baseline efficiencies are relatively well-defined. This approach is not normally used to estimate savings in less homogenous and more site-specific applications, especially in non-residential facilities where the range of operating conditions and energy using processes is significant and can vary widely from one project to another for a similar measure. Developing energy savings estimates for these more complex facilities require the use of one or more of the International Performance Measurement and Verification Protocol (IPMVP) options that require some form of on-site measurement.

By definition, deemed savings estimates require the development of engineering algorithms, tools, or models to estimate average savings as a function of one or more average inputs, including baseline usage patterns, equipment efficiency levels, and building thermal characteristics. This document organizes the methods and sources used to develop these average and default values by measure category and sector and lays out the resulting savings per measure estimates in the form of savings values, algorithms, and/or calculation tools for energy efficiency measures offered by utility program administrators for claiming and reporting energy savings impacts to the PUCT.

1.2 TRM SCOPE AND DEVELOPMENT CYCLE

One of the primary objectives of the TRM is uniform application of savings methods and their assumptions. The TRM provides consistent savings estimates across programs and utility service territories, as well as estimating program-level cost-effectiveness. By establishing clear qualification criteria for the development of projected and claimed savings estimates, the TRM provides transparency of savings for all interested stakeholders.

The TRM document also provides guidance on the update frequency for key inputs and/or equations based on the vintage of the input parameters, as well as the EM&V team's assessment of the level of variability in likely savings estimates across the range of measure applications. The intent is to help participants in the energy efficiency market save money and time by providing a single source to guide savings estimates and equations.

Finally, the EM&V team provides clear criteria for deciding whether future efficient technologies or systems are good candidates to be included in the TRM as a deemed savings measure estimate or a deemed algorithm with stipulated or variable parameters.

The data and algorithms in the TRM are to be used by electric utilities who serve as program administrators for the following purposes:

1. Projecting program savings for the next year
2. Reporting program savings for the previous year

PUCT staff has approval responsibility for the TRM (16 TAC § 25.181(q) (6) (C)). To facilitate proper vetting and collaborative input into the TRM, PUCT staff will distribute the TRM to the Energy Efficiency Implementation Project (EEIP) and will host an annual EEIP meeting to review the TRM.

1.3 TRM LAYOUT

This document is divided into separate documents for ease of use:

- **Volume 1: TRM Overview and User Guide** covers the process for TRM updates and version rollouts, weather zones, peak demand definitions, TRM structure, and the format of the TRM measure overviews.
  - **Appendix A:** Glossary of Terms
- **Volume 2: Residential Measures** contains the measure descriptions and deemed savings estimates and algorithms for measures installed in residential dwellings.
  - **Appendix A:** Central Air Conditioner and Heat Pumps Deemed Savings Tables
  - **Appendix B:** Mini-Split Air Conditioner and Heat Pump Deemed Savings Tables
- **Volume 3: Nonresidential Measures** contains the measure descriptions and deemed savings estimates and algorithms for measures installed in nonresidential businesses. Volume 3 also includes two appendices.
  - **Appendix A:** Measure Life Calculations for Dual Baseline Measures

- **Volume 4: M&V Protocols** contains protocols to estimate claimed savings for measures that have been reviewed and approved by the EM&V team. Volume 4 also contains two appendices**.**
    - **Appendix A**: M&V Metering Schedule
    - **Appendix B:** Counties by Weather Zone Assignment
- **Volume 5: Implementation Guidance** contains EM&V team recommendations regarding program implementation that may affect claimed savings.

2. TRM UPDATE PROCESS AND VERSION ROLLOUT

The TRM was developed in stages to ensure a smooth transition from the historical situation where a variety of different energy savings calculators and tools were used to estimate savings to a preferable situation where a common set of deemed savings methods and consistent calculators are used by all electric utilities and EESPs in Texas.

2.1 TRM VERSIONS

TRM version 9.0 is specified for Program Year (PY) 2022.

- **TRM 1.0** organized the deemed savings tables, algorithms, and calculators that were used in 2013 to estimate deemed savings into a consistent framework with common sector, end-use, and measure naming conventions across all utilities. TRM Version 1.0 also consolidated and organized the savings tools and calculators used to deem savings per measure in one place to allow for comparison of savings methods and approaches used in different utility service areas.
- **TRM 2.0,** the second version of the TRM, was finalized in April 2014 for utilities to use in planning for PY2015 projected and claimed savings. It contains prioritized changes to selected deemed savings estimates and/or calculators based on the EM&V contractor's initial reviews of deemed savings tables and calculators. It also includes documentation of currently approved peak demand reductions. An updated version, TRM 2.1, was filed at the beginning of PY2015 to provide additional clarifications as well as to include ENERGY STAR® updates and two new measures for which deemed savings were approved by the Commission since TRM 2.0 was filed.
- **TRM 3.0** was finalized in April 2015 for utilities to use in planning for PY2016 projected and claimed savings. TRM 3.0 includes additional prioritized updates informed by EUMMOT and EM&V primary research with Texas customers across all utility territories. It includes revisions and standardization to some input values and/or calculators, including consolidation of existing savings tables and recommended seasonal time demand patterns for measures where annual hours of use are not estimated by existing tools or calculators. In addition, Version 3.0 includes standardized approaches to calculate summer and winter peak savings at the measure level and is the first TRM to include standardized EM&V protocols. This updated version, TRM 3.1, includes identified updates and reviewed M&V protocols since TRM 3.0 was filed. A redlined version of TRM 3.1 was distributed in March 2016, which added additional examples of peak demand for M&V projects, corrected errors found in the new peak demand calculations, and added language regarding mechanical ventilation for new homes.
- **TRM 4.0** represented an agreed-upon shift in the TRM schedule to one TRM a year for both planning and implementation to be distributed by the end of August and finalized by the end of September for use in the next program year. TRM 4.0 includes major updates for solar PV, residential envelope measures, commercial HVAC, and roof measures, as well as several other updates as described in the summary tables at the beginning of each volume.

- **TRM 5.0** includes baseline updates in response to the statewide adoption of IECC and IRC 2015 codes in 2016. It also includes several new deemed measures: nonresidential evaporative pre-cooling, residential showerhead thermostatic restrictor valve, residential tub spout and showerhead thermostatic restrictor valve, and residential and nonresidential pool pump. New M&V protocols were developed for Compressed Air and Variable Refrigerant Flow (VRF) projects, as well as several other updates as described in the summary tables at the beginning of each volume.

- **TRM 6.0** includes updated LED estimated useful lives (EULs), incorporation of established documentation requirements, and new measure, including

  Residential: ENERGY STAR® connect thermostats; smart thermostat demand response; and building envelope—cool roofs;

  Commercial: entrance and exit door air infiltration, door gaskets for walk-in and reach-in coolers and freezers demand control kitchen ventilation**.**

- **TRM 7.0** includes updated LED estimated useful lives (EULs), incorporation of established documentation requirements, and new measures, including

  Residential: mini-split AC and HPs; packaged terminal HPs; evaporative cooling; ENERGY STAR® clothes dryers, freezers, air purifiers, electric vehicle supply equipment; advanced power strips; and solar attic fans;

  Commercial: LED traffic signals, CRACs, high volume low-speed fans, demand control kitchen ventilation, commercial ice makers, computer power management, premium efficiency motors, central DHW controls, and thermal energy storage.

  Volume 5 guidance language was transferred to other volumes, when applicable.

- **TRM 8.0** includes updated documentation and eligibility requirements (including when claiming electric resistance as a residential heating baseline), the addition of space heat adjustment factors for residential envelope measures, and new measures, including

  Commercial: computer room air handler motor efficiency, vacuum-sealing, and packaging machines, high-speed doors for cold storage, showerhead and tub spout temperature-sensitive restrictor valves, and electric vehicle supply equipment.

- **TRM 9.0** includes updating documentation, references, eligibility requirements, and adjusting deemed savings tables and algorithms for several measures, including residential measures and Commercial Food Service and Refrigeration measures in response to the March 2021 updates to the ENERGY STAR® Commercial Kitchen Equipment savings calculator. It also includes commercial HVAC coefficient assumptions for midstream delivery and several new measures, including

  Residential: low emissivity (Low-E) storm windows;

  Commercial: variable frequency drives for water pumping, stream trap repair or replacement, small commercial evaporative cooling, hydraulic gear lubricants, and hydraulic oils.

2.2 TRM UPDATE PROCESS

Deemed savings input parameters in the TRM will be reviewed at least annually by the PUCT's EM&V contractor (16 TAC § 25.181(q) (6) (B)). An annual review identifies needed updates and revisions as new technologies mature and building operating environments change. The EM&V team will assess the need to change or update future TRM's deemed savings based primarily on (a) feedback from the organizations that use the TRM values and equations for planning or reporting purposes, (b) EUMMOT's or the EM&V team's assessment of changes in measure technology and measure baselines due to changes in common practices, codes and/or performance standards, and (c) EM&V results that indicate reasonable updates could improve the accuracy of savings estimates. The EM&V team will make recommendations about the scope and detail needed for future updates to savings algorithms and values based on input gathered from EUMMOT, EESPs, the PUCT, and other stakeholders, EM&V research, and consideration of the uncertainties and the potential for bias in current TRM estimates.

The need for TRM deemed savings updates are based on the following factors: (1) the number and complexity of new measures proposed annually by utilities and EESPs; (2) the degree of uncertainty of savings estimates determined in the review process; (3) changes in baselines; (4) new data made available from site-based M&V activities; and (5) the cost of updating the TRM annually.

The petition process to establish Commission-approved deemed values for new measures will continue to be the mechanism for the introduction of deemed values for new measures. (16 TAC § 25.181(p) (2)). Any deemed values adopted by the PUCT through the established petition process at least two weeks before the submission of the draft TRM will be incorporated into the draft TRM. Any deemed values adopted by the Commission at least two weeks before the date of the final version of the TRM will be incorporated into the final version of the TRM. Regardless if new measures are in the TRM or not, Commission-approved measures may be included in programs 60 days after the petition is filed with the Commission.

2.3 TRM SCHEDULE

The EM&V team maintains a detailed schedule on the PUCT EM&V SharePoint site for the TRM that includes draft submission dates, comment due dates, EEIP meetings, and the date for filing the final versions. Final versions are then made available on the PUCT website and Texas Efficiency website[1], as well as the EM&V SharePoint website. The publication dates for each version of the TRM indicate the date that the TRM is expected to be approved by Commission staff. The TRM will be submitted to EUMMOT for review at least one month before the publication date. An EEIP meeting will be held annually for the presentation of key changes, providing a forum for questions and comments. The application of the TRM version for program year planning and evaluation is indicated below.

[1] Texas Efficiency: https:// http://www.texasefficiency.com/.

Table 1. TRM Rollout and Applicability to Utility Plans and Program Evaluation

TRM version and filing date	Program year for which TRM is used[2]	Program year plan filing date	Program year evaluation report date	Notes/comments
TRM v1.0 Dec 2013	PY2014	April 2013	June 2015	Inventory/summary of current deemed savings approaches and differences; Foreshadowing of any anticipated changes for TRM 2.0 and 3.0
TRM v2.0 April 2014	PY2015 planning	April 2014	n/a	First version with EM&V team recommended changes, intermediate/interim/accelerated version
TRM v2.1 January 2015	PY2015 implementation	April 2014	June 2016	Revised version of TRM v2.0 with clarifications and new measures approved by the Commission
TRM v3.0 April 2015	PY2016 planning	April 2015	n/a	Includes savings updates and EM&V protocols
TRM v3.1 November 2015	PY2016 implementation	April 2015	June 2017	Updates for PY2016 implementation identified after v3.0 filing
TRM v4.0 October 2016	PY2017	April 2016	June 2018	Addressed additional updates identified as part of the annual TRM prioritization process and PY2015 EM&V
TRM v5.0 October 2017	PY2018	April 2017	June 2019	Integrated new measures filed with the PUCT and addressed additional updates identified as part of the annual TRM prioritization process and PY2016 EM&V
TRM 6.0 October 2018	PY2019	April 2018	June 2020	Integrated new measures filed with the PUCT and addressed additional updates identified as part of the annual TRM prioritization process and PY2017 EM&V
TRM 7.0 October 2019	PY2020	April 2019	June 2021	Integrated new measures filed with the PUCT and addressed additional updates identified as part of the annual TRM prioritization process and PY2018 EM&V
TRM 8.0 November 2020	PY2021	April 2020	July 2022	Integrated new measures filed with the PUCT and addressed additional updates identified as part of the annual TRM prioritization process and PY2019 EM&V
TRM 9.0 November 2021	PY2022	April 2021	July 2023	Integrated new measures filed with the PUCT and addressed additional updates identified as part of the annual TRM prioritization process and PY2020 EM&V

[2] The TRM applies to measures completed within the program year specified. However, if a measure is approved in a prior program year and not completed, the TRM version effective at project approval may be used to ensure initial incentive estimates.

3. WEATHER DATA FOR WEATHER-SENSITIVE MEASURES

The normalized deemed savings estimates for many weather-sensitive energy-efficiency measures are developed with simulation models that use Typical Meteorological Year (TMY) data. Both TMY2 and TMY3[3] weather data are used in the current savings estimates. To create TMY data, a single, typical meteorological year is selected and assembled from 15 to 30 years of historical data. Whole months of actual year weather data that represent average weather for that month over the historical period are selected from the entire range and merged to create the TMY weather file. As such, the TMY data set represents typical rather than extreme conditions, and it is intended to represent the range of weather phenomena specific to that location with annual averages that are consistent with the location's long-term weather conditions. The TMY data sets are produced by the National Renewables Energy Laboratory's (NREL) Electric Systems Center under the Solar Resource Characterization Project, which is funded and monitored by the U.S. Department of Energy's Energy Efficiency and Renewable Energy Office. This data represents typical rather than extreme conditions. The TMY3 data sets are the third generation of TMY files and are based on more recent and accurate data and use a different format than previous versions. They are derived primarily from the 1991 to 2005 National Solar Radiation Data Base (NSRDB) archives. Going forward, only TMY3 data sets will be used.

The TMY3 data sets include the following hourly values of solar radiation and meteorological elements:

- dry bulb and wet bulb temperature
- relative humidity
- wind speed and direction
- cloud cover, and
- multiple solar radiation values.

Energy and demand savings for weather-sensitive measures are typically estimated using building simulation modeling as it can produce hourly energy consumption estimates by applying location-specific historical weather information contained in the TMY files.

3.1 TRM CLIMATE ZONES/REGIONS

For the simulation of savings estimates for weather-sensitive energy residential efficiency measures, there are currently five TMY3 files (weather stations) that are used to represent the areas served by the Texas electric utilities.[4] The nonresidential savings estimates are derived from five separate weather stations using TMY3 weather. The five TRM climate zone/regions and their representative weather station city locations are shown in Table 2. For the application of the energy and demand savings developed on this basis, the TRM climate zones/regions are mapped to Texas counties. This mapping is represented visually in Figure 1 and available in table format on the Texas Efficiency website.[5]

---

[3] TMY3 data sets are publicly available at: http://texasefficiency.com/index.php/regulatory-filings/deemed-savings.

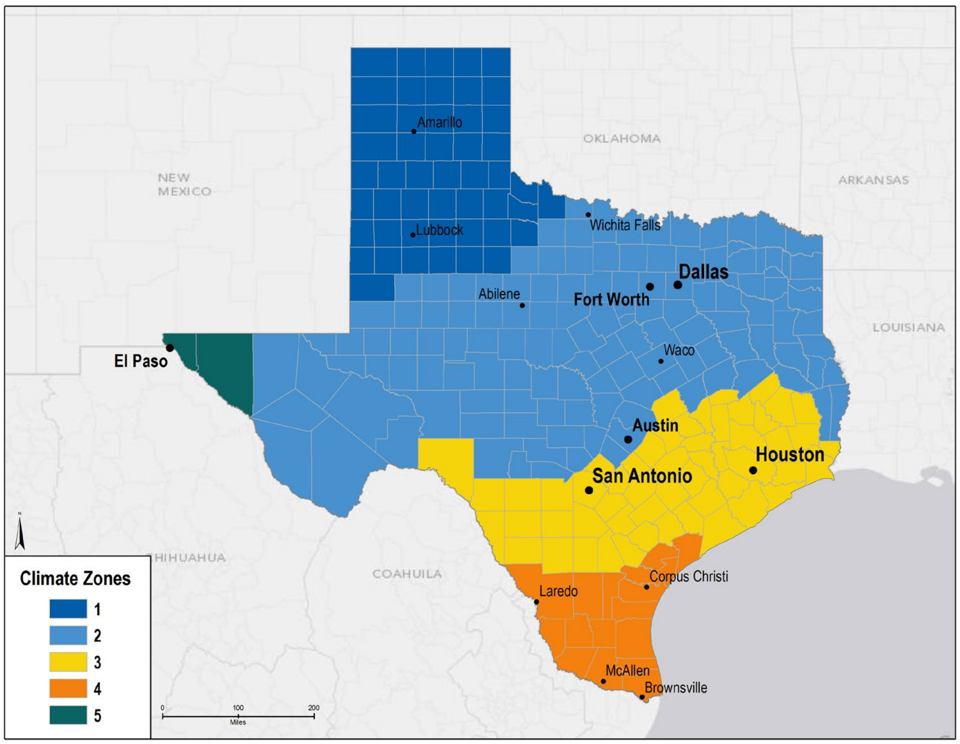
[4] The TRM climate zone/regions and county-level assignments were created and are currently maintained by Frontier Energy for the Electric Utilities Marketing Managers of Texas (EUMMOT).

[5] Available for download on Texas Efficiency website: http://texasefficiency.com/index.php/regulatory-filings/deemed-savings.

Table 2. Texas TRM Climate Zones

Representative city	TRM climate zone	TRM region name	Representative weather station
Amarillo, TX	1	Panhandle	Amarillo International Airport [Canyon - UT]
Dallas, TX	2	North	Dallas/Fort Worth International Airport
Houston, TX	3	South	George Bush Intercontinental Airport
Corpus Christi, TX	4	Valley	Corpus Christi International Airport [UT]
El Paso, TX[6]	5	West	El Paso International Airport [UT]

Figure 1: TRM Climate Zone Assignments by County



[6] El Paso Electric may treat residents of Van Horn, TX in Culberson County as climate zone 5 even though the rest of the county is classified as climate zone 2.

3.2 HISTORY AND STATUS OF WEATHER STATION APPLICATIONS

For residential measures, Frontier Energy initially used four climate zones for deemed savings development in Texas. They were Houston, Dallas/Fort Worth (DFW), Amarillo, and South Texas, loosely aligned with the contours of reasonable Texas climate zones and population centers of the largest IOUs (CenterPoint, Oncor, Xcel/SPS, and AEP-TCC, respectively). AEP-SWEPCO (NE Texas) and AEP-TNC (Abilene) used the deemed savings developed from the Dallas-Fort Worth (DFW) weather data. Entergy used Houston deemed savings, and TNMP used either the DFW or Houston deemed savings, depending on the relevant service territory. When El Paso Electric (EPE) was added to the Energy Efficiency Rule, EPE initially used the deemed savings that had been developed for the DFW region. That is, deemed savings for El Paso weather data were not regenerated for older measures; those measures continued to use the Dallas/Fort Worth values for the EPE service area. However, when deemed savings for newer measures were developed, the El Paso climate zone was added.

In addition, weather stations, other than the five weather stations currently used for residential measures, have been used for nonresidential measures, especially for savings estimates not developed by Frontier Energy. The result is that there are currently six different weather stations used by the TRM residential and nonresidential measures, as summarized in Table 3 and Table 4. Furthermore, some of the deemed savings estimates use TMY2 weather data rather than the latest TMY3 data.

These were defined and should be used for all weather-sensitive measures going forward.[7]

Table 3. Weather Station Codes

Weather station code	Weather station city location
AMA	Amarillo
DFW	Dallas/Fort Worth
HOU	Houston
CRP	Corpus Christi
MCA	McAllen
ELP	El Paso

Table 4. Summary of Weather Files Used for Energy Efficiency Measures

Sector	Measure ID	Weather station code (region)					
		AMA (1)	DFW (2)	HOU (3)	CRP (4)	MCA (4)	ELP (5)
Residential	All measures	1	1	1	1	–	1
Nonresidential	Lodging guest room occupancy sensor controls	1	1	1	–	1	1
Nonresidential	All measures	1	1	1	1	–	1

[7] There may always be exceptions for calculators and modeling tools that serve the national market, such as ENERGY STAR® calculators, which typically have a more limited selection of weather stations available.

4. PEAK DEMAND DEFINITIONS

P.U.C. SUBST. R. 25.181 defines peak demand, peak demand reduction, and the peak period for the Texas energy efficiency programs (16 TAC § 25.181 (c) (44) (45) (46)). This section summarizes the Electric Utilities Marketing Managers of Texas' (EUMMOT) and EM&V team's agreed-upon approach to calculate peak demand savings across measures using methodologies guided by these definitions. Beginning with TRM 4.0, the approach described in this section has been used to estimate demand savings for updates to existing measures and as new measures have been added to the TRM.

4.1 OVERVIEW

This section of the TRM achieves two purposes: 1) presents an overview of the approach to establish the summer peak hours/window and winter peak hours/window to be used for calculating the peak demand reduction or CF for measures, and 2) provides clear guidance to calculate peak demand reduction and CFs based on these established winter and summer peak hours/windows.

The end objective is to have a consistent approach to estimate peak demand reductions across measures. Additionally, demand reduction estimates for measures submitted through the petition process will also be reviewed for consistency with the approach.

4.2 APPROACH TO IDENTIFYING PEAK HOURS

This section describes the probability-based method developed to identify when utility system peaks (referred to as system peak coincident demand) occur in each of the TRM climate zones for use in estimating summer and winter peak demand reduction attributable to the implementation of energy efficiency measures. This approach is summarized in two steps:

1) Identify how individual utility territories map to the TRM climate zones for which savings are presented[8]
2) Establish the predicted peak hours in each season for each utility (i.e., summer, winter), using a regression model and historical utility and ERCOT load data to estimate a relationship between hourly energy use in TRM climate zone-specific peak hours and a set of explanatory variables (e.g., temperature, time of day)

4.2.1 Mapping Weather Zones to Utility Service Areas

Historical utility system load data are required to estimate peak hours. To identify the utility-specific peak hours, the load data needs to align with weather zones that correspond to specific utility service areas. Several issues complicate this process:

- The TRM delineates the weather stations used to represent a TRM Climate Zone.

[8] See TRM Vol.1 Section 3 for more detail on TRM climate zone definitions and how they map to city/weather zone/region.

- Utility system load data to be mapped to TRM Climate Zones are available from several sources:
  - ERCOT—publicly available through ERCOT, this data is specific to ERCOT Weather Zones, which then need to be aligned with TRM Climate Zones and utility service areas
  - Utility-Specific—in several cases, load data was provided by specific utilities (i.e., Climate Zone 1 and 5 data was provided by Xcel and El Paso, respectively)
- Some climate zones match well with a specific utility territory, while other climate zones encompass numerous utilities (some of which are outside the ERCOT market). Another way to put this is that many utilities do not lie within a single TRM Climate Zone, which adds complexity to the alignment effort.
- Not all utility systems within a given climate zone may reach their respective peak loads at the same interval and hour due to the composition of their customer base. Since the EE Rule and definition of peak demand reduction adopted here require consideration of *utility-specific peak demand*, this introduces another challenge to determine the appropriate peak period.

To determine the most appropriate mapping between available electric system load data and weather zone, Frontier Energy performed a correlation and ranking analysis. First, the analysis considered how well ERCOT-wide load peaks in demand (using the top 20 hours per season) correlated with load across the different weather zones within ERCOT territories.[9] Secondly, Frontier analyzed ERCOT-specific peaks and how well those correlated with utility-specific service territories. For ERCOT utilities, service areas more closely corresponded to specific ERCOT Weather Zones geographically (e.g., Oncor to the Central Zone, CenterPoint to the Coastal Zone).[10] For several non-ERCOT utilities (i.e., Entergy, SWEPCO), Frontier conducted a similar analysis using utility-specific system load data to determine whether their system peaks coincided with those of neighboring ERCOT Weather Zones.

Based on this analysis, the identification of peak demand hours using ERCOT weather zone load data provides a reasonable approximation to the peak demand hours for the utility systems within those zones.[11] Among non-ERCOT utilities, utility load data was provided for Xcel/SPS and El Paso Electric, which most appropriately mapped to TRM Climate Zones 1 and 5, respectively. For SWEPCO and Entergy, a high correlation with neighboring ERCOT zones obviated the need to establish separate TRM Climate Zones for these utility systems and supported the application of ERCOT Weather Zones as a proxy.

Table 5 provides a summary of this mapping effort, with additional details available in the *Approach to the Estimation of Peak Demand Reduction*.[12]

---

[9] Participating ERCOT utilities include AEP TCC, AEP TNC, CenterPoint, Oncor, and TNMP.

[10] ERCOT's weather zones are designed to represent geographical regions where climate and residential load patterns tend to be similar. Utility service area boundaries are also taken into account in their construction. See *ERCOT Load Profiling Guide*, Section 13: Changes to Weather Zone Definitions, October 1, 2010, at http://www.ercot.com/mktrules/guides/loadprofiling/current

[11] Each of the correlation relationships examined through this study found to be stronger in the summer than in the winter months.

[12] Available at: http://www.texasefficiency.com/index.php/regulatory-filings/deemed-savings.

Table 5. TRM Climate Zone Mapping to Utility Service Area

TRM climate zone	TRM region name	Representative city	Utilities serving within each zone	Mapping to electric system load data
1	Panhandle	Amarillo	AEP TNC, Xcel/SPS, SWEPCO	Outside ERCOT (using system load data from Xcel/SPS)
2	North	Dallas	AEP TNC, Entergy, Oncor, TNMP, SWEPCO	Sum of load data from five ERCOT zones: Far West, West, North, North Central, East
3	South	Houston	AEP TCC, CenterPoint, Entergy, TNMP	ERCOT's Coast Weather Zone
4	Valley	Corpus Christi	AEP TCC	ERCOT's Southern Weather Zone
5	West	El Paso	El Paso Electric	Outside ERCOT (using system load data from El Paso)

4.2.2 Identifying the Most Probable Hours for System Peaks

This estimation approach involves identifying a set of hours within the PUCT EE rule-defined summer and winter peak demand periods during which utilities' system peaks are likely to occur. Given the variability in when peaks occur, identifying several potential peak hours provides a better chance of estimating the actual peak than an approach that relies on a single hour. Frontier Energy determined that using the 20 most probable hours for this estimate (based on a regression of historical load data) provides a sufficient range of hours to assign the highest probability of being within the set of actual peak hours.

To estimate the top 20 hours most likely to be summer and winter peak hours, a logistic regression (referred to here as *peak probability analysis* (PPA)) was performed using weather data and the historical load data previously discussed. To estimate summer and winter peak probabilities for the five different TRM climate zones, typical meteorological year (TMY) weather data were used from five Texas weather station locations, noted above in Table 3. Parameter estimates from the logistic regression were applied to the TMY data for each location to estimate each hour's probability of being a peak demand hour and identify the 50 hours for each peak demand season (summer and winter) in the TMY3 datasets with the highest probability of being a peak hour.

While the objective of this approach is to develop a set of the top 20 hours, models need to produce probabilities for more than 20 hours to ensure some of these hours do not effectively occur over non-weekdays when TMY data are used in evaluating load patterns that have calendar-dependent components (differences in usage on weekdays vs. holidays and weekends). In the summer, utility system peaks typically occur on weekdays; moreover, the PUCT rule excludes holidays and weekends from the peak period. TMY data is a time series of observed climate data, which is entirely independent of the day of the week on a given observation. However, when the TMY data is used in practical applications (e.g., building simulation modeling), occupancy and operation patterns that reflect actual differences in weekday and weekend energy use are super-imposed on the climate data, with a specific calendar year. The selected calendar year determines the weekday/weekend/holiday framework for the weather data. To ensure a minimum of 20 probable peak hours could be identified for any given model year (January 1 start date) after removing hours that fall on weekends, Frontier Energy determined that sets of 50 hours were required.

The logistic regression model uses hourly load data sets for several historical years (the models in this analysis used system load data from 2007 through 2014) to estimate the relationship between setting a peak in a given hour and a set of explanatory variables, including temperature variables and dummy variables representing time-of-day and month-of-year. The hourly load data reflects the geographical areas depicted in Table 3, while the weather data correspond to the representative weather stations of those TRM Climate Zones.

The regression assigns marginal probabilities to changes in the explanatory variables. Given the estimated relationship between each peak hour and the explanatory variables, a probability is calculated for setting a peak in a given hour based on the temperature in that hour from the TMY weather data and the month in which it occurs and which hour of the day it is.

Within section 4.8, Table 10 through Table 19 summarize the 50 highest probability summer and winter peak hours for TRM Climate Zones 1 through 5 in the TMY3 datasets for the weather stations specified in Table 3.

4.3 ESTIMATING PEAK COINCIDENT DEMAND REDUCTIONS

The approach to identifying system peak hours described in section 4.2 provides a basis for estimating peak coincident demand reductions attributable to the implementation of energy efficiency measures in Texas. Individual measures can select the highest peak reduction between “summer” and “winter” peak periods. When multiple measures are installed, systems that interact require that the system use the same peak hour definitions for each individual calculation of saving. This is based on measure-specific load during the identified peak hours according to section 4.2.2 and presented in Table 10 through Table 19.

This section explains the “PDPF top 20 hours method” to calculate demand reduction. The calculation process identified the probable peak hours and estimates peak coincident demand savings for four kinds of measure load conditions: (1) those developed using hourly building simulation models, (2) those for which annual energy savings can be estimated, and for which normalized load shapes are available, (3) those based on field data from M&V monitoring of equipment energy use, and (4) whole building M&V energy model. Several approaches may be used to determine measure load; the following four examples are meant to demonstrate how those measured load results can be applied to derive reportable electricity demand reductions in Texas.

Using Building Simulation Models (for Weather-Sensitive Measure Impacts)

In some cases, deemed savings are estimated using building simulation models, which estimate the hourly energy use from implementing energy efficiency measures (i.e., modeling the difference between base and change case). When simulation models are run using the TMY3 datasets from the weather stations specified in Table 3, peak demand reductions can be estimated by determining the appropriate top 20 of 50 hours available for the climate zone in question (from one of Table 10 through Table 19). The 20 hours to be used are selected from the appropriate set of 50 hours according to a two-step process:

1. Assign a day of the week for each of the 50 hours according to the day it would have fallen on in the simulation model and screen out all hour intervals falling on weekends.
2. Sort the remaining weekday intervals in descending order of probability and select the top 20 hours.

Once the appropriate set of 20 probable peak hours has been identified, the PDPF top 20 hours method can be used to calculate the demand reduction. The unadjusted hourly kW savings from the simulation models in each of those intervals are paired with that hour's peak demand probability factor (PDPF). The final attributed demand savings should be estimated as the probability-weighted average using the PDPF factors of the hourly demand reductions estimated in each of those 20 hours.

PDPF top 20 hours method Example 1: Measures Using Building Simulation Models

<u>*Analysis Scenario*</u>: High-efficiency commercial air conditioning unit installed in TRM climate zone 4.

Step 1: Run the base and change case simulation models to generate 8,760 hourly simulation results

a) Use TMY3 data corresponding to the Corpus Christi International Airport weather station (as shown in Table 2) from the National Renewable Energy Laboratory (NREL) website: https://nsrdb.nrel.gov/data-sets/archives.html[13]
b) Run the building simulation model with the selected TMY3 weather data and assign a *calendar year*

Step 2: Calculate the ***summer peak demand savings***.

a) Use the PPA results in Table 13 to identify the top 20 weekday hours and associated peak demand probability factors from the 8,760 hourly simulation model output as follows.
    i. Based on the calendar year used for every value in the table, assign each record a weekday or weekend/holiday flag based on the day in the month/day/hour value.
    ii. Select the top 20 *weekday* records. Separate weekdays from weekends and select the top 20 weekday hours by ranking the weekdays according to the *peak demand probability factor* in the last column of the PPA table (highest to lowest). The month/day/hour combinations provide the specific intervals for which hourly demand reductions should be extracted from the 8760-building simulation output and used to calculate the *summer peak demand* values.

[13] See User's Manual for TMY3 Data Sets for more information: http://www.nrel.gov/docs/fy08osti/43156.pdf.

b) Calculate the claimed coincident summer peak demand reduction by taking the probability-weighted average of the hourly demand reduction estimates from the models, as shown in the following equation:

$$Peak\ Demand\ Savings\ (kW) = \frac{\sum_{hr=1}^{20} PDPF\ \times\ Unadjusted\ Peak\ Demand\ Reduction}{\sum PDPF}$$

Equation 1

Table 6 provides an example calculation for a simulation model run for TRM climate zone 4, in which the simulation was run for calendar year 2006 (January 1 = Sunday).

Table 6. Example of Probability-Adjusted Summer Coincident Peak Demand Calculation Using Hourly kW from Simulation Model Results

Month	Day	Hour ending	Relative probability PDPF	Unadjusted peak demand reduction (kW)	PDPF x peak demand reduction
8	18	16	0.380	4.31	1.64
8	9	17	0.305	4.35	1.33
8	9	16	0.302	2.95	0.89
8	7	17	0.247	4.11	1.02
8	15	17	0.247	3.33	0.82
8	16	17	0.247	4.02	0.99
8	10	17	0.247	3.18	0.79
8	7	16	0.234	4.00	0.94
8	15	16	0.234	3.05	0.71
8	16	16	0.234	4.41	1.03
8	10	16	0.234	3.22	0.75
8	17	16	0.234	3.75	0.88
6	7	17	0.232	4.23	0.98
8	9	15	0.201	3.73	0.75
8	8	17	0.188	3.70	0.70
8	17	17	0.188	3.97	0.75
8	4	17	0.188	4.13	0.78
8	11	17	0.188	4.20	0.79
8	18	17	0.188	4.37	0.82
8	4	16	0.186	3.01	0.56
			4.71	***Totals***	***17.91***
Probability-Weighted Peak Coincident Demand Reduction (kW)					**3.81**

Step 3: Calculate the ***winter peak demand*** savings using the values in Table 18. Use the same approach described above for calculating summer peak demand savings.

Step 4: Report the ***claimed peak demand*** value. Depending on the measure, either a summer peak or a winter peak demand (usually the higher of the two) shall be reported as the c*laimed peak demand* value. The basis for the value reported (summer or winter hours) also needs to be reported (identified).

For this approach to be valid, the simulation models must use the same TMY3 datasets for which the peak hours were identified by applying the relationships developed with the logistic regressions as specified in Table 2.

Using Normalized Load Shapes (for Non-Weather-Sensitive Measure Impacts)

Many deemed savings are estimated without using TMY3 data. For certain measures (particularly measures that are not weather-sensitive, such as residential lighting or appliance measures), peak demand reductions have typically been estimated as a function of annual energy savings estimates using a coincidence factor (i.e., ratio demonstrating the measure-specific load at the time of a utility system peak). For these measures, a method is presented to maximize the use of the available information and what is known about the probability of peaks occurring in given hours of the summer and winter peak demand periods.

The PDPF top 20 hours method requires having – or developing – hourly load shapes for the savings produced by the measure in question, reflecting the hourly fluctuations in their effects on energy usage. For some measures, it may only be feasible (or necessary) to produce a single hourly load shape reflecting the hourly distribution of the measure's impacts on any day of the year. For other measures, it may be feasible/more appropriate to develop hourly load shapes for each month of the year (for instance, the load shapes available in the Building America Analysis (BAA) spreadsheets are modified by monthly factors reflecting monthly variations in usage. These BAA load shapes are used to estimate the demand savings for residential lighting and appliance measures).[14] Because regression analysis provides information about the importance of both the hour of the day and the calendar month in which a given hour falls, both pieces of information should be used in estimating peak demand reductions when the data are available.

The PDPFs developed for the 8,760 intervals in each climate zone's TMY3 data provide a reasonable guide to the likelihood of a system peak demand in a given hour or month-hour combination within the summer or winter peak demand periods, which can be applied for estimating coincident peak demand savings for these non-TMY3 based measures. The PDPF estimated for every interval (representing month-day-hour combinations) is driven by the temperatures associated with those intervals in the TMY3 data.

The PDPFs for the 20 intervals identified as having the highest probability of producing utility system peak demand in each TRM climate zone can be aggregated for each hour or month-hour combination from the peak probability analysis results provided in Table 10 through Table 19. This is accomplished by summing the PDPFs for each TRM climate zone according to the

[14] Hourly and monthly residential load shapes are available from the National Renewable Energy Laboratory's 2014 Building America House Simulation Protocols and associated analysis spreadsheets. See NREL website for more information: https://www.nrel.gov/docs/fy14osti/60988.pdf.

number of times that hour (or month-hour combination) is repeated in the 20 most probable peak hours.[15] The result of aggregating relative probabilities by hour or month-hour pairs from the top 20 hours in the PDPF tables is presented in Table 20 through Table 29 for measures with a single load shape for the whole year and in Table 30 through Table 39 for measures with hourly load shapes varying by month.

PDPF top 20 hours method Example 2: Measures Using Normalized Load Shapes

Analysis Scenario: Residential efficient lighting measures in TRM Climate Zone 2, corresponding to TMY3 weather data for Dallas (as shown in Table 2).

Step 1: Identify the appropriate lighting end-use load shape for this analysis

a) Setting aside the possibility of generating an 8,760 hourly end-use load shape through simulation modeling, for this example, we draw from the NREL 2014 Building America House Simulation Protocols and associated spreadsheets.[16]

Step 2: Calculate the ***summer peak demand***.

a) Identify the peak hours or month-hour combinations from the appropriate table and associated PDPFs.
    i. The load shape for residential lighting in the Building America analysis spreadsheet has both hourly and monthly components, so the appropriate reference table for determining the summer peak demand reduction for TRM climate zone 2 for this example is Table 31.
    ii. When the best available data are hourly load shapes that do not vary across the year (e.g., by month), then select the appropriate tables for summer and winter peaks for the TRM Climate Zone in question from among Table 20 through Table 29 and apply the below-described methodology (absent the monthly modifications).

b) For each month and hour ending identified in the PDPF tables (in this case, Table 31), obtain the hourly PDPF values for the peak hours, and from the source load shape (in this case, the Building America analysis spreadsheet), select the monthly shares of annual load for the peak months.
    i. When working with monthly shares of annual load—as in this example, the daily share of the monthly load must also be calculated (as simply the reciprocal of the number of days in the month)

---

[15] Note that in working with load shapes we revert to not having information about whether a given peak interval would be on a weekend. As such, for this analysis the top 20 hours are simply the 20 hours of highest probability selected from the 50 hours identified in the PPA tables.

[16] The BA Analysis Spreadsheets can be downloaded at this address: http://energy.gov/eere/buildings/building-america-analysis-spreadsheets.

c) Estimate the Hourly Share of Annual Load (values in rows 1-7 of column H in Table 7) for each of the month-hour ending combinations by multiplying the three values identified in the previous step
    i. Multiply the hourly share of daily load (in column E) by the monthly share of annual load (column F) and the daily share of monthly load (column G). ((cell H1 in Table 7 below is calculated by multiplying cells E1 x F1 x G1 or 0.015 x 0.058 x 0.032 = 2.82×10^{-5}).

d) Calculate the *Probability Weighted Peak-Coincident Load Share* (column H row 8 of Table 7) by taking the product of each hour's *relative probability* (column D) and the *Hourly Share of Annual Load (in column H) and then taking the sum of each of these products.*

e) Calculate the *summer peak demand savings* (in cell H10) by multiplying the estimated *annual energy savings* (value in cell H9, Table 7) by the *probability-weighted peak-coincident load share* (value in cell H8).

Table 7. Example of Probability-Adjusted Summer Peak Demand Calculation Using Load Shapes

(A) Row	(B) Month	(C) Hour ending	(D) Relative probability PDPF	(E) Hourly share of daily load	(F) Monthly share of annual load	(G) Daily share of monthly load	(H) Hourly share of annual load
1	7	16	0.257	0.015	0.058	0.032	2.82E-05
2	7	17	0.244	0.056	0.058	0.032	1.05E-04
3	7	15	0.153	0.026	0.058	0.032	4.89E-05
4	8	15	0.131	0.026	0.065	0.032	5.49E-05
5	8	16	0.095	0.015	0.065	0.032	3.17E-05
6	8	17	0.070	0.056	0.065	0.032	1.18E-04
7	7	18	0.050	0.078	0.058	0.032	1.47E-04
8	***Probability Weighted Peak Load Share***						***6.62E-05***
9	***Annual Energy Savings (kWh)***						***800***
10	***Summer Peak Demand Savings (kW)***						***0.053***

When the best available data are hourly load shapes that do not vary across the year (e.g., by month), calculation of the hourly share of annual load (the values in column H of Table 7) is greatly simplified: divide the load shape values by 8,760, the number of hours in a year.

Step 3: Calculate the ***winter peak demand*** by repeating the procedure outlined in Step 2 using the appropriate table of winter peak hours and relative probabilities for the climate zone in question (in this case, Climate Zone 2).

Step 4: Report the ***claimed peak demand savings*** value.

a) Depending on the measure, either the summer peak or winter peak demand reduction would be used (usually the higher of the two) as the c*laimed peak demand reduction* value. The basis for the value (summer or winter hours) would also need to be reported.

Estimating Coincident Peak Demand Impacts with Field Data from M&V Activities (for Non-Weather-Sensitive Measure Impacts)

Depending on the nature of a given project, field data collection periods for estimating annual energy savings and peak demand reductions may vary. While field data collected during the summer and winter peak months is preferable for estimating summer and winter peak demand reductions (respectively), field data is not always collected during these periods. For projects or measures affecting loads that are not weather-driven, peak demand impacts can still be estimated using the PDPF top 20 hours method.

Sufficient field data should be collected to allow for the construction of an hourly load shape that characterizes the fluctuations in the energy savings being produced by the implemented measure over the appropriate period.

PDPF top 20 hours method Example 3: Measures Estimating Peak Demand Impact with Field Data from M&V Activities (for Non-Weather-Sensitive Measure Impacts)

<u>Analysis Scenario</u>: A 200 horsepower pump motor for an industrial process is retrofitted with variable speed controls. The business operates 12 hours per day, Monday through Friday, closed weekends, and holidays. Pump motor field metering data below provides the following hourly kW reduced profile for a typical work week or billing hour KW load reductions. This customer is located in TRM climate zone 4, corresponding to TMY3 weather data for Corpus Christi (as shown in Figure 2) (summer peak hours are highlighted in Figure 2).

Figure 2: Example 3 Sample of Hourly kW Savings for VFD Controls Application

Demand Reduction Profile for VFD on 600 Hp Motor - Variable Operations 12 hour per day Monday - Friday																								
Day/Time	0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00
Sunday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Monday	0	0	0	0	0	0	0	150	550	550	550	550	550	550	550	550	400	400	400	50	0	0	0	0
Tuesday	0	0	0	0	0	0	0	90	126	126	126	126	126	126	126	126	126	0	0	0	0	0	0	0
Wednesday	0	0	0	0	0	0	0	39	63	63	63	63	63	63	63	63	63	225	225	50	0	0	0	0
Thursday	0	0	0	0	0	0	0	175	225	225	225	225	225	225	225	225	55	10	0	0	0	0	0	0
Friday	0	0	0	0	0	0	0	85	112	112	112	112	112	112	112	112	112	112	112	50	0	0	0	0
Saturday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Step 1: Estimate the ***summer peak demand reduction***. Create a *probability-adjusted peak demand load savings profile table* (i.e., analysis table) similar to Table 8 below using the appropriate PDPFs for the climate zone, in this case, Table 23.

a) Populate the two left columns of the analysis table (*hour ending* and *relative probability*) with values from the appropriate PPA table (this example uses the hours and relative probabilities from Table 23)

b) Calculate the a*verage hourly demand reduction* for each hour in the analysis table created in Step 1 (for Climate Zone 4, hours ending 15:00, 16:00, and 17:00)
    a. Sum the observed demand savings for each hour and divide by the number of observations for that hour (i.e., observations=5)

c) Calculate each hour's *probability-weighted demand reduction* by multiplying the *relative probability* of peak in each hour by the *average hourly demand reduction* for that hour

d) Calculate the Peak Demand Reduction by summing the hourly Probability-Weighted Demand Reduction values

Table 8. Example 3—Probability-Adjusted Summer Peak Demand Calculation Using Load Savings Profile (from field data)

Hour ending	Relative probability PDPF	Average hourly demand reduction (kW)	Probability-weighted peak hour demand reduction (kW)
17	0.481	153.7	73.9
16	0.478	108.0	51.6
15	0.041	106.7	4.4
Total Probability Weighted Peak Hours Demand Savings (kW)			***129.9***
Summer Peak Demand Savings (kW)			***129.9***

Step 2: Calculate the ***winter peak demand reduction*** by repeating the procedure outlined in Step 1, but using the appropriate table of winter peak hours and relative probabilities for the climate zone in question from among Table 15 through Table 19 (in this case, Table 18).

Step 3: Report the ***claimed peak demand*** value. Depending on the measure, either the summer peak or winter peak demand reduction would be used (usually the higher of the two) as the c*laimed peak demand reduction* value. The basis for the value (summer or winter hours) would also need to be reported.

PDPF top 20 hours method Example 4: Measures Using Billing Analysis: Whole Building Energy Model

<u>*Analysis Scenario*</u>: Multiple energy efficiency measures are installed at a commercial facility, and the energy savings is developed using IPMVP option C from utility data. Following IPMVP option C guidance, a regression model[17] is developed to determine hourly normalized utility data for both the pre- and post-install periods. Annual energy savings is completed using the regression models to estimate the annual consumption based on TMY3 weather files and building occupation. This customer is in TRM climate zone 3, corresponding to TMY3 weather data for Houston (as shown in Figure 2).

Step 1: Review energy consumption regression model results for both the pre- and post-install periods to determine if it is applicable to the hourly consumption during the times around the peak demand periods for the site. Regression models are developed to estimate the energy consumption for the majority of conditions, but a peak period is intended to be outside the conditions where the regression model is designed to be relevant. An alternate regression model for the peak demand is required when the measured peak demand varies from the modeled peak demand at the high and low measured temperature[18] period by greater than 20%.

[17] The regression model may have multiple dependent factors including weather, occupancy, or production. See Volume 4 for further discussion of development of regression models.

[18] Or other regression model-dependent variables

Step 2: Calculate the ***summer peak demand savings***.

a) Use the PPA in Table 12 to identify the top 20 hours and associated peak demand probability factors. Since the regression model normalized output is not associated with an actual year, the top 20 hours are applicable, and all variables can be set to the normal peak operations that would typically occur.

b) Calculate the claimed coincident summer peak demand reduction by using the regression model in combination with the hourly temperature and hourly maximum operating profile to calculate the modeled hourly consumption.

c) For this example, the following regression models are used:

$$PreInstall\ Demand\ (kW) = 155 + 3.2\ x\ CDT65$$

Equation 2

$$PostInstall\ Demand\ (kW) = 175 + 0.85\ x\ CDT65$$

Equation 3

$$Peak\ Demand\ Savings\ (kW) = \frac{\sum_{hr=1}^{20} PDPF\ x\ (PreInstall\ Demand - Postinstall\ Demand)}{\sum PDPF}$$

Equation 4

Table 6 provides an example calculation for the regression model run for TRM climate zone 3, where CDT65 is equal to the temperature (°F) minus 65.

Table 9. Example of Probability-Adjusted Summer Coincident Peak Demand Calculation Using Regression Model Results

Month	Day	Hour ending (CDT)	Hourly temperature	Relative probability PDPF	Regression model pre-install	Regression model post-install	Regression model peak demand reduction	PDPF x peak demand reduction
8	1	17	102.92	0.92938	276.34	207.23	69.11	64.23
8	2	17	102.92	0.92938	276.34	207.23	69.11	64.23
8	1	16	102.92	0.918911	276.34	207.23	69.11	63.51
8	2	16	102.02	0.865717	273.46	206.47	67.00	58.00
8	3	16	100.04	0.650841	267.13	204.78	62.34	40.58
8	2	18	102.02	0.575415	273.46	206.47	67.00	38.55
8	4	17	98.96	0.523849	263.67	203.87	59.81	31.33
8	12	17	98.96	0.523849	263.67	203.87	59.81	31.33
8	4	16	98.96	0.486478	263.67	203.87	59.81	29.09
8	5	16	98.96	0.486478	263.67	203.87	59.81	29.09

Month	Day	Hour ending (CDT)	Hourly temperature	Relative probability PDPF	Regression model pre-install	Regression model post-install	Regression model peak demand reduction	PDPF x peak demand reduction
8	29	16	98.96	0.486478	263.67	203.87	59.81	29.09
8	1	15	100.94	0.425501	270.01	205.55	64.46	27.43
8	2	15	100.94	0.425501	270.01	205.55	64.46	27.43
8	4	15	100.94	0.425501	270.01	205.55	64.46	27.43
8	1	18	100.94	0.40785	270.01	205.55	64.46	26.29
8	9	17	98.06	0.384956	260.79	203.10	57.69	22.21
8	11	17	98.06	0.384956	260.79	203.10	57.69	22.21
8	29	17	98.06	0.384956	260.79	203.10	57.69	22.21
8	10	16	98.06	0.350206	260.79	203.10	57.69	20.20
8	12	16	98.06	0.350206	260.79	203.10	57.69	20.20
Total PDPF =				***10.9164***	***Total =***			***694.64***
Probability-Weighted Peak Coincident Demand Reduction (kW)								***63.63***

Step 3: Calculate the ***winter peak demand*** savings using the values in Table 17. Use the same approach described above for calculating summer peak demand savings.

Step 4: Report the ***claimed peak demand*** value. Depending on the measure, either a summer peak or a winter peak demand (usually the higher of the two) shall be reported as the *claimed peak demand* value. The basis for the value reported (summer or winter hours) also needs to be reported (identified).

4.4 CONSISTENCY WITH EE RULE

Total System Peak versus Residential and Commercial Class Peaks

A literal reading of the “goal” language in the EE rule (16 TAC 25.181) suggests that peak hours should coincide with residential and commercial peak loads rather than total system loads. Total system peak data is used in these calculations for the following reasons:

- Residential and commercial load data cannot be obtained for ERCOT utilities that match the PUCT’s definition. ERCOT does not track which customers are served with Manufacturing Tax Exemption Certifications, thus able to “opt-out” from programs by declaring themselves as industrial customers. The “opt-out” industrial customers vary over time for both ERCOT and non-ERCOT utilities.
- ERCOT could subtract customers, with a billing demand of over 700 kW in two months within a 12-month period, from total system load for each ERCOT weather zone, providing an estimate of combined residential plus commercial loads. However:
    - These would not exactly meet the requirements of the rule;

- The data is not publicly available; and
- ERCOT management approval would be required to obtain data prior to September 2013.

Consequently, utility system load data that includes all customers is used in calculations presented here. Since industrial loads tend to be non-weather-sensitive, the use of demand data, including all customers, is not likely to introduce significant error into the calculation. It is assumed that residential and commercial sectors will tend to peak when the aggregate load on the utility system reaches peak.

Furthermore, the estimation of the total system peak is consistent with definitions of peak demand reduction used in system planning and rate design activities.

Modeling Peak Periods Using Historical Load Data

The PPA modeling used to generate the top 50 hours by season, and climate zone relied primarily on load data from 2007 through early 2014. The eight years of load data obtained from ERCOT and the non-ERCOT utilities were sufficient to establish strong regression relationships between load levels and explanatory variables.

Climate Zone Mapping to Utility Service Areas

The EE Rule peak demand definition is specific to demand occurring at a utility's system peak. The approach used to map utility territories to load data and aligning these with TRM climate zones sufficiently approximates utility peak demands given the availability of data; however, it is worth clarifying a few points in this methodology where assumptions were required to meet these criteria.

First, this approach uses available data to approximate peaks occurring in utility service areas. TRM climate zones/regions are the geographic conventions used throughout the TRM to assign weather regions and provide consistency in calculating weather-sensitive impacts for energy efficiency measures. Through the assumptions used in linking utility service areas to specific climate regions, this approach to estimate peak hours (and calculating demand impacts) provides an appropriate approximation for the peak periods of these utility-specific territories.

Second, while TRM climate zones 1 and 5 use utility-specific load data, other climate zones rely on ERCOT load data to approximate peak probabilities (each of which included several utility services areas).

Finally, utility services areas do not always align with specific TRM climate zones, and often these territories will span more than one climate zone. By using participant ZIP codes to map individual utility customers to the appropriate climate zone, utility-specific peak impacts will be tailored to these instances.

4.5 DOCUMENTATION AND TRACKING REQUIREMENTS

When the PDPF top 20 hours method is used, the following information must be specified, tracked, and made available in a centralized location:

- The calendar year used for the analysis (applies only when using building simulation or modeling that overlays weekday and weekend load patterns on hourly data from the TRM climate zone TMY3 files)
- Peak demand season to specify the season basis for the claimed peak demand (i.e., summer, winter)[19]
- Load shapes - all building, end-use, and measure load shapes used for these calculations should be made available in a centralized location (e.g., EUMMOT website), citing data sources

4.6 MULTIFAMILY GUIDANCE

If a multifamily customer is individually metered, savings should be claimed for the residential sector. If a multifamily customer is master-metered, they are a commercial account, and savings should be claimed for the commercial sector. For example,

- Major renovation from multi-metered to individually metered complex. The savings should be claimed in the residential sector since benefits will accrue for residential customers, and the participants are those individual ESIIDS (or another unique identifier).
- Multifamily customers may be considered low-income/hard-to-reach (HTR) customers if they meet eligibility requirements, and savings may be applied to meet low-income/HTR program goals, regardless of meter type (master or individually metered). However, the savings should be claimed in the program that matches the meter type.

4.7 MULTIPLE PROJECT GUIDANCE

If a customer site has multiple projects that have dependent operations, it is acceptable to use multiple PDPF top 20 hours method calculations to determine peak demand reduction, though the attributed peak demand should use only a single peak demand season (winter or summer). If a customer site has multiple projects that have independent operation, the attributed peak demand can utilize different peak demand seasons consistent with equipment operation. For example,

- A project that includes HVAC equipment and a new control system may use the peak demand calculation for the individual HVAC equipment and field data M&V for the controls operation. The claimed peak demand should be the winter peak from both the

[19] While either summer or winter impacts can be used as claimed peak demand savings in relation to savings goals, there is value in having both summer ***and*** winter estimates available for planning purposes. In the process of calculating measure-specific peak demand, it is recommended that estimates of both summer and winter impacts are provided, unless cost prohibitive.

equipment and controls or the summer peak for both equipment and controls. This is because the HVAC equipment and controls operate together as a system.

- A project that includes interior and exterior parking lot lighting may use separate peak demand calculations, and the claimed peak demand may be either summer or winter peak demand independently. This is because the operation of the exterior lighting is based on photocells or other controls that are independent of the operation of interior lighting operating parameters.

4.8 PEAK PROBABILITY ANALYSIS (PPA) TABLES

The following tables provide peak probability factors, by season and TRM climate zone, that map utility service areas to the highest probability peak hours for summer and winter peaks. The PPA tables include the temperature from the TMY3 data file. By inclusion, the other data points from the TMY3 file (relative humidity, precipitation, etc.) for the identified hours may be used for the analysis and modeling. The additional data points are not included in the TRM but can be accessed at http://www.texasefficiency.com/index.php/regulatory-filings/deemed-savings.

Table 10. Highest Probability Summer Peak Hours Using TMY3 Data—TRM Zone 1

Month	Day	Hour ending (CDT)	Hourly temperature	Relative maximum temperature	Relative probability PDPF
7	26	17	98.06	0.980208	0.894782
7	26	16	98.96	0.989204	0.880210
8	13	17	96.08	0.960416	0.878616
7	25	17	96.98	0.969412	0.809068
7	27	17	96.98	0.969412	0.809068
8	13	16	96.08	0.960416	0.777782
7	21	16	96.98	0.969412	0.672027
7	25	16	96.98	0.969412	0.672027
7	27	16	96.98	0.969412	0.672027
8	22	16	95.00	0.949620	0.635575
7	26	18	96.98	0.969412	0.598464
7	21	17	95.00	0.949620	0.541631
7	20	16	96.08	0.960416	0.534168
8	14	17	93.02	0.929828	0.501439
6	25	17	99.68	0.996401	0.471907
8	14	16	93.92	0.938824	0.464966
7	25	18	96.08	0.960416	0.454771
7	26	15	98.06	0.980208	0.450474
8	13	15	96.08	0.960416	0.410981
7	9	17	93.92	0.938824	0.370595
7	31	16	95.00	0.94962	0.363619
8	25	17	91.94	0.919032	0.33385
6	24	17	98.78	0.987405	0.333372
8	25	16	93.02	0.929828	0.327207
7	21	15	96.98	0.969412	0.290011
7	25	15	96.98	0.969412	0.290011
7	27	15	96.98	0.969412	0.290011
6	25	18	100.04	1	0.283900
8	13	18	93.02	0.929828	0.261315
6	24	16	99.32	0.992803	0.255159
6	25	16	99.32	0.992803	0.255159
7	1	17	93.02	0.929828	0.247844
7	20	17	93.02	0.929828	0.247844

Month	Day	Hour ending (CDT)	Hourly temperature	Relative maximum temperature	Relative probability PDPF
7	24	17	93.02	0.929828	0.247844
7	28	17	93.02	0.929828	0.247844
7	31	17	93.02	0.929828	0.247844
7	24	16	93.92	0.938824	0.221617
8	12	17	91.04	0.910036	0.219034
8	22	17	91.04	0.910036	0.219034
8	7	16	91.94	0.919032	0.195066
8	12	16	91.94	0.919	0.195
7	21	18	93.92	0.939	0.172
7	27	18	93.92	0.939	0.172
6	26	17	97.34	0.973	0.165
8	14	15	93.92	0.939	0.148
7	18	17	91.94	0.919	0.141
7	19	17	91.94	0.919	0.141
7	1	16	93.02	0.930	0.137
7	9	16	93.02	0.930	0.137
7	28	16	93.02	0.930	0.137

Table 11. Highest Probability Summer Peak Hours Using TMY3 Data—TRM Zone 2

Month	Day	Hour ending (CDT)	Hourly temperature	Relative maximum temperature	Relative probability PDPF
7	28	16	104.00	1	0.907820
7	28	17	102.92	0.989615	0.814721
7	28	15	102.92	0.989615	0.728393
7	12	17	102.02	0.980962	0.658955
8	16	15	100.94	0.970577	0.580281
8	16	16	100.04	0.961923	0.454025
7	28	18	102.02	0.980962	0.434022
7	11	17	100.94	0.970577	0.418685
8	17	15	100.04	0.961923	0.377912
7	10	16	100.94	0.970577	0.375504
7	11	16	100.94	0.970577	0.375504
7	12	16	100.94	0.970577	0.375504
8	17	16	99.68	0.958462	0.374406
8	17	17	99.32	0.955000	0.340336
7	12	15	100.94	0.970577	0.305196
7	27	15	100.94	0.970577	0.305196
8	16	17	98.96	0.951538	0.270767
7	27	17	100.04	0.961923	0.240394
7	27	16	100.04	0.961923	0.208991
8	8	15	98.96	0.951538	0.184638
8	9	15	98.96	0.951538	0.184638
7	10	15	100.04	0.961923	0.161783
7	11	15	100.04	0.961923	0.161783
8	17	18	98.96	0.951538	0.128439
8	8	16	98.06	0.942885	0.119879
7	10	17	98.96	0.951538	0.105521
8	7	15	98.06	0.942885	0.090497
8	10	15	98.06	0.942885	0.090497
8	13	15	98.06	0.942885	0.090497
8	24	15	98.06	0.942885	0.090497
8	9	16	97.70	0.939423	0.089275
8	7	16	97.34	0.935962	0.065899
8	10	16	97.34	0.935962	0.065899

Month	Day	Hour ending (CDT)	Hourly temperature	Relative maximum temperature	Relative probability PDPF
8	16	18	98.06	0.942885	0.060815
8	8	17	96.98	0.932500	0.057330
7	9	17	98.06	0.942885	0.049281
8	7	17	96.80	0.930769	0.049062
8	10	17	96.80	0.930769	0.049062
7	11	18	98.96	0.951538	0.044726
7	27	18	98.96	0.951538	0.044726
7	9	16	98.06	0.943	0.041
8	3	17	96.44	0.927	0.036
8	6	17	96.44	0.927	0.036
8	3	15	96.98	0.933	0.036
8	6	15	96.98	0.933	0.036
8	11	15	96.98	0.933	0.036
8	14	15	96.98	0.933	0.036
8	3	16	96.62	0.929	0.035
8	6	16	96.62	0.929	0.035
7	13	15	98.06	0.943	0.031

Table 12. Highest Probability Summer Peak Hours Using TMY3 Data—TRM Zone 3

Month	Day	Hour ending (CDT)	Hourly temperature	Relative maximum temperature	Relative probability PDPF
8	1	17	102.92	1	0.929380
8	2	17	102.92	1	0.929380
8	1	16	102.92	1	0.918911
8	2	16	102.02	0.991255	0.865717
8	3	16	100.04	0.972017	0.650841
8	2	18	102.02	0.991255	0.575415
8	4	17	98.96	0.961524	0.523849
8	12	17	98.96	0.961524	0.523849
8	4	16	98.96	0.961524	0.486478
8	5	16	98.96	0.961524	0.486478
8	29	16	98.96	0.961524	0.486478
8	1	15	100.94	0.980762	0.425501
8	2	15	100.94	0.980762	0.425501
8	4	15	100.94	0.980762	0.425501
8	1	18	100.94	0.980762	0.407850
8	9	17	98.06	0.952779	0.384956
8	11	17	98.06	0.952779	0.384956
8	29	17	98.06	0.952779	0.384956
8	10	16	98.06	0.952779	0.350206
8	12	16	98.06	0.952779	0.350206
8	10	17	96.80	0.940536	0.221282
8	9	16	96.98	0.942285	0.215012
8	3	15	98.96	0.961524	0.176375
8	8	17	96.08	0.933541	0.153237
8	27	17	96.08	0.933541	0.153237
8	28	17	96.08	0.933541	0.153237
8	11	16	96.08	0.933541	0.134819
8	26	16	96.08	0.933541	0.134819
8	12	15	98.06	0.952779	0.108599
8	29	15	98.06	0.952779	0.108599
8	19	17	95.00	0.923047	0.084225
8	26	17	95.00	0.923047	0.084225
8	8	16	95.00	0.923047	0.073383

Month	Day	Hour ending (CDT)	Hourly temperature	Relative maximum temperature	Relative probability PDPF
8	27	16	95.00	0.923047	0.073383
8	28	16	95.00	0.923047	0.073383
8	10	15	96.98	0.942285	0.058306
8	4	18	96.98	0.942285	0.054444
8	12	18	96.98	0.942285	0.054444
8	15	17	93.92	0.912553	0.044655
8	20	17	93.92	0.912553	0.044655
8	15	16	93.92	0.913	0.039
8	19	16	93.92	0.913	0.039
8	20	16	93.92	0.913	0.039
8	9	15	96.08	0.934	0.034
8	27	15	96.08	0.934	0.034
8	28	15	96.08	0.934	0.034
7	14	17	96.98	0.942	0.034
8	11	18	96.08	0.934	0.032
8	28	18	96.08	0.934	0.032
8	5	17	93.02	0.904	0.026

Table 13. Highest Probability Summer Peak Hours Using TMY3 Data—TRM Zone 4

Month	Day	Hour ending (CDT)	Hourly temperature	Relative maximum temperature	Relative probability PDPF
8	18	16	96.08	0.979808	0.380225
8	9	17	93.92	0.957781	0.305170
8	9	16	95.00	0.968795	0.302115
8	7	17	93.02	0.948603	0.247248
8	10	17	93.02	0.948603	0.247248
8	15	17	93.02	0.948603	0.247248
8	16	17	93.02	0.948603	0.247248
8	19	17	93.02	0.948603	0.247248
8	6	16	93.92	0.957781	0.233993
8	7	16	93.92	0.957781	0.233993
8	10	16	93.92	0.957781	0.233993
8	15	16	93.92	0.957781	0.233993
8	16	16	93.92	0.957781	0.233993
8	17	16	93.92	0.957781	0.233993
8	19	16	93.92	0.957781	0.233993
6	7	17	96.08	0.979808	0.231957
8	9	15	96.08	0.979808	0.201074
8	4	17	91.94	0.937589	0.188163
8	5	17	91.94	0.937589	0.188163
8	6	17	91.94	0.937589	0.188163
8	8	17	91.94	0.937589	0.188163
8	11	17	91.94	0.937589	0.188163
8	17	17	91.94	0.937589	0.188163
8	18	17	91.94	0.937589	0.188163
8	27	17	91.94	0.937589	0.188163
8	4	16	93.02	0.948603	0.185965
8	5	16	93.02	0.948603	0.185965
8	11	16	93.02	0.948603	0.185965
8	27	16	93.02	0.948603	0.185965
6	7	16	96.08	0.979808	0.173590
8	16	15	95.00	0.968795	0.150812
8	18	15	95.00	0.968795	0.150812
8	1	17	91.04	0.928411	0.147727

Month	Day	Hour ending (CDT)	Hourly temperature	Relative maximum temperature	Relative probability PDPF
8	2	17	91.04	0.928411	0.147727
8	3	17	91.04	0.928411	0.147727
8	12	17	91.04	0.928411	0.147727
8	13	17	91.04	0.928411	0.147727
8	21	17	91.04	0.928411	0.147727
8	22	17	91.04	0.928411	0.147727
8	31	17	91.04	0.928411	0.147727
8	2	16	91.94	0.938	0.139
8	3	16	91.94	0.938	0.139
8	12	16	91.94	0.938	0.139
8	13	16	91.94	0.938	0.139
8	22	16	91.94	0.938	0.139
8	31	16	91.94	0.938	0.139
9	10	17	93.92	0.958	0.131
8	4	15	93.92	0.958	0.111
8	7	15	93.92	0.958	0.111
8	10	15	93.92	0.958	0.111

Table 14. Highest Probability Summer Peak Hours Using TMY3 Data—TRM Zone 5

Month	Day	Hour ending (CDT)	Hourly temperature	Relative maximum temperature	Relative probability PDPF
8	7	16	98.96	0.970006	0.725586
7	2	15	100.04	0.980592	0.717902
7	3	14	100.04	0.980592	0.702518
8	6	15	96.98	0.950598	0.678213
8	8	15	96.98	0.950598	0.678213
7	2	16	100.94	0.989414	0.654366
7	3	16	100.94	0.989414	0.654366
6	15	15	100.94	0.989414	0.610964
7	1	15	98.96	0.970006	0.601451
7	3	15	98.96	0.970006	0.601451
6	14	14	100.94	0.989414	0.593054
7	1	14	98.96	0.970006	0.583402
8	4	15	96.08	0.941776	0.576910
6	2	16	102.02	1	0.560372
7	1	16	100.04	0.980592	0.550531
6	2	15	100.04	0.980592	0.503974
6	14	15	100.04	0.980592	0.503974
8	4	16	96.98	0.950598	0.503578
8	6	16	96.98	0.950598	0.503578
7	26	15	98.06	0.961184	0.494011
6	2	14	100.04	0.980592	0.485289
6	15	14	100.04	0.980592	0.485289
7	2	14	98.06	0.961184	0.475341
7	26	14	98.06	0.961184	0.475341
8	7	15	95.00	0.931190	0.447083
8	11	15	95.00	0.931190	0.447083
8	27	15	95.00	0.931190	0.447083
6	14	16	100.94	0.989414	0.430480
8	4	14	95.00	0.931190	0.428684
8	6	14	95.00	0.931190	0.428684
8	7	14	95.00	0.931190	0.428684
6	7	15	98.96	0.970006	0.375975
7	6	15	96.98	0.950598	0.366672

Month	Day	Hour ending (CDT)	Hourly temperature	Relative maximum temperature	Relative probability PDPF
6	5	16	100.04	0.980592	0.328415
6	15	16	100.04	0.980592	0.328415
8	26	15	93.92	0.920604	0.324093
7	6	16	98.06	0.961184	0.319686
8	8	14	93.92	0.920604	0.307936
8	11	14	93.92	0.920604	0.307936
8	27	14	93.92	0.920604	0.307936
6	1	15	98.06	0.961	0.280
6	5	15	98.06	0.961	0.280
6	6	15	98.06	0.961	0.280
6	18	15	98.06	0.961	0.280
8	27	16	95.00	0.931	0.280
6	5	14	98.06	0.961	0.266
6	7	14	98.06	0.961	0.266
7	6	14	96.08	0.942	0.258
8	10	15	93.02	0.912	0.237
6	6	16	98.96	0.970	0.225

Table 15. Highest Probability Winter Peak Hours Using TMY3 Data—TRM Zone 1

Month	Day	Hour ending (CDT)	Hourly temperature	Relative minimum temperature	Relative probability PDPF
12	16	20	14.54	7.56	0.721729
2	16	8	6.98	0	0.708012
12	16	21	12.92	5.94	0.701978
12	16	19	16.34	9.36	0.556675
2	14	20	21.92	14.94	0.486565
2	14	19	21.92	14.94	0.398140
2	14	21	21.92	14.94	0.382398
12	16	8	11.66	4.68	0.363779
12	30	21	19.94	12.96	0.361170
12	16	22	13.28	6.30	0.344873
12	30	20	22.64	15.66	0.333252
1	16	20	21.74	14.76	0.280425
12	16	9	10.04	3.06	0.254420
2	17	8	17.06	10.08	0.238066
12	16	10	12.38	5.40	0.229522
1	16	21	21.02	14.04	0.227651
2	14	8	17.96	10.98	0.206482
2	15	8	17.96	10.98	0.206482
2	16	9	14.00	7.02	0.199925
1	16	19	22.28	15.30	0.195983
12	12	21	24.08	17.10	0.195940
12	12	20	26.42	19.44	0.188175
2	16	20	28.94	21.96	0.185310
2	28	20	28.94	21.96	0.185310
2	3	21	26.96	19.98	0.181842
2	16	21	26.96	19.98	0.181842
12	29	21	24.98	18.00	0.168707
1	11	20	24.98	18.00	0.167845
12	30	19	25.34	18.36	0.167724
1	11	21	23.00	16.02	0.164638
2	1	20	30.02	23.04	0.154423
2	3	20	30.02	23.04	0.154423
2	15	20	30.02	23.04	0.154423

Month	Day	Hour ending (CDT)	Hourly temperature	Relative minimum temperature	Relative probability PDPF
1	30	8	15.26	8.28	0.151537
2	1	21	28.04	21.06	0.151426
2	28	21	28.04	21.06	0.151426
12	17	8	17.60	10.62	0.145980
12	11	20	28.04	21.06	0.142922
12	29	20	28.04	21.06	0.142922
1	29	21	24.08	17.10	0.136619
1	30	21	24.08	17.100	0.137
2	14	22	21.92	14.940	0.130
12	30	22	19.58	12.600	0.128
12	11	21	26.96	19.980	0.119
12	14	21	26.96	19.980	0.119
1	30	20	27.14	20.160	0.115
12	14	20	29.30	22.320	0.114
2	15	19	30.02	23.040	0.113
2	28	19	30.02	23.040	0.113
2	14	10	19.04	12.060	0.112

Table 16. Highest Probability Winter Peak Hours Using TMY3 Data—TRM Zone 2

Month	Day	Hour ending (CDT)	Hourly temperature	Relative minimum temperature	Relative probability PDPF
2	11	8	12.02	1.08	0.916726
2	11	7	10.94	0	0.742601
2	10	20	19.04	8.10	0.717078
2	10	21	17.96	7.02	0.708888
2	10	19	19.94	9.00	0.615930
2	11	21	19.04	8.10	0.568022
2	11	9	14.00	3.06	0.516421
2	11	20	21.02	10.08	0.450242
2	11	19	21.92	10.98	0.341324
2	10	22	17.06	6.12	0.316268
2	11	10	15.08	4.14	0.294199
1	12	8	21.92	10.98	0.093075
2	11	22	19.94	9.00	0.082097
12	31	20	26.06	15.12	0.065604
12	31	21	24.98	14.04	0.063193
12	31	19	26.96	16.02	0.042535
2	12	8	21.92	10.98	0.037332
1	17	8	24.08	13.14	0.029056
12	31	22	24.26	13.32	0.011431
2	2	8	24.08	13.14	0.011181
12	30	20	29.30	18.36	0.010934
12	30	19	29.66	18.72	0.009429
1	12	7	23.00	12.06	0.007781
12	30	21	28.94	18.00	0.006994
12	9	8	25.70	14.76	0.006776
2	3	8	24.98	14.04	0.006721
12	7	20	30.38	19.44	0.005934
12	8	20	30.38	19.44	0.005934
12	9	20	30.38	19.44	0.005934
12	7	19	30.56	19.62	0.005664
12	8	19	30.56	19.62	0.005664
12	9	19	30.56	19.62	0.005664
12	8	8	26.06	15.12	0.005525

Month	Day	Hour ending (CDT)	Hourly temperature	Relative minimum temperature	Relative probability PDPF
2	12	7	21.92	10.98	0.005458
1	17	7	24.08	13.14	0.004217
12	7	21	30.02	19.08	0.003789
12	8	21	30.02	19.08	0.003789
12	9	21	30.02	19.08	0.003789
1	13	8	28.04	17.10	0.003115
1	16	8	28.04	17.10	0.003115
12	3	20	31.64	20.700	0.003
1	12	9	26.06	15.120	0.003
12	10	8	27.32	16.380	0.003
12	3	21	30.92	19.980	0.002
1	12	21	32.00	21.060	0.002
12	3	19	32.36	21.420	0.002
1	4	8	28.94	18.000	0.002
12	10	7	24.62	13.680	0.002
12	8	9	26.06	15.120	0.002
12	9	9	26.06	15.120	0.002

Table 17. Highest Probability Winter Peak Hours Using TMY3 Data—TRM Zone 3

Month	Day	Hour ending (CDT)	Hourly temperature	Relative minimum temperature	Relative probability PDPF
2	11	20	30.92	9.90	0.502885
2	11	8	21.02	0	0.464756
2	11	7	21.02	0	0.437624
2	11	9	21.02	0	0.405064
2	11	21	30.02	9.00	0.368255
2	11	10	24.08	3.06	0.355696
2	11	19	35.06	14.04	0.277598
2	12	8	24.08	3.06	0.200333
2	12	7	24.08	3.06	0.183350
2	11	22	28.94	7.92	0.164428
2	3	7	26.06	5.04	0.091280
1	22	21	35.96	14.94	0.091131
1	23	8	28.04	7.02	0.087855
1	23	7	28.04	7.02	0.079459
1	11	20	39.02	18.00	0.067479
1	18	20	39.02	18.00	0.067479
1	18	19	41.00	19.98	0.062001
1	11	21	37.04	16.02	0.060733
2	12	9	26.96	5.94	0.057470
12	20	19	39.92	18.90	0.054753
1	18	21	37.94	16.92	0.042934
1	11	8	30.02	9.00	0.041312
1	19	8	30.02	9.00	0.041312
1	19	7	30.02	9.00	0.037183
2	12	20	39.02	18.00	0.036307
2	12	10	30.92	9.90	0.033164
1	11	9	30.02	9.00	0.032685
2	12	21	37.04	16.02	0.032568
1	4	20	41.00	19.98	0.031360
1	21	20	41.00	19.98	0.031360
1	22	20	41.00	19.98	0.031360
1	22	22	35.06	14.04	0.030503
12	20	20	39.92	18.90	0.027589

Month	Day	Hour ending (CDT)	Hourly temperature	Relative minimum temperature	Relative probability PDPF
1	5	7	30.92	9.90	0.026094
1	11	7	30.92	9.90	0.026094
2	2	20	39.92	18.90	0.025473
2	2	22	33.98	12.96	0.024772
12	25	8	30.02	9.00	0.023773
1	19	9	30.92	9.90	0.022906
2	3	8	30.02	9.00	0.021943
2	5	19	42.08	21.060	0.022
2	12	19	42.08	21.060	0.022
1	11	22	35.96	14.940	0.021
1	19	20	42.08	21.060	0.020
2	15	7	30.02	9.000	0.020
1	4	21	39.92	18.900	0.020
1	4	19	44.06	23.040	0.019
1	11	19	44.06	23.040	0.019
1	20	19	44.06	23.040	0.019
1	21	19	44.06	23.040	0.019

Table 18. Highest Probability Winter Peak Hours Using TMY3 Data—TRM Zone 4

Month	Day	Hour ending (CDT)	Hourly temperature	Relative minimum temperature	Relative probability PDPF
2	11	10	28.94	2.88	0.474019
2	11	20	35.96	9.90	0.467055
1	17	20	39.02	12.96	0.443391
2	11	21	35.06	9.00	0.408858
2	11	8	26.06	0	0.404184
2	11	9	26.96	0.90	0.397264
1	17	19	39.02	12.96	0.357624
2	11	7	26.96	0.90	0.311355
1	19	20	41.00	14.94	0.294982
1	17	21	39.92	13.86	0.259323
1	19	21	39.92	13.86	0.259323
12	25	21	39.56	13.50	0.234162
2	11	22	35.06	9.00	0.227514
1	19	19	41.00	14.94	0.226254
12	25	20	41.36	15.30	0.224276
12	25	22	37.94	11.88	0.180665
12	20	20	42.62	16.56	0.161018
12	25	10	35.96	9.90	0.149340
2	11	19	39.92	13.86	0.144545
12	20	21	42.44	16.38	0.107021
12	20	19	42.98	16.92	0.106593
12	25	19	42.98	16.92	0.106593
1	18	20	44.96	18.90	0.103484
1	17	22	41.00	14.94	0.094969
1	19	22	41.00	14.94	0.094969
2	12	10	35.96	9.90	0.084176
12	21	20	44.96	18.90	0.082289
1	20	9	35.96	9.90	0.079878
1	19	10	39.02	12.96	0.077104
1	12	20	46.04	19.98	0.075138
12	25	9	35.60	9.54	0.070471
2	12	8	33.08	7.02	0.064709
1	12	21	44.96	18.90	0.063655

Month	Day	Hour ending (CDT)	Hourly temperature	Relative minimum temperature	Relative probability PDPF
1	18	21	44.96	18.90	0.063655
2	12	9	33.98	7.92	0.062986
1	20	8	35.96	9.90	0.062511
12	21	10	39.02	12.96	0.060945
2	2	20	44.06	18.00	0.059184
12	21	19	44.96	18.90	0.058971
12	25	7	35.06	9.00	0.058372
12	26	7	35.06	9.000	0.058
2	12	7	33.08	7.020	0.058
12	25	8	35.42	9.360	0.058
1	20	7	35.96	9.900	0.056
12	20	22	42.08	16.020	0.054
12	21	21	44.96	18.900	0.050
2	2	21	42.98	16.920	0.050
1	19	9	37.94	11.880	0.044
1	18	19	46.94	20.880	0.041
1	15	8	37.94	11.880	0.034

Table 19. Highest Probability Winter Peak Hours Using TMY3 Data—TRM Zone 5

Month	Day	Hour ending (CDT)	Hourly temperature	Relative minimum temperature	Relative probability PDPF
12	26	19	35.06	13.14	0.678814
12	26	20	35.96	14.04	0.592910
12	2	19	41.00	19.08	0.509178
12	18	19	41.00	19.08	0.509178
12	19	19	41.00	19.08	0.509178
12	27	19	41.00	19.08	0.509178
12	21	19	42.08	20.16	0.476850
12	28	19	42.08	20.16	0.476850
12	2	20	39.92	18.00	0.475420
12	18	20	39.92	18.00	0.475420
12	19	20	39.92	18.00	0.475420
12	27	20	39.92	18.00	0.475420
12	3	19	42.98	21.06	0.450045
12	30	19	42.98	21.06	0.450045
12	28	20	41.00	19.08	0.443299
12	29	20	41.00	19.08	0.443299
12	30	20	41.00	19.08	0.443299
12	26	21	33.98	12.06	0.419388
12	12	19	44.06	22.14	0.418272
12	14	19	44.06	22.14	0.418272
12	29	19	44.06	22.14	0.418272
12	3	20	42.08	20.16	0.411645
12	31	20	42.08	20.16	0.411645
12	4	19	44.96	23.04	0.392291
12	4	20	42.98	21.06	0.385803
12	12	20	42.98	21.06	0.385803
12	14	20	42.98	21.06	0.385803
12	16	20	42.98	21.06	0.385803
12	21	20	42.98	21.06	0.385803
12	29	21	35.96	14.04	0.362971
12	31	19	46.04	24.12	0.361912
12	1	20	44.06	22.14	0.355632
12	1	19	46.94	25.02	0.337401

Month	Day	Hour ending (CDT)	Hourly temperature	Relative minimum temperature	Relative probability PDPF
12	6	19	46.94	25.02	0.337401
12	16	19	46.94	25.02	0.337401
12	25	19	46.94	25.02	0.337401
12	6	20	44.96	23.04	0.331326
12	3	21	37.94	16.02	0.310091
12	28	21	37.94	16.02	0.310091
12	20	20	46.04	24.12	0.303312
12	11	19	48.92	27.000	0.287
12	2	21	39.02	17.100	0.283
12	18	21	39.02	17.100	0.283
12	19	21	39.02	17.100	0.283
12	24	20	46.94	25.020	0.281
12	25	20	46.94	25.020	0.281
12	26	18	35.96	14.040	0.280
12	27	21	39.92	18.000	0.262
1	26	19	37.94	16.020	0.256
2	8	19	41.00	19.080	0.254

Table 20 through Table 29 provide Peak Hour Probability Factors (PHPFs) developed using TMY3 data for loads that vary by peak hour.

Table 20. TRM Climate Zone 1 Hour Ending Relative Probability of Summer Peak

Hour ending	Relative probability PDPF
16	0.425
17	0.422
18	0.084
15	0.069

Table 21. TRM Climate Zone 2 Hour Ending Relative Probability of Summer Peak

Hour ending	Relative probability PDPF
16	0.352
17	0.314
15	0.284
18	0.050

Table 22. TRM Climate Zone 3 Hour Ending Relative Probability of Summer Peak

Hour ending	Relative probability PDPF
16	0.421
17	0.372
15	0.117
18	0.090

Table 23. TRM Climate Zone 4 Hour Ending Relative Probability of Summer Peak

Hour ending	Relative probability PDPF
17	0.481
16	0.478
15	0.041

Table 24. TRM Climate Zone 5 Hour Ending Relative Probability of Summer Peak

Hour ending	Relative probability PDPF
15	0.497
16	0.346
14	0.157

Table 25. TRM Climate Zone 1 Hour Ending Relative Probability of Winter Peak

Hour ending	Relative probability PDPF
20	0.246
8	0.233
21	0.226
19	0.156
9	0.061
22	0.047
10	0.031

Table 26. TRM Climate Zone 2 Hour Ending Relative Probability of Winter Peak

Hour ending	Relative probability PDPF
21	0.202
20	0.186
8	0.164
19	0.151
7	0.112
9	0.078
22	0.062
10	0.044

Table 27. TRM Climate Zone 3 Hour Ending Relative Probability of Winter Peak

Hour ending	Relative probability PDPF
7	0.194
8	0.185
20	0.156
21	0.127
9	0.113
19	0.097
10	0.087
22	0.040

Table 28. TRM Climate Zone 4 Hour Ending Relative Probability of Winter Peak

Hour ending	Relative probability PDPF
20	0.278
21	0.221
19	0.127
10	0.109
22	0.071
8	0.071
9	0.069
7	0.054

Table 29. TRM Climate Zone 5 Hour Ending Relative Probability of Winter Peak

Hour ending	Relative probability PDPF
19	0.560
20	0.396
21	0.043

Table 30 through Table 39 provide PDPF's for each peak month-hour developed using TMY3 Data for use to estimate peak demand impacts for load shapes that vary by month, day, and hour.

Table 30. TRM Climate Zone 1 Relative Probability of Summer Peak for Month-Hour Combinations

Month	Hour	Relative probability PDPF
7	16	0.274
7	17	0.274
8	16	0.150
8	17	0.110
7	18	0.084
6	17	0.038
7	15	0.036
8	15	0.033

Table 31. TRM Climate Zone 2 Relative Probability of Summer Peak for Month-Hour Combinations

Month	Hour	Relative probability PDPF
7	16	0.257
7	17	0.244
7	15	0.153
8	15	0.131
8	16	0.095
8	17	0.070
7	18	0.050

Table 32. TRM Climate Zone 3 Relative Probability of Summer Peak for Month-Hour Combinations

Month	Hour	Relative probability PDPF
8	16	0.421
8	17	0.372
8	15	0.117
8	18	0.090

Table 33. TRM Climate Zone 4 Relative Probability of Summer Peak for Month-Hour Combinations

Month	Hour	Relative probability PDPF
8	16	0.478
8	17	0.433
6	17	0.048
8	15	0.041

Table 34. TRM Climate Zone 5 Relative Probability of Summer Peak for Month-Hour Combinations

Month	Hour	Relative probability PDPF
7	15	0.201
8	15	0.161
7	16	0.155
8	16	0.144
6	15	0.135
7	14	0.107
6	14	0.049
6	16	0.047

Table 35. TRM Climate Zone 1 Relative Probability of Winter Peak for Month-Hour Combinations

Month	Hour	Relative probability PDPF
2	8	0.184
12	21	0.144
12	20	0.143
12	19	0.075
2	20	0.066
2	19	0.054
2	21	0.052
12	8	0.049
12	22	0.047
1	20	0.038
12	9	0.034
12	10	0.031
1	21	0.031
2	9	0.027
1	19	0.026

Table 36. TRM Climate Zone 2 Relative Probability of Winter Peak for Month-Hour Combinations

Month	Hour	Relative probability PDPF
2	21	0.193
2	20	0.176
2	8	0.146
2	19	0.145
2	7	0.112
2	9	0.078
2	22	0.060
2	10	0.044
1	8	0.018
12	20	0.010
12	21	0.010
12	19	0.006
12	22	0.002

Table 37. TRM Climate Zone 3 Relative Probability of Winter Peak for Month-Hour Combinations

Month	Hour	Relative probability PDPF
2	7	0.175
2	8	0.163
2	20	0.123
2	9	0.113
2	21	0.090
2	10	0.087
2	19	0.068
2	22	0.040
1	21	0.037
1	20	0.033
1	8	0.022
1	7	0.019
1	19	0.015
12	19	0.013

Table 38. TRM Climate Zone 4 Relative Probability of Winter Peak for Month-Hour Combinations

Month	Hour	Relative probability PDPF
1	20	0.129
1	19	0.102
1	21	0.090
2	10	0.083
2	20	0.081
2	21	0.071
2	8	0.071
2	9	0.069
12	20	0.067
12	21	0.060
2	7	0.054
2	22	0.040
12	22	0.032
12	10	0.026
2	19	0.025

Table 39. TRM Climate Zone 5 Relative Probability of Winter Peak for Month-Hour Combinations

Month	Hour	Relative probability PDPF
12	19	0.560
12	20	0.396
12	21	0.043

5. STRUCTURE AND CONTENT

This section provides measure codes and measure overviews to assist using TRM volumes 2 through 5.

5.1 MEASURE CODES

The EM&V team developed measure ID codes to allow users to quickly access the information they need for market sector, end-use, and measure description. Users can use the ID codes to quickly identify key aspects of a measure, even if they cannot determine energy savings from the code. Due to differences in commercial and residential measures, the construction of the measure code differs slightly for each sector. The commercial codes stay at a higher level than the residential codes. Table 40 through Table 43 describe the encoding process used for the measure ID.

Table 40. Residential TRM Measure ID Creation

Sequence	Category	ID	Description
1	Sector	R	Residential
2	Measure Category	LT	Lighting
		HV	HVAC
		BE	Building envelope
		WH	Domestic hot water
		AP	Appliances
		HS	Whole house
		RN	Renewables
		LM	Load management
3	Measure Code	XX	Per specific measure (See Table 42)

Table 41. Nonresidential TRM Measure ID Creation

Sequence	Category	ID	Description
1	Sector	NR	Nonresidential
2	Measure Category	LT	Lighting
		HV	HVAC
		BE	Building envelope
		FS	Food service
		RF	Refrigeration
		WH	Domestic hot water
		MS	Miscellaneous
		RN	Renewables
		LM	Load management
3	Measure Code	XX	Per specific measure (See Table 43)

Table 42. Residential and Nonresidential Measure Code Mapping

Sector	Measure category	Measure description	Measure code	TRM volume
Residential	LT	ENERGY STAR® omni-directional LED lamps	OD	2
	LT	ENERGY STAR® specialty and directional LED lamps	SD	2
	HV	Air conditioner or heat pump tune-ups	TU	2
	HV	Duct sealing	DS	2
	HV	ENERGY STAR® ground source heat pumps	GH	2
	HV	Central air conditioner and heat pumps	CH	2
	HV	Mini-split air conditioners and heat pumps	MS	2
	HV	Large capacity split system and single-package air conditioners and heat pumps	LC	2
	HV	Packaged terminal heat pumps	PT	2
	HV	ENERGY STAR® room air conditioners	RA	2
	HV	ENERGY STAR® connected thermostats	CT	2
	HV	Smart thermostat load management	TD	2
	HV	Evaporative cooling	EC	2
	HV	Air conditioning tune-ups	TU	4
	BE	Air infiltration	AI	2
	BE	Ceiling insulation	CI	2
	BE	Attic encapsulation	AE	2
	BE	Wall insulation	WI	2

Sector	Measure category	Measure description	Measure code	TRM volume
	BE	Floor insulation	FI	2
	BE	ENERGY STAR® windows	EW	2
	BE	Solar screens	SS	2
	BE	Cool roofs	CR	2
	WH	Faucet aerators	FA	2
	WH	Low-flow showerheads	SH	2
	WH	Water heater pipe insulation	PI	2
	WH	Water heater tank insulation	TI	2
	WH	Water heater installations – electric tankless and fuel substitution	WH	2
	WH	Heat pump water heaters	HW	2
	WH	Solar water heaters	SW	2
	WH	Showerhead temperature-sensitive restrictor valves	SV	2
	WH	Tub spout and showerhead temperature-sensitive restrictor valves	TV	2
	AP	ENERGY STAR® ceiling fans	FN	2
	AP	ENERGY STAR® clothes washers	CW	2
	AP	ENERGY STAR® clothes dryers	CD	2
	AP	ENERGY STAR® dishwashers	DW	2
	AP	ENERGY STAR® refrigerators	RF	2
	AP	ENERGY STAR® freezers	FZ	2
	AP	ENERGY STAR® pool pumps	PP	2
	AP	ENERGY STAR® air purifiers	AP	2
	AP	Advanced power strips	PS	2
	AP	ENERGY STAR® electric vehicle supply equipment	EV	2
	AP	Refrigerator/freezer recycling	RR	2
	HS	Residential new construction	NH	4
	RN	Residential solar photovoltaics	PV	4
	RN	Solar shingles	SS	4
	RN	Solar attic fans	SF	4
	LM	Residential load curtailment	LM	4

Table 43. Nonresidential Measure Code Mapping

Sector	Measure category	Measure description	Measure code	TRM volume
Nonresidential	LT	Lamps and fixtures	LF	3
	LT	Lighting controls	LC	3
	LT	LED traffic signals	TS	3
	HV	Air conditioner and heat pump tune-ups	TU	3
	HV	Split and packaged air conditioners and heat pumps	SP	3
	HV	HVAC chillers	CH	3
	HV	Packaged terminal air conditioners, heat pumps, and room air conditioners	PT	3
	HV	Computer room air conditioners	CR	3
	HV	Computer room air handler motor efficiency	CM	3
	HV	HVAC variable frequency drives	VF	3
	HV	Condenser air evaporative pre-cooling	EP	3
	HV	High-volume low-speed fans	HF	3
	HV	Small commercial evaporative cooling	EC	3
	HV	Ground source heat pumps	GH	4
	HV	Air Conditioning tune-ups	TU	4
	HV	Variable refrigerant flow systems	VR	4
	BE	ENERGY STAR® cool roofs	CR	3
	BE	Window treatments	WT	3
	BE	Entrance and exit door air infiltration	DI	3
	FS	ENERGY STAR® combination ovens	CO	3
	FS	ENERGY STAR® electric convection ovens	CV	3
	FS	ENERGY STAR® dishwashers	DW	3
	FS	ENERGY STAR® hot food holding cabinets	HC	3
	FS	ENERGY STAR® electric fryers	EF	3
	FS	ENERGY STAR® electric steam cookers	SC	3
	FS	ENERGY STAR® ice makers	IM	3
	FS	Demand controlled kitchen ventilation	KV	3
	FS	Pre-rinse spray valves	SV	3
	FS	Vacuum-sealing & packaging machines	VS	3
	RF	Door heater controls	HC	3
	RF	ECM evaporator fan motors	FM	3

Sector	Measure category	Measure description	Measure code	TRM volume
	RF	Electronic defrost control	DC	3
	RF	Evaporator fan controls	FC	3
	RF	Night covers for open refrigerated display cases	NC	3
	RF	Solid and glass door reach-ins	RI	3
	RF	Strip curtains for walk-in refrigerated storage	SC	3
	RF	Zero-energy doors for refrigerated cases	ZE	3
	RF	Door gaskets for walk-in and reach-in coolers and freezers	DG	3
	RF	High-speed doors for cold storage	HS	3
	RN	Nonresidential solar photovoltaics	PV	4
	RN	Solar shingles	SS	4
	WH	Central domestic hot water controls	DC	3
	WH	Showerhead temperature-sensitive restrictor valves	SV	3
	WH	Tub spout and showerhead temperature-sensitive restrictor valve	TV	3
	MS	Vending machine controls	VC	3
	MS	Lodging guest room occupancy sensor controls	LC	3
	MS	Pump-off controllers	PC	3
	MS	ENERGY STAR® pool pumps	PP	3
	MS	Computer power management	CP	3
	MS	Premium efficiency motors	PM	3
	MS	ENERGY STAR® electric vehicle supply equipment	EV	3
	MS	Variable frequency drives for water pumping	WP	3
	MS	Steam trap repair and replacement	ST	3
	MS	Hydraulic gear lubricants	HL	3
	MS	Hydraulic oils	HO	3
	MS	Behavioral measure	BC	4
	MS	Air compressors less than 75hp	CA	4
	MS	Commercial retro-commissioning	RC	4
	MS	Thermal energy storage	TS	4
	LM	Nonresidential load curtailment	LM	4

5.2 MEASURE OVERVIEW LAYOUT

A "measure overview" is the basic structure that is used to characterize all measures in the TRM. There is one measure overview section per TRM measure, and it encapsulates all the information needed to characterize the measure, calculate the deemed savings, document the sources used for those calculations, track changes made to the measure overview, and record any issues and recommendations to improve the approach. Note that although the basic template structure described here is generally used for all measures, there are some measures that require an adaptation or modification. Furthermore, there are some sections of the general template that are not applicable to specific measures, in which case they are not used for the measure overview. Each measure overview contains the following sections:

Sector and TRM measure name. At the top of every measure overview section, the sector (residential or nonresidential) and TRM measure name are presented. The sector, end-use, and TRM measure name are also shown in the page footer to make scrolling through the TRM easier.

Measure overview summary. This section, which appears just below the measure name, contains a bulleted list that is a concise characterization of the measure. It starts with the measure ID and includes characteristics such as market sector, measure category, applicable building types, fuels affected, decision/action types (e.g., retrofit, replace-on-burnout), program delivery method, deemed savings type (value or calculated), and the savings methodology (e.g., engineering estimation, calculator, building simulation, billing analysis).

Measure description. This section provides a general description of the measure, the eligibility criteria, the *baseline condition* (e.g., efficiency level, technology, performance), and the *high-efficiency condition*. Any special conditions, scenarios, or required technology/performance certifications, or relevant codes and standards are also described in this section.

Energy and demand savings methodology. This section of the measure overview presents and describes the parameters, equations, assumptions, and reference sources that are used for the energy and demand savings for the measure. An extensive set of subsections is used to describe the details:

- **Savings algorithms and input variables.** Provide the actual equations and parameters that are used for the savings calculations and provide explanations and references. This section may contain any look-up tables of stipulated values that are used for the calculations.
- **Deemed energy and demand savings tables.** Presents the tabulated deemed energy and demand savings values developed using the algorithms and look-up table parameters. If site-specific inputs or equipment specifications are required, then a statement to that extent rather than result tables will be listed in this section.
- **Claimed peak demand savings.** Briefly describes the current and prospective peak demand values that will be used, coincidence factors, and the basis used to derive those values. If the basis of the current peak demand value is not known, then that will be noted, and the team will follow up with the utilities, implementers, or others to determine the basis.

- **Additional calculators and tools.** If a calculator or other tool is available and typically used for calculating measure savings, then that tool and/or tools would be briefly described in this section. If a tool is not used, then "NA" would be recorded for this section, or it will be excluded from the measure overview.
- **Measure life and lifetime savings.** This section notes the EUL and its source and describes how lifetime savings should be calculated. For a subset of HVAC retrofit measures, assumptions for early retirement will also be discussed in this section. For example, for commercial HVAC early retirement, the measure life does not necessarily equal the EUL.

Additional parameters. This section is used for unique, measure-specific parameters that affect savings calculations but are not currently included in the calculation algorithms. This section will only appear in the measure overview for those measures that require additional parameters. Examples include in-service rate and non-energy benefits impact, which are targeted as future residential parameters.

Program tracking data and evaluation requirements. This section specifies the recommended list of primary inputs and contextual data needed for evaluation and proper application of the savings. For example, the application of interactive HVAC factors should, at a minimum, require tracking the space conditioning type in which a lighting system is used (air-conditioned or low/medium temperature refrigerated); otherwise, the interactive HVAC savings should not be applied. As there are negative heating impacts, the heating system fuel type (electric or gas) should also be recorded.

References and efficiency standards. All references and citations are summarized in this section.

- **Petitions and rulings.** Provides a running list of the relevant petitions and rulings related to deemed savings for the specific measure.
- **Relevant standards and reference sources.** Provides a bulleted list of the applicable energy-efficiency standards (e.g., Federal appliance standards, ASHRAE 90.1), associated links, and their relevance to the measure. It also lists all sources used for the development of inputs to savings, values, and deemed savings calculations.

Document revision history. This table is used to track the revision history of the measure overview. An example is shown in Table 44.

Table 44. Nonresidential [Measure Name] Revision History[20]

TRM version	Date	Description of change
v1.0	11/2013	TRM v1.0 origin
v2.0	4/2014	No revision.
v2.1	1/2015	Updated to most recent ENERGY STAR® standard.
v3.0	4/2015	Update of savings method to allow for….
v3.1	11/2015	No revision.
v4.0	10/2016	No revision.

[20] Subsequent rows added with each new version.

APPENDIX A: GLOSSARY

P.U.C. SUBST. R. 25.181, relating to Energy Efficiency Goal (Project No. 39674), contains definitions in section (c). Below, we provide additional definitions relevant to the TRM as well as definitions from § 25.181 denoted with a *****.

Accuracy. A concept that refers to the relationship between the true value of a variable and an estimate of the value. The term can also be used in reference to a model or a set of measured data or to describe a measuring instrument's capability.

ASHRAE Guideline 14. American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) Guideline 14, *2002 Measurement of Energy and Demand Savings* (http://www.ashrae.org).

Benchmarking. A process that compares the energy, emissions, and other resource-related conditions of a facility against industry best practices or other benchmarks such as average per square foot energy consumption of similar buildings in the same city or climate zone.

Bias. The extent to which a measurement or a sampling or analytic method systematically underestimates or overestimates a value. Some examples of types of bias include engineering model bias; meter bias; sensor placement bias; inadequate or inappropriate estimates of what would have happened absent a program or measure installation; a sample that is unrepresentative of a population; and selection of other variables in an analysis that are too correlated with the savings variable (or each other) in explaining the dependent variable (such as consumption).

Billing analysis. A term used to define either (1) a specific measurement and verification (M&V) approach used to estimate project savings; or (2) any analytic methodology used to determine the project or program energy savings based on the use of the energy consumption data contained in consumer billing data. It compares billing data from program participant(s) over a period of time before the energy-efficient measures are installed at a customer site(s) to billing data for a comparable period of time afterward. If used to describe an M&V approach, it is equivalent to IPMVP option C, whole-building analysis. If used to describe an evaluation approach, it is comparable to the large-scale data analysis approach.

Building energy simulation model. Computer models based on physical engineering principles and/or standards used to estimate energy use and/or savings. These models usually incorporate site-specific data on customers and physical systems, such as square footage, weather, surface orientations, elevations, space volumes, construction materials, equipment use, lighting, and building occupancy. Building simulation models can usually account for interactive effects between end uses (e.g., lighting and HVAC), part-load efficiencies, and changes in external and internal heat gains/losses. Examples of building simulation models include DOE-2, Energy Plus, and Carrier HAP.

Calendar year for peak demand. The calendar year applied to the 8760 TMY3 data. The choice of the calendar year determines the weekday/weekend/holiday classification for each day.

Calibration. In economic, planning, or engineering modeling, the process is to adjust the components of the model to reflect reality as closely as possible to prepare for the model's use in future applications. The term also applies to the process whereby metering and measurement equipment is periodically adjusted to maintain industry measurement standards.

Claimed savings. Values reported by an electric utility after the energy efficiency activities are complete, and prior to the time, an independent, third-party evaluation of the savings is performed. Claimed savings may use results of prior evaluations or values in technical reference manual version in effect at project acceptance. However, claimed savings are adjusted from projected savings estimates by correcting for any known data errors, actual installation rates, per-unit savings values, operating hours, and savings persistence rates. Claimed savings can be indicated as first year, demand, energy, lifetime energy, gross, and/or net savings.

Coincident demand. The demand of a device, circuit, or building that occurs at the same time as peak demand of a utility's system load or other time of peak of interest, such as facility peak demand. The peak of interest should be specified (e.g., "demand coincident with the utility system peak"). The following are examples of peak demand:

- Demand coincident with utility system peak load
- Demand coincident with independent system operator/regional transmission organization summer or winter peak or according to performance hours defined by wholesale capacity markets
- Demand coincident with high electricity demand days

Coincidence factors (CF).[21] Coincidence factors are the fractions of rated load reductions that occur during each of the peak demand windows. They are the ratio of the demand reductions during the coincident window to the connected load reductions. Other issues, such as diversity and load factors, are automatically accounted for, and only the coincidence factor will be necessary to determine coincident demand reductions from readily observable equipment nameplate (rated) information. In other words, coincident demand reduction will simply be the product of the coincidence factor and the connected equipment load kW reduction.

Common practice. The predominant technology(ies) implemented, or practice(s) undertaken in a particular region or sector. Common practices can be used to define a baseline.

Cooling degree days. See *degree days*.

Custom program. An energy efficiency program intended to provide efficiency solutions to unique situations not amenable to common or prescriptive solutions. Each custom project is examined for its individual characteristics, savings opportunities, efficiency solutions, and often, customer incentives.

Database for energy-efficient resources (DEER). A California database designed to provide publicly available estimates of energy and peak demand savings values, measure costs, and effective useful life (http://www.deeresources.com/).

Decision/action types. This refers to the type of equipment installation that is performed. Acceptable values include retrofit (RET), new construction (NC), early retirement (ER), and replace-on-burnout (ROB). The definition of each of these values can be found in this glossary.

[21] Source: Petition #39146, page 15.

Deemed savings calculation. An industry-wide engineering algorithm used to calculate energy and/or demand savings of the installed energy efficiency measure that has been developed from common practice that is widely considered acceptable for the measure and purpose and is applicable to the situation being evaluated. These calculations may include stipulated assumptions for one or more parameters in the algorithm but typically requires some data associated with the actual installed measure. An electric utility may use the calculation with documented measure-specific assumptions instead of energy and peak demand savings determined through measurement and verification activities or the use of deemed savings. (§ 25.181 (c) (7))

Deemed savings value. An estimate of energy or demand savings for a single unit of an installed energy efficiency measure that has been developed from data sources and analytical methods that are widely considered acceptable for the measure and purpose and are applicable to the situation being evaluated. An electric utility may use deemed savings values instead of energy and peak demand savings determined through measurement and verification activities. (§ 25.181 (c) (8))

Degree days. For any individual day, an indication of how far that day's average temperature departed from a fixed temperature, usually 18.3°C/65°F. Heating degree days, which measure heating energy needs, quantify how far the average temperature was below 65°F. Similarly, cooling degree days, which measure cooling energy needs, quantify how far the temperature averaged above 65°F. In both cases, smaller values represent less energy consumption; however, values below 0 are set equal to 0 because energy demand cannot be negative. Furthermore, because energy demand is cumulative, degree day totals for periods exceeding one day are simply the sum of each individual day's degree days total. Degree days are used in calculations of heating and cooling energy consumption and in evaluation regression analyses to adjust for differences in heating and cooling requirements between baseline and project scenarios.

Demand savings. A quantifiable reduction in demand. (§ 25.181 (c) (10))

Demand-side management (DSM). Strategies used to manage energy demand, including energy efficiency, load management, fuel substitution, and load building.

Direct install program. An energy efficiency program design strategy involving the direct installation of measures in customer premises by a contractor sponsored by the program. Such programs generally involve one-for-one replacement of existing equipment with more efficient equipment and may include a customer rebate.

Diversity. That characteristic of a variety of electric loads where maximum individual demands of each load usually occur at different times.

Diversity factor. The ratio of the sum of the demands of a group of users to their maximum coincident demand during a specified period of time (e.g., summer or winter).

Early retirement (ER). An early retirement scenario occurs when existing, functional, actively used equipment is replaced with similar, higher efficiency equipment. The equipment being replaced should have at least one year of remaining useful life (RUL). In this case, a dual baseline will have to be considered, which uses the pre-existing equipment as the baseline for savings during the RUL period, and code requirement/industry-standard practice baseline for estimating the balance of the EUL period for the new equipment.

End-use. General categories of energy efficiency measures reflecting the type of services provided (e.g., lighting, HVAC, motors, and refrigeration). Also referred to as measure category.

End-use metering. The direct measuring of energy consumption or demand by specific end-use equipment, typically as part of load research studies or to measure the impacts of demand-side management programs.

Energy efficiency ratio (EER). A measure of efficiency in air conditioning and heat pump units within a certain capacity range. This is the ratio of the cooling capacity in Btus per hour to the total electrical input in watts under specified test conditions (expressed in Btu/W-hr).

Energy efficiency service provider (EESP). A person or other entity that installs energy efficiency measures or performs other energy efficiency services under this section. An energy efficiency service provider may be a retail electric provider or commercial customer, provided that the commercial customer has a peak load equal to or greater than 50 kW. An energy efficiency service provider may also be a governmental entity or a non-profit organization but may not be an electric utility.

Energy savings. A quantifiable reduction in a customer's consumption of energy that is attributable to energy efficiency measures usually expressed in kWh or MWh. (§ 25.181 (c) (18))

Engineering model. Engineering equations used to calculate energy use and savings. These models are usually based on a quantitative description of physical processes that transform delivered energy into useful work, such as heat, lighting, or motor drive. In practice, these models may be reduced to simple equations in spreadsheets that calculate energy use or savings as a function of measurable attributes of customers, facilities, or equipment (e.g., lighting use = watts x hours of use).

ERCOT weather zones. The eight weather zones used by the Electric Reliability Council of Texas represent distinct geographic regions of Texas.

Error: The deviation of measurements from the true value of the variable being observed, also called *measurement error*.

Estimated useful life (EUL). The number of years until 50% of installed measures are still operable and providing savings and is used interchangeably with the term "measure life." The EUL determines the period over which the benefits of the energy efficiency measure are expected to accrue. (§ 25.181 (c) (19))

EUMMOT. The Electric Utility Marketing Managers of Texas (EUMMOT) is a voluntary organization of electric investor-owned utilities formed to address utility industry energy efficiency issues and serve as a forum to facilitate coordination among the energy efficiency program managers across the state.

EUMMOT EUL Summary Spreadsheet. This is a current list of the approved EULs for residential and commercial energy efficiency measures. The list is updated and maintained by EUMMOT and available from the Texas Energy Efficiency website[22]. It contains the EULs, as well as a reference to the source/citation, including the relevant petition number.

Evaluated Savings. Savings estimates reported by the EM&V contractor after the energy efficiency activities and impact evaluation are complete. These savings differ from claimed savings in that the EM&V contractor has conducted some of the evaluation and/or verification activities. These values may rely on claimed savings for factors such as installation rates and the Technical Reference Manual (applicable version at project incentive agreement or more recent) for values such as per unit savings values and operating hours. These savings estimates may also include adjustments to claimed savings for data errors, per unit savings values, operating hours, installation rates, savings persistence rates, and other considerations. Evaluated savings can be indicated as first year, demand, energy, lifetime energy, gross, and/or net savings. (§ 25.181 (c) (20))

FEMP M&V Guidelines. U.S. Department of Energy Federal Energy Management Program's *2008 M&V Guidelines: Measurement and Verification for Federal Energy Projects*.

Fuel Switching. Using an alternative fuel (usually of lower carbon intensity) to produce the required energy.

Heating Degree Days. See *degree days*.

Home Energy Rating System (HERS). An indexing system, associated with ENERGY STAR®, used in residential new construction to rate the pre- and post-construction of new homes to highlight and indicate the degree of energy efficiency embedded in the construction. The HERS Index is a scoring system established by the Residential Energy Services Network (RESNET) in which a home built to the specifications of the HERS Reference Home (based on the 2006 International Energy Conservation Code) scores a HERS Index of 100, while a net-zero energy home scores a HERS Index of 0. The lower a home's HERS Index, the more energy-efficient it is in comparison to the HERS Reference Home. Each 1-point decrease in the HERS Index corresponds to a 1% reduction in energy consumption compared to the HERS Reference Home.

HVAC, HVAC&R. Heating, ventilation, and air conditioning; Heating, ventilation, air conditioning, and refrigeration.

Indirect Energy (Demand) Savings (Indirect Program Energy Savings). The use of the words "indirect savings" or "indirect program savings" refers to programs that are typically information, education, marketing, or outreach programs in which the program's actions are expected to result in energy savings achieved through the actions of the customers exposed to the program's efforts, without direct enrollment in a program that has energy-savings goals.

Inspections. Facility site visits to document the existence, characteristics, and operation of baseline or project equipment and systems, as well as factors that affect energy use.

[22] Available for download at the Texas Efficiency website: http://texasefficiency.com/index.php/regulatory-filings/deemed-savings

In-Service Rate (ISR). The percentage of measures that are incentivized by an energy efficiency program that is actually installed in a defined period of time. The installation rate is calculated by dividing the number of measures installed by the number of measures incented by an energy efficiency program in a defined period of time.

Interactive Effects. For a typical definition, see “Interactive HVAC Effects.” However, interactive effects can also refer to the interaction of a package of measures that affect the same end-use and the resulting reduction of measure savings for an individual measure versus that achieved by the package.

Interactive HVAC (&R) Factors. The factors used to adjust basic lighting savings for interactive HVAC&R effects. The space types and factors used in the TRM are shown below. Note that “electric refrigerated” means air-conditioned spaces, and “refrigerated spaces” refers to both building floor areas, and equipment spaces cooled to temperatures lower than 41 degrees Fahrenheit.

Table 45. Deemed Interactive HVAC Effects

Space conditioning type	Energy interactive HVAC factor	Demand interactive HVAC factor
Air Conditioned	1.05	1.10
Med. Temp Refrigeration (33-41ºF)	1.25	1.25
Low Temp Refrigeration (-10-10ºF)	1.30	1.30
None (Uncooled/Unrefrigerated)	1.00	1.00

International Performance Measurement and Verification Protocol (IPMVP). A guidance document issued by the Efficiency Valuation Organization with a framework and definitions describing the M&V approaches. (§ 25.181 (c) (33))

Lifetime Energy (Demand) Savings. The energy (demand) savings over the lifetime of an installed measure(s), project(s), or program(s). May include consideration of measure estimated useful life, technical degradation, and other factors. It can be gross or net savings. (§ 25.181 (c) (34))

Load Factor. A percentage indicating the difference between the amount of electricity a consumer used during a given time span and the amount that would have been used if the use had stayed at the consumer’s highest demand level during the whole time. The term also means the percentage of capacity of an energy facility, such as a power plant or gas pipeline, that is used in a given period of time. It is also the ratio of the average load to the peak load during a specified time interval.

Load Shapes. Representations such as graphs, tables, and databases that show the time-of-use pattern of customer or equipment energy use. These are typically shown over a 24-hour or whole-year (8,760 hours) period.

Main Meter: The meter that measures the energy used for the whole facility. There is at least one meter for each energy source and possibly more than one per source for large facilities. Typically, utility meters are used, but data loggers may also be used if they isolate the load for the facility being studied. When more than one meter per energy source exists for a facility, the main meter may be considered the accumulation of all the meters involved.

Market Penetration. A measure of the diffusion of a technology, product, or practice in a defined market, as represented by the percentage of annual sales for a product or practice, the percentage of the existing installed stock for a product or category of products, or the percentage of existing installed stock that uses a practice.

Market Saturation. A percentage indicating the proportion of a specified end-user market that contains a particular product. An example would be the percentage of all households in a geographical area that have a certain appliance.

Market Sectors. General types of markets that a program may target or in which a service offering may be placed. Market sectors include categories such as residential, commercial, industrial, agricultural, government, and institutional.

Market Segments. A part of a market sector that can be grouped together as a result of a characteristic similar to the group. For example, within the residential sector are market segments such as renters, owners, multifamily, and single-family.

Measure. [verb] Use of an instrument to assess a physical quantity or use of a computer simulation to estimate a physical quantity.

Measure. [noun] See *energy efficiency measure*.

Measure Categories. This is also referred to as the end-use or the general category that the measure falls into. Examples include, but are not limited to, HVAC, lighting, water heating, and food service.

[TRM] Measure Overview. There is one measure overview section per TRM measure, and it encapsulates all the information needed to characterize the measure, calculate the deemed savings, document the sources used for those calculations, track changes made to the measure overview, and record any issues and recommendations for improving the approach.

Measure Persistence. The duration of an energy-consuming measure, considering business turnover, early retirement of installed equipment, technical degradation factors, and other reasons measures might be removed or discontinued.

Measurement Boundary. The boundary of the analysis for determining direct energy and/or demand savings.

Metering. The collection of energy consumption data over time through the use of meters. These meters may collect information with respect to an end-use, a circuit, a piece of equipment, or a whole building. *Short-term metering* generally refers to data collection for no more than a few weeks. *End-use metering* refers specifically to separate data collection for one or more end-uses in a facility, such as lighting, air conditioning, or refrigeration. *Spot metering* is an instantaneous measurement (rather than over time) to determine an energy consumption rate.

Monitoring. The collection of relevant measurement data over time at a facility including, but not limited to, energy consumption or emissions data (e.g., energy and water consumption, temperature, humidity, volume of emissions, hours of operation) for the purpose of savings analysis or to evaluate equipment or system performance.

New Construction. Residential and nonresidential buildings that have been newly built or have added major additions or renovations. Major renovation projects should use a new construction baseline if either of the following conditions are met: 1) the building type changes in combination with the renovation or 2) renovation scope includes removing drywall and gutting the existing building to the studs. New construction programs focus on the installation of equipment with efficiencies that exceed standard codes at the time of installation. Energy and demand savings are calculated in a similar method to those for replace-on-burnout (ROB) projects, as the savings are taken based on a codes/standard baseline.

Panel Data Model. An estimation analysis model that contains many data points over time rather than averaged, summed, or otherwise aggregated data.

PDPF Top 20 Hours Method. The name of the calculation method to determine Peak Demand Reduction for projects using the TRM. The calculation develops a peak demand by weighting demand estimates for each of the 20 peak (summer or winter) hours derived using a given TMY dataset for a given TRM climate zone and weighting those estimates by their respective peak demand probability factors. Peak Demand Probability Factors (PDPF) is described in detail below.

Peak Demand Period. The EE Rule defines the full peak period as the hours from 1 p.m. to 7 p.m. during the months of June, July, August, and September, and the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. during the months of December, January, and February (excluding weekends and federal holidays). These are also referred to as the “summer peak period” and the “winter peak period.” For custom calculations and to comply with the TRM, refer to the peak demand reduction definition.

Peak Demand Reduction. Consistent with the EE Rule, this is defined as the reduction in demand during the times of the utility’s summer peak period or winter peak period. Peak demand savings will be calculated based on measure-specific hourly loads during those top hours identified in defining the peak period.

Peak Hours. This appendix outlines a process for calculating the peak hours through analytically identifying specific hours within the *Rule-defined peak demand period* that the system is most likely to realize its greatest demand. To estimate the peak hours for both the summer and winter periods, a probabilistic modeling approach developed by Frontier Energy is used to identify the top 20 hours for each season by TRM climate zone.

Peak Probability Analysis (PPA). This is the name used to describe the regression-based approach used by Frontier Energy to develop the peak demand hours used to estimate peak demand reduction and coincidence factors for 8,760 or other load shape data.

Peak Demand Probability Factors (PDPF). These probability factors are outputs from the PPA models that reflect the relative probability that a TRM climate zone seasonal (summer/winter) peak load will occur on a given hour from a TMY dataset. Considering the day of the week according to the model year used in conjunction with the TMY data, the 20 TMY hours with the highest peak demand probability factors are included in the set of 20 peak hours (summer or winter) used to estimate peak demand impacts for a given measure in a given TRM climate zone.

Petitions. Historically, petitions were filed by the utilities as needed to update existing deemed savings or file new deemed savings for PUCT approval. You can find the petitions and associated filings using the Project Number (also called a "Control Number") on the PUCT website: http://interchange.puc.state.tx.us.

Potential Studies. Studies conducted to assess market baselines and future savings that may be expected for different technologies and customer markets over a specified time horizon.

Prescriptive Program. An energy efficiency program focused on measures that are one-for-one replacements of the existing equipment and for which fixed customer incentives can be developed based on the anticipated similar savings that will accrue from their installation.

Primary Effects. Effects that the project or program are intended to achieve. For efficiency programs, this is primarily a reduction in energy use (and/or demand) per unit of output.

Probability-Adjusted Peak Demand. A peak demand estimate created by using the PDPF top 20 hours method.

Program Administrator. An entity selected by a regulatory or other government organization to contract for and administer an energy efficiency portfolio within a specific geographic region and/or market. Typical administrators are utilities selected by a public service commission or a nonprofit or state government agency, as determined by legislation.

Program Year (PY). The calendar year approved for program implementation. Note that program years can be shorter than 12 months if programs are initiated mid-year.

Project. An activity or course of action involving one or multiple energy efficiency measures at a single facility or site.

Projected Savings. Values reported by an electric utility prior to the energy efficiency activities for program and/or portfolio design or planning purposes. These values are based on pre-program or portfolio estimates of factors such as per-unit savings values, operating hours, installation rates, and savings persistence rates. These values may use results of prior evaluations and/or values in the Technical Reference Manual. Projected savings can be indicated as first year, demand, energy, lifetime energy, gross, and/or net savings.

Project Sponsor. See Energy Efficiency Service Provider (EESP) definition. EESPs are often referred to as the project sponsor.

Regression Analysis. Analysis of the relationship between a dependent variable (response variable) to specified independent variables (explanatory variables). The mathematical model of their relationship is the regression equation.

Remaining Useful Life (RUL). The RUL is an estimate of the number of years equipment would remain operational if not replaced by program intervention. In the case of HVAC units, the RUL is a function of the technology and age of the replaced unit. A separate table is provided for units in which the age of the equipment is unknown. The RUL estimate in years is usually much lower than the EUL.

Replace-on-Burnout (ROB). ROB defines a situation when an older, inoperable unit is replaced after failure or the equipment is older than the estimated average EUL. For this scenario, the measure baseline condition would be based on a code/standard or "standard practice" rather than the efficiency of the equipment that was previously installed.

Retrofit (RET). Energy efficiency activities in existing residential and non-residential buildings, where 1) existing equipment or systems are replaced by energy-efficient equipment or systems or 2) where efficient equipment or systems are added to an existing facility (e.g., the addition of thermal insulation). This can include both early retirement (ER) and replace-on-burnout (ROB).

Retrofit Isolation. The savings measurement approach defined in IPMVP Options A and B, as well as ASHRAE Guideline 14 that determines energy or demand savings through the use of meters to isolate the energy flows for the system(s) under consideration. IPMVP Option A involves "Key Parameter Measurement," and IPMVP Option B involves "All Parameter Measurement."

Seasonal Energy Efficiency Ratio (SEER). A measure of efficiency in air conditioning units and heat pump units within a certain capacity range. This is the total cooling output in Btus during its normal usage period for cooling, divided by the total electrical energy input in watt-hours during the same period, as determined using specified federal test procedures.

Seasonally-Varying Measures. Any measure whose performance, energy use, and demand varies seasonally or monthly due to changes in operation (e.g., agricultural businesses), schools, outdoor lighting, or even residential lighting (since lights may be on sooner during the winter due to shorter days).

Secondary Effects. Unintended impacts of the project or program such as rebound effect (e.g., increasing energy use as it becomes more efficient and less costly to use), activity shifting (e.g., when generation resources move to another location), and market leakage (e.g., emission changes due to changes in supply or demand of commercial markets). Secondary effects can be positive or negative.

Simple Measurement and Verification Savings Approach. A simple M&V approach falls between a deemed calculation approach and a full M&V approach in that only some of the deemed calculation parameters are measured, whereas, for a full M&V approach, all of the algorithm parameters would be measured.

Statistically Adjusted Engineering (SAE) Models. A category of statistical analysis models that incorporate the engineering estimate of savings as a dependent variable. The regression coefficient in these models is the percentage of the engineering estimate of savings observed in changes in energy use. For example, if the coefficient on the SAE term is 0.8, this means that the customers are, on average, realizing 80% of the savings from their engineering estimates.

Stipulated Values. A specified and *agreed-upon* value to be used in energy and/or demand savings calculations. The basis and process for developing this value should be recorded along with the values so that when/if better information or data becomes available, a revision of the values can be considered—usually used in the context of "measurement" versus "stipulated" values and considering the required rigor/accuracy/certainty required for a specific parameter and the resulting savings estimate.

Technical Degradation Factor. A multiplier used to account for the time-and-use-related change in the energy savings of a high-efficiency measure or practice relative to a standard-efficiency measure or practice due to the technical operational characteristics of the measures, including operating conditions and product design.

TRM Climate Zone/Region. TMY3 weather data is used to produce normalized deemed savings estimates for weather-sensitive measures. Rather than using a multitude of weather stations, only five weather stations are used to represent the region served by the EUMMOT utilities. The five climate zone/regions and their representative cities are:

- TRM Climate Zone 1 (Panhandle Region): Amarillo International AP [Canyon - UT]
- TRM Climate Zone 2 (North Region): Dallas-Fort Worth Intl AP
- TRM Climate Zone 3 (South Region): Houston Bush Intercontinental
- TRM Climate Zone 4 (Valley Region): Corpus Christi International AP
- TRM Climate Zone 5 (West Region): El Paso International AP [UT]

TRM climate zone/region mapping is done at the county level.

Uncertainty. The range or interval of doubt surrounding a measured or calculated value within which the true value is expected to fall within some degree of confidence.

Upstream Program. A program that provides information and/or financial assistance to entities in the delivery chain of high-efficiency products at the retail, wholesale, or manufacturing level. Such a program is intended to yield lower retail prices for the products.

Utility Program Tracking Data. The data sources in which utility energy efficiency measure savings and associated project information is stored. Tracking data is used for the EM&V process. Often shortened to “program tracking data” or just “tracking data.”

Weather-Sensitive Measures. Any measure whose performance, energy use, and demand are influenced by the weather. HVAC (direct and indirect like building shell measures) and water heating measures are the most obvious example.

Whole-Building Calibrated Simulation Approach. A savings measurement approach (defined in IPMVP Option D and ASHRAE Guideline 14) involves the use of an approved computer simulation program to develop a physical model of the building to determine energy and demand savings. The simulation program is used to model the energy used by the facility before and after the retrofit. The pre- or post-retrofit models are calibrated with measured energy use and demand data as well as weather data.

Whole-Building Metered Approach. A savings measurement approach (defined in the IPMVP option C and ASHRAE Guideline 14) that determines energy and demand savings through the use of whole-facility energy (end-use) data, which may be measured by utility meters or data loggers. This approach may involve the use of monthly utility billing data or data gathered more frequently from the main meter.